INTEGRITY MANAGEMENT

Activities and Associated Costs for Transmission Lines and Distribution Systems

Transmission Integrity Overview

The Company continues to implement integrity activities defined in its Transmission Integrity Management Plan for transmission lines as originally mandated by the "Pipeline Safety Improvement Act of 2002" and later codified in the Federal Regulations (49 CFR Part 192, Subpart O). The transmission integrity management regulations require the Company to identify all high consequence areas (HCA) along the segments of feeder lines that are defined as transmission lines.[50]

Once the Company identified these HCAs, it calculated a risk score for each segment located in the HCA. These risk scores established the initial priority for when the Company initially assessed each HCA. The Company verifies each HCA and calculates the risk score on an annual basis. Subsequent to this initial assessment, federal regulations require the Company to reassess each HCA at intervals not to exceed seven calendar years from the initial or previous assessment, or sooner based on results of the previous assessment.

Additionally, the Company is required by the transmission integrity rules to conduct additional ongoing preventive and mitigative measures on feeder lines in HCAs and in class 3 and 4 locations.[51] These additional measures include monitoring excavations (excavation standby) near these feeder lines and performing semi-annual leak surveys.

Distribution Integrity Overview

On December 4, 2009, PHMSA issued its final rule titled: "Integrity Management Program for Gas Distribution Pipelines." This final rule became effective on February 12, 2010, with implementation required by August 2, 2011.

The distribution integrity management rule requires the Company to develop, write and implement a distribution integrity management program with the following elements:

> Knowledge; identify threats; evaluate and rank risks; identify and implement measures to address risks; measure performance, monitor results, and evaluate effectiveness; periodically evaluate and improve program; and report results.

[50] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operation Pressure (MAOP) at or above a pressure that produces a hoop stress of 20% of Specified Minimum Yield Strength (SMYS)).
[51] Class location as defined by 49 CFR Part 192 (§192.5).

The Company continues to implement activities defined in its Distribution Integrity Management Plan for the distribution system. It implements the activities to mitigate the threats that are identified in the plan.

Transmission Integrity Management

Costs

Table 6.1 details the anticipated costs associated with transmission integrity management.

Baseline Assessment Plan

The Baseline Assessment Plan prescribes the methods that the Company will use to assess the integrity of each HCA. The Company determines these methods based upon the known or anticipated threats to these segments. The most common threats on the pipeline include corrosion and third-party damage. The Company has used multiple assessment methods in the past to address these threats, including external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), direct visual examination, pressure testing, and inline inspection. The Company has completed the Baseline Assessment Plan for all segments of pipe.

External Corrosion Direct Assessment

ECDA is an assessment method that evaluates the integrity of the pipeline segments for the threat of external corrosion, including segments of cased gas transmission pipelines. Refer to Figure 6.1 for an overview of the ECDA process.

The ECDA methodology is a four-step process. The four steps of the process include:

Pre-Assessment - This step utilizes historic and current data to determine whether ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions. ECDA regions are areas along the pipeline that have similar characteristics. There may be multiple regions along a single pipeline segment. Examples of ECDA regions include segments in casings or segments with different types of external coatings.

Indirect Inspection - This step utilizes above-ground inspection methods such as close interval survey, pipeline current mapper or DC voltage gradient survey, to identify, and quantify the severity of coating faults and areas of diminished cathodic protection. The analysis of this data can help identify areas along the pipeline segment where corrosion may have occurred or may be occurring. The Company uses a minimum of two indirect inspection tools over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. The Company categorizes indications from indirect inspections according to severity. A third indirect inspection tool is required for initial assessments of the segment.

Direct Examination - This step includes excavations of the pipe for direct examination to determine if there is corrosion occurring on the pipeline. For initial assessments (i.e. first time assessments for an HCA), a minimum of two excavations are required for each ECDA region and a minimum of four excavations in total for the ECDA project. The ECDA project may contain more than one pipeline and more than one ECDA region. Reassessments require a minimum of one excavation per ECDA region and a minimum of two excavations in total for the ECDA project. The Company selects excavation sites based on a review of the data collected during the pre-assessment and the indirect surveys.

The Company uses this information to identify the areas on the pipeline within each region where external corrosion is most likely. The Company must also excavate at a location where it has not identified any indications. The Company uses the information gathered at this site to help validate the effectiveness of the ECDA process. When corrosion or other pipeline damage or coating damage is found during the direct examination step, the Company repairs the pipe or coating. The Company may select additional sites for examination based on the findings of the required direct examinations.

Post-Assessment - This step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals and provide feedback for continuous improvement.

Internal Corrosion Direct Assessment

ICDA is a process used to predict the most likely areas of internal corrosion, including those caused by chemical and microbiologically induced corrosion. ICDA focuses on directly examining locations at which internal corrosion is most likely to occur.

The basis of ICDA is the detailed examination of the most susceptible locations along a pipeline where liquids, if any, would first accumulate in the pipeline. If the locations most likely to accumulate liquids have no indications of internal corrosion, all other locations further downstream are considered to be free from internal corrosion. ICDA relies on the ability to identify locations most likely to accumulate liquids.

The ICDA methodology is a four-step process that is intended to assess the threat of internal corrosion in pipelines and assist in verifying pipeline integrity.

The initial baseline assessment plan included ICDA. The Company was able to eliminate internal corrosion as a threat of concern going forward based on the fact that internal corrosion was not found at the conclusion of completing ICDA on the entire pipeline system as well as the implementation of the Company's ongoing internal corrosion plan.

Visual Examination of Aboveground Pipe and Pipe in Vaults

The Company assesses aboveground piping (e.g. spans and valve assemblies) and piping in vaults by visual examination when the piping is located in an HCA and the Company cannot assess the pipe utilizing other methods.

Inline Inspection

When a pipeline has been constructed and configured, or retro-fitted in such a way to allow for inline inspection, the Company assesses the pipe using inline inspection tools commonly called "smart pigs." These tools are equipped with sensors that collect data as the tool travels through the pipeline and can reveal areas of wall loss and dents that may require repair or cutout. The Company has 132 miles of transmission piping (16% of the Company's transmission system) that can be inspected using smart pigs. As the Company replaces aging infrastructure, it designs and builds the new pipelines to accommodate inline inspection tools. Recent advancements in technology allow some limited application of inline inspection tools for non-piggable pipelines. The Company has helped fund these advancements through its research and development program. The Company has used these advanced tools to assess locations of its system that it previously could not.

The inline inspection tools provide specific data on the condition of the pipeline segment being inspected. The Company analyzes data that it collects along the pipeline segment for defects and areas of concern (e.g. wall loss or dents) and excavates for further evaluation and repair or cut out, if necessary.

High Consequence Area Validation

Each year, the Company conducts a field survey of all transmission line segments to validate the current HCA as well as identify any new potential sites that may trigger a new HCA. Sites that may trigger a new HCA include the following: office buildings, businesses, community centers, churches, day care centers, retirement centers, hospitals, and prisons.

The Company maintains this information in its mapping system and uses it to calculate HCAs on an annual basis.

Distribution Integrity Management

Costs

Table 6.2 details the anticipated costs associated with distribution integrity management.

Implementation

The Company implemented its written Distribution Integrity Management Plan in August of 2011. Implementation included identifying the threats associated with the distribution system within each operating region as well as calculating a risk score for each identified threat. The risk scores are calculated by subject matter experts (SME) for each operating region utilizing known infrastructure data and leak history. The threats and the associated risk scores are validated by comparison to a second geographic information system (GIS) risk model. Once the Company identified the threats and calculated the risk scores for each threat, each operating region identified possible measures that could be implemented or are currently being implemented that would help mitigate the risks on the distribution system. The process of identifying threats and calculating the risk for each threat is ongoing and is evaluated on an annual basis.

Key Performance Integrity Metrics

Table 6.3 details specific performance metrics associated with the transmission integrity management program.

New Regulations

The following regulations may have significant impact on the Company:

Safety of Gas Transmission and Gathering Lines (Mega Rule)

PHMSA initially published an advanced notice of proposed rulemaking (ANPRM) for the Mega Rule on August 25, 2011. On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) in the Federal Register. The Mega Rule is intended to increase the level of safety associated with the transportation of gas by imposing regulations to prevent failures like those involved in recent incidents. The Mega Rule also seeks to clarify and enhance some existing requirements and address certain statutory mandates and National Transportation Safety Board (NTSB) recommendations.

If adopted, the proposed rule would require additional pipeline integrity management measures for pipelines that are not in HCAs, as well as clarifications and selected enhancements to integrity management activities related to pipelines within HCAs. This could have a substantial impact on the costs in the integrity management program.

The proposed Mega Rule addresses several integrity management topics, including:

- Revision of integrity management repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies and other defects;

- Codifying functional requirements related to the nature and application of risk models consistent with current industry standard;
- Codifying requirements for collecting, validating, and integrating pipeline data models consistent with current industry standards;
- Strengthening requirements for applying knowledge gained through the integrity management program models consistent with current industry standards;
- Strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference;
- Adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; and
- Codifying requirements for management of change consistent with current industry standards.

With respect to non-integrity management requirements, the proposed Mega Rule would impose:

- A new ‘‘moderate consequence area’’ definition;
- Requirements for monitoring gas quality and mitigating internal corrosion;
- Requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys;
- Requirements for management of change, including invoking the requirements of ASME/ ANSI B31.8S, Section 11;
- Repair criteria for pipeline segments located in areas not in an HCA; and
- Requirements for verification of maximum allowable operating pressure (MAOP) and for verification of pipeline material for certain onshore steel gas transmission pipelines including establishing and documenting MAOP if the pipeline MAOP was established in accordance with §192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP.

The proposed Mega Rule also proposes requirements for additional topics that have arisen since issuance of the ANPRM including:

- Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster or other similar event;
- Allowing extension of the 7-year reassessment interval upon written notice;
- Requiring operators to report each instance when the MAOP exceeds the margin (build-up) allowed for operation of pressure limiting or control devices;
- Adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats;
- Adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities; and
- Incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using inline inspection, internal corrosion direct assessment and stress corrosion cracking direct assessment.

The new administration has delayed the publication of the Mega Rule regulation. In March 2018 PHMSA's Gas Pipeline Advisory Committee (GPAC) gathered to continue its work on developing the proposed rule for Transmission and Gathering Pipelines. PHSMA outlined that it intended to break the rule up into 3 rulemakings i) the Congressional mandates, ii) topics outside the mandates, and iii) gathering lines. PHMSA is currently focused on finalizing the first rulemaking, which covers key issues within the Congressional mandate such as MAOP reconfirmation and assessments of pipelines outside of HCAs. The industry anticipates the first rule making will be published in 2019.

Plastic Pipe Rule

PHMSA published this regulation as a NPRM on May 21, 2015, with an anticipated final rule publication in 2018. PHMSA is proposing to amend the natural and other gas pipeline safety regulations to address regulatory requirements involving plastic piping systems used in gas services. These proposed amendments are intended to correct errors, address inconsistencies and respond to petitions for rulemaking. The requirements in several subject matter areas are affected, including incorporation of tracking and traceability provisions; design factor for polyethylene (PE) pipe; more stringent mechanical fitting requirements; updated and additional regulations for risers; expanded use of Polyamide-11 (PA-11) thermoplastic pipe; incorporation of newer Polyamide-12 (PA-12) thermoplastic pipe; and incorporation of updated and additional standards for fittings.

Valve Installation and Minimum Rupture Detection Standards Rule

PHMSA plans to publish this rule as an NPRM in April 2018. This rule is expected to cover rupture detection and response time metrics including the integration of automatic shutoff valves and remote control valves on transmission pipelines with an objective to improve overall incident response.

Miscellaneous Rule

PHMSA published this regulation as a final rule on March 11, 2015, with an effective date of October 1, 2015. One component of this rulemaking includes the performance of post-construction inspections and qualification of plastic pipe joiners. Post-construction inspection could have a significant impact on the Company. PHMSA is currently in the process of developing guidance for the interpretation and implementation on the requirements associated with post-construction inspection. The effective date for the rules requirements for post construction inspection has been extended indefinitely by PHMSA. The Company anticipates publication of further guidance in the future.

Industry and Company Best Practices

Interstate Natural Gas Association of America (INGAA) Integrity Management Continuous Improvement Initiative (IMCI)

The Company has identified new industry and Company best practices for transmission pipelines that aligns with the direction and intent of PHMSA's proposed Mega Rule. INGAA's IMCI extends the application of Integrity Management from HCAs to 90% of the population living adjacent to transmission pipeline corridors, first time assessment to be complete by the end of 2020. As a result of this initiative, the indirect inspection costs are expected to increase in 2019 and 2020.

Close Interval Survey (CIS)

The Company has initiated an internal best practice to conduct CIS on its transmission pipelines of its cathodic protection system. The goal is to complete this initial survey by 2024. As a result of this initiative, CIS inspection costs were added this year, and are expected to increase in 2019 before decreasing slightly in 2020.

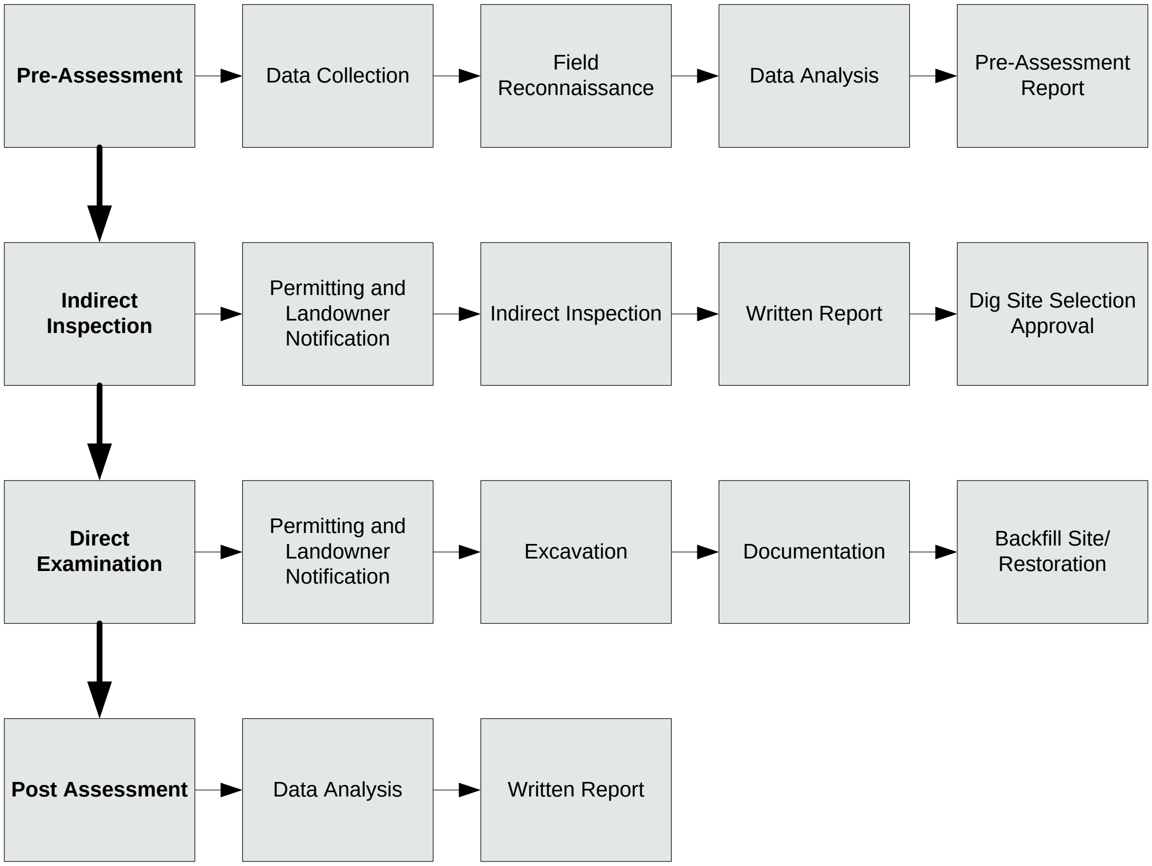

Figure 6.1: ECDA Process Overview

Table 6.1: Transmission Integrity Management Costs

$ Thousands

Activity	2018	2019	2020
Transmission Integrity Management			
ECDA			
Pre-Assessment			
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53) (26.5 HCA miles @ $2,000/mile)	53		
2019 (FL18, 21, 47) (29.2 HCA miles @ $2,000/mile)		58	
2020 (FL19, 23, 28, 29, 70, 71, 74, 125) (85.9 HCA miles @ $2,000/mile)			172
Indirect Inspections			
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53) (26.5 HCA miles @ $30,000/mile)	795		
2019 (FL18, 21, 47) (29.2 HCA miles @ $30,000/mile)		876	
2020 (FL19, 23, 28, 29, 70, 71, 74, 125) (85.9 HCA miles @ $30,000/mile)			2,577
Direct Examinations			
2018(FL6, 12, 13, 22, 24, 33, 46, 51, 53) (12 Excavations @ $35,000 ea.)	210	210	
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53) (Pipetel 4 sites, 4 casings @ $175,000/site)		700	
2019 (FL18, 21, 47) (8 excavations @ $35,000 ea.)		140	140
2019 (FL18, 21, 47) (Pipetel 2 sites, 2 casings @ $175,000 ea.)			350
2020 (FL19, 23, 28, 29, 70, 71, 74, 125) (16 excavations @ $35,000 ea.)			280
Post Assessment			
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53)(17.5 HCA miles @ $1,500/mile)	26		
2019 (FL18, 21, 47) (23.5 HCA miles @ $1,500/mile)		35	
2020 (FL19, 23, 28, 29, 70, 71, 74, 125) (85.9 miles @ $1,500)			129
CIS			
Indirect Inspections			
2018 (FL104, 19, 72) (59.3 miles @ $10,000/mile)	593		
2019 (FL4/11, 81, 68) (121.7 miles @ $10,000/mile)		1,217	
2020 (FL85, 65) (111 miles @ $10,000/mile)			1,110

ICDA			
ICDA is complete, no longer required (refer to the on-going QGC Internal Corrosion Plan).			
Inline Inspection			
2018 (FL104)	350		
2018 (FL072)	250		
2018 (FL019)	350		
2018 (FL026/34) (Pipetel)	110		
2018 (FL042) (Pipetel)	190		
2018 Excavations/ Validations Digs/ Remediation (12 excavations @ $35,000 ea.)	210	210	
2019 (FL081)		350	
2019 (FL068)		350	
2019 (FL004)		350	
2019 (Pipetel)		110	
2019 (Pipetel)		110	
2019 Excavations/ Validations Digs/ Remediation (12 excavations @ $35,000 ea.)		210	210
2020 (FL085)			250
2020 (FL065)			350
2020 (FL071)			300
2020 (Pipetel)			110
2020 (Pipetel)			110
2020 Excavations/ Validations Digs/ Remediation (12 excavations @ $35,000 ea.)			210
Direct Examination (Spans and Vaults)			
2018 - Vaults (17 @ $15,000/vault)	255		
2018 - Spans Reassessment (@ $10,000/span)	70		
2019 - Vaults (15 @ $15,000/vault)		225	
2019 - Spans Reassessment (1 @ $10,000/span)		10	
2020 - Vaults (16 @ $15,000/vault)			240
2020 - Spans (3 @ $75,000/span)			225
2020 - Spans Reassessment (7 @ $10,000/span)			70

Pressure Test Assessment			
2018 - 1 pipeline segments @ $100,000/segment	100		
2019 - 6 pipeline segments @ $100,000/segment		600	
2020 - 6 pipeline segments @ $100,000/segment			600
Excavation Standby			
6 employees (2,080 hrs x 6 x $70/hr)	874	874	874
Additional Leak Survey			
3 employees (2,080 hrs x 3 x $70/hr)	437	437	437
Additional Cathodic Protection Survey			
2 employees (2,080 hrs x 3 x $70/hr)	291	291	291
Administration			
Project Coordination (5 employees (2,080 hrs x 5 x $70/hr))	728	728	728
Data Integration Specialists (2 employees (2,080 hrs x 2 x $70/hr))	291	291	291
Construction Records Tech (2,080 x $70/hr)	146	146	146
Supervisor (2,080 hrs x $70/hr)	146	146	146
Engineer (3 employees (2,080 hrs x 3 x $70/hr))	437	437	437
IM Engineer - Engineer Tech (1 employee (2,080 hrs @ $ 70/hr))	146	146	146
Damage Prevention Tech (2,080 hrs x $70/hr)	146	146	146
New Position - Engineer (2,080 hrs x $70/hr)	146	146	146
Process Assistant (2,080 hrs x $50/hr)	104	104	104
New Position – Damage Prevention Tech (2 employees (2,080 hrs @ $50/hr))		208	208
New Position - Data Integration Specialists (2,080 hrs x $70/hr)			146
Training (for IM and Engineering personnel $4,000 x 13 employees)	52	52	52
Consultant - 3rd Party Review	30	30	30
Transmission Integrity Management Total ($ Thousands)	7,536	9,943	11,761

Table 6.2: Distribution Integrity Management Costs

$ Thousands

Activity	**2018**	**2019**	**2020**
Distribution Integrity Management			
NOTE: *The costs estimated here are based on additional and accelerated actions initiated based on the threats identified. The costs also reflect the administration costs associated with this new regulation.*			
Additional and Accelerated Actions			
Stray Current Surveys	350	350	350
Additional Leak Survey	300	300	300
Region specific accelerated actions	150	150	150
Damage Prevention (IHP Standby)	1,500	1,500	1,500
Meter Paints	500	358	
2018 - FL106 Digs (1 @ $35,000 ea.)	35		
2018 - Tethered ILI - FL062	300		
2019 - FL062 Digs (1 @ $35,000 ea)	35		
ILI – Discretionary		500	
Discretionary Digs (3 @ $35,000 ea)			105
ILI – Discretionary			500
Administration			
Consultant - 3rd Party Plan Review		30	
Distribution Integrity Management Total ($ Thousands)	3,170	2,830	2,905
Total Integrity Costs ($ Thousands)	10.706	12,773	14,666

Table 6.3: HCA Miles Assessed/Anomalies Repaired

YEAR	HCA Miles Assessed	Anomalies Repaired
2012	26.470	28
2013	50.367	27
2014	54.555	20
2015	11.040	2
2016	37.226	4
2017	13.110	9
NOTE: Approximately 17 miles of HCA were assessed in 2014 that were originally planned to be completed in 2015. Due to favorable circumstances for completing the direct examinations these assessments were completed early.		