Magellan Pipeline Company

Final Report No. 20-022

2018 Operational Reliability Assessment of the Longhorn Pipeline System

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March 25, 2020

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on

2018 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

March 25, 2020

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EXECUTIVE SUMMARY

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2018 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 Texon to Barnhart 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 2018 maintenance reports were reviewed and correlated to in-line inspection (ILI) assessments from 2017 and 2018 to validate the ILI specified tool performance using the supplied background information and the API 1163 ILI validation methodology. Twenty-three of the maintenance reports included ILI anomaly investigations. The ILI anomaly investigations found correlating features on all 23 digs. ILI metal loss anomalies reported on the Crane to El Paso pipeline segments were all found as metal loss in-ditch.

The corrosion management data have been reviewed including internal corrosion coupon data, rectifier inspections, test point surveys, close interval surveys (CIS), atmospheric inspections, and tank inspection reports. Internal corrosion coupons for both the refined and crude lines continue to show low corrosion rates; less than 0.37 mpy. Atmospheric inspection and tank inspection reports indicate no immediate action is required. Monitoring should continue to identify future potential changes.

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 2018. The 1,843 ID reductions identified from the 2018 electronic geometry pig (EGP) assessments were compared to the existing laminations reported by the 2009/2010 UT assessments. Fourteen dents and 95 geometric anomalies (GMA) were found to either correlate or be present on the same joint as a lamination reported from the 2009/2010 UT assessments; six of the correlations have been previously repaired. Based on the 2018 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 ground movement on five of the seven faults (Akron, Melde, McCarty, Negyev, and Oates) continues to be small and not to be a significant threat to the pipeline at this time. However, since 2016, the rate of ground movement at the Akron fault has become noticeable and requires close monitoring. Of the two other fault lines (Hockley and Breen), ground movement needs to be monitored. The latter fault crossing, Breen, shows little annual displacement but the three-year average rate of displacement is cause for concern. If this rate of movement continued, the pipe at the Breen crossing will reach its allowable limit in 2020[1]. Kiefner recommends exploring the option of strain-gauging the pipelines in critical locations[2] and/or increasing the frequency of movement measurements along with utilizing finite element analysis for a more robust predictive capability of if/when/where pipe movements become critical.

The last recorded waterway inspections at five river crossings (the Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River) are from September 2017. 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 ft. Close monitoring for the latter is recommended as there appear to be fluctuations around a fairly shallow cover. The James River and Llano River waterways were inspected in 2018. Inspections indicate low depth of cover (1.5ft) at the Llano River crossing and exposed pipeline at the James River crossing. No remediation or mitigation have been reported for the latter.

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 severe rainfall and flooding in September, October, and November of 2018.

Magellan performs incident investigations on all events including near misses. During 2018, there were five minor incidents, two near-misses, and one major incident. The major incident was an accidental release of 282 bbls of crude oil from the Eckert Valve Station due to operator

[1] i.e. the displacement which results in induced stress of 90% SMYS.
[2] There are limitations to this when pipelines are buried or hard to reach.

error during maintenance activities. Corrective actions were implemented in accordance with Magellan's incident investigation report which was provided to PHMSA.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. Magellan should continue 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 2018 facilities data indicate 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 5-year intervals to evaluate and control potential hazards associated with the operation and maintenance of the facilities. Two PHAs were completed in 2018, one for the Crane Crude Facility and the other for the El Paso Terminal Holly Receipt and Storage Tank Project.

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 that 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, a new / enhanced damage prevention program was implemented, and ROW markers and signs were repaired or replaced where necessary.

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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
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
bbl	barrels
BHGE	Baker Hughes, a GE Company
bpd	barrels per day
bph	barrels per hour
CFR	Code of Federal Regulations
CGR	Corrosion growth rate
CIS	Close interval survey
CMP	Corrosion Management Plan
CMS	Content Management System
CP	Cathodic Protection – A method of protection against galvanic corrosion of a buried or submerged pipeline through the application of protective electric currents.
Def	Deformation
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 • Environmental Impact Statement (EIS)
EFW	Electric-flash weld is a type of EW using electric-induction to generate weld heat.
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
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.
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.
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
FEA	Finite element analysis
GMA	Geometric Anomaly – An ID Reduction less than 2% of pipe diameter
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)

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

ID Inside nominal diameter of line pipe

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 a part of the currently active Longhorn Pipeline, and the actual junction is at MP 9 (2 miles from the J-1 Valve).

Jct Junction

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.
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
mil	One thousandth of an inch (0.001 in)
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.
ML	Metal loss
MOCR	Management of Change Recommendation
MOP	Maximum Operating Pressure

MP	Mile Post
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 are 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. 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.
PMI	Positive Material Identification
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.
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 than the system operating pressure or surge pressure. The POE for each pipe joint is POE joint.
POF	Probability of Failure
RBDA	Reliability-based design analysis
Recommendation	Suggestion for activities or changes in procedures that are intended to enhance integrity management systems, but are not specifically mandated in the LMP

Repair	The LMP describes a repair as a temporary or permanent alteration made to the pipeline or its affiliated components that are intended to restore the allowable operating pressure capability or to correct a deficiency or possible breach in mechanical integrity of the asset.
Requirement	Activities that must be performed to comply with the LMP commitments
Risk	A measure of loss measured in terms of both the incident likelihood of occurrence and the magnitude of the consequences
Risk Assessment	A systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives.
Root Cause Analysis (RCA)	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.
SBRMA	Scenario-Based Risk Mitigation Analysis
SCC	Stress-Corrosion Cracking – A form of environmental attack on 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[3])
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
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

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

Tier I Areas	Areas of normal cross-country pipeline
Tier II Areas	Areas designated in the EA as environmentally sensitive due to population or environmental factors
Tier III Areas	Areas designated as in the EA as environmentally hypersensitive due to the presence of high population or other environmentally sensitive areas
TFI	Transverse Field Inspection – An MFL Inspection tool with the field oriented in the circumferential direction. The tool differs from conventional MFL because these conventional tools have their field oriented in the axial direction or along the axis of the pipe.
TPD	Third-party damage – 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.
UltraScan™ CD	BHGE's ultrasonic crack detection in-line inspection tool.
UT	Ultrasonic testing – A nondestructive 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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1 INTRODUCTION

1.1 Objective

The annual Operational Reliability Assessment (ORA) report on the Longhorn Pipeline System for the 2018 operating year has been conducted by Kiefner and Associates, Inc. (Kiefner). The ORA report 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 Longhorn pipeline system has been operated by Magellan since 2005 and under Magellan's ownership since 2009. 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. The EA took place prior to the then newly configured pipeline refined product service. The EA "Finding of No Significant Impact" was conditioned upon Longhorn's commitment to implement certain integrity-related activities and plans prior to pipeline start-up and periodically throughout the operation of the system. Longhorn's commitment to minimize the likelihood and consequences of product releases was specified in the Longhorn Mitigation Plan (LMP). These commitments 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.

The LMP committed Longhorn to retaining an independent third-party technical company to perform the annual 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. The ORAPM identifies the list of data needed to conduct the ORA; Appendix B – New Data Used in this Analysis provides the data used for the 2018 ORA Report. 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)[4]
7. Threats to Facilities Other than Line Pipe

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, listed below, 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. A diagram of the functions and relative interactions of the LPSIP and the ORA is provided in Figure 1.

1. Corrosion Management Plan
2. In-Line Inspection (ILI) and Rehabilitation Program
3. Key Risk Area Identification and Assessment
4. Damage Prevention Program
5. Encroachment Procedures

[4]SCC has not been identified as a threat of concern to the Longhorn Pipeline and has not been recognized as a threat in the past, but was added as SCC has been an unexpected problem for some pipelines.

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

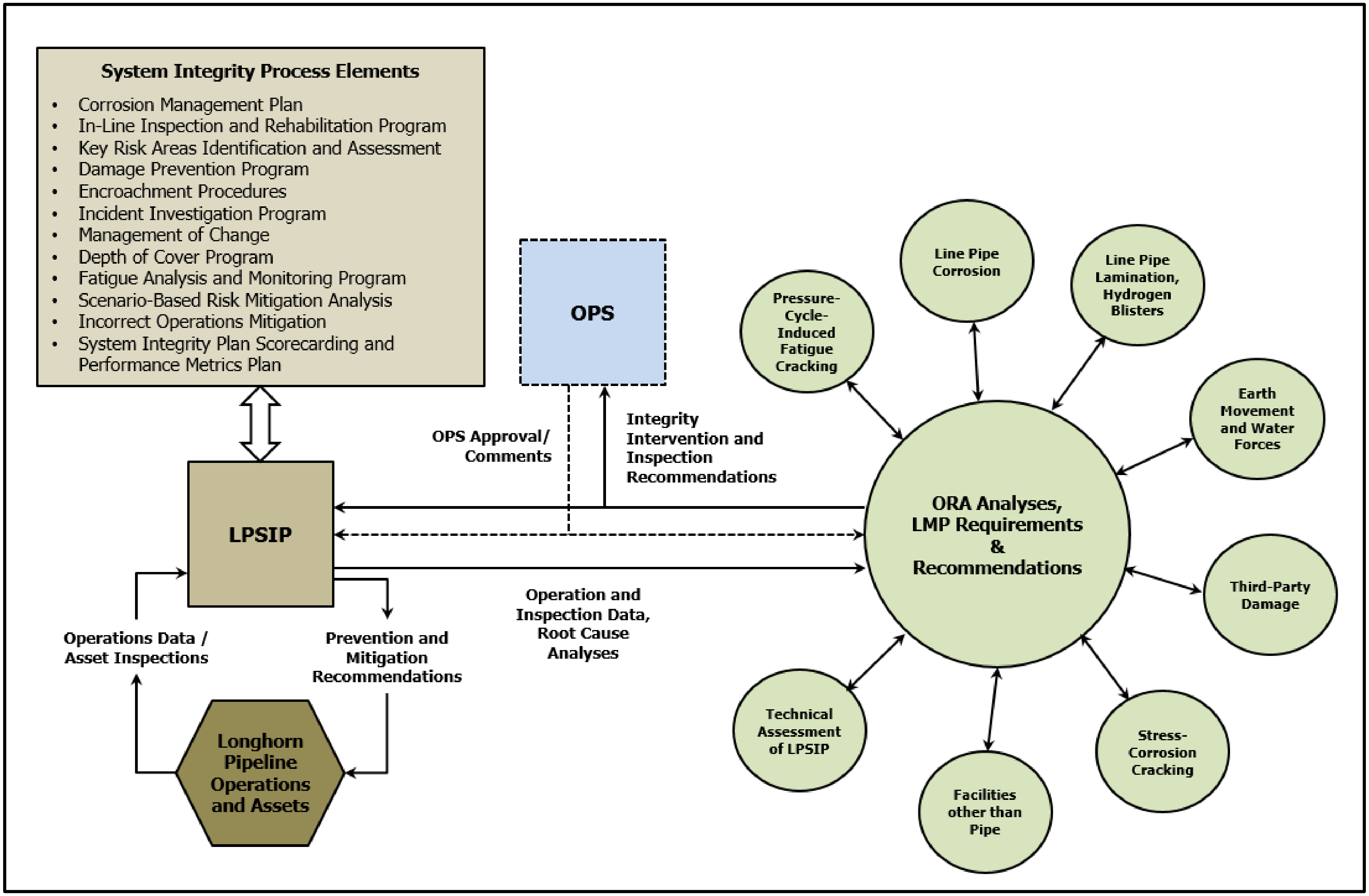

Figure 1. ORA Functions and Interaction with the LPSIP

1.4 Longhorn Pipeline System Description

The Longhorn pipeline system is comprised of a crude oil system (Eastern portion) and a refined products system (Western portion). Figure 2 shows the Longhorn System Map. Tier Levels are shown in Figure 3. A close-up of the Houston area is shown in Figure 4.

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, 237-miles of 18-inch pipe from Crane Station to the El Paso Terminal, 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. A timeline showing the history of the Longhorn Pipeline System is shown in Figure 5.

The Eastern portion of the Longhorn system transports crude oil over 424 miles through an 18-inch pipeline from Crane Station to Satsuma Station. Intermediate pumping stations are located 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 9 miles of 20-inch pipe from the 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	Tier	MOP (psig)
Crane	Pump	457.5	II	1034
Texon	Pump	416.6	II	898
Barnhart	Pump	373.4	II	898
Cartman	Pump	344.3	II	952
Kimble County	Pump	295.2	II	898
James River	Pump	260.2	I	965
Eckert	Pump	227.9	I	959
Cedar Valley	Pump	181.6	II	965
Bastrop	Pump	141.8	I	965
Warda	Pump	112.9	I	981
Buckhorn	Pump	68.0	I	965
Satsuma	Pump	34.1	III	787
E. Houston	Terminal	2.35	II	786

Table 2. Refined Product Pipeline Station Locations

Station	Type	Milepost	Tier	MOP (psig)
Odessa[5]	Meter	NA	I	1440
Crane	Pump	457.5	I	1440
Cottonwood	Valve	576.3	I	1440
El Paso	Terminal	694.4	I	1440

The current flow rate for the crude system is 292,000 barrels per day (bpd) from Crane to East Houston. The flow rate for the refined product system is 50,400 bpd from Odessa to El Paso. There were no operational changes to the Longhorn Pipeline System during 2018.

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

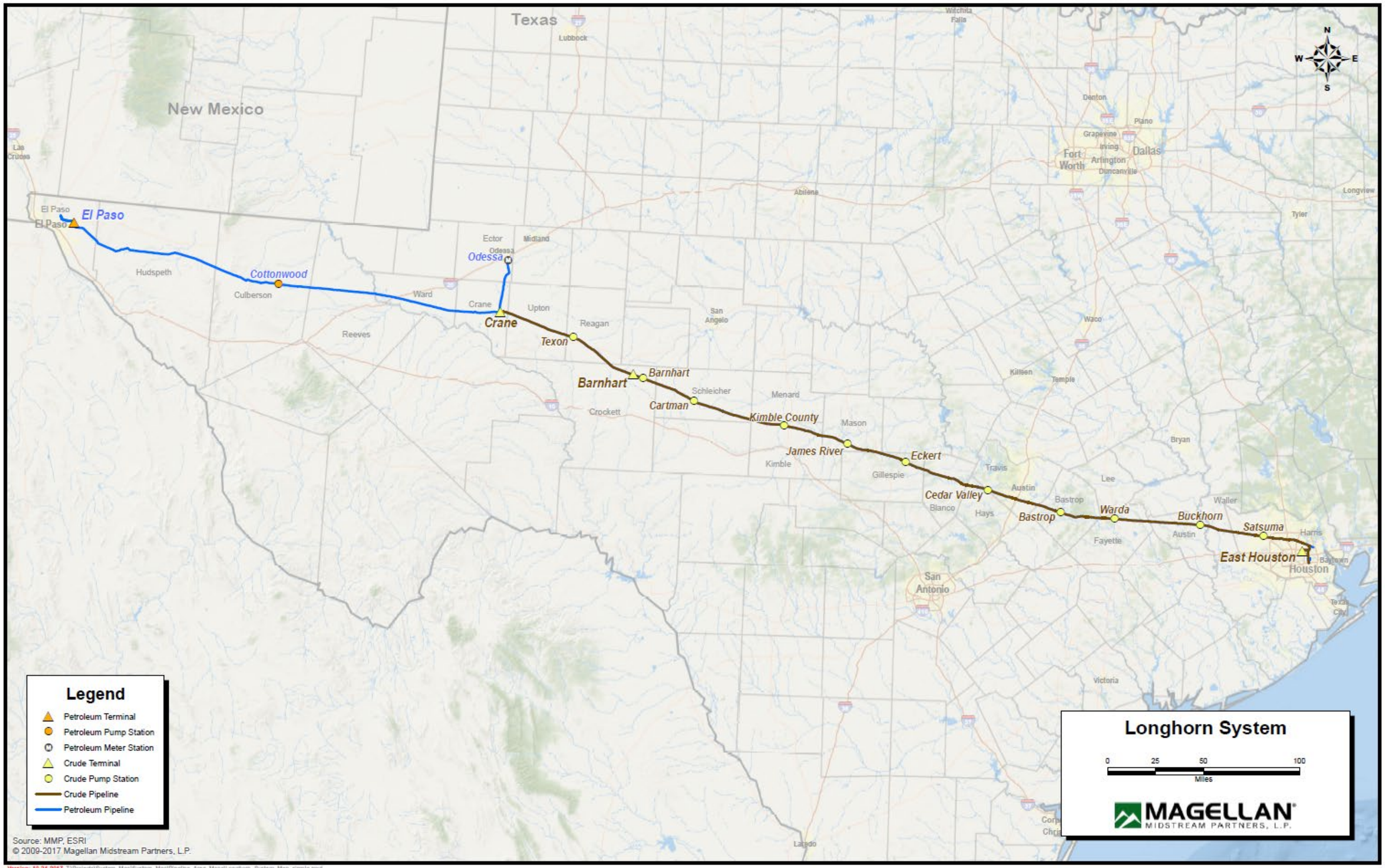

Figure 2. Longhorn System Map (2018)

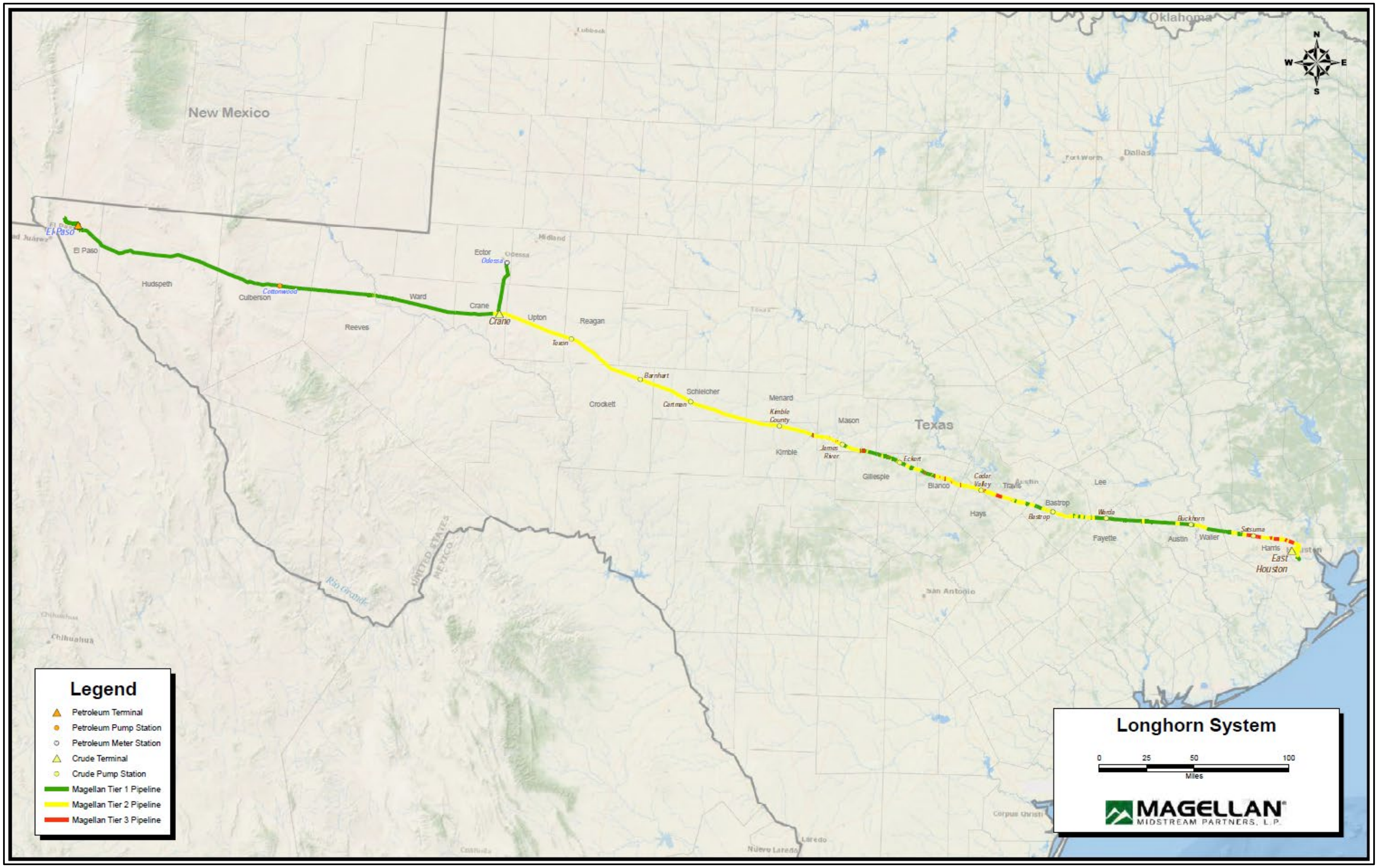

Figure 3. Longhorn System Map showing Tier Levels (2018)

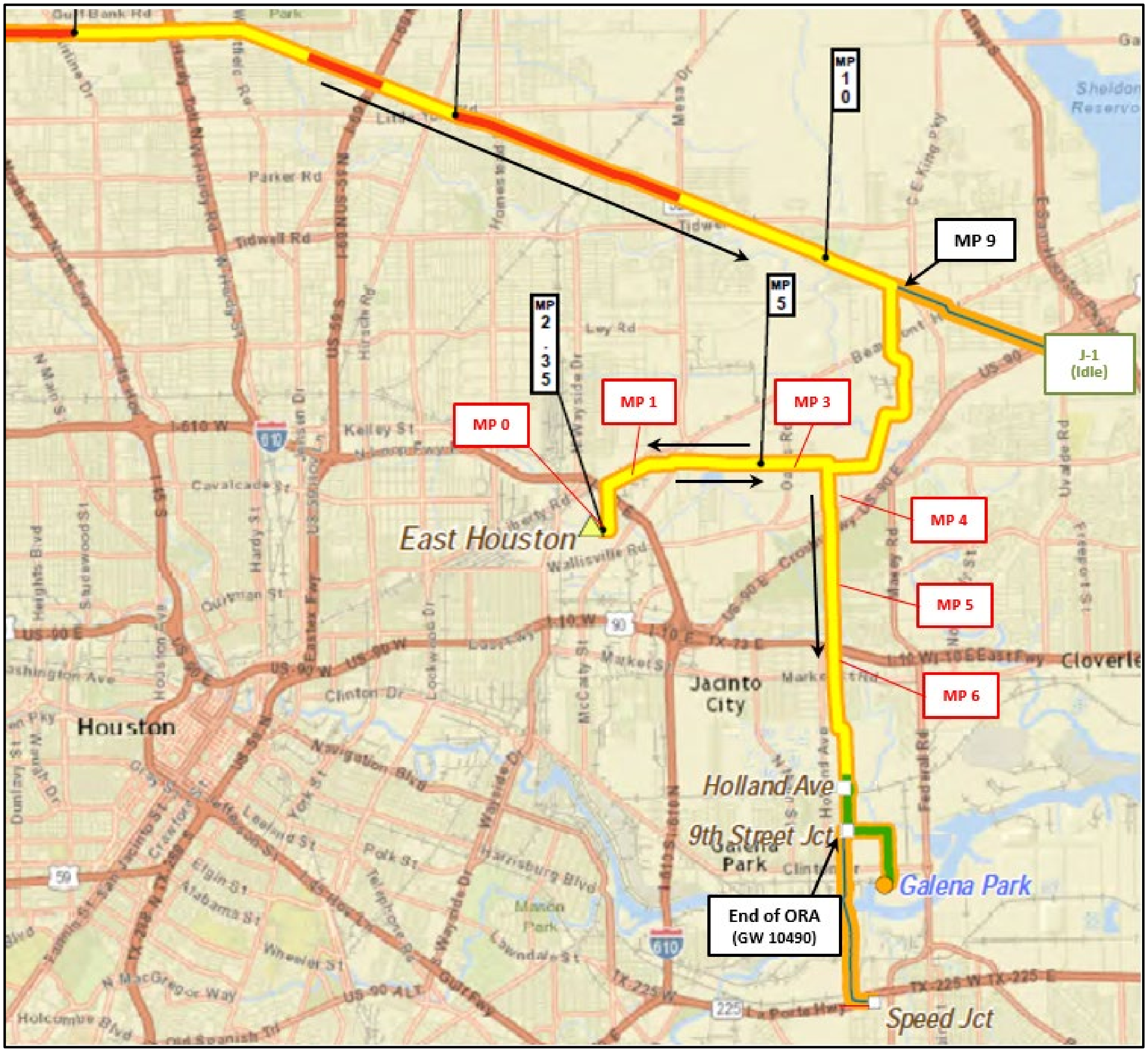

Figure 4. Map of Longhorn System within Houston Area (2018)

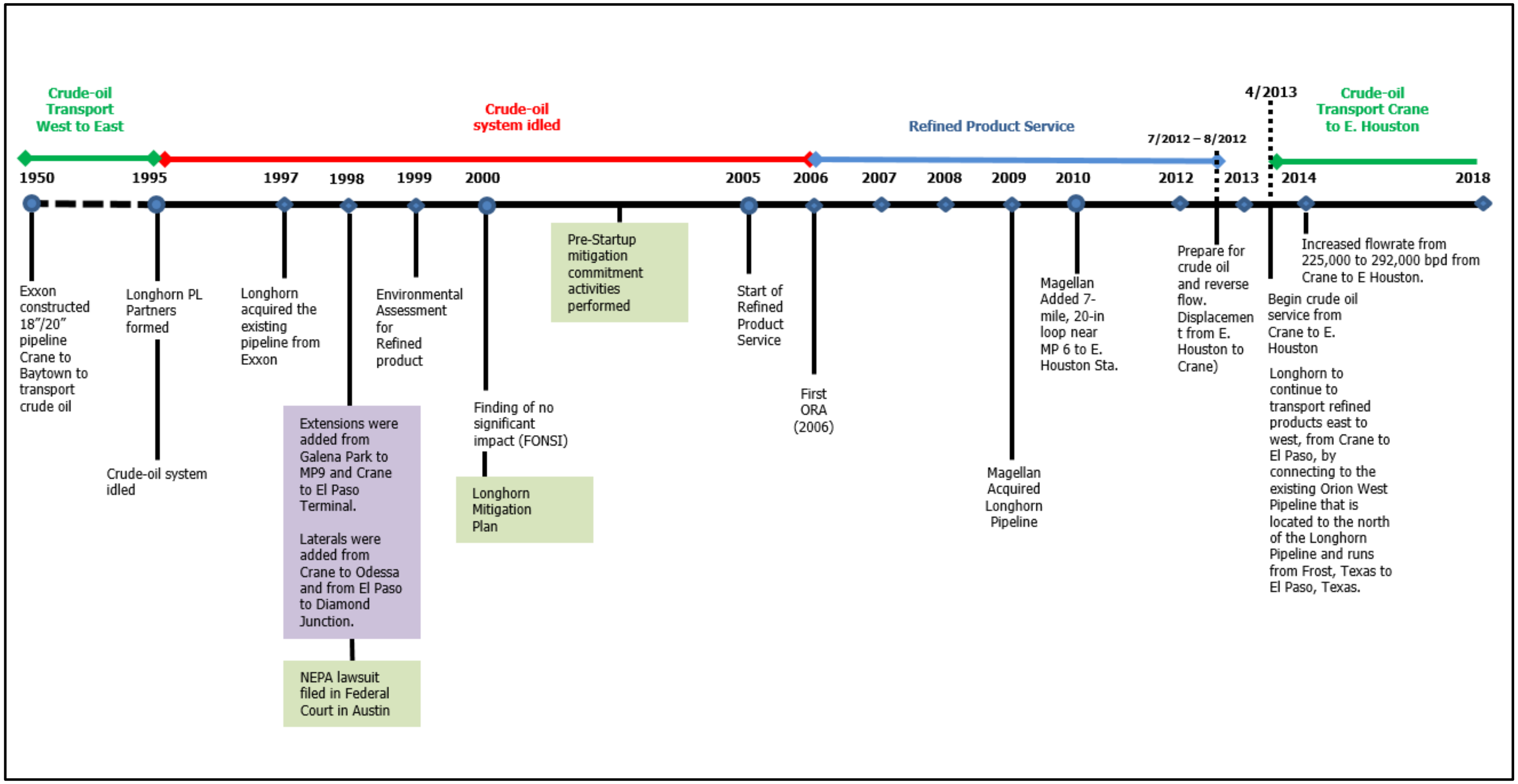

Figure 5. Timeline of the Longhorn Pipeline System

2 ORA ANALYSES AND LONGHORN MITIGATION PLAN REQUIREMENTS

The LMP monitors the following threats for the ongoing integrity of the Longhorn pipeline: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, earth movement, TPD, SCC, and threats to facilities other than line pipe. In 2018, one ILI assessment was performed on the Longhorn crude line from Crane to Texon using Baker Hughes, a GE Company (BHGE) MagneScan tool. Three ILI assessments were performed on the Longhorn refined line; Crane to Cottonwood to El Paso and El Paso to Strauss using T.D. Williamson's (TDW) MFL tool. Electronic geometry pig (EGP) assessments were run on nine segments of the Longhorn crude system in the first quarter of 2018 between the Crane (MP 457.5) and Warda (MP 112.9) pump stations. Three EGP assessments were performed on the Longhorn refined system. The EGP assessments were performed using TDW's Deformation tool. Refer to Table 3 (crude system) and Table 4 (refined system) for a list of assessments performed in 2018 by pipeline segment.

Table 3. Longhorn Crude System ILI Assessments

Bastrop to Warda	**Cedar Valley to Bastrop**	**Eckert to Cedar Valley**	**James River to Eckert**	**Kimble County to James River**	**Cartman to Kimble County**	**Barnhart to Cartman**	**Texon to Barnhart**	**Crane to Texon**	
141.8 to 112.9	**181.6 to 141.8**	**227.9 to 181.6**	**260.2 to 227.9**	**295.2 to 260.2**	**344.3 to 295.2**	**373.4 to 344.3**	**416.6 to 373.4**	**457.5 to 416.6**	
Corrosion									
									MFL*
									10/16/18
Pressure Cycle Induced Fatigue									
								UCD*	
								10/19/18	
Third-Party Damage									
Def	Def	Def	Def	Def	Def	Def	Def	Deformation	
1/4/18	1/3/18	3/7/18	3/6/18	2/27/18	2/22/18	2/20/18	2/16/18	2/13/18	

*The final reports for the UCD and MFL assessment performed on Crane to Texon were received in 2019; analysis will be included in the 2019 ORA report.

Table 4. Longhorn Refined System ILI Assessments

Crane to Cottonwood	Cottonwood to El Paso	El Paso to Strauss
457.5 to 576.3	**576.3 to 694.4**	**0.0 to 9.4**
Corrosion		
MFL	MFL*	MFL**
4/18/18	11/1/17	10/25/2018
Third-Party Damage		
Deformation	Deformation*	Deformation**
4/18/18	11/1/17	10/25/2018

*The final report for the Cottonwood to El Paso ILI assessment was received in 2018.
**The final report for the ILI assessment was received in 2019; analysis will be included in the 2019 ORA Report.

2.1 Pressure-Cycle-Induced Fatigue

The Eastern section of the Longhorn pipeline system that carries crude oil from Crane Station to Satsuma Station was internally inspected by General Electric (GE) in 2015 using a Transverse field magnetic flux inspection (TFI) tool to detect and size narrow axial indications such as linear indications in the longitudinal seam of ERW and FW pipe. The segment from Satsuma to Speed Junction was inspected by TDW in 2014 using their spiral magnetic flux leakage (SMFL) technology to detect and size longitudinal seam flaws. Linear indications could potentially enlarge in service due to pressure-cycle induced fatigue if subjected to pressure cycling loads sufficient to cause crack growth. Longitudinal seam flaws are more prevalent in pipes manufactured using older welding technology such as low frequency electrical resistance weld (LF-ERW) and flash welded (FW) pipe. Also, pipe seams in vintage pipes manufactured prior to 1970 typically exhibit low toughness compared to pipes produced using modern welding technology. As a result, manufacturing flaws in or 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 could 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 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 reach a critical size.

Although the likelihood of such flaws being present in the newer pipe material (1998, 2010, 2012 and 2013) is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses were considered for the New Pipeline as well as for the Existing Pipeline. The potential effects of pressure-cycle-induced fatigue are calculated for the

Existing Pipeline on the basis of the results of the TFI and SMFL tool runs from Crane to 9th Street junction[6] 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: 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]). 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 significantly if a Charpy value of 15 ft-lbs is assumed compared to using 25 ft-lbs. 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.

The fatigue assessment methodology involved:

- Operating pressure data processing using Rainflow cycle counting;
- Segmentation of the pipeline to account for pipe properties and attribute changes including outside diameter, grade, wall thickness and elevation changes.
- Establishment of initial crack sizes from the ILI-indicated dimensions and the detection threshold from the ILI vendor performance specification.
- Determination of the final sizes of flaws at failure or critical size (predicted burst pressure equal to the MOP of the pipeline segments adjusted for elevation at the location of the segment analyzed).

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[6] 9th Street junction is approximately 2.50 miles upstream of Speed Junction. The segment considered in the 2018 ORA terminates at girth weld 10490 in 2014 SMFL inline inspection assessment.
[7] API Specification 5L, 45th Edition, Includes Errata, 2015

- Fatigue crack growth assessment using fracture mechanics principles.
- Estimate time taken for both ILI-indicated and hypothetical threshold anomalies to grow to critical size.

2.1.1 Pressure Cycle Processing

Magellan supplied one-year of operational pressure data for the crude oil pipeline system from Crane Station through Satsuma Station, receipt point at East Houston Terminal, discharge point at the East Houston Station and receipt point at Speed Jct. The pressure readings were recorded from January 1, 2018 to December 31, 2018 at 1-minute intervals. The pressure data used in the analysis were recorded at the discharge, suction and receipt point of these stations and facilities.

Rainflow counting was used to prepare the pressure data for analysis. The pressure spectrum based on pressure records for each pump station was rainflow cycle-counted to reduce the stochastic signal into cycles that can be used in the fatigue model. The basic concept of the rainflow counting method is to determine the peaks and valleys of the randomly-varying pressure data and to eliminate the intermediate pressures that are between the peaks and valleys (smaller peaks and valleys are also recognized by the process). The cycle-counting analysis produces count and sequence of cycles of various amplitudes which are then used with crack-growth calculation schemes. Kiefner's rainflow cycle counting process complies with ASTM E-1049 guidelines for rainflow counting methods.[8]

2.1.2 Pipeline Segmentation for Threshold Anomaly Evaluation

The fatigue assessment was conducted for 124 points along the length of the crude oil portion of the pipeline. Each of these points corresponds to a pipe property change including OD, grade, wall thickness, elevation, proximity to pump station discharge, and date of installation.

Due to the density of liquid products, elevation changes impact the internal pressure loading of the pipe due to hydrostatic head losses and gains. Data for the intermediate locations between the pressure measurement locations were simulated based on elevation changes and the hydraulic pressure gradient.

Locations near a pump discharge typically tend to experience more aggressive pressure cycles than locations away from the pump discharge. For the purpose of the current analysis, where pipe with similar attributes (grade, wall thickness, and other attributes) were present in a given Discharge-Suction/receipt segment, the pipe closest to the upstream pump station was used in the analysis. It is not necessary to calculate a fatigue life at all the points where the susceptible

[8] ASTM, "Standard Practices for Cycle Counting in Fatigue Analysis", E 1049, Annual Book of Standards, 2002.

pipe exists because pipe further downstream will have a longer fatigue life based on the hydraulic gradient and need not be evaluated as long as its difference in elevation, relative to upstream locations, is not significant. A complete summary of the pipe segments evaluated as part of this study is presented in Appendix E – Pipeline Segments used for Threshold Anomaly Evaluation. The case locations were chosen with reference to the operating direction and pump locations as of 2019. The analysis was performed using pressure data collected since the most recent TFI or SMFL inspections (2014 and 2015) to December 2018.

The pipe segmentation also accounted for the age of the pipe as it relates to determining the initial flaw sizes. The line pipe that is expected to be the most susceptible to longitudinal seam fatigue-crack-growth is the 1947 to 1953 pipe material. Pursuant to the procedure in Section 3.4 of the ORAPM, 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% WT for features between one and two inches in length and a minimum depth of 25% WT 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.

A slightly different procedure is applied to the calculation of time to failure for the new pipe installed from 1995 through 2013. Instead of using the sizes of flaws detected by the TFI tool, the starting flaw size was based on the largest flaw that could have escaped detection by the manufacturer's ultrasonic seam inspection. That would be the size of the "calibration" flaw used to test the ultrasonic seam inspection detection threshold. The calibration flaw size comes from API Specification 5L and 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.

2.1.3 Fatigue Crack Growth Assessment

To conduct a pressure-cycle analysis for the Longhorn Pipeline, the well-known and widely accepted "Paris Law" model was used. The crack-growth calculations were performed using

Kiefner's Pipelife software.[9] Pipelife uses the Paris Law[10] equation, $da/dN=C(\Delta K)^n$, to estimate the incremental crack growth for a given feature in response to the pressure cycles counted from the rainflow method; where da/dN is the increment of crack growth per load cycle, ΔK is the range of cyclic stress-intensity at the crack-tip, and C and n are material crack-growth parameters. The cyclic stress intensity factor was determined using the Newman-Raju equation.[11] Details of these equations are available in the Mock ORA (Reference [2]). The pressure cycles were applied and crack growth was calculated until failure was predicted at the MOP at the feature location. The cumulative number of pressure cycles at failure was then converted to a time to failure in years based on the interval over which the pressure data were collected. The fatigue life is the time in years for the defect to grow from the initial crack size to the final critical size. 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) as specified in the ORAPM.

The material-parameter constants used in the Paris equation affect the amount of crack growth that is calculated in response to a given pressure cycle. The constants are commonly referred to as the "crack-growth rate" (CGR) parameters. These parameters 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 that are published in the Fitness-For-Service API Standard 579-1/ASME FFS-1[12] were used.

The time to failure and reassessment intervals estimated by Kiefner can be used by Magellan to reassess the integrity of the pipeline as required and in accordance with the LMP.

2.1.4 Fatigue Assessment Results

Table 5 shows the segments with a predicted reassessment interval less than 10 years for flaws potentially present in the pipeline at the detection threshold of the 2014 and 2015 ILI tool but missed by those ILIs. For the threat of pressure-cycle-induced fatigue, the reassessment intervals were calculated as the shortest time to failure based on the pressure cycles since the most recent TFI tool run for each segment. The reassessment interval is based on the remediation of all cracks detectable by the TFI, a high probability of detection for TFI finding all

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[9] Kiefner, J. F., Kolovich, C. E., Wahjudi, T. F., and Zelenak, P. A., *"Estimating Fatigue Life For Pipeline Integrity Management"*, Paper Number IPC04-0167, Proceedings of IPC 2004, International Pipeline Conference, Calgary, Alberta, Canada (October 4 - 8, 2004).

[10] Paris, P. C. and Erdogan, F., *"A Critical Analysis of Crack Propagation Laws"*, Transactions of the ASME, Journal of Basic Engineering, Series D, Vol. 85, No. 5, pp 405-09.

[11] Newman, J.C. and Raju, I.S., "An Empirical Stress-Intensity Factor Equation for the Surface Crack", Engineering Fracture Mechanics, Vol 15, No 1-2, pp. 185-192, 1981.

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

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.

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 16.37 years (from August 11, 2015) on the Texon to Barnhart segment. The shortest time to failure occurred on an 18-inch, 0.250 WT, Grade X52 pipe that was installed in 1953 and located at approximately 1.2 miles (~ 6000 feet) from the Texon pump discharge. Applying a factor of safety of 2.22, a reassessment interval of 7.37 years is recommended based on the current operating pressures. This reassessment interval is relative to the latest inspection date of August 11, 2015. The results for the Texon-Barnhart segment of the pipeline remained unchanged compared to the 2017 assessment performed by Kiefner for this segment. This suggests that pressure cycling for this pipeline segment has not changed significantly since the 2017 Kiefner assessment. The remaining life predicted for the Crane to El Paso segment appears to have increased beyond historical estimates. This is likely to be a result of that segment being operated less aggressively than in previous years as the pipe attributes used in the current assessment is the same as those in previous analyses. Table 6 compares the results from the current 2018 fatigue assessment with those from the previous three annual assessments.

The shortest time to failure predicted for the newer installed pipe was 313 years with a reassessment interval of 141 years from the date of the last ILI in 2015. The segment with the newer installed pipe having the shortest predicted time to failure is located on the Crane-Texon segment (pipe installed in 1998). These results suggest that the newer pipe is unlikely to be susceptible to pressure-cycle induced fatigue crack growth if future operation is similar to, or less aggressive, compared to historical operation. The fatigue results for all the pipeline segments analyzed from Crane Station to 9th Street Junction and Crane to El Paso are presented in Appendix F – Fatigue Assessment Results.

Table 5. Predicted Time to Failure Less than 10 Years for a Threshold Anomaly Potentially Missed by ILI

Pipeline Segment	OD, inch	WT, inch	Yield Stress, psi	Defect Location, ft	Elevation, ft	Calc. Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	ILI Date
Texon-Barnhart	18	0.250	52,000	2,199,954	2,675	16.37	7.4	12/25/2022	8/11/2015
Crane-Texon	18	0.250	52,000	2,406,295	2,525	16.73	7.5	01/28/2023	7/17/2015
Cartman-Kimble	18	0.281	45,000	1,816,881	2,445	19.37	8.7	05/20/2024	8/29/2015
Bastrop-Warda	18	0.281	45,000	748,348	395	19.58	8.8	10/06/2024	12/11/2015
James River-Eckert	18	0.281	45,000	1,373,347	1,705	21.33	9.6	03/28/2025	8/19/2015
Cartman-Kimble	18	0.281	65,000	1,817,361	2,445	21.85	9.8	07/02/2025	8/29/2015

Table 6. Comparison of Reassessment Dates from Past ORAs

Segment	2015 Report	2016 Report	2017 Report	2018 Report
East Houston to 9th Street Junction	5/15/2214	8/23/2202	7/11/2174	03/15/2195
Satsuma to East Houston	9/14/2027	11/14/2032	4/1/2035	09/07/2034
Buckhorn to Satsuma	6/15/2028	1/31/2039	3/1/2034	10/17/2034
Warda to Buckhorn	12/27/2020	10/23/2027	11/23/2027	09/19/2030
Bastrop to Warda	6/16/2020	4/7/2025	4/5/2024	10/06/2024
Cedar Valley to Bastrop	3/6/2039	8/13/2046	2/9/2040	03/08/2044
Eckert to Cedar Valley	8/1/2023	9/30/2033	8/9/2034	10/07/2032
James River to Eckert	7/9/2027	11/5/2023	6/27/2025	03/28/2025
Kimble County to James River	9/25/2034	9/11/2027	8/28/2030	09/06/2027
Cartman to Kimble County	11/23/2024	3/29/2022	10/20/2023	05/20/2024
Barnhart to Cartman	12/16/2053	1/17/2040	4/22/2045	12/01/2036
Texon to Barnhart	9/9/2024	7/23/2021	12/11/2022	12/25/2022
Crane to Texon	4/24/2023	4/13/2022	10/14/2027	01/28/2023
Crane to El Paso	11/29/2238	11/29/2238	3/22/2109	01/04/2498

2.2 Corrosion

Current ILI assessments were reviewed with an understanding of the background and approach for API 1163 ILI verification. API 1163 Second Edition, April 2013 describes methods in Section 7 and 8 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. For further background and approach on API 1163 Section Edition, April 2013 refer to Appendix C – Approach to API 1163 Verification.

For each assessment listed in Table 3 and Table 4, process verification and quality control were reviewed. The general results for all of the 2018 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 were determined to be consistent over the entirety of the ILI assessments.

The threat of corrosion can be monitored using ILI assessments, which 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. ILI assessments completed in 2018 are listed in Table 3 for the crude system and Table 4 for the refined system. An overall ILI reassessment schedule can be found in Section 6, Table 40 for the crude system and Table 41 for the refined system. The next crude system assessment for corrosion is in 2019 for the East Houston to Satsuma segment. The next refined system assessment for corrosion is due in 2021 for the 8-inch Crane to Odessa segment.

A run-to-run comparison was performed to determine external and internal corrosion growth rates (CGRs) for the MFL assessments performed or received in 2018. The three segments reviewed are: Crane to Texon, Crane to Cottonwood, and Cottonwood to El Paso. Each segment had a previous MFL assessment; Crane to Texon was performed in 2006, Crane to Cottonwood in 2013, and Cottonwood to El Paso in 2012. The overall matched results from the run-to-run comparison are shown in Table 7. There are no pipe replacements with reported metal loss features between the current and previous assessments. CGRs were calculated for the three segments between Texon to El Paso and are shown in Table 8. There were not enough data pairs to support CGR calculations for external metal loss features on the Cottonwood to El Paso segment and for internal metal loss mill anomalies on the Crane to Cottonwood and Cottonwood to El Paso segments. Data correlation and calculations were done using Kiefner's CorroSure software.

Table 7. Overall Results of the Run-to-Run Comparisons

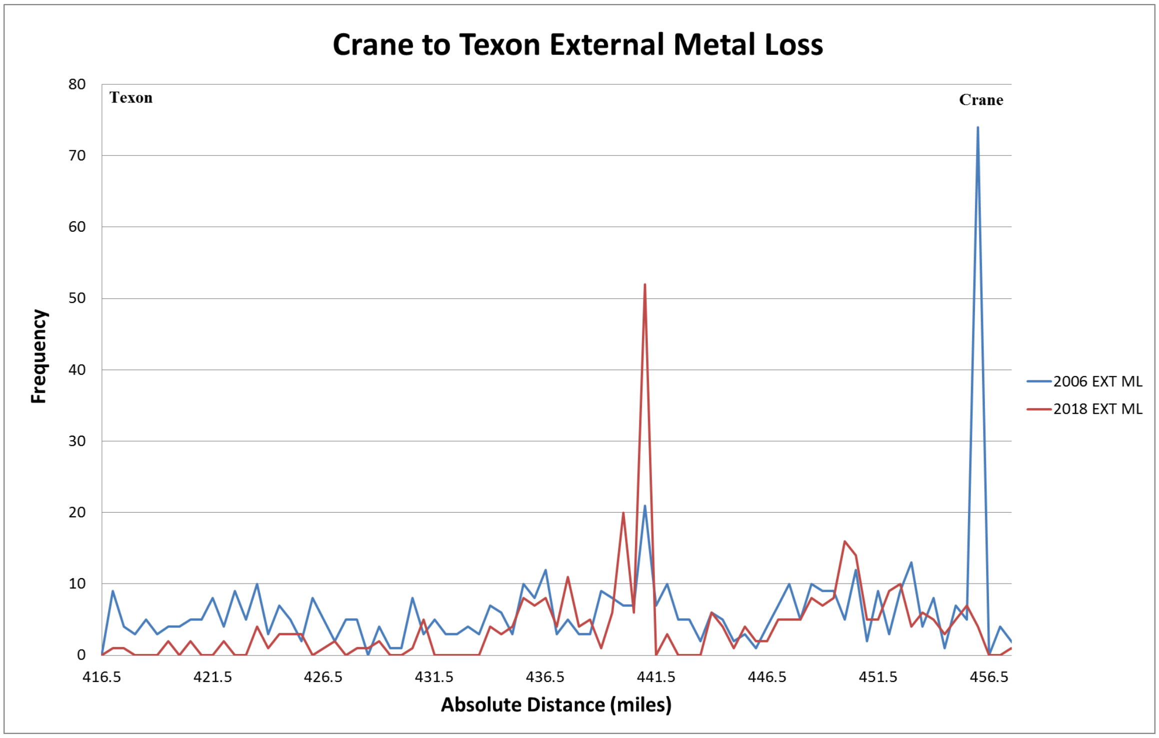
Segment	Matched Features		Total Matched Features	Maximum Available Matches	% Matched Features
	Corrosion	Manufacturing			
Crane to Texon	247	172	419	536	78.2%
Crane to Cottonwood	8887	41	8928	18423	48.5%
Cottonwood to El Paso	2724	N/A	2724	5931	45.9%

Table 8. Corrosion Growth Rate Results for 2018 MFL Assessments

Segment	Upper Bound CGR (mpy)		
	EXT ML	INT ML	INT ML Mill Anomalies
Crane to Texon	3.61	3.37	4.12
Crane to Cottonwood	3.28	2.89	N/A
Cottonwood to El Paso	N/A	4.36	N/A

External corrosion growth along a pipeline should be expected to have the potential for variability along the length of pipeline due to differences in cathodic protection, coating conditions, pipe age, and environment. A histogram of metal loss frequency (occurrences or count) along the linear distance of the pipeline can give indication of where external metal loss features are more likely. A comparison of external metal loss frequency histograms for the 2006 and 2018 MFL assessments can be seen in Figure 6 for the Crane to Texon segment. Figure 7 shows the external metal loss frequency histogram for the 2013 and 2018 MFL assessment for the Crane to Cottonwood segment. No external metal loss features were reported on the 2012/2013 MFL assessment from Cottonwood to El Paso. Internal metal loss frequencies were also reviewed and are shown in Figure 6 through Figure 8.

Figure 8 shows the 2017 ILI assessment as reporting more internal metal loss throughout the assessment as compared with the internal metal loss reported in the 2012 ILI assessment. Figure 6 shows that the external metal loss features are showing a similar trend in reported metal loss along the pipeline. Near MP 456.5 there is an increase in metal loss feature count compared to the rest of the line segment. As shown in Figure 6, the metal loss is reported as external based on the 2006 MFL data while the 2018 MFL data indicates the metal loss as internal; indicating there is an internal/external feature call discrepancy between assessments. Figure 7 shows higher external metal loss feature counts in the 2013 assessment between MP 497.5 and 527.5 compared to the 2018 assessment; the run-to-run comparison indicated some internal/external feature call discrepancy in this area. All three figures (Figure 6 through Figure 8) are showing areas where the 2018 MFL data has reported an increase in metal loss features over the previous assessment. The increase in metal loss features appears to be occurring in the low level feature counts (ML ≤20% WT).



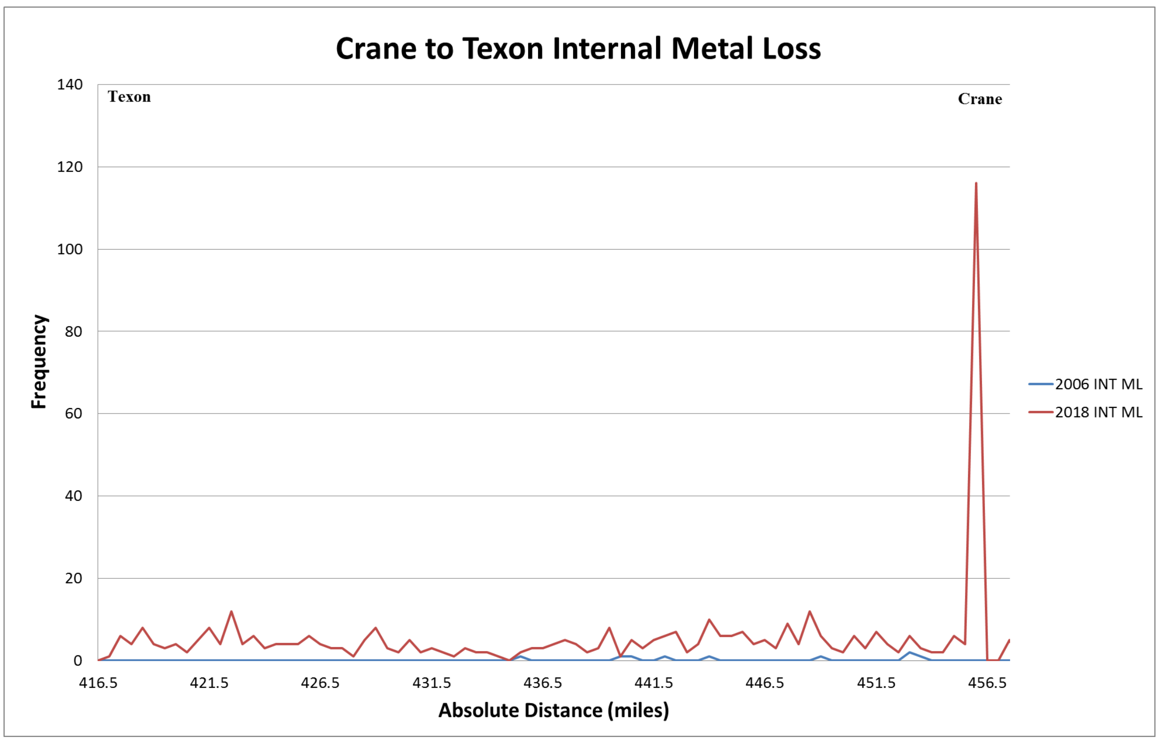


Figure 6. Crane to Texon Metal Loss Frequency by Linear Distance along the Pipeline (2006 MFL vs 2018 MFL)

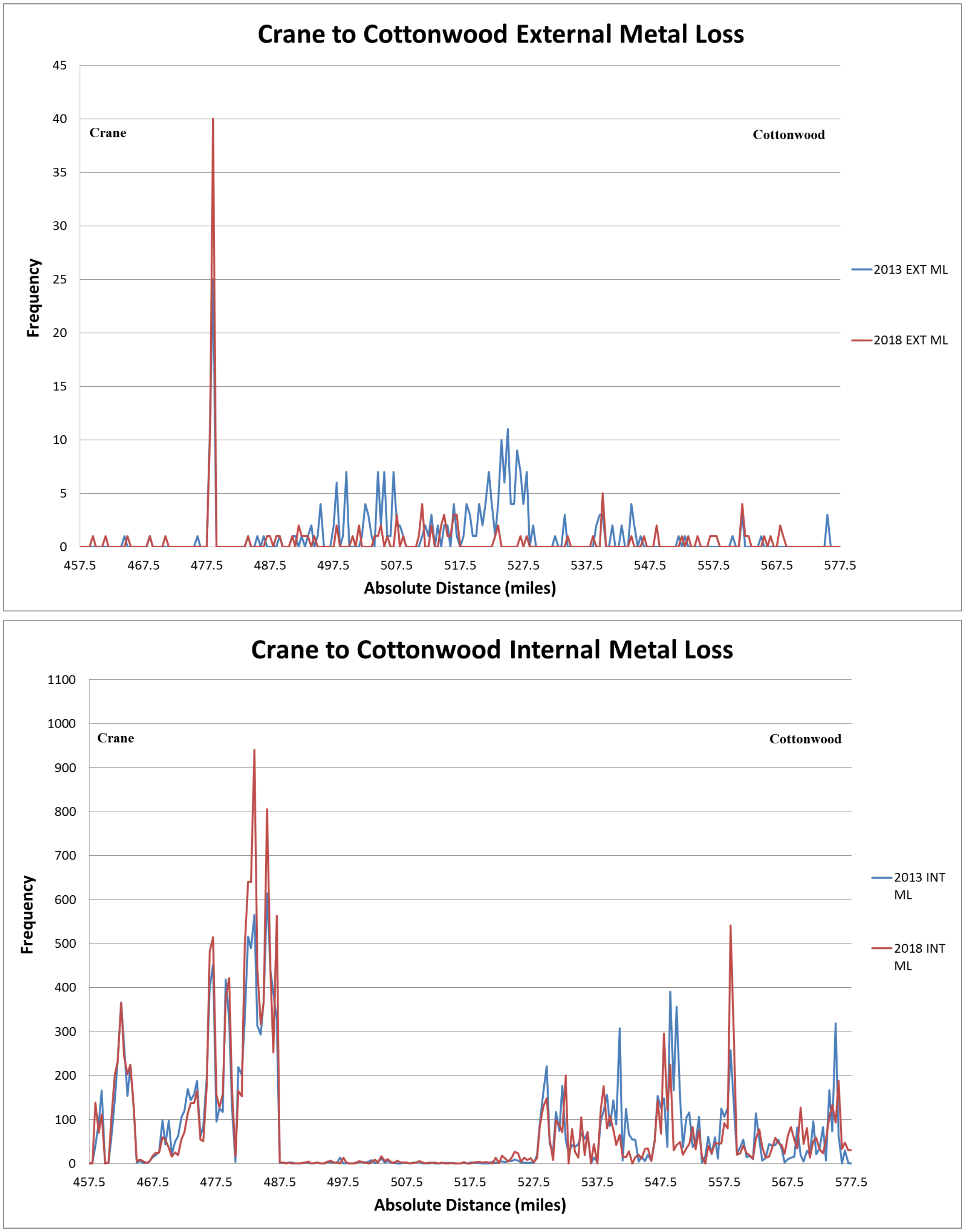


Figure 7. Crane to Cottonwood Metal Loss Frequency by Linear Distance along the Pipeline (2013 MFL to 2018 MFL)

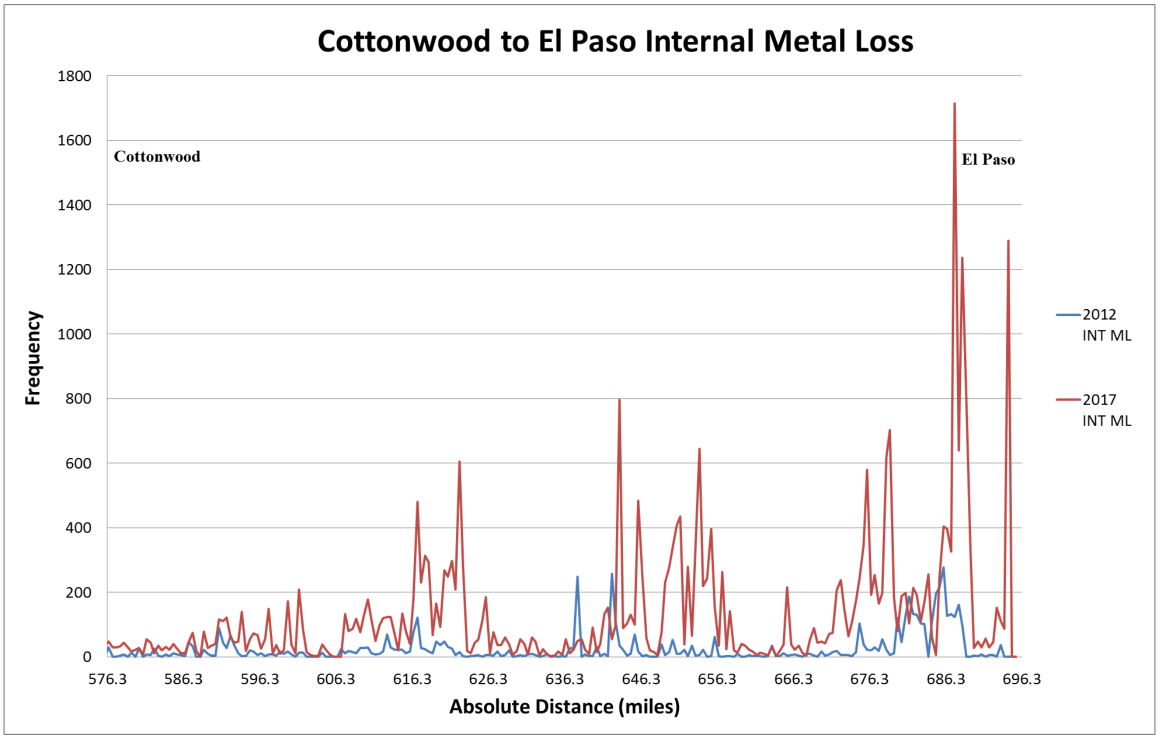


Figure 8. Cottonwood to El Paso Metal Loss Frequency by Linear Distance along the Pipeline (2012 MFL to 2017 MFL)

2.2.1 Maintenance Reports and In-Ditch Evaluations

In 2018, Magellan performed 23 in-ditch assessments; 19 of the assessments were ILI anomaly investigations which correspond to current ILI assessments (2017 and 2018 MFL). Anomaly investigations also included nondestructive evaluation (NDE) reports with detailed investigation results. Seventy-nine maintenance reports and four positive material identification (PMI) reports were received for 2018; Table 9 provides a breakdown of the assessment types addressed in the maintenance reports. Table 10 provides a breakdown, per pipeline segment, of where the maintenance occurred (HCA, segment, and tier). The total number of ILI anomalies addressed, per pipeline segment in 2018, is listed in Table 11; the total number includes the targeted ILI anomalies and any anomaly found in the area of repair for that associated dig.

Magellan requires PMI[13] tests to be completed at 50% of the ILI anomaly investigation locations that do not have material documentation. In 2018; seven of the 23 ILI anomaly investigation locations met the PMI requirement, Magellan performed PMI testing at four of the seven anomaly investigation locations (57%) which satisfies PMI requirements. Table 12 details, per pipeline segment, the quantity of ILI anomaly investigation digs performed in 2018 and the number of ILI investigation digs that met PMI dig requirements. Table 13 gives an overview of PMI testing since the requirement to perform PMI testing was added in the 2014 ORA.

Table 9. Maintenance Report Items

Maintenance Report Items	Number
Anomaly Investigation	23
Investigate Exposed Pipe	1
Unauthorized 3rd Party Encroachment	1
Foreign Line Crossing	1
New Foreign Line Crossing	23
Foreign Line Crossing AC Mitigation System	1
New Poly Pipeline Crossing	13
New Fiber Optic Cable Crossing	2
New Overhead Powerline Crossing	3
ROW Sign Addition, Replacement, and Repair	4
Lease Road Crossing ROW	3
Repair Leak Detection System	4
Positive Material Identification	4

[13] 2012 Longhorn Pipeline Reversal EA (Reference [6]).

Table 10. Remediations per Maintenance Reports Completed in 2018

	18″ Cottonwood to El Paso	18″ Crane to Cottonwood	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 Flush Line	8″ El Paso to Kinder Morgan	12″ El Paso to Kinder Morgan	8″ Crane to Odessa
ILI Date*	11/1/17	4/18/18	**	2/16/18	2/20/18	2/22/18	2/27/18	3/6/18	3/7/18	1/3/18	1/4/18	-	-	-	-	-	-	-	-	-
Maintenance Report	Yes	Yes	Yes	No	Yes	Yes	No	No	No	Yes	Yes	Yes	Yes	No	No	No	No	No	No	No
Tier I	9	47	0	0	0	0	0	0	0	0	1	5	1	0	0	0	0	0	0	0
Tier II	0	1	8	0	1	1	0	0	0	1	0	1	0	0	0	0	0	0	0	0
Tier III	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Total Digs	9	48	8	0	1	1	0	0	0	4	0	6	1	0	0	0	0	0	0	0
HCA	0	12	0	0	0	0	0	0	0	3	0	1	1	0	0	0	0	0	0	0
Non-HCA	9	36	8	0	1	1	0	0	0	1	1	5	0	0	0	0	0	0	0	0

*Per Longhorn EA Section 9.3.2.3, EGP assessments are required every 3 years in accordance with the LMP; pipeline segments between Crane and Warda were assessed in 2018.

**Multiple ILI assessments: MFL 10/16/2018, UCD 10/19/2018, and Deformation 2/13/2018.+-

Table 11. Reported ILI Anomalies Excavated per 2018 Maintenance and ILI Anomaly Investigation Reports

ILI Anomaly Called	Number of Anomalies Addressed	18″ Cottonwood to El Paso	18″ Crane to Cottonwood	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 ML	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
External ML associated w/Lamination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
External ML crosses GW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal ML	166	118	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal ML crosses Long Seam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Anomaly w/ML	3	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crack-like feature at SW	32	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crack-like feature at GW	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction w/associated ML	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction on Weld	1	1	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
Geometric Anomaly	2	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0
Geometric Anomaly associated w/Mill Anomaly w/ML	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geometric Anomaly associated w/ML	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Girth Weld Anomaly	0	0	0	0	0	0	0	0	0	0	0	0	0	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
Lamination Intermittent	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent associated w/ML	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seam Weld Anomaly	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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
TOTAL	**210**	**119**	**48**	**39**	**0**	**0**	**2**	**0**	**0**	**0**	**0**	**0**	**1**	**1**	**0**	**0**	**0**	**0**	**0**

Table 12. Summary of ILI Investigations in 2018

	Pipeline Segment	Number of ILI Investigation Digs	Number of Segments meeting PMI Requirements
Refined System	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	9	0
	18-in Crane to Cottonwood	3	0
Crude System	18-in Crane to Texon	7	7
	18-in Texon to Barnhart	0	0
	18-in Barnhart to Cartman	1	0
	18-in Cartman to Kimble County	1	0
	18-in Kimble County to James River	0	0
	18-in James River to Eckert	0	0
	18-in Eckert to Cedar Valley	0	0
	18-in Cedar Valley to Bastrop	0	0
	18-in Bastrop to Warda	0	0
	18-in Warda to Buckhorn	1	0
	18-in Buckhorn to Satsuma	1	0
	20-in Satsuma to E. Houston	0	0
	20-in E. Houston to 9th Street Junction	0	0
	Total	**23**	**7**

Table 13. Positive Material Identification Testing Activity

	Pipeline Segment	2014	2015	2016	2017	2018
Refined System	8-in El Paso to Chevron	0	0	0	0	0
	8-in Crane to Odessa	0	0	0	0	0
	12-in El Paso to Kinder Morgan	0	0	0	0	0
	18-in Cottonwood to El Paso	0	0	0	0	0
	18-in Crane to Cottonwood	0	0	0	0	0
Crude System	18-in Crane to Texon	0	1	7	0	4
	18-in Texon to Barnhart	0	0	8	3	0
	18-in Barnhart to Cartman	0	0	11	0	0
	18-in Cartman to Kimble County	0	0	12	0	0
	18-in Kimble County to James River	0	0	5	0	0
	18-in James River to Eckert	0	1	3	0	0
	18-in Eckert to Cedar Valley	1	0	6	7	0
	18-in Cedar Valley to Bastrop	0	0	20	6	0
	18-in Bastrop to Warda	0	1	3	4	0
	18-in Warda to Buckhorn	0	2	0	14	0
	18-in Buckhorn to Satsuma	0	0	0	8	0
	20-in Satsuma to E. Houston	0	4	0	0	0
	20-in E. Houston to 9th Street Junction	0	0	0	0	0
	Total PMI Tests Performed	**1**	**9**	**75**	**42**	**4**
	Segments without available Material Documentation	**2**	**18**	**141**	**64**	**7**
	Percentage Addressed (Requirement of 50%)	**50%**	**50%**	**53%**	**65%**	**57%**

The 2017/2018 MFL tool performance analysis considered results from all assessments performed on the refined system and on the crude system. The systems were also reviewed by individual segments (i.e., Crane to Cottonwood) and compared to the overall system results to see if any segment differed significantly from the whole. The Crane to Texon segment had less than five metal loss data pairs and was not considered for individual tool performance as there was not a statistically significant number of metal loss validation measurements.

The 2017 and 2018 MFL assessments from Crane to Texon, Crane to Cottonwood, and Cottonwood to El Paso were correlated with 2018 dig results found in the in-ditch ILI anomaly investigation maintenance and NDE reports. The ILI anomaly investigation digs resulted in 57 individually correlated features. A breakdown of the ILI anomaly investigation dig data correlations can be found in Table 14. No laminations were identified during 23 ILI investigation digs. The 2018 field investigations resulted in 19 internal ML to internal ML data pairs (1 from Crane to Texon and 18 from Crane to El Paso). All 19 ML data pairs correlate to the 2017/2018 MFL assessments. A review of the MFL internal ML to internal ML data pairs found 17 out of the 19 correlations were within the ±10% tool performance specification. Figure 9 shows the in-ditch and ILI data pairs expressed as a unity plot for the MFL data; the unity plot is indicating that the MFL tool tended to over call depth on an average of 5.0% for correctly identified internal metal loss features found in 2018 for the Crane to Cottonwood and Cottonwood to El Paso segments. There is not enough data to determine a trend for the MFL tool on the Crane to Texon segment.

A statistical analysis was performed to determine the average, standard deviation and if outliers or extreme values were present. Additional information on average, standard deviation, outliers, and extreme value can be found in Appendix D – Introduction to Normal Distribution and Outliers. The statistical analysis results are shown in Table 15; a negative value represents that the ILI tool has under called the features when compared to the in-ditch data. No correlated features were removed from the statistical analysis. Table 15 and Figure 10 and Figure 11 demonstrate the difference between the ILI predicted depth and in-ditch depth based on a normal distribution for all correlated internal metal loss features used in the statistical analysis. Comparing the best fit curves to the correlated data shows that there are areas of deviation from the curve. This indicates that the correlated data could be non-normally distributed. Additional features would be needed to conclusively support a bias.

Table 14. 2018 ILI Field Investigation Data Correlations

Pipeline Segment	EXT ML to EXT ML	EXT ML to Gouge	EXT Mill Anomaly to Gouge	INT ML to INT ML	INT Mill Anomaly to INT ML	Geometric Anomaly (GMA) Associated with ML to GMA w/Gouge	Geometric Anomaly (GMA) Associated with Mill Anomaly to GMA	Dent to Dent	Crack Like Seam Feature to Lack of Fusion	Crack Like Seam Feature to OD Crack	Total Data Correlations
8-in El Paso to Chevron	0	0	0	0	0	0	0	0	0	0	**0**
8-in Crane to Odessa	0	0	0	0	0	0	0	0	0	0	**0**
12-in El Paso to Kinder Morgan	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cottonwood to El Paso	0	0	0	9	0	0	0	0	0	0	**9**
18-in Crane to Cottonwood	0	0	0	9	0	0	0	0	0	0	**9**
18-in Crane to Texon	0	1	1	0	1	1	1	1	30	3	**39**
18-in Texon to Barnhart	0	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	**0**
18-in Cartman to Kimble County	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**
18-in James River to Eckert	0	0	0	0	0	0	0	0	0	0	**0**
18-in Eckert to Cedar Valley	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cedar Valley to Bastrop	0	0	0	0	0	0	0	0	0	0	**0**
18-in Bastrop to Warda	0	0	0	0	0	0	0	0	0	0	**0**
18-in Warda to Buckhorn	0	0	0	0	0	0	0	0	0	0	**0**
18-in Buckhorn to Satsuma	0	0	0	0	0	0	0	0	0	0	**0**
18-in Satsuma to E. Houston	0	0	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	0	**0**
Total	**0**	**1**	**1**	**18**	**1**	**1**	**1**	**1**	**30**	**3**	**57**

*Note: data correlations are between reported features from most recent ILI assessment; 2017 and 2018 MFL; and the 2018 in-ditch reported findings.

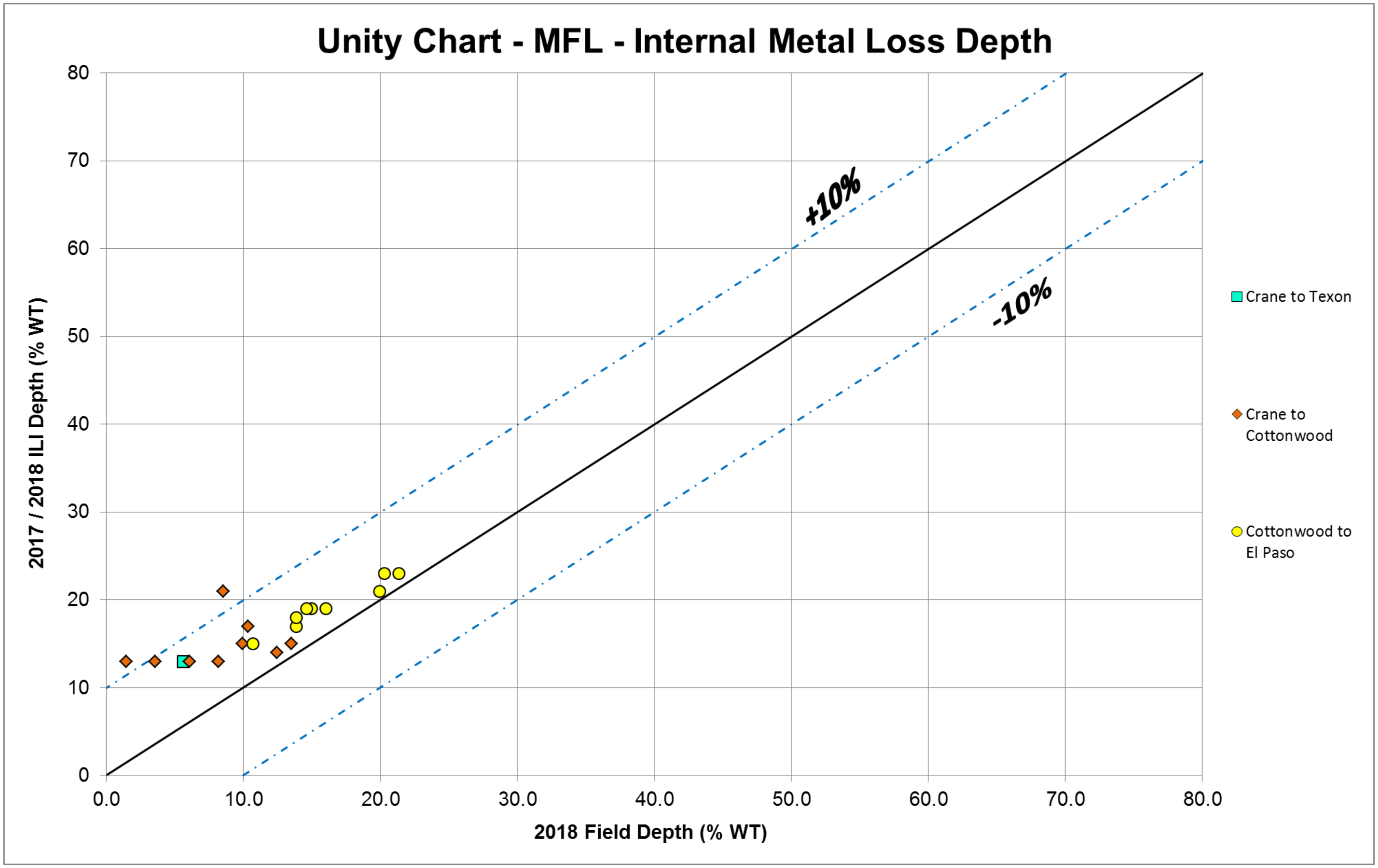


Figure 9. Unity Chart for Depth Verification for MFL Internal Metal Loss (Upper Bound ±10% WT)

Table 15. Summary of Sizing and Population Density for MFL Internal Metal Loss Features

	2018 Overall MFL Internal ML Results	Crane to Cottonwood	Cottonwood to El Paso
Number of features used in analysis	18	9	9
Total number of features	18	9	9
Average size difference	4.9% WT	6.7% WT	3.2% WT
Standard deviation	3.4% WT	3.9% WT	1.2% WT
Outliers	≤ -4.3% WT	≤ -3.7% WT	≤ 0.0% WT
	≥ 14.1% WT	≥ 17.1% WT	≥ 6.4% WT
Extreme Values	≤ -11.2% WT	≤ -11.5% WT	≤ -2.4% WT
	≥ 21.0% WT	≥ 24.9% WT	≥ 8.8% WT

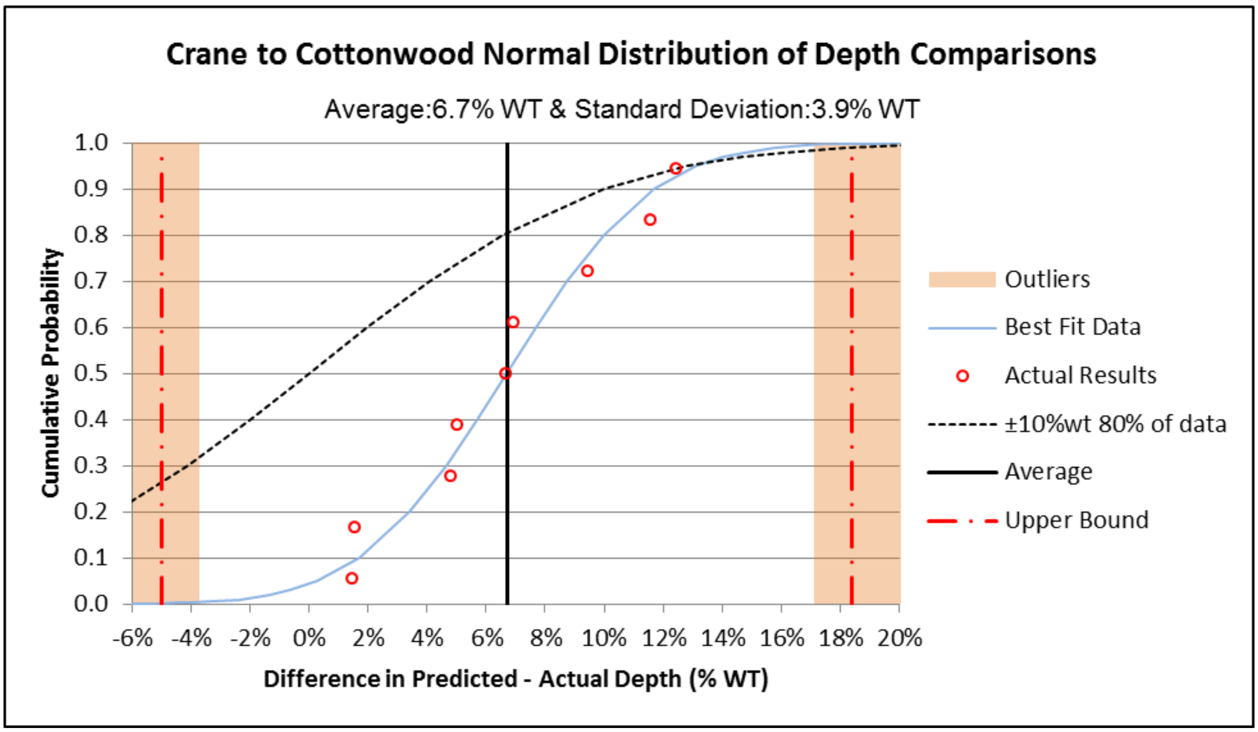


Figure 10. Internal Metal Loss Normal Distribution Chart for the Difference between In-ditch and ILI Predicted Depths for 2018 Crane to Cottonwood ILI Anomaly Investigation Data Pairs

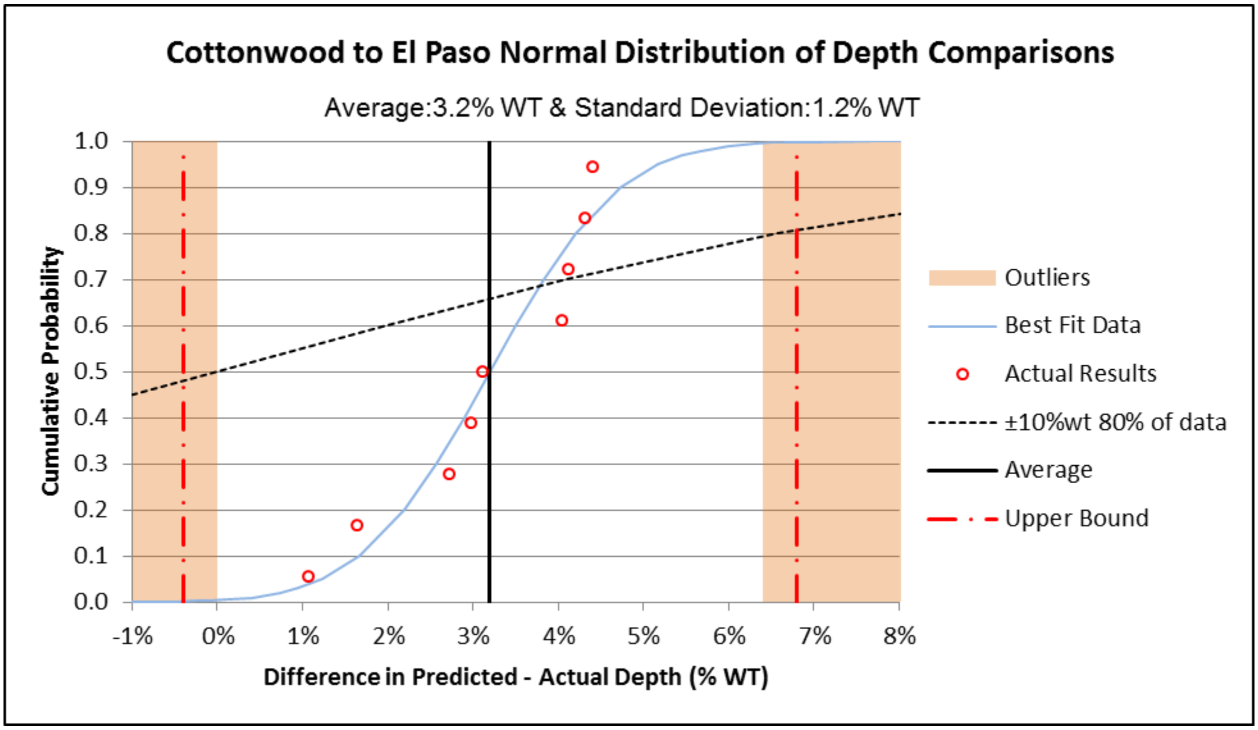


Figure 11. Internal Metal Loss Normal Distribution Chart for the Difference between In-ditch and ILI Predicted Depths for 2018 Cottonwood to El Paso ILI Anomaly Investigation Data Pairs

2.2.2 ID Reductions

Magellan runs 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. ID reductions greater than or equal to 2% of the pipe diameter are referred to as dents. ID reductions less than 2% of the pipe diameter are referred to as geometric anomalies (GMA).

The 2018 EGP assessments reported 1,843 ID reductions; 1,654 between Crane and Warda pump stations and 189 between the Crane and El Paso pump stations. Ninety-four of the ID reductions are noted as being previously repaired. The remaining 1,749 ID reductions are classified as 127 dents and as 1,622 GMAs. No dents with metal loss were reported. Two GMAs, not in an HCA, located on the Cottonwood to El Paso segment were noted as being associated with metal loss; Magellan has addressed these features. Sixteen GMAs were reported as interacting with a girth weld; one is noted as being previously repaired. Four of the 16 GMAs interacting with a girth weld are located in an HCA.

Shown in Table 16, 459 of the reported ID reductions are located within HCAs; with 22 noted as previously repaired. 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 third of the pipe and with a depth greater than 6% OD).

Table 16. ID Reductions Located within HCAs [14]

Segment	Quantity	Quantity Noted as Repaired	Peak Depth (% OD)	Comment
Kimble County to James River	42	2	2.9*	• Two GMAs noted as repaired • Five dents located on the bottom 1/3 of pipe • 13 GMAs located on top 2/3 of pipe • 22 GMAs located on bottom 1/3 of pipe
James River to Eckert	91	5	2.9*	• Five GMAs noted as repaired • Nine dents located on the bottom 1/3 of pipe • 44 GMAs located on top 2/3 of pipe • 33 GMAs located on bottom 1/3 of pipe
Eckert to Cedar Valley	112	8	3.7*	• Four dents and four GMAs noted as repaired • 19 dents located on the bottom 1/3 of pipe • 12 GMAs located on top 2/3 of pipe • 73 GMAs located on bottom 1/3 of pipe
Cedar Valley to Bastrop	150	6	3.1**	• One dent and five GMAs noted as repaired • Seven dents located on the bottom 1/3 of pipe • 45 GMAs located on top 2/3 of pipe • 92 GMAs located on bottom 1/3 of pipe
Bastrop to Warda	61	1	2.2	• One dent noted as repaired • One dent located in a bend on the bottom 1/3 of pipe • 31 GMAs located on top 2/3 of pipe • 28 GMAs located on bottom 1/3 of pipe
Crane to Cottonwood	1	0	1.1	• One GMA on bottom 1/3 of pipe
Cottonwood to El Paso	2	0	0.8	• Two GMAs on bottom 1/3 of pipe
Total	**459**	22		

*Dent with peak depth is located on the bottom 1/3 of pipe.

**Dent with peak depth is located on the top 2/3 of pipe and is noted as being previously repaired.

2.2.3 Laminations and Hydrogen Blisters

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. 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

[14] 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.

hydrogen migration and hydrogen blistering. Managing internal corrosion and monitoring CP levels could help mitigate these threats.

ID reductions identified from the 2018 EGP assessments were correlated with laminations reported from the 2009/2010 UT assessments. Fourteen dents and 95 GMAs reported from the 2018 assessments were found to either correlate or be present on the same joints with laminations reported from the 2009/2010 UT assessments, shown in Table 17. Two dents and four GMAs are noted as having been previously repaired.

A review of the 2018 maintenance reports showed that no digs were scheduled as an ILI investigation dig due to a lamination. No laminations were reported during in-ditch assessments in 2018. Monitoring reported laminations for ID reductions might indicate the initiation of a hydrogen blister. Per the Longhorn EA Section 9.3.2.3, the monitoring frequency recommended should coincide with the EGP tool assessment schedule. EGP assessments are required for the Existing Pipe every three years in accordance with the LMP, with exception of the section between East Houston and Speed Junction. The next EGP assessment for the crude system is in 2020 for the East Houston to Satsuma segment.

Table 17. ID Reductions Correlating with Laminations[15]

Segment	Quantity			Peak Depth (% OD)	List of Joints	Comment
	Joint(s)	Dent(s)	GMA(s)			
Crane to Texon	8	-	8	1.6	2950, 18260, 20720, 24810, 26640, 41190, 43010, 43100	• One GMA on GW 20720 reported near pipeline crossing
Texon to Barnhart	3	1	3	2.3	4830, 7690, 36240	• The dent and GMA reported on GW 4830 are noted as repaired
Barnhart to Cartman	4	1	3	2.6	14160, 25880, 25920, 26580	
Cartman to Kimble County	27	2	26	3.0	3090, 4530, 12100, 14710, 15190, 16760, 21460, 23780, 24620, 26340, 27290, 30180, 31840, 32610, 32890, 33700, 38330, 46470, 48040, 48490, 50250, 50290, 52120, 59970, 60080, 60740, 65530	• Ten GMAs reported near multiple pipelines on GWs 12100, 23780, 26340, 27290, 32610, 33700, 46470, 50250, 52120, and 60740
Kimble County to James River	12	3	10	3.6	1010, 8420, 15620, 21630, 24240, 25410, 29940, 30780, 36620, 37990, 39560, 45410	
James River to Eckert	14	2	12	2.1	3300, 7150, 16230, 18000, 19770, 26630, 27630, 28120, 28380, 33060, 33070, 36710, 39870, 42170	• The dent reported on GW 18000 is noted as repaired • One GMA on GW 19770 located near the road
Eckert to Cedar Valley	18	5	13	2.6	10800, 15760/70, 18630, 25980, 26180, 28130, 28180, 30490, 30710, 31860, 33870, 33980, 36430, 38030, 38160, 40110, 43160, 52170/80	• GMA and lamination on 15760 and 15770 were located on the same joint but reported at differing GW. • One GMA reported as crossing GW 52170 • GMA and lamination on 52170 and 52180 were located on the same joint but reported at differing GWs.
Cedar Valley to Bastrop	2	-	6	1.0	22490, 37900	• Five GMAs are reported on GW; three of the GMAs are noted as repaired.
Bastrop to Warda	13	-	14	0.8	2440, 11190, 11750, 25660, 31320, 31510, 31540, 32570, 33410, 35560, 36460, 38740, 39790	
Total	**102**	**14**	**95**			

[15] Features may not be directly correlating (i.e. overlapping area), but were identified in this table if reported on the same joint.

2.3 Earth Movement and Water Forces

2.3.1 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 18.

Table 18. 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 were unavailable.

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[16] 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 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 were 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[17].

[16] 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.
[17] ASME B31.4-2012. The standard allows longitudinal stress up to 90% of SMYS.

ASME B31.4 increased the allowable longitudinal stress level from 54% SMYS to 90% SMYS in 2012. The new allowable limit was used to determine the critical displacement at the three faults passed by the new East Houston Line constructed in 2012. Given the pipeline vintage, Kiefner opted for a lower limit of 80% SMYS to determine the critical displacement at the Hockley fault. Please see the 2014 ORA Report for details of the analysis.

Table 19 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 Table 19. 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.

Table 19. Summary of Estimated Allowable Fault Displacement at Faults

	Allowable Displacement (in)	Average Rate of Movement (in/year)	Time to Reach Allowable Displacement (years)
Akron	4.17	0.020	220
Melde	4.13	0.003	1,515
Breen	1.50	0.004 | 0.12	375 | 13**
Hockley	1.25	0.020	62
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
** Based on three year average

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. A section of the pipeline at the Hockley fault line which was installed in the 1950s has theoretically reached or exceeded its estimated mean time to failure but with the following caveats:

- Use of the 80% SMYS as failure criterion rather than the actual stress at failure; and
- Conservative assumption in the FEA as has been discussed in the 2014 ORA Annual Report.

The 2018 re-surveys at Akron, Melde, and Breen indicate movement exceeding the historical average rates of movement. While the change does not impact the historical average as much, monitoring of data for 2019 and 2020 need evaluation to see if the years to reach allowable displacement requires adjusting.

Recommendations for Magellan to consider for remediating the pipeline segment at the Hockley fault as the 28 & 29 re-surveys[18] indicate continuous movement close to or above the average and further numerical shortening of time to reach the allowable displacement.

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. In 2017, there was a considerable amount of backward movement in the Akron fault in comparison to the previous 12 years of monitoring. This trend has continued in 2018. In 2018, it was reported the trend lines show no measurable movement on the Melde and Breen faults. While this remains the case for Melde, the short term trend at the Breen fault line shows new movement which requires close monitoring.

The survey trend before and after 2015 continues to hold for the Hockley fault. The relative displacement at the Breen fault remains low but there is a noticeable movement starting in 2017. Relative displacements at the Melde fault remain steady with small variation around the mean location of the pipe. Since 2015, there has been relatively large movement at the Akron fault. While the deviation from the mean position is currently small, the rate of movement for the last three years is 0.12 inches/yr. Continued monitoring at the Akron fault is highly recommended. If the movement trend at Akron follows the same trend in 2019, some form of remediation will be necessary.

Kiefner recommends including long term and short term rates of movement (see Table 19) from now onward. The average rates do not appear to artificially dampen the rate of movement and result in non-conservative estimates of time to potential failure.

Currently, calculations indicate 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.

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

[18] Geosyntec - TXR0130/2nd Half 2018 Semi-Annual Fault Displacement Monitoring Report final

based on field observations at the top four faults listed in Table 19. Actual measurements over the past 13 years show rates that are less than an order of magnitude of 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. A semi-annual monitoring frequency is appropriate.

Semi-annual fault measurements have been conducted at the seven fault monitoring sites from the inception of the ORA in mid-2004[19] through December 2018. 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 five sites. At the Hockley fault the accumulative movement is approaching the acceptance limit. The Breen fault line appears to show significant movement in the last three years. The following is a suggested approach for remediation:

- Excavate and expose the pipeline segment including three joints at each side of the fault within three to 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. It is also recommended that the quality of the girth welds in the exposed segment be examined at this time.

2.3.2 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 river 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 inspection by ONYX indicated no exposed pipelines at the crossings, with all locations maintaining minimum depth of cover. The Onyx river inspection included a note on placing an additional grout bag on 11/20/2018 at 31.193048/-96.890213 for supporting the pipeline as the previous bag has been silted in. There is minimum risk for the pipeline being exposed at these crossings based on the inspection data.

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 Crossing if necessary, such as installing the pipeline deeper through HDD or placing a concrete mat at the river bottom to prevent scouring.

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

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.

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.

The James River and Llano River waterways were inspected in 2018. At the Llano River, the pipeline was not exposed but the cover depth was reported at 1.5 ft (maximum was 4.5 ft). Engineering drawings appear to indicate the cover has been washed away even though the bedding is made of rock. Kiefner expects monitoring of the Llano River waterway for the Longhorn pipeline to be repeated in 2020. The inspection report also indicates the river banks are stable. At the James River, the inspection report indicates 28 ft of exposed pipeline with 14 ft suspended with exposed river weight. No remediation has been reported. Kiefner recommends revisiting the locations with exposed pipe, establish whether the exposure has been a temporary event or has become permanent. If the status at James River crossing has been a temporary event, then it is suggested to establish whether it can occur again. If pipe exposure is as before, then sand bags, re-establishing cover, protective mats are recommended.

Figure 12. James River Inspection, 2018[20]

[20] Onyx Report.

2.3.3 Flood Monitoring

In 2018, the water surface at the Colorado River (Bastrop), Pin Oak Creek (Smithville), and Pedernales River (near Johnson City) were monitored daily. The water levels in 2018 were between 2.44 ft and 22.13 ft at Bastrop, 1.29 ft to 18.30 ft at Smithville, and 9.39 ft to 15.95 ft at Johnson City. On October 17th, 2018, the water level exceeded the flood stage at the Johnson City monitoring gate for Pedernales River and dropped back to 12.22 ft the next day. Magellan has committed to visually inspecting the water crossings whenever a flood condition occurs.

2.4 Third-Party Damage

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 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 DOC over the pipeline. In all cases, different threats could exist at different locations along the pipeline.

The annual Third-Party Damage Prevention Program Assessment contains Longhorn specific information. Data included in this assessment include the number of detected unauthorized ROW encroachments, changes in activity levels and one-call frequency, physical hits, near-misses, DOC, 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 2018. 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.

Based on a review of the third party damage data and a review of the 2018 Third Party Damage Annual Assessment, Kiefner concluded:

- There were no physical hits to the pipeline.

- There were two ROW near-misses.
- There was one one-call violation.
- There was an increase of approximately 19% in aerial patrol observations; 93 percent of the observations involved non-company activity.
- There were 79 ROW encroachments recorded, five of which were unauthorized.
- One-call frequency increased by 6% and the number of tickets sent to Field Operations for clearing/locating increased by 16% from 2016 to 2017.

2.4.1 ROW Surveillance

Total possible surveillance 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), weather permitting. The cumulative miles of patrols for these three areas by month for 2018 are listed in Table 20.

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 severe rainfall and flooding during September, October, and November of 2018.

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.

Table 20. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Tiers II & III: Aerial Patrol (every 2.5 days, not to exceed 72 hours)													
301: MP528 to E. Houston	14,028	8,615	15,284	14,901	13,263	15,133	15,041	14,727	9,396	11,184	9,500	10,940	**152,012**
Tier I: Aerial Patrol (once/week, not to exceed 12 days)													
303: MP528 to MP694	1,578	1,052	789	1,052	1,052	1,315	1,052	1.315	789	1,578	1,315	1,052	**13,939**
Ground Patrol (once/week)													
Edwards Aquifer: MP170.5-MP173.3	8	6	11	17	22	11	17	60	48	48	48	14	**310**

Table 21 shows the level of non-company activity by category and tier level. Non-company activity increased by 45% from 2017; industrial activity increased by approximately 68%.

Table 21. Non-Company Aerial Patrol Events

Activity	Tier			Total	%
	I	II	III		
Industrial Activity	48	87	16	151	31
Misc. Third Party Activity	20	77	17	114	23
No Activity Found	21	35	15	71	15
Foreign Line Crossing	55	4	4	63	13
Road Maintenance/Construction	9	10	13	32	7
Housing Development	20	6	3	29	6
Agricultural Activity	9	11	1	21	4
Commercial Development	1	3	1	5	1
Other, Exposure	1	1	0	2	-
Emergency Observations	0	0	0	0	-

The Annual Third Party Damage Prevention Program reported 79 ROW encroachments, a 3% decrease from 2017, five of which were unauthorized. The breakdown by month and tier is shown in Table 22.

Table 22. ROW Encroachment by Month and Tier

Encroachments	Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	I	3	3	11	3	3	5	6	1	4	4	13	5	**61**
	II	0	0	1	2	1	0	0	1	2	0	3	0	**10**
	III	0	0	0	1	1	0	1	0	0	0	0	0	**3**
Unauthorized	I	1	0	0	0	3	0	0	0	0	0	0	0	**4**
	II	0	0	0	0	1	0	0	0	0	0	0	0	**1**
	III	0	0	0	0	0	0	0	0	0	0	0	0	**0**

2.4.2 One-Call Ticket Analysis

Of 18,426 one-calls in 2018, it appeared that 28% of the required "field locates" were potential ROW encroachments (see Table 23). A listing of one-calls by month and tier is provided in Table 24.

There was one one-call violation during 2018 which involved a landowner installing a fence without placing a one call. No contact with the pipeline occurred.

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.

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 9,069 (49%) of the one-call tickets. Travis County (Austin) accounted for 3485 (19%) of the one-call tickets. Thus, 68% 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 1,476 tickets (8%).

Table 23. One-Call Activity by Month[21]

Month	One-Call Clear	Field Locate	Total Tickets
Jan	543	340	1377
Feb	575	330	1299
Mar	743	385	1606
Apr	665	347	1463
May	836	363	1671
Jun	727	450	1670
Jul	602	428	1506
Aug	678	514	1745
Sep	595	475	1497
Oct	589	521	1481
Nov	590	536	1574
Dec	632	454	1537
Totals	**7775**	**5143**	**18426**

Table 24. Number of One-Calls by Month and Tier

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	496	445	540	497	651	610	558	577	487	497	527	484	**6369**
II	671	634	801	726	766	810	719	897	765	750	798	790	**9126**
III	210	220	266	240	253	250	229	272	245	234	249	262	**2931**
Total	**1377**	**1299**	**1606**	**1463**	**1671**	**1670**	**1506**	**1745**	**1497**	**1481**	**1574**	**1537**	**18426**

2.4.3 Inspection Activities

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[22] and Crane Station be carried out within three years of a previous inspection. EGP inspection tools were run in 2018 on nine pipeline segments from Crane to Warda. For specific inspection dates to fulfill the requirement for each of the 12 intervals spanning the Existing Pipeline from Crane to East Houston see Section 5, Table 40 on Integration of Intervention Requirements.

2.4.4 Public Awareness

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

[21] From 2018 Third Party Damage Report
[22] Valve J-1 is no longer in service. ILI assessments for TPD are currently performed from E. Houston to Crane.

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. The number of visits to the safety section of the website per month during 2018 is shown Table 25.

Table 25. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Safety/Environment	94	101	124	129	134	139	113	138	133	131	95	103	**1434**
System Integrity Plan	95	128	88	85	93	81	91	73	64	77	77	67	**1019**
Brochures	27	27	38	43	18	19	31	27	29	40	42	24	**365**
Call Before You Dig	79	81	72	96	71	60	51	48	17	57	58	44	**734**
Emergency Response	95	127	68	65	62	66	55	48	67	119	55	44	**871**
Pipeline Safety	271	193	139	112	131	142	111	102	131	134	174	175	**1815**
State One Call	8	2	3	8	6	3	4	6	8	2	1	0	**51**
What We Do – Longhorn Info	256	250	291	308	318	282	245	278	247	209	245	193	**3122**

2.5 Stress-Corrosion Cracking

SCC is a form of environmental attack on 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. In the 68 years the Existing Pipeline has been in operation, there have been no SCC failures and no SCC has been discovered at any location on the pipeline.

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 was required to inspect for SCC, for the first three years (2005-2007) 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 2018 Magellan performed 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). 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.

2.6 Threats to Facilities

This section of the ORA addresses the operational reliability of facilities other than line pipe, including pump stations, terminals, and associated mechanical components. Magellan monitors the integrity of these facilities through scheduled maintenance and inspection activities prescribed by the LPSIP. The LPSIP Mechanical Integrity Program focuses on maintaining the integrity of all equipment within the Longhorn system (e.g., station pumps, tanks, valves, and control 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.

The preventive maintenance program is implemented through the use of a software database system called Enviance/Compliance Management System (CMS). The software system establishes an 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.

A Facility Risk Management Program is in place to manage the risks at above ground facilities. The LMP requires that all changes on the Longhorn system be evaluated using an appropriate Process Hazard Analysis (PHA) methodology (Hazard and Operability (HAZOP), What-if Analysis) and that the change be assessed to ensure that the appropriate risk mitigation levels on the system are maintained. PHAs are also conducted on a 5-year interval to evaluate and control the hazards associated with the Longhorn facilities. Two PHAs were completed in 2018; one for the El Paso Terminal Holly Receipt and Storage Tank Project and the other for the Crane Crude Facility.

Facility inspections addressing items related to safety, security, and environmental compliance are conducted on a regular basis. 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. 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.

Kiefner received four facility inspection reports for 2018: Crane (9/18), Barnhart (10/29), El Paso (11/14), and Warda (12/21).

Six of the 12 Longhorn System incidents occurred at facilities: five minor, one major. The major incident involved incorrect operations during maintenance at the Eckert Pump Station which resulted in a release of 282 barrels of crude oil. The total cost of cleanup and remediation was $7.319 million. Corrective actions were implemented in accordance with Magellan's incident investigation report which was provided to PHMSA.

From the standpoint of facility data acquired for 2018, one can conclude that the facilities had been well maintained, but additional emphasis is needed to reduce operational errors.

3 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.

3.1 Longhorn Corrosion Management Plan

The LMP entails an extensive Corrosion Management Plan (CMP) to control the extent of corrosion. The 2018 CMP considered the following items: Probability of Exceedance (POE), analysis review of internal corrosion coupons, review of field dig reports (covered under 0 Tool Performance and ILI Validation), review of the CP system for buried pipelines, review of the atmospheric inspection for above grade appurtenances, and review of the tank inspections.

3.1.1 Probability of Exceedance Analysis

POE calculations were performed on the 18-inch Crane to Cottonwood and the 18-inch Cottonwood to El Paso using the TDW MFL tool information and utilizing a CGR of 5 mpy for external metal loss and 1 mpy for internal metal loss over a 5-year range. Ten metal loss features were found to meet POE dig requirements of 1 x 10^{-5}; two on the Crane to Cottonwood segment and eight on the Cottonwood to El Paso segment. The metal loss features that had a POE value less than 10^{-7} at the next reassessment interval were removed from further analysis with reliability-based design analysis (RBDA). This left only 88 metal loss features (11 on Crane to Cottonwood and 77 on Cottonwood to El Paso) for which a POF was calculated using RBDA.

The distributions of each input parameter were assumed or generated from existing industry reports or sources. The CGR parameter was assumed to be a constant 5 mpy for external metal loss and 1 mpy for internal metal loss to show a more direct comparison with the POE results. RBDA was implemented using a Monte Carlo simulation for each year of growth over a 5-year range. For each feature, the POF due to rupture was considered when the actual burst pressure was less than the maximum allowable surge pressure (MASP) or 1.1 times MOP; while the POF due to leak was considered when the actual anomaly depth was greater than 80% WT. The burst pressures were assessed utilizing the Modified B31G method because it was the assessment used in the POE analysis and is an assessment method used by Magellan.

The results of RBDA are listed below for probability of rupture at the time of the next assessment (5 years). Table 26 shows the results, for comparison, from both the POE and the RBDA calculations for features with a calculated POE of 1 x 10^{-5} or greater.

- Crane to Cottonwood:
  - The results of the traditional POE calculations resulted in two features with a rupture probability greater than 1 x 10^{-5}.
  - The RBDA calculations resulted in no features with a rupture probability greater than of 1 x 10^{-5}.
- Cottonwood to El Paso:
  - The results of the traditional POE calculations resulted in eight features with a rupture probability greater than 1 x 10^{-5}.
  - The RBDA calculations resulted in four features with a rupture probability greater than 1 x 10^{-5}.

Table 26. Results of RBDA and POE Analysis at Next Reassessment Interval for POE 1 x 10^{-5}

Pipeline Segment	Absolute Distance (feet)	Predicted Depth (% WT)	Predicted Length (inch)	POE (Rupture)	RBDA (Rupture)
Crane to Cottonwood	621267.31*	21	8.58	1.996E-05	4.000E-06
Crane to Cottonwood	588797.64*	17	15.38	1.031E-05	2.000E-06
Cottonwood to El Paso	524942.42*	21	68.64	7.204E-05	2.330E-04
Cottonwood to El Paso	241565.20*	23	8.02	4.105E-05	1.100E-05
Cottonwood to El Paso	205108.70*	19	18.31	4.104E-05	2.500E-05
Cottonwood to El Paso	418736.78*	23	7.18	2.556E-05	7.000E-06
Cottonwood to El Paso	272710.32*	19	12.29	2.018E-05	5.000E-06
Cottonwood to El Paso	205091.05*	19	11.89	1.871E-05	9.000E-06
Cottonwood to El Paso	354018.71*	17	20.27	1.581E-05	1.300E-05
Cottonwood to El Paso	584738.02*	18	13.18	1.367E-05	5.000E-06

*Feature was addressed in 2018

3.1.2 Internal Corrosion Coupons

Internal corrosion is monitored using internal corrosion coupons placed at 39 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. Thirty of the 39 locations sampled with coupons were located on the crude line while nine were located on the refined line. No corrosion to the maximum of 0.12 mpy corrosion rate was observed on the internal corrosion coupons for the crude line. No corrosion to the maximum of 0.37 mpy corrosion rate was observed on the internal corrosion coupons for the refined line. Monitoring should continue to identify future potential changes in the pipelines. Internal corrosion coupon results are shown in Table 27 for the crude line and Table 28 for the refined line.

Table 27. Internal Corrosion Coupon Results for Crude Line

Pipe OD (in)	Location	Line Designation (Line ID)	Coupon Number	Inserted	Removed	Exposure (days)	Rate (MPY)	Comments
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	H9769	12/12/2017	4/11/2018	120	0.00	
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	AA1500	4/11/2018	8/14/2018	125	0.00	
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	AA1757	8/14/2018	12/12/2018	120	0.02	
20	E. Houston	East Houston ML (6645)	U4346	12/14/2017	5/3/2018	140	-	**
20	E. Houston	East Houston ML (6645)	V2393	5/3/2018	8/15/2018	104	0.00	
20	E. Houston	East Houston ML (6645)	U9884	8/15/2018	1/4/2019	142	0.01	
18	Satsuma	Satsuma Station ML (6645)	H9777	12/29/2017	4/30/2018	122	0.00	
18	Satsuma	Satsuma Station ML (6645)	AA1492	4/30/2018	8/24/2018	116	0.02	
18	Satsuma	Satsuma Station ML (6645)	AA1761	8/24/2018	12/14/2018	112	0.03	
18	Cedar Valley	Cedar Valley Station ML (6645)	H9776	12/14/2017	4/13/2018	120	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	AA1491	4/13/2018	8/10/2018	119	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	AA1760	8/10/2018	12/19/2018	131	0.00	
18	Cartman	Cartman Station ML (6645)	H9775	12/12/2017	4/17/2018	126	0.00	
18	Cartman	Cartman Station ML (6645)	AA1490	4/17/2018	9/13/2018	149	0.00	
18	Cartman	Cartman Station ML (6645)	AA1759	9/13/2018	1/22/2019	131	0.01	
24	Crane	Tank Manifold at Crane (6645)	H9770	12/4/2017	4/13/2018	130	0.00	
24	Crane	Tank Manifold at Crane (6645)	AA1501	4/13/2018	9/13/2018	153	0.00	
24	Crane	Tank Manifold at Crane (6645)	U9927	10/24/2018	1/22/2019	90	0.07	
16	Crane	Plains WTI – Delivery (6645)	U4341	12/4/2017	4/13/2018	130	0.12	
16	Crane	Plains WTI – Delivery (6645)	V2394	4/13/2018	8/16/2018	125	0.06	
16	Crane	Plains WTI – Delivery (6645)	U9882	8/16/2018	12/12/2018	118	0.02	
16	Crane	Plains WTS – Delivery (6645)	U4342	12/4/2017	4/13/2018	130	0.03	
16	Crane	Plains WTS – Delivery (6645)	V2391	4/13/2018	8/16/2018	125	0.05	
16	Crane	Plains WTS – Delivery (6645)	U9885	8/16/2018	12/12/2018	118	0.02	
12	Crane	Centurion – Delivery (6645)	U4343	12/4/2017	4/13/2018	130	0.03	*
12	Crane	Centurion – Delivery (6645)	V2399	4/13/2018	9/13/2018	155	0.03	
12	Crane	Centurion – Delivery (6645)	U9892	9/13/2018	12/12/2018	90	0.02	
16	Crane	Advantage – Delivery to Crane (6645)	U4339	12/4/2017	4/3/2018	130	0.03	
16	Crane	Advantage – Delivery to Crane (6645)	V2392	4/13/2018	8/16/2018	125	0.05	
16	Crane	Advantage – Delivery to Crane (6645)	U9878	8/16/2018	12/12/2018	118	0.02	

*Coupon is noted as having mechanical wear from holder.

**Damaged, coupon could not be processed.

Table 28. Internal Corrosion Coupon Results for Refined Line

Pipe OD (in)	Location	Line Designation (Line ID)	Coupon Number	Inserted	Removed	Exposure (days)	Rate (MPY)	Comments
8	Crane	8” Odessa to Crane (6648)	U4340	12/4/2017	4/13/2018	130	0.03	
8	Crane	8” Odessa to Crane (6648)	V2390	4/13/2018	8/16/2018	125	0.04	
8	Crane	8” Odessa to Crane (6648)	U9879	8/16/2018	12/12/2018	118	0.01	
18	El Paso	18” Mainline (6645)	N0024	12/15/2017	4/14/2018	120	0.00	
18	El Paso	18” Mainline (6645)	AX0063	4/14/2018	8/15/2018	123	0.00	
18	El Paso	18” Mainline (6645)	N0159	8/15/2018	12/12/2018	119	0.00	
8	El Paso	8” Plains Outbound (6650)	N0161	12/15/2017	4/4/2018	120	0.04	
8	El Paso	8” Plains Outbound (6650)	N0025	4/14/2018	8/15/2018	123	0.06	
8	El Paso	8” Plains Outbound (6650)	N0160	8/15/2018	12/12/2018	119	0.37	

3.1.3 Cathodic Protection System

In order to evaluate the effectiveness of the CP systems that are currently in place for the Longhorn pipeline system, the rectifier inspections and maintenance, test point surveys, and close interval surveys were reviewed. The rectifiers were inspected monthly in 2018, including output voltage and current. The pipe to soil readings were performed at least once at test points in 2018. A close interval survey was performed by Tucker Service from 7/11/18 to 12/28/18 for five segments of the crude line. These five segments are from Crane to Kimble County, Kimble County to Bastrop, Bastrop to Satsuma, Satsuma to East Houston and East Houston to Speed Jct.

Based on the Longhorn Corrosion Management Plan, corrosion control activities are governed by company policies and procedures and DOT Part 195 regulations, and are consistent with NACE International RP01-69, ASME, and API recommended practices where applicable.

NACE International has established criteria considered indicative of CP for metallic piping in NACE Standard Practice SP0169-2013 (formerly RP01-69) – “Control of External Corrosion on Underground or Submerged Metallic Piping Systems.” The Standard lists the following criteria:

- A minimum of 100 mV of cathodic polarization. Either the formation or the decay of polarization must be measured to satisfy this criterion.
- A structure-to-electrolyte potential of -850 mV or more negative as measured with respect to a saturated copper/copper sulfate (CSE) reference electrode. This potential may be either a direct measurement or the polarized potential or a current-applied potential. Interpretation of a current-applied measurement requires consideration of the significance of voltage drops in the earth and metallic paths.

The CIS summary data for five segments of the crude line, provided by Tucker Service, is listed in Table 29, indicating the pipeline lengths that do not meet the criteria. Figure 13 and Figure

14 show such locations for the Crane to Kimble segment and the Kimball to Bastrop segment, respectively.

Table 29. CIS Summary for Crude Line

Line Segment	Total feet not meeting 100mV shift criteria	Total feet not meeting -0.850 mV IRF criteria	Total feet not meeting -1200 mV IRF criteria
Crane to Kimble	60.5	29229.9	323213.3
Kimble to Bastrop	651.5	249551.3	31485.17
Bastrop to Satsuma	0	192769.9	26063.9
Satsuma to E-Houston	442.5	0	49564.6
E-Houston to Speed Junction	5364	45	21162.18

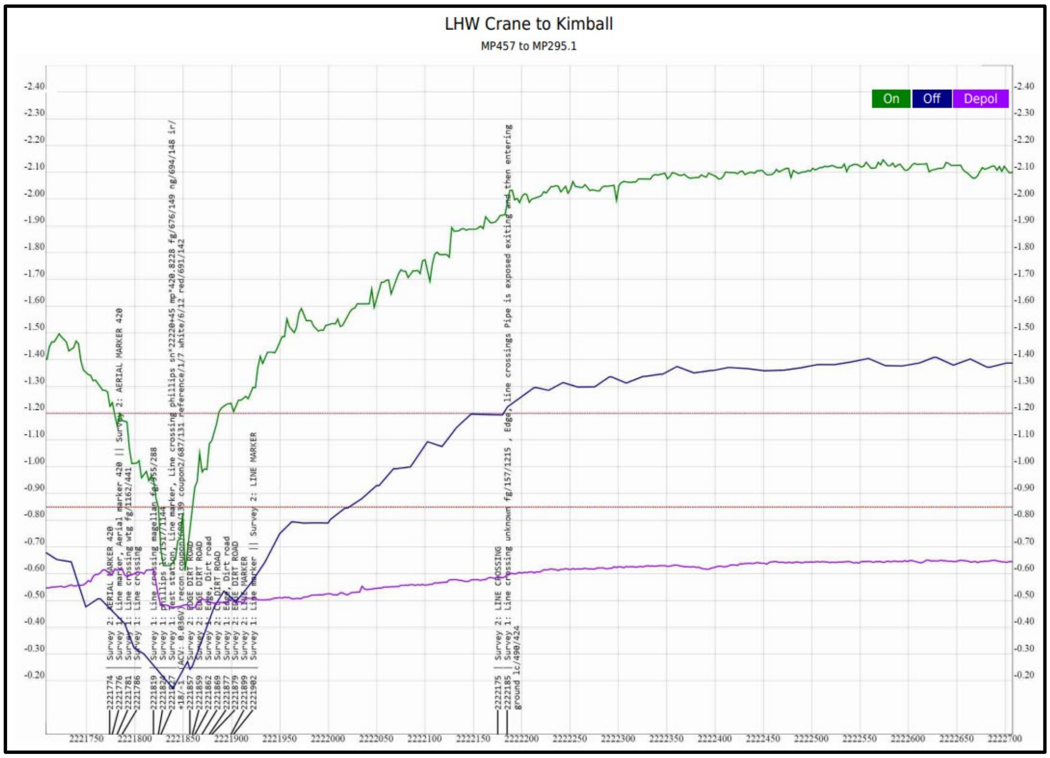


Figure 13. Location of Crane to Kimball not Meeting Any Criteria

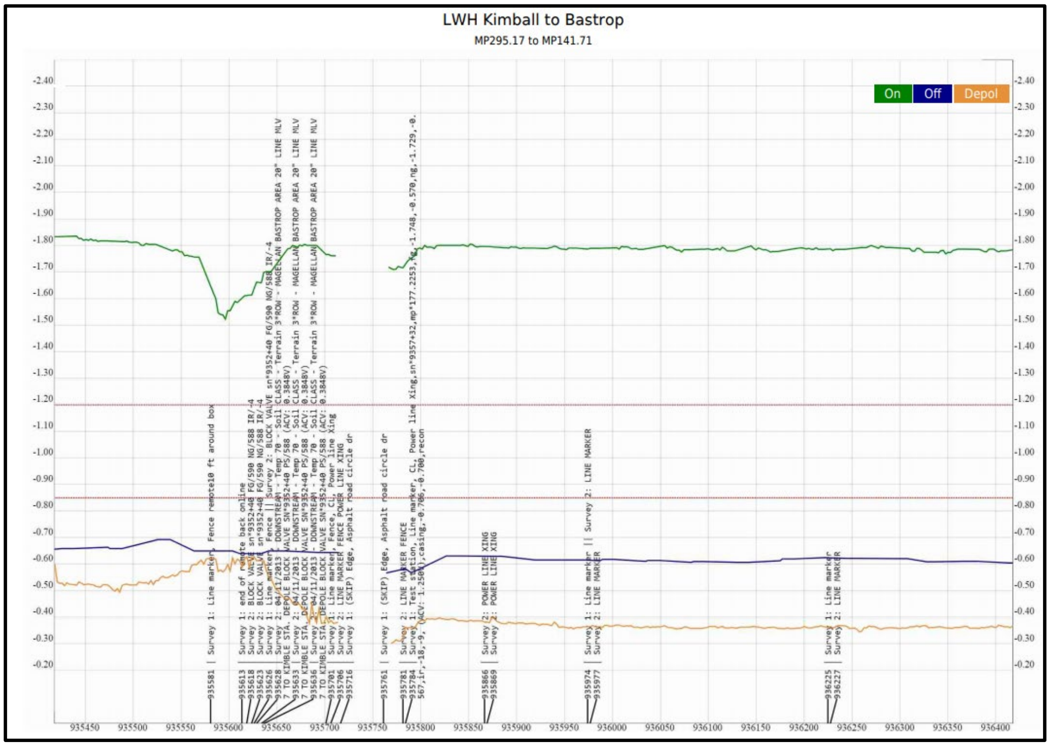


Figure 14. Location of Kimball to Bastrop not Meeting Any Criteria

The 2018 CIS data also indicate that most of the pipe sections show the "instant off" readings slightly more electronegative than -1200 mV with respect to a CSE reference electrode, meaning these pipe sections may be overprotected by the CP system. Over cathodic polarization on the pipe may cause external coating blister or damage.

The CIS summary report shows the CP related features for each line segment, including the number of line crossings, the number of casings, the number of bonds, and the number of rectifiers which are listed in Table 30.

Table 30. CP Related Features for Crude Line

Line Segment	# of line crossings	# of casings	# of bonds	# of rectifiers
Crane to Kimble	14	162	15	41
Kimble to Bastrop	21	34	7	35
Bastrop to Satsuma	46	30	5	31
Satsuma to E-Houston	20	28	7	3
E-Houston to Speed Junction	40	0	4	1

The condition of above grade appurtenances is monitored by annual atmospheric inspection, including station piping, tanks, valve settings, and exposed piping. Table 31 lists the locations of concern in the Longhorn Pipeline System where corresponding repairs are needed.

Table 31. Atmospheric Inspection Summary

Segment Code and Pipe	Atmospheric Facility Type	Inspection Date	Milepost	Inspection Remarks
174	Station Piping	5/18/2018	15.000	Flange and bolts need painted
174	Station Piping	5/19/2018	44.000	Flange and bolts need painted
174	Tank	5/19/2018	125.000	Roof and bottom extension 3 shell light surface rust on southeast side to southwest side of tank
177	Station piping	5/22/2018	1.000	4” drain between launcher and receiver needs touch up
177	Station piping	5/22/2018	6.000	Spot repair 1” piping x 4
178	Station piping	5/23/2018	3.000	Surface rust/flaking paint
178	Station piping	5/23/2018	3.500	Surface rust/flaking paint
178	Station piping	5/23/2018	4.500	Recoat 1” relief valve/piping
190	Station piping	5/16/2018	1.500	Flaking paint and general corrosion, blast and recoat 150’ (system 2)
190	Station piping	5/16/2018	4.000	General corrosion at pump suction and discharge (blast and recoat flange to flange)
194	Station piping	5/30/2018	3.000	General Corrosion at unpainted areas throughout
6645	Benched crossing	5/4/2018	15.6901	Recoat interface
6645	Benched crossing	5/4/2018	17.2217	East side of bank washed out
6645	Exposed pipe	5/31/2018	108.1300	Silted in
6645	Exposed pipe	5/22/2018	116.2000	2 inch spot at 9 o’clock with general corrosion
6645	Valve settings	5/11/2018	198.9706	(2) uncoated 2 in relief valves
6645	Valve settings	5/11/2018	203.4669	(2) uncoated 2 in relief valves
6645	Exposed pipe	5/23/2018	228.8036	Silted in, covered with rock
6645	Valve settings	5/15/2018	276.8326	2 spots dime size on each side of valve. Touch up with spray can

3.1.4 Tank Inspection

A total of 13 tanks were inspected and their inspection types are listed in Table 32. Eight of the 13 tanks were inspected externally and five of the 13 tanks were inspected internally. The external inspection reports for Tanks 8 and 16 show that no problems requiring immediate action were found on foundation, shell, piping and appurtenances, fixed roof, and access structure. The external inspection reports for Tanks 51, 52, 53, 55, 56, and 191-50 show that the shell coating is in fair to good condition and no corrosion was reported. The shell coating condition should be monitored in future inspections. The internal inspection report for Tank 018 indicates the corroded areas on the bottom should be patched per API 653 Standards. The external inspection reports for Tanks 20, 21, 22, and 23 indicate that these tank bottoms are to be replaced.

Table 32. Tank Inspection Summary

Tank #	Product	External inspection	Internal inspection	Inspection date
8	Transmix	X		3/12/2018
16	Gasoline	X		3/13/2018
018	Ethanol		X	7/20/2018
20	Gasoline		X	6/20/2018
21	Gasoline		X*	11/1/2018, 2/8/2019
22	Diesel		X	6/20/2018
23	Gasoline		X	3/28/2019
51	Crude oil	X		4/26/2018
52	Crude oil	X		4/26/2018
53	Crude oil	X		4/26/2018
55	Crude oil	X		4/24/2018
56	Crude oil	X		4/24/2018
191-50	Crude oil	X		3/08/2018

*Tank 21 has post internal inspection on 11/1/2018 and new bottom internal inspection 2/8/2019.

3.2 In-Line Inspection and Rehabilitation Program

In general the 2018 MFL assessments reported more metal loss features when compared with the previous MFL assessments completed in 2012/2013. This is due to an increase in anomalies reported to be in the 10 to 20% WT range. Possible explanations for the difference in shallow features reported include: 1) tool tolerance and 2) reporting criteria. A run-to-run comparison was performed between the current MFL assessment and previous MFL assessment. The comparison indicated areas with possible internal/external feature call discrepancy between the current and previous MFL assessments; see Section 2.2 Corrosion for further details.

The 2018 EGP assessments reported 1,843 ID reductions with 459 located in HCAs. None of the features reported required a repair based on regulatory requirements, however 94 features have been noted as previously repaired with 22 of those located in HCAs.

3.3 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 2018. The results show that none of the pipeline segments exceeded the risk threshold; therefore no additional mitigative measures were required or recommended.

3.4 Damage Prevention Program

Prevention activities include ROW surveillance, One-Call System, and public-awareness activities that continued to be successful in 2018.

The Longhorn Damage 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 severe rainfall and flooding in September, October, and November of 2018.

3.5 Encroachment Procedures

Encroachments are entries to the pipeline 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 was a total of 79 encroachments during 2018, five 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.

3.6 Incident Investigation Program

Magellan is performing incident investigations on all Department of Transportation (DOT)-reportable[23] incidents as well as smaller non-reportable incidents and near-miss events.

During 2018, there were five minor incidents, two near-misses, and one major incident (DOT-Reportable) at the Eckert Pump Station that involved an accidental release of 282 barrels of crude oil due to operator error during maintenance activities. Approximately 258 barrels were recovered. A number of procedures were not followed. Corrective actions were implemented in accordance with Magellan's incident investigation report which was provided to PHMSA.

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.

3.7 Depth-of-Cover Program

A 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.

[23] **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.

3.8 Fatigue Analysis and Monitoring Program

The 2018 fatigue analysis incorporated results from the 2014 SMFL and 2015 TFI tool runs and determined the reassessment interval that has been used by Magellan to effectively monitor the potential for fatigue degradation from pressure-cycle-induced crack growth. From the data obtained during the 2014 SMFL and 2015 TFI tool runs, the shortest time to reassessment is calculated to be 7.3 years from August 2015 leading to a reassessment date of 2022 for the Texon to Barnhart segment. The analysis for this program is covered under Section 2.1 of this report.

3.9 Risk Analysis Program

The objective of Magellan's Risk Analysis 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 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 the 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.

Magellan's risk model is updated periodically as new information becomes available. The pipeline risk model was updated with information from operations in 2018 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).

PHAs are performed on all new facilities, when changes occur in existing facilities, and at 5-year intervals to evaluate and control potential hazards. Two PHAs were completed in 2018; one for the El Paso Terminal Holly Receipt and Storage Tank Project and the other for the Crane Crude Facility.

3.10 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. Six of the incidents in 2018 involved human error/incorrect operations which included minor releases (2 gallons red diesel, 5 gallons diesel, and 10 gallons ethanol), excavation near-misses, and one major incident at the Eckert Pump Station, which resulted in a release of 282 bbls (DOT-Reportable) of crude oil. The release was caused by a failure to close a valve following maintenance activities (failure to follow procedures). These incidents have been formally documented and investigated and corrective actions have been implemented.

3.11 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. A PHA was conducted for the El Paso Terminal Holly Receipt and Storage Tank Project and also for the Crane Crude Facility based on the required 5-year interval.

3.12 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; and
- 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, ROW markers and signs were repaired or replaced where necessary (see Table 33) and public-awareness meetings were held (Table 34). From the standpoint of metal loss deterioration measures, there were 10 metal loss features that met POE dig requirements from the 2018 ILI runs. In terms of failure measures, there was one DOT-reportable incident and no physical hits to the pipeline.

Table 33. Markers Repaired or Replaced[24]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	1	8	4	4	2	2	34	26	0	1	21	2	105

Table 34. Educational and Outreach Meetings[25]

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25	30	30	16	16
School Program - Houston	2	2	3	4		6	5	6	1	3	4	4	5	5
School Program - Austin	3	2	7	3	4	3	4	5	5	2	2	2	3	2
Texas Statewide School Pipeline Safety Outreach													16	3
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							*	12
TOTAL	28	18	25	21	17	22	20	22	17	30	36	36	24	38

NOTE: Public meetings were tallied for the years 2005-2018 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.
- Texas Statewide: Texas School Safety Conference
- 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 2018 TPD Annual Assessment for details.

4 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 (listed below). The 2018 status of each of these measures is evaluated in Section 4.1 through 4.3.

- Activity measures – proactive activities aimed at preserving pipeline integrity

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[24] Mitigation Plan Scorecard 2018.

- Deterioration measures – evidence of deterioration of pipeline integrity
- Failure measures – occurrences of failures or near failures

4.1 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 2018.
- 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.
- 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 35 lists the status of action items for 2018. Table 36 provides a summary of the LPSIP Activity Measures from 2005 through 2018.

Table 35. Number and Status of Action Items per Month for 2018

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	506	500	779	669	500	650	524	508	803	829	512	698	**7478**
Completed	502	502	751	652	500	646	514	496	723	821	510	693	**7310**
Open at End of Month	4	0	28	17	0	6	10	12	80	8	2	5	**172**

Table 36. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
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	152,322
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	536	460	291	76	66	539	266	130	315	194	105
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	36	24	24
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	8,977
	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	6,849
	Tier III	1,498	1,617	1,653	1,459	833	833	918	918	1,312	1,554	3,167	3,111	2,793	1,526

4.2 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 37.

In 2018 there were no immediate conditions as defined by the LPSIP and 49 CFR 195.452. The 2018 results follow a similar trend to recent years (2009-2017) where no immediate conditions had been reported. The monitoring and excavation program should continue to address significant reported anomalies.

Ten ILI reported metal loss features met POE evaluation dig requirements in 2018. 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 37. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
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	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	0
	Tier II	NA	0.0208	NA	NA	0	0	0	0	0	0	0.004	0	0	0
	Tier III	0.192	NA	0.003	NA	0	0	0	0	0	0	0	0	0	0
Total number of anomalies per hydrostatic tests		NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*
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	0.067

*Hydrostatic tests were performed for pipeline commissioning purposes
~POE calculations only performed on the MFL assessments; the number of POE evaluations per mile pigged did not include the TFI mileage.

4.3 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 38. Response times, volumes, and costs are for DOT-reportable leaks. Service interruptions reported during 2018 are shown in Table 39.

Table 38. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Number of leaks (DOT-reportable)		2	0	1	3	0	1	2	0	2	2	0	0	3	1
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	NA	Immed.	Immed.
	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	Immed.	NA
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	282
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA	NA
	Tier III	0	0	0	0	0	0	0	NA	4	0	0	NA	28	NA
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	94
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA	NA
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0	NA	28	NA
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50	< $50	NA	> $100k	< $25	0	NA	>$528k	$7.2M
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50	< $25	NA	< $25k < $50k > $100k	< $25	0	NA	$28k $500k No info	$7.2M
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	5
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	0
Number of near-misses to the pipeline by third parties		7	1	7	5	6	2	4	3	2	0	4	0	8	2
Number of service interruptions		115	165	155	74	16*	17	9	8	15	15	11	8	13	114

Table 39. Service Interruptions per Month for 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
No./Month	11	6	10	8	9	11	0	11	14	14	12	8	**114**

5 INTEGRATION OF INTERVENTION REQUIREMENTS AND RECOMMENDATIONS

5.1 Integration of Primary Line Pipe Inspection Requirements

Section 11 of the ORAPM 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 EGP tools must be run at least every three years.

There is overlap in anomaly detection capabilities of the various commercially available ILI tools and considerable variability in vendor availability. 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.

Table 40 and Table 41 present the most recent completed ILI assessment and note requirement dates for future planned assessments for the crude and refined pipelines, respectively. The required reassessments are specified per the ORAPM. Reassessment requirements for pressure-cycle-fatigue crack growth reassessment intervals were based on the analysis performed in Section 2.1 of this report. Reassessment requirements for corrosion and TPD are based on the most recent inspection date; corrosion inspections are required to be run every five years while TPD are required every three years for the crude line and five years for the refined line. Earth movement, the fifth component for threat integration, is not included in Table 40 because it is currently addressed using surface surveys rather than ILI technology. For a complete listing of all ILI assessments that have occurred on both the crude and refined pipelines refer to the 2018 Longhorn ORA Final Report.

Table 40. Completed ILI Runs and Planned Future ILI's for Longhorn Crude System

		E. Houston to Satsuma	Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley	Cedar Valley to Eckert	Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
	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**	**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	Multi-Data											
	Date of Tool Run	1-Oct-14											
	Tool		TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run		18-Dec-15	16-Dec15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Tool												MFL
	Date of Tool Run												16-Oct-18
	Pressure Cycle Induced Fatigue												
	Tool	TFI ‡											
	Date of Tool Run	6-Jul-07											
	Tool		TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run		18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Tool												UCD
	Date of Tool Run												19-Oct-18
	Laminations & Hydrogen Blisters												
	Tool												UCD
	Date of Tool Run												19-Oct-18
	Third Party Damage												
	Tool	Def.	Def.	Def.									
	Date of Tool Run	14-Sep-17	13-Sep-17	12-Sep-17									
	Tool				Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.
	Date of Tool Run				4-Jan-18	3-Jan-18	7-Mar-18	6-Mar-18	27-Feb-18	22-Feb-18	20-Feb-18	16-Feb-18	13-Feb-18
	Next Required Assessment												
	Corrosion	1-Oct-19	18-Dec-20	16-Dec-20	11-Dec-20	8-Dec-20	4-Dec-20	19-Aug-20	1-Sep-20	29-Aug-20	24-Aug-20	11-Aug-20	16-Oct-23
	Pressure-Cycle Induced Fatigue	2034	2034	2030	2024	2044	2032	2025	2027	2024	2036	2022	2023
	Third-Party Damage	14-Sep-20*	13-Sep-20*	12-Sep-20*	4-Jan-21*	3-Jan-21*	7-Mar-21*	6-Mar-21*	27-Feb-21*	22-Feb-21*	20-Feb-21*	16-Feb-21*	13-Feb-21*

‡ 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 41. 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 Strauss	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			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
	Tool	MFL					MFL	
	Date of Tool Run	18-Apr-18					24-Oct-18	
	Third-Party Damage							
	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
	Tool	Deformation					Deformation	
	Date of Tool Run	18-Apr-18					24-Oct-18	
Next Required Assessment								
	Corrosion	18-Apri-23	1-Nov-22	5-Oct-2021	13-Jul-22	13-Jul-22	24-Oct-23	14-Jul-22
	Pressure-Cycle Induced Fatigue	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not susceptible*	*Not Susceptible*
	Third-Party Damage	18-Apri-23	1-Nov-22	Oct-5-2021	13-Jul-22	13-Jul-22	24-Oct-23	14-Jul-22

5.2 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 an EGP tool to be run every three years on the Existing Pipeline (between Valve J-1 and Crane). This interval is due to greater risk of mechanical damage on the Existing Pipeline. The Existing Pipeline is often buried shallower than 30 inches in depth below the surface because of burial requirements when the pipeline was built. For the new pipeline extensions the HCA requirement (49 CFR 195.452) requires an EGP tool to be run every five years. The risk for mechanical damage on the New Pipeline is less due to the pipeline being buried at least 30 inches deep.

5.3 Pipe Replacement Schedule

There were no pipe replacements in 2018.

6 NEW INTEGRITY MANAGEMENT TECHNOLOGIES

6.1 Fault Displacement Monitoring

During a resurvey event at each station, the relative vertical distance between the top of each pair of benchmarks was measured using an automatic level and leveling rod graduated in two millimeter increments held on top of each benchmark. Level rod measurements were made to the nearest 0.001 meter (m) with an error range of +/- 0.001 m. A total of four measurement readings, collected by two people who alternate collecting the measurements and holding the level rod, are averaged to reduce the potential for human measurement error. Subtracting the baseline distance measurement from the resurvey distance measurement yields the amount of vertical displacement that has occurred over the time between two measurement events.”

While there is nothing amiss with how the fault movements are measured, it is nevertheless manual, prone to human error, and of a frequency (twice a year) which is more suited to where little or no earth movement is expected and, there is little chance of seismic events. It is also ex post facto.

Additionally, the monitoring is indirect. It does not measure the movement of the pipe as a result of earth movement. The impact of the movement on the pipe needs to be calculated or assumed by some manner; preferably FEA. However, the results of the FEA cannot be verified against measured movement or stresses of the pipe. FEA is a very reliable and accurate toll for predicting stresses with known loads and boundary conditions. In displacement monitoring, FEA needs calibrating.

The use of live monitoring of strains and movement in pipelines has become routine in the pipeline industry. The results are accurate, direct, and can be used to calibrate the complimentary FEA. Live monitoring allows for pro-active mitigation if and when the need arises. And, it yields far greater data to use for predictive modelling.

Use of strain gauges with live monitoring reports requires access to the pipeline. If, installing live monitoring technology at the fault line locations is not an option, then numerical simulation of potential movement of the pipeline arising from earth movement is beneficial. This option relies heavily on data and modeling with stress and strain windows for the pipe which is, again, superior to the current comparison of movement which causes a stress of a certain level in the pipe.

The monitoring – annual or semi-annual – survey of waterways to confirm minimum depth of cover for the pipeline does not rely on high technology either but, in this case, there is little merit in applying more sophisticated techniques. At the same time, there does not appear to be a formal process for calculating the re-assessment interval. This should be remedied by introducing an index which identified where should be surveyed how frequently.

7 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.
7. The Longhorn Mitigation Plan, September 2000.

APPENDIX A – MITIGATION COMMITMENTS

Table A-1. Longhorn Mitigation Commitments (pg 1 of 6)

No.	Description	Timing of Implementation	Risk(s) Addressed
1	Longhorn shall hydrostatically test the hypersensitive (Tier III) and sensitive (Tier II) areas of the pipeline and those portions of the pipeline identified by the Surge Pressure Analysis as being potentially subject to surge pressures in excess of current MASP. See Mitigation Appendix, Item 1 and 9.	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Previous Defects; Establish Safety Factor
2	Longhorn shall "proof test" all portions of the pipeline from the J-1 Valve to Crane Station that have not been hydrostatically tested pursuant to Mitigation Commitment No. 1. See Mitigation Appendix, Item 2	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Previous Defects
3	Longhorn shall replace approximately 19 miles of the existing pipeline over the Edwards Aquifer recharge and contributing zones with thick walled pipe; the pipe will be protected by a concrete barrier. See Mitigation Appendix, Item 3	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Previous Defects
4	Longhorn shall perform the following additional cathodic protection mitigation work: (a) Install 13 additional CP ground beds at locations described in Mitigation Appendix, Item 4. (b) Perform interference testing at 20 locations, if necessary, as described in Mitigation Appendix, Item 4. (c) Replace at least 600 feet of coating identified by the CP survey analysis as described in Mitigation Appendix, Item 4. (d) Repair or replace, as necessary, 12 shorted casings identified by the CP survey analysis at the locations described in Mitigation Appendix, Item 4.	Prior to startup / Completed	Corrosion
5	Longhorn shall lower, replace, or recondition, if necessary, the pipe at 12 locations per the Environmental Assessment (including Marble Creek). See Mitigation Appendix, Item 5.	Prior to startup / Completed	Outside Force Damage, Corrosion, and Material Defects
6	Longhorn shall remove stopple fittings at the following locations: Station Nos. 9071+36, 8936+35, and 8796+99 (MP 171.86, 169.25, and 166.61). See Mitigation Appendix, Item 6.	Prior to startup / Completed	Material Defects
7	Longhorn shall excavate the pipeline at two locations, near Satsuma Station and in Waller County, indicated by the 1995 in-line inspection and determine condition and repair, if necessary. See Mitigation Appendix, Item 7.	Prior to startup / Completed	Material Defects and Corrosion
8	Longhorn shall replace the pipeline at the crossing of Rabb's Creek and investigate at least 5 dent locations identified by Kiefner, based upon the 1995 in-line inspection, and repair, if necessary. See Mitigation Appendix, Items 8 and 19.	Prior to startup / Completed	Material Defects, Corrosion, and Outside Force Damage

Table A-2 (continued). Longhorn Mitigation Commitments (pg 2 of 6)

No.	Description	Timing of Implementation	Risk(s) Addressed
9	Longhorn shall remediate any maximum allowable surge pressure problems identified by Longhorn's most recent Surge Pressure Analysis by hydrostatically testing those portions of the pipeline which the Surge Pressure Analysis indicates could exceed maximum allowable surge pressures. The hydrostatic test will requalify the portions of the pipeline which will be tested to a maximum allowable surge pressure which is within permissible limits as established by the most recent Surge Pressure Analysis. Further, Longhorn will implement appropriate measures in all Tier II and Tier III areas of the pipeline to eliminate the possibility of conditions causing a surge pressure which would exceed maximum operating pressure (MOP). See Mitigation Appendix, Item 9 and Longhorn Mitigation Commitment 34.	Prior to startup / Completed	Material Defects and Corrosion
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

Table A-3 (continued). Longhorn Mitigation Commitments (pg 3 of 6)

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:	Prior to startup / Completed	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
21	Longhorn shall increase the frequency of inspections at pump stations to every two and one-half days in sensitive startup and hypersensitive areas. Additionally, remote cameras for monitoring pump stations will be installed, within 6 months of startup for existing stations, and at future stations prior to startup. See Mitigation Appendix, Item 21.	Continuously after startup	Outside Force Damage, Corrosion, Material Defects, Leak Detection and Control
22	Longhorn shall commission a study that quantifies the costs and benefits of additional valves at the following river and stream crossings: Marble Creek; Onion Creek; Long Branch; Barton Creek; Fitzhugh Creek; Flat Creek; Cottonwood Creek; Hickory Creek; White Oak Creek; Crabapple Creek; Squaw Creek; Threadgill Creek; and James River. Longhorn shall install additional valves if it determines, on the basis of the study, with DOT/OPS concurrence, that additional valves will be beneficial. See Mitigation Appendix, Item 22.	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Leak Detection and Control
23	Longhorn shall develop a response center in the middle area of the pipeline which will include available response equipment and personnel such that under normal conditions, a maximum 2-hour full response can be assured. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	Leak Detection and Control
24	Longhorn shall revise its facilities response plan to better address firefighting outside of metropolitan areas (Houston, Austin and El Paso) where HAZMAT units do not exist. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	

Table A-4 (continued). Longhorn Mitigation Commitments (pg 4 of 6)

No.	Description	Timing of Implementation	Risk(s) Addressed
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
26	Longhorn shall revise its facility response plan to provide for more detailed response planning for areas where high Control populations of potentially sensitive receptors are on or adjacent to the pipeline right-of-way. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	Leak Detection and Control
27	Longhorn shall provide evidence (as-built engineering drawings and similar such documentation) that secondary Control containment was installed, during construction, under and around all storage and relief tanks, in accordance NFPA 30. Longhorn shall install secondary containment at the Cedar Valley pump station in Hays County.	Prior to startup / Prior to startup	Leak Detection and Control
28	Longhorn shall revise its facility response plan, if or as necessary, to make it consistent, to the extent practicable, the referenced plans are Control with the City of Austin's Barton Springs oil spill developed contingency plan and the United States Fish and Wildlife Service's Barton Springs Salamander Recovery Plan. See Mitigation Appendix, Item 28.	Prior to startup / Completed	Leak Detection and Control
29	Longhorn shall provide funding for a contractor (employing personnel with the necessary education, training and experience) to conduct water quality monitoring at each of 12 locations in proximity to stream crossings of the pipeline to determine the presence of gasoline constituents. See Mitigation Appendix, Item 29.	For a period of two years after startup to evaluate the effectiveness of the program and thereafter as dictated by the Longhorn ORA (See Section 4.0).	Leak Detection and Control

Table A-5 (continued). Longhorn Mitigation Commitments (pg 5 of 6)

No.	Description	Timing of Implementation	Risk(s) Addressed
30	Longhorn shall provide alternate water supplies to certain water municipalities and private well users as detailed in Longhorn's contingency plans. See Mitigation Appendix, Item 30.	Prior to startup / Completed	Leak Detection and Control
31	Longhorn shall perform a surge pressure analysis prior to any increase in the pumping capacity above those rates for which analyses have been performed or any other change which has the capability to change the surge pressures in the system. Longhorn will be required to submit mitigation measures acceptable to DOT/OPS prior to any such change in the system, which mitigation measures will adequately address any MASP problems on the system identified by the surge pressure analysis.	Prior to any change in the system that has the capability to cause surge pressures to occur on the system.	Material Defects
32	Longhorn shall perform pipe-to-soil potential surveys semi-annually over sensitive and hypersensitive areas (which is twice the frequency required by DOT regulation – 49 CFR 195.573), and corrective measures will be implemented, as necessary, where indicated by the surveys. See Longhorn Pipeline System Integrity Plan, Section 3.5.1.	No more than six months after startup and semi-annually thereafter.	Corrosion
33	(a) Longhorn shall provide the necessary funding to establish as adequate refugium and captive breeding program for the Barton Springs Salamander to offset any losses that might occur in the highly unlikely event of a release that caused the loss of individual salamanders. This program will be conducted in coordination with the Austin Ecological Services Field Office of the U.S. Fish and Wildlife Service; and	Within 30 days of startup / Completed	Potential adverse effects to the Barton Springs Salamander
	(b) Longhorn shall perform conservation measures developed in consultation with the U.S. Fish and Wildlife service to mitigate potential impacts to threatened and endangered specifies in the highly unlikely event that future pipeline construction activities and operation may adversely affect such species or their habitat. See Mitigation Appendix, Item 33.	At any time such activity could have an adverse effect on listed species or habitat.	Potential adverse effects to listed species or habitat
35	Longhorn shall not transport products through the pipeline system which contain the additive methyl tertiary butyl ether (MTBE) or similar aliphatic ether additives (e.g., TAME, ETBE, and DIPE) in greater than trace amounts. This limitation with be incorporated into the Longhorn product specifications.	During the operational life of the pipeline system	Potential adverse impacts to water resources
36	Longhorn shall prepare site-specific environmental studies for each new pump station planned for construction. These studies shall be responsive to National Environmental Policy Act requirements as supplements to the EA of the Proposed Longhorn Pipeline System. For each such pump station, Longhorn shall submit the site-specific environmental study to the U.S. DOT no less than 180 days prior to commencement of construction.	Prior to construction of any new pump station	Consistency with NEPA

Table A-6 (continued). Longhorn Mitigation Commitments (pg 6 of 6)

No.	Description	Timing of Implementation	Risk(s) Addressed
37	Longhorn shall maintain pollution legal liability insurance of no less than $15 million to cover on-site and off-site third party claims for bodily injury, property damage, and costs of response and cleanup in the event of a release of product from the Longhorn Pipeline System.	Prior to startup and during the operational life of the pipeline system	Financial Assurance
38	Longhorn shall submit periodic reports to DOT/OPS that will include information about the status of mitigation commitment implementation, the character of interim developments as related to mitigation commitments, and the results of mitigation-related studies and analyses. The reports shall also summarize developments related to its ORA. The reports shall be made available to the public.	Quarterly during the first 2 years of system operation and annually thereafter for the operational life of the pipeline system.	Assurance of mitigation commitment implementation and public access to related information.
39	The Longhorn Mitigation Plan, and associated Pipeline System Integrity Plan and ORA, shall not be unilaterally changed. The LMP may be modified only after Longhorn has reviewed proposed changes with DOT/OPS and has received from DOT/OPS written concurrence with the proposed modifications.	During the operational life of the pipeline system	Assurance of full implementation of the Longhorn Mitigation Commitments.

APPENDIX B – NEW DATA USED IN THIS ANALYSIS

B.1. Data Used in this Analysis

Table B-1. 2018 ORA Data List (pg 1 of 2)

Topics	Data / Notes
1. Pipeline and Facilities	• Alignment Sheets – 6643 – E. Houston to 9th Street – 6645 – E. Houston to El Paso • Linefill Sheets • Maps and Flow Schematics (strip maps, KMZ files) • Tier Classifications • List of HCAs • Facility Inspection Reports – Crane (9/18) – Barnhart (10/29) – El Paso (11/14) – Warda (12/21)
2. Flow and Pressure Data	• Monthly spreadsheet of flow and pressures • Service Interruptions
3. ILI & Anomaly Investigation Reports	• ILI Reports – Crane to Texon - MFL - Caliper – Crane to Texon - NPS – Crane to Texon - Deformation – Texon to Barnhart - Deformation – Barnhart to Cartman - Deformation – Cartman to Kimble - Deformation – Kimble to James River - Deformation – James River to Eckert - Deformation – Eckert to Cedar Valley - Deformation – Cedar Valley to Bastrop - Deformation – Bastrop to Warda – Deformation – El Paso to Strauss – MFL • Tool specifications
4. Hydrostatic Testing Reports	• No hydrostatic tests performed in 2018.
5. Corrosion Management Surveys & Reports	• Cathodic Protection Data – Rectifier Inspection Reports – Rectifier Maintenance Reports – Test Point Exception Reports – CIS Reports ▪ E-Houston to Speed ▪ Satsuma to E Houston ▪ Bastrop to Satsuma ▪ Kimble to Bastrop ▪ Crane to Kimble • Coupon Data • Atmospheric Inspection Reports • Tank Inspections • 7.04-ADM-001 Corrosion Control Program

Table B-1 (continued). 2018 ORA Data List (pg 2 of 2)

Topics	Data / Notes
6. Earth Movement & Water Forces	• Fault monitoring (semi-annual reports) • River crossing and scouring surveys – James River Report – Llano River Report • Master River Inspections Spreadsheet • Flood monitoring (daily)
7. Maintenance and Inspection Reports	• Maintenance Reports • Nondestructive Evaluation (NDE) • Positive Material Identification (PMI) • Mainline Valve Inspection Reports • Longhorn Year-end Preventive Maintenance Tasks Summary
8. Project Work Progress and Quality Control Reports	• CMS Year End Task Report • Preventive Maintenance Summary • Scorecards • Annual Asset Integrity Summary for 2018 • 2018 Annual Commitment Implementation Status Report • 2018 Annual Self-Audit
9. One-Call Violations and Third-Party Damage Prevention Data	• Third-Party Damage Report • One-call list • Encroachments • Patrol Data • Depth of Cover Surveys (None) • Website Visits • Damage Prevention Training
10. Incident, Root Cause and Metallurgical Failure Analysis Reports	• Incident Data and Incident Investigation Reports
11. Other LPSIP / Risk Assessment Studies, Evaluations and other Program Data	• Process Hazard Analyses – Crane Crude PHA – El Paso Terminal Holly receipt and Storage Tank Project PHA
12. Leak Detection	• Pipeline Leak Monitoring (PLM) Records • Description of System(s)
13. Integrity Management Plan (IMP) & Related Procedures	• IMP Plan and related procedures

B.2. Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity

B.2.1 PHMSA Advisories

There were none that were applicable to the Longhorn Pipeline during 2018.

B.2.2 PHMSA Notices

Pipeline Safety: Guidance on the Extension of the 7-year Integrity Management Reassessment Interval by 6 Months, 11/15/2018. PHMSA published this document to seek public comments on frequently asked questions (FAQs) developed to provide guidance on what constitutes sufficient justification for an operator to request a 6-month extension to a gas pipeline's 7-year integrity management reassessment interval. This guidance, which consists of one revised and two new FAQs, will implement authority granted by Congress in Section 5(e) of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act).

B.2.3 DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2018.

B.2.4 Literature Reviewed

See references.

APPENDIX C – APPROACH TO API 1163 VERIFICATION

Approach to API 1163 Verification

API 1163 2nd Edition, April 2013 describes methods in Section 7 and Section 8 that can be applied to verify that the ILI tool was working as expected and reported inspection results are within the performance specification for the pipeline being inspected. Within the Standard, a distinction is made between results with and without field verification measurements. API 1163 Section 7 provides information for what the ILI Vendor is to provide regarding pre-, mid-, and post-inspection checks for proper tool runs. API 1163 Section 8 Figure 6 (Figure C-1 in this document) describes a process for validating ILI measurements using three levels of validation, shown in Figure C-2.

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

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

The validation levels differ based on the risk of the pipeline segment and the amount of validation data.

Validation Level 1 (Annex C):

- 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 low levels of 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.

Validation Level 2 (Annex C):

- 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 typically be greater than or equal to five, but not be 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 (§8.2.6)

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

Depending upon 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. Some actions to consider are: performing additional validation digs to gather more information to possibly improve the current tool performance, accept the determined tool performance as is and adjust the depth accuracy applied to the reported ILI features; or have the ILI Vendor regrade the data. Figure C-1 shows API 1163 Section 8 Figure 6, which summarizes the process for evaluation of system results. For clarity of wording in the flow chart, "historical data" is taken to mean the data limited to the particular line, whereas "large-scale historical data" is taken to mean the data on this line, as well as any similar diameter lines with the same ILI tool type used for inspection.

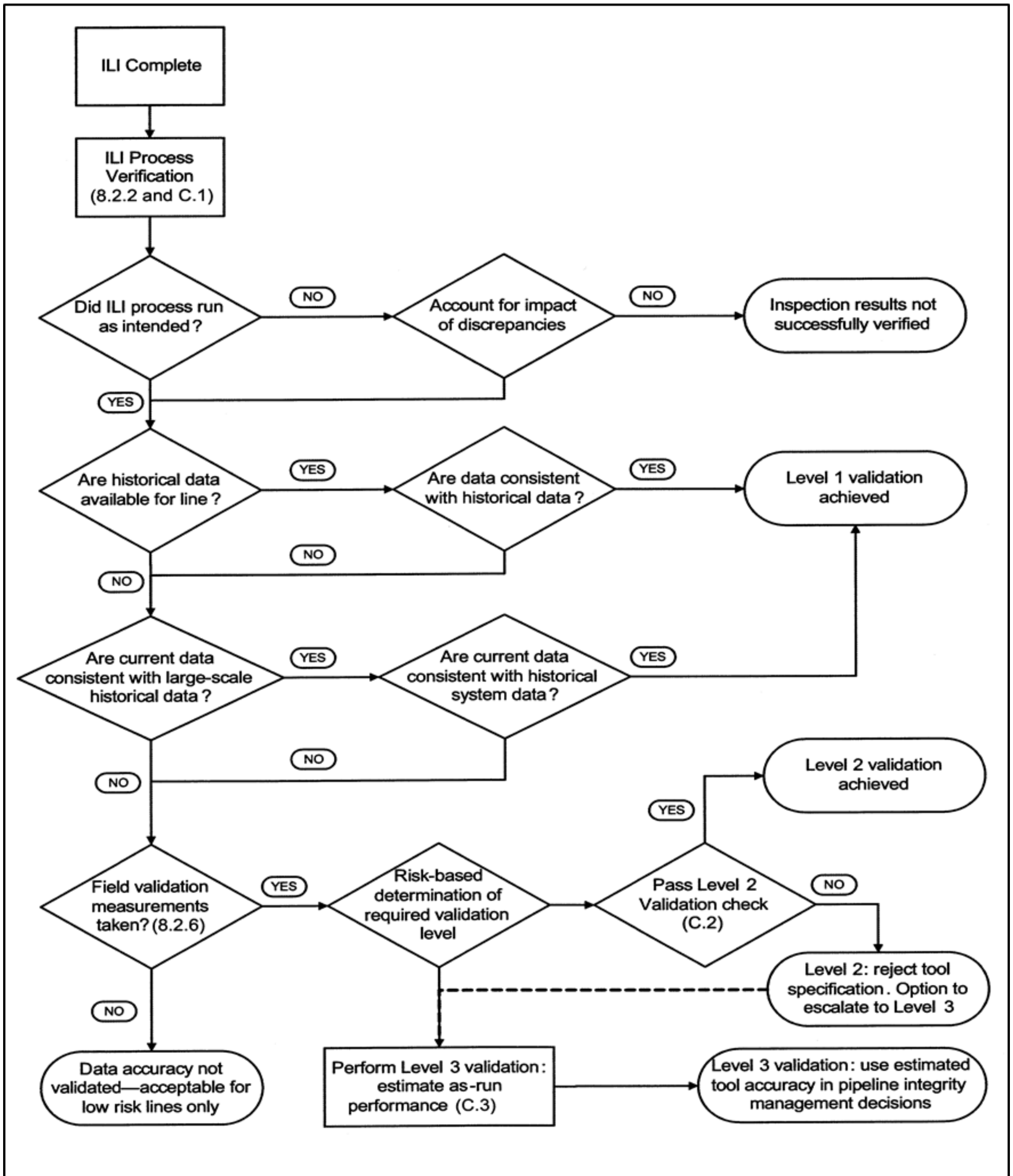

Figure 6—Inspection Results Verification and Validation Process

Figure C-1. Evaluation of System Results from API 1163 Section 8 Figure 6

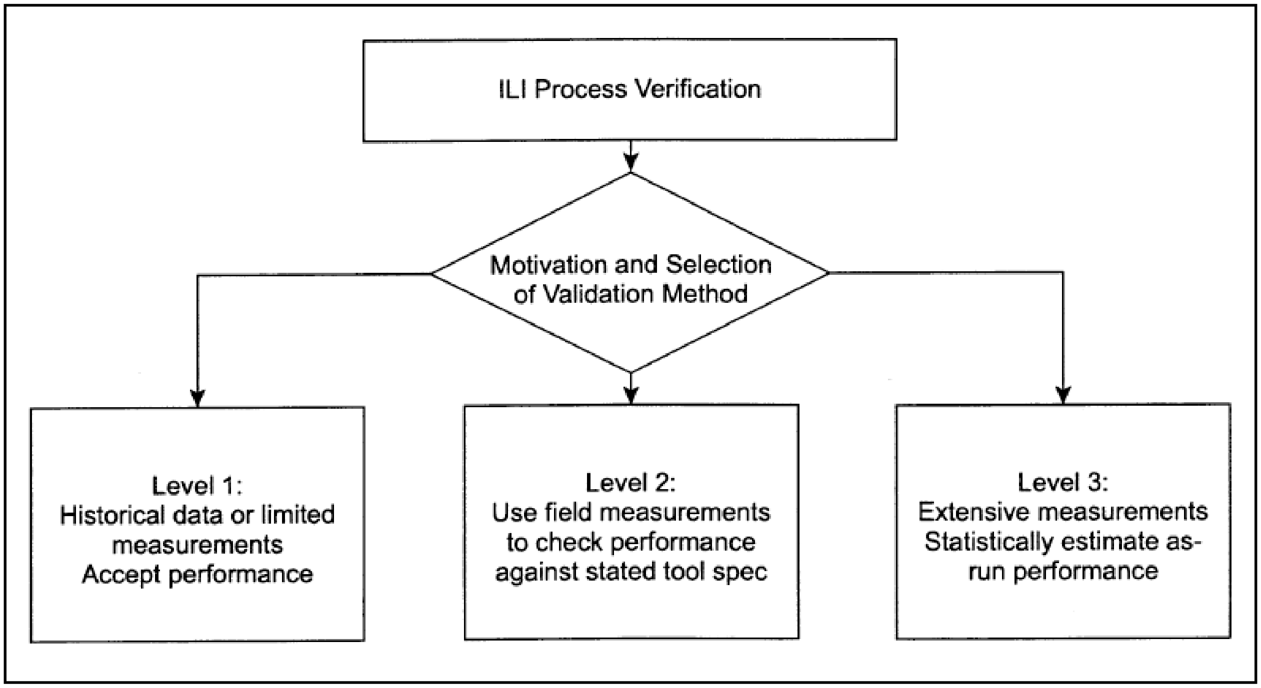

Figure C-2. Overview of Three Levels of Validation

APPENDIX D – INTRODUCTION TO NORMAL DISTRIBUTION AND OUTLIERS

Before an in depth probabilistic analysis is performed, some common statistical values should be calculated to determine if any data should be excluded from the analysis. These values would include the average, standard deviation, normal distribution, outliers, and extreme values.

Normal Distribution

A normal distribution is a probability distribution that is commonly referred to as the bell curve that is symmetrical around the mean value. Errors in measurements tend to closely resemble a normal distribution which is why ILI vendors will use normal distributions to explain the ILI tool's sizing accuracy. Some common parameters that are associated with a normal distribution are the average or mean, standard deviation, and cumulative probability. The standard deviation is a quantification of how dispersed a set of data is. The cumulative probability is the probability a value is less than or equal to a specified value of the normal distribution. These values can be determined using Equation 1 through Equation 5 and can be calculated in Excel using the Excel functions in Equation 6 through Equation 9.

$X_i =$ the individual value of each measurement in the data set

$n =$ the total number of values in the data set

$\mu =$ the mean value of the data set

$\sigma =$ the standard deviation of the data set

$CDF_i =$ the cumulative probability from the cumulative distribution function of a normal distribution

$erf =$ the error function associated with the cumulative distribution function

$p =$ a specified cumulative probability

$QF_i =$ the data value for a specified cumulative probability

$$\mu = \frac{1}{n}\sum_{i=1}^{n} X_i$$ **Equation 1**

$$\sigma = \sqrt{\frac{\sum_{i+1}^{n}\left(X_i - \mu\right)^2}{n-1}}$$ **Equation 2**

$$CDF_i = \frac{1}{2}\left[1 + erf\left(\frac{X_i - \mu}{\sigma\sqrt{2}}\right)\right]$$ **Equation 3**

$$erf(x) = \frac{2}{\sqrt{\pi}}\int_0^x e^{-t^2}\,dt$$ **Equation 4**

$$QF_i = \mu + \sigma\sqrt{2}erf^{-1}(2F-1)$$ **Equation 5**

$$\mu = AVERAGE(Range\ of\ Values)$$ **Equation 6**

$$\sigma = STDEV(Range\ of\ Values)$$ **Equation 7**

$$CDF_i = NORM.DIST(X_{i,}\mu, \sigma, TRUE)$$ **Equation 8**

$$QF = NORM.INV(p, \mu, \sigma)$$ **Equation 9**

Outliers and Extreme Values

An outlier and extreme value is any value that is observed to lie an abnormal distance from the other values in a data set. These abnormal distances can be quantified using Tukey's schematic box plot method. This method uses the 25th and 75th percentiles of the normal distribution to define an interquartile range (IQR) that encompasses 50% of the population. From the IQR, inner and outer fences can be established outside of the 25th and 75th percentiles. An outlier is considered to be any value that is beyond the inner fence. An extreme value is considered to be any value that is beyond the outer fence. These values can be determined using Equation 10 through Equation 14 and can be calculated in Excel using the Excel functions in Equation 15 and Equation 16.

$\mu =$ the mean value of the data set

$\sigma =$ the standard deviation of the data set

$Q_1 =$ the 25th percentile of the normal distribution (value at the cumulative probability of 0.25)

$Q_3 =$ the 75th percentile of the normal distribution (value at the cumulative probability of 0.75)

$IQR =$ the interquartile range of the normal distribution

$LOF =$ the outside fence of the lower 25th percentile

$LIF =$ the inside fence of the lower 25th percentile

$UIF =$ the inside fence of the upper 75th percentile

$UOF =$ the outside fence of the upper 75th percentile

$$IQR = Q_3 - Q_1$$ **Equation 10**

$$LOF = Q_1 - 3 * IQR$$ **Equation 11**

$$LIF = Q_1 - 1.5 * IQR$$ **Equation 12**

$$UIF = Q_3 - 1.5 * IQR$$ **Equation 13**

$$UOF = Q_3 - 3 * IQR$$ **Equation 14**

$$Q_1 = NORM.INV(0.25, \mu, \sigma)$$ **Equation 15**

$$Q_3 = NORM.INV(0.75, \mu, \sigma)$$ **Equation 16**

APPENDIX E – PIPELINE SEGMENTS USED FOR THRESHOLD ANOMALY EVALUATION

Table E-1. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations on Crude Oil Pipeline (pg 1 of 4)

S/N	Pipeline Segment	Wall Thickness	Grade	Closest Dist. to Upstream Pump Discharge for Pipe with Attribute	Elevation (feet)	Year of Installation of Pipe Nearest to U/S Pump Discharge	Oldest pipe with Attribute	Newest pipe with Attribute	Flaw Depth WT in PCFA	Threshold Anomaly Depth at ILI Detection Threshold (%)
1	Crane-Texon	0.250	X52	24062+95	2525.26	1953	1953	1953	0.125	0.5
2	Crane-Texon	0.281	X46	22422+53	2664.11	1953	1953	1953	0.141	0.5
3	Crane-Texon	0.281	X65	24157+75	2524.11	1998	1998	1998	0.028	0.1
4	Crane-Texon	0.375	B	24158+24	2523.98	1950	1950	1950	0.188	0.5
5	Crane-Texon	0.375	X52	23916+23	2575.26	1950	1950	1950	0.188	0.5
6	Crane-Texon	0.375	X65	24112+45	2540.29	1950	1950	1950	0.188	0.5
7	Crane-Texon	0.385	X65	24020+03	2536.65	1950	1950	1950	0.193	0.5
8	Texon-Barnhart	0.250	X52	21999+54	2674.67	1953	1953	1953	0.125	0.5
9	Texon-Barnhart	0.281	X65	21388+14	2664.34	1998	1998	2012	0.028	0.1
10	Texon-Barnhart	0.312	X45	21351+54	2665.78	1950	1950	1950	0.156	0.5
11	Texon-Barnhart	0.375	B	22000+11	2674.97	2012	2012	2012	0.038	0.1
12	Texon-Barnhart	0.375	X42	21998+94	2674.48	2012	2012	2012	0.038	0.1
13	Texon-Barnhart	0.375	X52	19727+34	2602.17	1998	1998	1998	0.038	0.1
14	Texon-Barnhart	0.375	X65	21353+94	2664.90	1999	1999	1999	0.038	0.1
15	Texon-Barnhart	0.385	X65	21599+94	2722.74	2000	2000	2000	0.039	0.1
16	Barnhart-Cartman	0.281	X45	19262+28	2532.58	1950	1950	1950	0.141	0.5
17	Barnhart-Cartman	0.281	X65	19716+78	2604.66	1998	1998	2007	0.028	0.1
18	Barnhart-Cartman	0.312	X45	19726+03	2603.38	1950	1950	1950	0.156	0.5
19	Barnhart-Cartman	0.312	X52	19717+38	2604.86	1998	1998	1998	0.031	0.1
20	Barnhart-Cartman	0.312	X60	18862+38	2501.35	2000	2000	2000	0.031	0.1
21	Barnhart-Cartman	0.312	X65	18853+98	2500.59	2000	2000	2000	0.031	0.1
22	Barnhart-Cartman	0.375	X45	18180+24	2445.80	2012	2012	2012	0.038	0.1
23	Barnhart-Cartman	0.375	X52	18561+24	2477.46	2007	2007	2007	0.038	0.1
24	Barnhart-Cartman	0.375	X60	18860+28	2501.08	2000	2000	2000	0.038	0.1
25	Barnhart-Cartman	0.375	X65	18852+18	2500.72	2000	2000	2002	0.038	0.1
26	Barnhart-Cartman	0.385	X65	19265+88	2531.56	2000	2000	2000	0.039	0.1
27	Barnhart-Cartman	0.500	X52	18303+24	2452.03	2012	2012	2012	0.050	0.1
28	Cartman-Kimble	0.281	X45	18168+81	2444.72	1950	1950	1950	0.141	0.5
29	Cartman-Kimble	0.281	X52	17883+21	2398.62	1950	1950	1950	0.141	0.5
30	Cartman-Kimble	0.281	X65	18173+61	2445.11	1950	1950	1950	0.141	0.5
31	Cartman-Kimble	0.312	X45	18174+51	2445.21	1950	1950	1950	0.156	0.5

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis Locations (pg 2 of 4)

S/N	Pipeline Segment	Wall Thickness	Grade	Closest Dist. to Upstream Pump Discharge for Pipe with Attribute	Elevation (feet)	Year of Installation of Pipe Nearest to U/S Pump Discharge	Oldest pipe with Attribute	Newest pipe with Attribute	Flaw Depth WT in PCFA	Threshold Anomaly Depth at ILI Detection Threshold (%)
32	Cartman-Kimble	0.375	B	18178+76	2445.67	2004	2004	2004	0.038	0.1
33	Cartman-Kimble	0.375	X45	17141+01	2228.94	2000	2000	2000	0.038	0.1
34	Cartman-Kimble	0.375	X52	17307+51	2270.64	2002	2002	2004	0.038	0.1
35	Cartman-Kimble	0.375	X65	17884+41	2399.70	2002	2000	2002	0.038	0.1
36	Cartman-Kimble	0.385	X65	17586+21	2413.68	2000	2000	2000	0.039	0.1
37	Cartman-Kimble	0.500	X52	18037+41	2425.85	2012	2012	2012	0.050	0.1
38	Kimble-James River	0.219	X52	14758+39	1668.73	1967	1967	1967	0.110	0.5
39	Kimble-James River	0.281	X45	15584+59	2222.70	1950	1947	1967	0.141	0.5
40	Kimble-James River	0.281	X65	15260+29	2122.51	2013	1998	2013	0.028	0.1
41	Kimble-James River	0.375	X42	14878+99	1826.87	1995	1995	1995	0.038	0.1
42	Kimble-James River	0.375	X45	14604+19	1511.29	1950	1950	2013	0.188	0.5
43	Kimble-James River	0.375	X45	14596+69	1533.33	2013		2013	0.038	0.1
44	Kimble-James River	0.375	X52	15585+23	2221.42	1998	1998	2012	0.038	0.1
45	Kimble-James River	0.375	X65	15144+49	2105.81	2002	1998	2012	0.038	0.1
46	Kimble-James River	0.385	X65	14607+19	1528.31	2000	1998	2000	0.039	0.1
47	James River-Eckert	0.281	X45	13733+47	1704.59	1950			0.141	0.5
48	James River-Eckert	0.281	X65	13371+07	1648.59	2013	2012	2013	0.028	0.1
49	James River-Eckert	0.312	X45	12039+26	1717.19	1950			0.156	0.5
50	James River-Eckert	0.312	X60	13585+57	1776.94	1950			0.156	0.5
51	James River-Eckert	0.375	B	13735+06	1712.30	1950			0.188	0.5
52	James River-Eckert	0.375	X42	13448+47	1841.57	1950			0.188	0.5
53	James River-Eckert	0.375	X52	13200+97	1511.42	1950			0.188	0.5
54	James River-Eckert	0.375	X65	12921+69	1698.43	2012		2012	0.038	0.1
55	James River-Eckert	0.375	X65	13586+77	1777.82	1950			0.188	0.5
56	James River-Eckert	0.375	X70	12186+09	1605.97	1950			0.188	0.5
57	James River-Eckert	0.385	X65	13435+87	1783.23	1950			0.193	0.5
58	Eckert-Cedar Valley	0.281	X45	12033+42	1735.56	1950	1950	2012	0.141	0.5
59	Eckert-Cedar Valley	0.281	X45	11499+12	1648.03	2012		2012	0.028	0.1
60	Eckert-Cedar Valley	0.312	X45	12029+82	1743.77	1950	1950	1950	0.156	0.5
61	Eckert-Cedar Valley	0.375	B	10508+23	996.46	2012	2012	2012	0.038	0.1
62	Eckert-Cedar Valley	0.375	X52	12035+40	1728.15	2006	1995	2013	0.038	0.1

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis Locations (pg 3 of 4)

S/N	Pipeline Segment	Wall Thickness	Grade	Closest Dist. to Upstream Pump Discharge for Pipe with Attribute	Elevation (feet)	Year of Installation of Pipe Nearest to U/S Pump Discharge	Oldest pipe with Attribute	Newest pipe with Attribute	Flaw Depth WT in PCFA	Threshold Anomaly Depth at ILI Detection Threshold (%)
63	Eckert-Cedar Valley	0.375	X65	11998+62	1821.75	2012	2000	2012	0.038	0.1
64	Eckert-Cedar Valley	0.385	X65	11389+62	1584.81	2000	2000	2010	0.039	0.1
65	Eckert-Cedar Valley	0.500	B	11439+42	1704.59	2012	2012	2012	0.050	0.1
66	Cedar Valley-Bastrop	0.281	X45	8965+58	789.93	1950	1950	1950	0.141	0.5
67	Cedar Valley-Bastrop	0.281	X65	8430+98	552.89	2013	2013	2013	0.028	0.1
68	Cedar Valley-Bastrop	0.312	X45	8896+16	707.58	1950	1950	1950	0.156	0.5
69	Cedar Valley-Bastrop	0.375	X52	9099+68	865.22	2002	2002	2002	0.038	0.1
70	Cedar Valley-Bastrop	0.375	X65	9590+73	1032.32	2002	2002	2002	0.038	0.1
71	Cedar Valley-Bastrop	0.385	X65	9561+68	972.67	2002	2000	2002	0.039	0.1
72	Cedar Valley-Bastrop	0.500	X65	7828+82	502.53	2012	2012	2012	0.050	0.1
73	Bastrop-Warda	0.281	X45	7483+48	395.21	1950	1950	1950	0.141	0.5
74	Bastrop-Warda	0.281	X65	7157+10	347.90	1950	1950	2012	0.141	0.5
75	Bastrop-Warda	0.312	X45	6789+27	469.91	1950	1950	1950	0.156	0.5
76	Bastrop-Warda	0.312	X65	5965+07	355.48	1967	1967	1967	0.156	0.5
77	Bastrop-Warda	0.375	B	7360+80	393.70	2002	2002	2002	0.038	0.1
78	Bastrop-Warda	0.375	X42	6797+67	430.25	1950	1950	1950	0.188	0.5
79	Bastrop-Warda	0.375	X45	7113+00	336.88	1950	1950	1950	0.188	0.5
80	Bastrop-Warda	0.375	X52	6887+67	356.46	1995	1995	2002	0.038	0.1
81	Bastrop-Warda	0.375	X65	7115+70	337.04	2002	2002	2013	0.038	0.1
82	Bastrop-Warda	0.385	X65	7115+40	337.04	2000	2000	2002	0.039	0.1
83	Warda-Buckhorn	0.281	X45	5702+41	380.18	1950	1950	2012	0.141	0.5
84	Warda-Buckhorn	0.281	X45	4506+01	337.80	2012		2012	0.028	0.10
85	Warda-Buckhorn	0.312	X45	5961+54	359.09	1950	1950	1950	0.156	0.5
86	Warda-Buckhorn	0.375	B	5518+21	512.01	1950	1950	1950	0.188	0.5
87	Warda-Buckhorn	0.375	X52	5041+21	391.11	2012	1950	2000	0.038	0.1
88	Warda-Buckhorn	0.375	X52	4027+51	340.39	1950	1950	X	0.188	0.5
89	Warda-Buckhorn	0.375	X65	5945+30	314.76	2002	2000	2002	0.038	0.1
90	Warda-Buckhorn	0.385	X65	4539+01	319.26	1950	1950	2000	0.193	0.5
91	Warda-Buckhorn	0.385	X65	4080+61	229.04	2000		2000	0.039	0.1
92	Buckhorn-Satsuma	0.281	X45	3587+47	170.64	1950	1947	2013	0.141	0.5
93	Buckhorn-Satsuma	0.281	X45	3064+08	179.43	2013		2013	0.028	0.1

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis Locations (pg 4 of 4)

S/N	Pipeline Segment	Wall Thickness	Grade	Closest Dist. to Upstream Pump Discharge for Pipe with Attribute	Elevation (feet)	Year of Installation of Pipe Nearest to U/S Pump Discharge	Oldest pipe with Attribute	Newest pipe with Attribute	Flaw Depth WT in PCFA	Threshold Anomaly Depth at ILI Detection Threshold (%)
94	Buckhorn-Satsuma	0.281	X52	1955+44	136.98	1950	1950	1984	0.141	0.5
95	Buckhorn-Satsuma	0.281	X65	2496+20	176.05	2002	2002	2010	0.028	0.1
96	Buckhorn-Satsuma	0.375	B	1983+64	141.50	1984	1947	1998	0.038	0.1
97	Buckhorn-Satsuma	0.375	B	1803+16	125.72	1947	1947		0.188	0.5
98	Buckhorn-Satsuma	0.375	X42	3386+31	150.00	1998	1984	1998	0.038	0.1
99	Buckhorn-Satsuma	0.375	X45	3373+11	141.24	1998	1950	2013	0.038	0.1
100	Buckhorn-Satsuma	0.375	X45	3372+81	141.44	1950	1950		0.188	0.5
101	Buckhorn-Satsuma	0.375	X52	2025+86	142.62	1950	1950	2010	0.188	0.5
102	Buckhorn-Satsuma	0.375	X52	1947+38	135.93	2010		2010	0.038	0.1
103	Buckhorn-Satsuma	0.375	X65	3371+01	142.03	2012	1950	2012	0.038	0.1
104	Buckhorn-Satsuma	0.375	X65	3073+11	177.17	1950	1950		0.188	0.5
105	Buckhorn-Satsuma	0.385	X65	3071+61	177.13	2002	2002	2002	0.039	0.1
106	Buckhorn-Satsuma	0.500	X42	3387+21	149.51	1950	1950	2012	0.250	0.5
107	Buckhorn-Satsuma	0.500	X42	3386+91	149.70	2012		2012	0.050	0.1
108	Satsuma-East Houston Terminal	0.250	X52	312+01	34.78	2010	2010	2010	0.025	0.1
109	Satsuma-East Houston Terminal	0.312	B	1800+22	125.56	1947	1947	1987	0.156	0.5
110	Satsuma-East Houston Terminal	0.312	X52	482+41	38.62	1998	1998	1998	0.031	0.1
111	Satsuma-East Houston Terminal	0.312	X60	832+03	56.73	2000	2000	2002	0.031	0.1
112	Satsuma-East Houston Terminal	0.344	X52	381+01	30.48	1998	1998	2010	0.034	0.1
113	Satsuma-East Houston Terminal	0.375	B	1572+09	120.83	1988	1947	1988	0.188	0.5
114	Satsuma-East Houston Terminal	0.375	X42	1171+67	85.89	1988	1988	1988	0.188	0.5
115	Satsuma-East Houston Terminal	0.375	X52	1122+56	82.71	2004	1998	2013	0.038	0.1
116	Satsuma-East Houston Terminal	0.375	X60	1688+49	116.60	2012	1947	2012	0.038	0.1
117	Satsuma-East Houston Terminal	0.375	X60	490+46	39.30	1947	1947		0.188	0.5
118	EHS-9th Str. (U/S of Speed JCT)	0.312	X52	188+83	17.35	1998	1998	1998	0.031	0.10
119	EHS-9th Str. (U/S of Speed JCT)	0.344	X52	235+10	17.78	1998	1998	1998	0.034	0.10
120	EHS-9th Str. (U/S of Speed JCT)	0.375	B	0+02	36.59	2010	1998	2011	0.038	0.10
121	EHS-9th Str. (U/S of Speed JCT)	0.375	X52	0+14	36.55	2010	1998	2011	0.038	0.10
122	EHS-9th Str. (U/S of Speed JCT)	0.375	X60	187+12	19.4	2013	2011	2013	0.038	0.10
123	EHS-9th Str. (U/S of Speed JCT)	0.500	X42	403+64	0.1	2011	2011	2011	0.050	0.10
124	EHS-9th Str. (U/S of Speed JCT)	0.500	X52	363+98	4.7	1998	1998	2011	0.050	0.10

Table E-2. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations in Refined Product Pipeline

S/N	Pipeline Segment	Wall Thickness	Grade	Closest Dist. to Upstream Pump Discharge for Pipe with Attribute	Elevation (feet)	Year of Installation of Pipe Nearest to U/S Pump Discharge	Oldest pipe with Attribute	Newest pipe with Attribute	Flaw Depth WT in PCFA	Threshold Anomaly Depth at ILI Detection Threshold (%)
1	Crane-Cottonwood	0.281	X65	30429+00.25	3843.37	1998	1998	2004	0.028	0.1
2	Crane-Cottonwood	0.375	X52	30430+16.00	3841.17	2008	1998	2008	0.038	0.1
3	Crane-Cottonwood	0.375	X65	30429+60.25	3840.19	2008	1998	2008	0.038	0.1
4	Crane-Cottonwood	0.500	X52	27879+57.25	2620.73	2008	2008	2008	0.050	0.1
5	Cottonwood-El Paso	0.281	X65	36664+58.00	4022.34	1998	1998	1998	0.028	0.1
6	Cottonwood-El Paso	0.375	X52	36665+05.25	4022.34	1998	1998	1998	0.038	0.1
7	Cottonwood-El Paso	0.375	X65	36642+98.00	4017.06	1998	1998	1998	0.038	0.1

APPENDIX F – FATIGUE ASSESSMENT RESULTS

Table F-1 and Table F-2 show the fatigue lives predicted for threshold anomalies accounting for pipe properties and attribute changes including wall thickness, grade, pipe OD, elevation changes and nearness to the pump station discharge locations. The fatigue results are presented in increasing order of time to failure or reassessment interval.

Note that, in cases where the calculated times to failure were in excess of 500 years, an artificial cap of 500 years was imposed to reduce the calculation time. Also, note that the reassessment intervals were calculated using a safety factor of 2.22 consistent with the specification for safety factor in the Magellan ORA Manual which requires that the reassessment interval be taken as 45% of the shortest fatigue life.

Table F-1. Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 1 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Texon-Barnhart	18	0.250	52,000	2,199,954.00	2,675	898	16.37	7.4	12/25/2022	1953	50%	8/11/2015
Crane-Texon	18	0.250	52,000	2,406,295.00	2,525	1,033	16.73	7.5	01/28/2023	1953	50%	7/17/2015
Cartman-Kimble	18	0.281	45,000	1,816,881.00	2,445	952	19.37	8.7	05/20/2024	1950	50%	8/29/2015
Bastrop-Warda	18	0.281	45,000	748,348.00	395	981	19.58	8.8	10/06/2024	1950	50%	12/11/2015
James River-Eckert	18	0.281	45,000	1,373,347.00	1,705	965	21.33	9.6	03/28/2025	1950	50%	8/19/2015
Cartman-Kimble	18	0.281	65,000	1,817,361.00	2,445	952	21.85	9.8	07/02/2025	1950	50%	8/29/2015
Kimble-James River	18	0.219	52,000	1,475,839.00	1,669	898	26.67	12.0	09/06/2027	1967	50%	9/1/2015
Cartman-Kimble	18	0.281	52,000	1,788,321.00	2,399	952	27.81	12.5	03/09/2028	1950	50%	8/29/2015
Cartman-Kimble	18	0.312	45,000	1,817,451.00	2,445	952	30.10	13.6	03/20/2029	1950	50%	8/29/2015
Warda-Buckhorn	18	0.281	45,000	570,241.00	380	965	32.77	14.8	09/19/2030	1950	50%	12/16/2015
Kimble-James River	18	0.281	45,000	1,558,459.00	2,223	898	32.84	14.8	06/17/2030	1950	50%	9/1/2015
Bastrop-Warda	18	0.281	65,000	715,710.00	348	980	35.81	16.1	01/26/2032	1950	50%	12/11/2015
Eckert-Cedar Valley	18	0.281	45,000	1,203,342.00	1,736	959	37.39	16.8	10/07/2032	1950	50%	12/4/2015
Warda-Buckhorn	18	0.312	45,000	596,154.00	359	965	37.49	16.9	11/04/2032	1950	50%	12/16/2015
Buckhorn-Satsuma	18	0.281	45,000	358,747.00	171	787	41.81	18.8	10/17/2034	1950	50%	12/18/2015
James River-Eckert	18	0.312	60,000	1,358,557.00	1,777	965	43.15	19.4	01/25/2035	1950	50%	8/19/2015
Satsuma-East Houston Terminal	20	0.312	35,000	180,022.25	126	786	44.26	19.9	09/07/2034	1947	50%	10/1/2014
Barnhart-Cartman	18	0.312	45,000	1,972,603.00	2,603	898	47.23	21.3	12/01/2036	1950	50%	8/24/2015
Barnhart-Cartman	18	0.281	45,000	1,926,228.00	2,533	898	51.30	23.1	10/02/2038	1950	50%	8/24/2015

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 2 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Eckert-Cedar Valley	18	0.312	45,000	1,202,982.00	1,744	959	58.33	26.3	03/13/2042	1950	50%	12/4/2015
Crane-Texon	18	0.281	46,000	2,242,253.00	2,664	1,034	58.85	26.5	01/18/2042	1953	50%	7/17/2015
Cedar Valley-Bastrop	18	0.281	25,000	896,55800	790	965	62.65	28.2	03/08/2044	1950	50%	12/8/2015
James River-Eckert	18	0.375	35,000	1,373,506.00	1,712	965	65.59	29.5	03/05/2045	1950	50%	8/19/2015
Crane-Texon	18	0.375	35,000	2,415,824.25	2,524	1,034	72.99	32.9	06/01/2048	1950	50%	7/17/2015
Texon-Barnhart	18	0.312	45,000	2,135,154.00	2,666	898	78.83	35.5	02/12/2051	1950	50%	8/11/2015
Bastrop-Warda	18	0.312	45,000	678,927.00	470	981	81.66	36.8	09/22/2052	1950	50%	12/11/2015
James River-Eckert	18	0.375	65,000	1,358,677.00	1,778	964	88.89	40.0	09/03/2055	1950	50%	8/19/2015
Crane-Texon	18	0.375	65,000	2,411,245.00	2,540	1,034	90.09	40.6	02/13/2056	1950	50%	7/17/2015
James River-Eckert	18	0.375	42,000	1,344,847.00	1,842	965	98.20	44.2	11/12/2059	1950	50%	8/19/2015
Cedar Valley-Bastrop	18	0.312	45,000	889,616.00	708	965	105.30	47.4	05/14/2063	1950	50%	12/8/2015
Crane-Texon	18	0.375	52,000	2,391,623.00	2,575	1,034	107.97	48.6	03/04/2064	1950	50%	7/17/2015
Crane-Texon	18	0.385	65,000	2,402,003.00	2,537	1,033	110.72	49.9	05/31/2065	1950	50%	7/17/2015
Bastrop-Warda	18	0.375	45,000	711,300.00	337	981	110.83	49.9	11/13/2065	1950	50%	12/11/2015
James River-Eckert	18	0.385	65,000	1,343,587.00	1,783	965	116.86	52.6	04/07/2068	1950	50%	8/19/2015
James River-Eckert	18	0.312	45,000	1,203,926.00	1,717	965	121.50	54.7	05/11/2070	1950	50%	8/19/2015
Warda-Buckhorn	18	0.375	35,000	551,821.00	512	965	127.56	57.5	06/01/2073	1950	50%	12/16/2015
James River-Eckert	18	0.375	52,000	1,320,097.00	1,511	965	131.86	59.4	01/10/2075	1950	50%	8/19/2015
Satsuma-East Houston Terminal	20	0.375	35,000	157,209.18	121	786	135.57	61.1	10/25/2075	1988	50%	10/1/2014

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 3 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Bastrop-Warda	18	0.312	65,000	596,507.00	355	981	150.50	67.8	09/26/2083	1967	50%	12/11/2015
Bastrop-Warda	18	0.375	42,000	679,767.00	430	981	166.38	74.9	11/21/2090	1950	50%	12/11/2015
Buckhorn-Satsuma	18	0.375	45,000	337,281.00	141	787	176.68	79.6	07/19/2095	1950	50%	12/18/2015
Kimble-James River	18	0.375	45,000	1,460,419.00	1,511	898	261.96	118.0	09/01/2133	1950	50%	9/1/2015
James River-Eckert	18	0.375	70,000	1,218,609.00	1,606	965	275.92	124.3	12/04/2139	1950	50%	8/19/2015
Buckhorn-Satsuma	18	0.375	65,000	307,311.00	177	787	279.25	125.8	10/01/2141	1950	50%	12/18/2015
Satsuma-East Houston Terminal	20	0.375	42,000	117,167.18	86	786	289.08	130.2	12/19/2144	1988	50%	10/1/2014
Buckhorn-Satsuma	18	0.281	52,000	195,544.00	137	787	302.31	136.2	02/20/2152	1950	50%	12/18/2015
Crane-Texon	18	0.281	65,000	2,415,775.00	2,524	1,034	313.49	141.2	10/02/2156	1998	10%	7/17/2015
Barnhart-Cartman	18	0.281	65,000	1,971,678.00	2,605	898	385.39	173.6	03/30/2189	1998	10%	8/24/2015
EHS-9th Str. (U/S of Speed JCT)	20	0.375	35,000	2.00	37	1,168	400.59	180.4	03/15/2195	2010	10%	10/2/2014
EHS-9th Str. (U/S of Speed JCT)	20	0.375	52,000	14.42	37	1,168	414.90	186.9	08/25/2201	2010	10%	10/2/2014
James River-Eckert	18	0.281	65,000	1,337,107.00	1,649	965	417.52	188.1	09/16/2203	2013	10%	8/19/2015
Warda-Buckhorn	18	0.385	65,000	453,901.00	319	965	467.67	210.7	08/16/2226	1950	50%	12/16/2015
EHS-9th Str. (U/S of Speed JCT)	20	0.312	52,000	18,882.67	17	1,168	471.94	212.6	05/06/2227	1998	10%	10/2/2014
Satsuma-East Houston Terminal	20	0.312	60,000	83,203.38	57	2,143	500.00	225.2	12/24/2239	2000	10%	10/1/2014

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 4 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Kimble-James River	18	0.375	45,000	1,459,669.00	1,533	2,258	500.00	225.2	11/23/2240	2013	10%	9/1/2015
Kimble-James River	18	0.385	65,000	1,460,719.00	1,528	3,139	500.00	225.2	11/23/2240	2000	10%	9/1/2015
Texon-Barnhart	18	0.385	65,000	2,159,994.00	2,723	3,118	500.00	225.2	11/02/2240	2000	10%	8/11/2015
Buckhorn-Satsuma	18	0.281	45,000	306,408.00	179	1,671	500.00	225.2	03/11/2241	2013	10%	12/18/2015
Texon-Barnhart	18	0.375	35,000	2,200,011.00	2,675	1,798	500.00	225.2	11/02/2240	2012	10%	8/11/2015
Texon-Barnhart	18	0.375	42,000	2,199,894.00	2,674	2,081	500.00	225.2	11/02/2240	2012	10%	8/11/2015
Cartman-Kimble	18	0.500	52,000	1,803,741.00	2,426	3,390	500.00	225.2	11/20/2240	2012	10%	8/29/2015
Kimble-James River	18	0.375	65,000	1,514,449.00	2,106	3,045	500.00	225.2	11/23/2240	2002	10%	9/1/2015
Texon-Barnhart	18	0.375	52,000	1,972,734.00	2,602	2,539	500.00	225.2	11/02/2240	1998	10%	8/11/2015
Bastrop-Warda	18	0.375	35,000	736,080.00	394	1,790	500.00	225.2	03/04/2241	2002	10%	12/11/2015
Eckert-Cedar Valley	18	0.281	45,000	1,149,912.00	1,648	1,661	500.00	225.2	02/25/2241	2012	10%	12/4/2015
Barnhart-Cartman	18	0.312	65,000	1,885,398.00	2,501	2,517	500.00	225.2	11/15/2240	2000	10%	8/24/2015
Bastrop-Warda	18	0.375	65,000	711,570.00	337	3,021	500.00	225.2	03/04/2241	2002	10%	12/11/2015
Barnhart-Cartman	18	0.375	60,000	1,886,028.00	2,501	2,858	500.00	225.2	11/15/2240	2000	10%	8/24/2015
Cedar Valley-Bastrop	18	0.281	65,000	843,098.00	553	2,269	500.00	225.2	03/01/2241	2013	10%	12/8/2015
Cedar Valley-Bastrop	18	0.385	65,000	956,168.00	973	3,095	500.00	225.2	03/01/2241	2002	10%	12/8/2015
James River-Eckert	18	0.375	65,000	1,292,169.00	1,698	3,046	500.00	225.2	11/10/2240	2012	10%	8/19/2015
Satsuma-East Houston Terminal	20	0.375	52,000	112,256.38	83	2,292	500.00	225.2	12/24/2239	2004	10%	10/1/2014

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 5 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Satsuma-East Houston Terminal	20	0.375	60,000	168,849.18	117	2,555	500.00	225.2	12/24/2239	2012	10%	10/1/2014
Cartman-Kimble	18	0.375	45,000	1,714,101.00	2,229	2,252	500.00	225.2	11/20/2240	2000	10%	8/29/2015
Barnhart-Cartman	18	0.500	52,000	1,830,324.00	2,452	3,405	500.00	225.2	11/15/2240	2012	10%	8/24/2015
Buckhorn-Satsuma	18	0.375	35,000	198,364.00	142	1,853	500.00	225.2	03/11/2241	1984	10%	12/18/2015
Buckhorn-Satsuma	18	0.500	42,000	338,721.00	150	1,225	500.00	225.2	03/11/2241	1950	50%	12/18/2015
Eckert-Cedar Valley	18	0.375	35,000	1,050,823.00	996	1,851	500.00	225.2	02/25/2241	2012	10%	12/4/2015
Buckhorn-Satsuma	18	0.375	65,000	337,101.00	142	3,045	500.00	225.2	03/11/2241	2012	10%	12/18/2015
Cartman-Kimble	18	0.375	35,000	1,817,876.00	2,446	1,576	500.00	225.2	11/20/2240	2004	10%	8/29/2015
Buckhorn-Satsuma	18	0.375	35,000	180,316.00	126	1,522	500.00	225.2	03/11/2241	1947	50%	12/18/2015
Barnhart-Cartman	18	0.385	65,000	1,926,588.00	2,532	3,128	500.00	225.2	11/15/2240	2000	10%	8/24/2015
Texon-Barnhart	18	0.375	65,000	2,135,394.00	2,665	3,043	500.00	225.2	11/02/2240	1999	10%	8/11/2015
Cartman-Kimble	18	0.375	65,000	1,788,441.00	2,400	2,986	500.00	225.2	11/20/2240	2002	10%	8/29/2015
Barnhart-Cartman	18	0.312	60,000	1,886,238.00	2,501	2,358	500.00	225.2	11/15/2240	2000	10%	8/24/2015
Eckert-Cedar Valley	18	0.375	52,000	1,203,540.00	1,728	2,523	500.00	225.2	02/25/2241	2006	10%	12/4/2015
Cedar Valley-Bastrop	18	0.500	65,000	782,882.00	503	4,098	500.00	225.2	03/01/2241	2012	10%	12/8/2015
Kimble-James River	18	0.281	65,000	1,526,029.00	2,123	2,141	500.00	225.2	11/23/2240	2013	10%	9/1/2015
Cedar Valley-Bastrop	18	0.375	65,000	959,073.00	1,032	2,998	500.00	225.2	03/01/2241	2002	10%	12/8/2015
Buckhorn-Satsuma	18	0.385	65,000	307,161.00	177	3,139	500.00	225.2	03/11/2241	2002	10%	12/18/2015
Warda-Buckhorn	18	0.375	65,000	594,530.00	315	2,972	500.00	225.2	03/09/2241	2002	10%	12/16/2015

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 6 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Eckert-Cedar Valley	18	0.375	65,000	1,199,862.00	1,822	3,031	500.00	225.2	02/25/2241	2012	10%	12/4/2015
EHS-9th Str. (U/S of Speed JCT)	20	0.375	60,000	18,712.30	19	2,535	500.00	225.2	12/25/2239	2013	10%	10/2/2014
Barnhart-Cartman	18	0.375	52,000	1,856,124.00	2,477	2,541	500.00	225.2	11/15/2240	2007	10%	8/24/2015
Buckhorn-Satsuma	18	0.375	52,000	194,738.00	136	2,549	500.00	225.2	03/11/2241	2010	10%	12/18/2015
Buckhorn-Satsuma	18	0.375	42,000	338,631.00	150	2,129	500.00	225.2	03/11/2241	1998	10%	12/18/2015
Kimble-James River	18	0.375	52,000	1,558,523.00	2,221	2,512	500.00	225.2	11/23/2240	1998	10%	9/1/2015
Texon-Barnhart	18	0.281	65,000	2,138,814.00	2,664	2,167	500.00	225.2	11/02/2240	1998	10%	8/11/2015
Kimble-James River	18	0.375	42,000	1,487,899.00	1,827	2,133	500.00	225.2	11/23/2240	1995	10%	9/1/2015
Buckhorn-Satsuma	18	0.500	42,000	338,691.00	150	2,859	500.00	225.2	03/11/2241	2012	10%	12/18/2015
Barnhart-Cartman	18	0.375	65,000	1,885,218.00	2,501	3,052	500.00	225.2	11/15/2240	2000	10%	8/24/2015
Warda-Buckhorn	18	0.375	52,000	504,121.00	391	2,541	500.00	225.2	03/09/2241	2012	10%	12/16/2015
Satsuma-East Houston Terminal	20	0.375	60,000	49,046.38	39	2,267	500.00	225.2	12/24/2239	1947	50%	10/1/2014
Barnhart-Cartman	18	0.375	45,000	1,818,024.00	2,446	2,253	500.00	225.2	11/15/2240	2012	10%	8/24/2015
Barnhart-Cartman	18	0.312	52,000	1,971,738.00	2,605	1,430	500.00	225.2	11/15/2240	1998	10%	8/24/2015
Cartman-Kimble	18	0.375	52,000	1,730,751.00	2,271	2,531	500.00	225.2	11/20/2240	2002	10%	8/29/2015
Bastrop-Warda	18	0.385	65,000	711,540.00	337	3,109	500.00	225.2	03/04/2241	2000	10%	12/11/2015
Buckhorn-Satsuma	18	0.375	45,000	337,311.00	141	2,252	500.00	225.2	03/11/2241	1998	10%	12/18/2015
Cartman-Kimble	18	0.385	65,000	1,758,621.00	2,414	3,112	500.00	225.2	11/20/2240	2000	10%	8/29/2015

Table F-1 (continued). Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Crude Oil Pipeline (pg 7 of 7)

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Cedar Valley-Bastrop	18	0.375	52,000	909,968.00	865	2,536	500.00	225.2	03/01/2241	2002	10%	12/8/2015
Buckhorn-Satsuma	18	0.375	52,000	202,586.00	143	2,099	500.00	225.2	03/11/2241	1950	50%	12/18/2015
Satsuma-East Houston Terminal	20	0.344	52,000	38,101.38	30	2,106	500.00	225.2	12/24/2239	1998	10%	10/1/2014
Eckert-Cedar Valley	18	0.500	35,000	1,143,942.00	1,705	2,476	500.00	225.2	02/25/2241	2012	10%	12/4/2015
Buckhorn-Satsuma	18	0.281	65,000	249,620.00	176	2,282	500.00	225.2	03/11/2241	2002	10%	12/18/2015
Eckert-Cedar Valley	18	0.385	65,000	1,138,962.00	1,585	3,138	500.00	225.2	02/25/2241	2000	10%	12/4/2015
Bastrop-Warda	18	0.375	52,000	688,767.00	356	2,532	500.00	225.2	03/04/2241	1995	10%	12/11/2015
Warda-Buckhorn	18	0.375	52,000	402,751.00	340	1,646	500.00	225.2	03/09/2241	1950	50%	12/16/2015
Warda-Buckhorn	18	0.281	45,000	450,601.00	338	1,682	500.00	225.2	03/09/2241	2012	10%	12/16/2015
Satsuma-East Houston Terminal	20	0.250	52,000	31,201.38	35	1,524	500.00	225.2	12/24/2239	2010	10%	10/1/2014
Warda-Buckhorn	18	0.385	65,000	408,061.00	229	3,147	500.00	225.2	03/09/2241	2000	10%	12/16/2015
Satsuma-East Houston Terminal	20	0.312	52,000	48,241.38	39	1,907	500.00	225.2	12/24/2239	1998	10%	10/1/2014
EHS-9th Str. (U/S of Speed JCT)	20	0.344	52,000	23,509.67	18	2,059	500.00	225.2	12/25/2239	1998	10%	10/2/2014
EHS-9th Str. (U/S of Speed JCT)	20	0.500	42,000	40,363.67	0	2,576	500.00	225.2	12/25/2239	2011	10%	10/2/2014
EHS-9th Str. (U/S of Speed JCT)	20	0.500	52,000	36,398.17	5	3,066	500.00	225.2	12/25/2239	1998	10%	10/2/2014

Table F-2. Time to Failure and Reassessment Interval Predicted for ILI Threshold Anomaly Sizes Accounting for Pipe Segmentation on the Refined Product Pipeline

Pipeline Segment	OD, inch	WT, inch	SMYS, psi	Defect Location, feet	Elevation, feet	Defect Failure Press, psig	Time to Failure, years	Re-assessment Interval, years	Re-assessment Due Date	Year of Installation of Pipe Nearest to U/S Pump Discharge	Threshold Anomaly Depth at ILI Detection Threshold (%)	ILI Date
Crane - Cottonwood	18	0.281	65,000	30429+00.25	3843.37	2,291	500.00	225.2	01/04/2498	1998	10%	N/A
Crane - Cottonwood	18	0.375	52,000	30430+16.00	3841.17	2,551	500.00	225.2	01/05/2508	2008	10%	N/A
Crane - Cottonwood	18	0.375	65,000	30429+60.25	3840.19	3,068	500.00	225.2	01/05/2508	2008	10%	N/A
Crane - Cottonwood	18	0.500	52,000	27879+57.25	2620.73	3,409	500.00	225.2	01/05/2508	2008	10%	N/A
Cottonwood - El Paso	18	0.281	65,000	36664+58.00	4022.34	2,291	500.00	225.2	01/04/2498	1998	10%	N/A
Cottonwood - El Paso	18	0.375	52,000	36665+05.25	4022.34	2,551	500.00	225.2	01/04/2498	1998	10%	N/A
Cottonwood - El Paso	18	0.375	65,000	36642+98.00	4017.06	3,068	500.00	225.2	01/04/2498	1998	10%	N/A