GUNSTER
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August 1, 2024

E-Portal

Mr. Adam Teitzman, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20240071-GU: Petition for Approval of Safety, Access, and Facility Enhancement Program (SAFE) Modifications.

Dear Mr. Teitzman:

Attached for filing in the above-referenced docket, please find Florida City Gas's Responses to Staff's Second Set of Data Requests.

Thank you for your assistance with this filing.

Kind regards,

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe St., Suite 601
Tallahassee, FL 32301
(850) 521-1706

Enclosure

Re: Docket No. 20240071-GU: Petition for Approval of Safety, Access, and Facility Enhancement Program (SAFE) Modifications.

Florida City Gas's Responses to Staff's Second Set of Data Requests

1. **Please refer to the utility's response to Staff's First Data Request, No. 1. As the contractor's risk assessment report is now complete, please provide a construction timeline detailing the anticipated activities throughout the term of the proposed expansion to the SAFE program. As part of this response, please explain how FCG prioritized the projects.**

Company Response
A construction timeline detailing the anticipated activities throughout the term of the proposed expansion to the SAFE program has been included herein as Exhibit A. The Company has received the final risk assessment report prepared by the outside contractor, which outlines and ranks the risk of the facilities considered for replacement under the scope of this program. The risk ranking methodology utilized by the contractor is in accordance with section 192.1007(c) of Title 49 of the Code of Federal Regulations, which considers and evaluates current and potential threats on the gas distribution system as well as the likelihood and consequence of failure by pipe segment. The Company will prioritize the facilities for replacement based on highest risk of failure identified in the contractor's risk assessment, input from the Company subject matter experts, and from the Company's DIMP, which considers factors such as pipe diameter, material, pipeline class locations, surrounding population density, leak history, areas with common risky materials and other environmental factors.

2. **Please confirm if there are any additional projects related to the problematic pipe and facilities consisting of obsolete span, and exposed pipe not in the program modifications the utility intends on locating or including for recovery in a future petition to modify the SAFE program.**

Company Response
Florida City Gas submitted all the projects related to the problematic pipe that the Company is aware of at this moment. Any additional identified projects will be submitted to this Commission for future recovery.

3. **Are the new rates in the same timeline as the original continuation of the program?**

Company Response
If approved Florida City Gas will start the recovery in 2024 using the same ten years as the original SAFE continuation program.

a. **Does FCG expect to full recover SAFE investments, including the proposed program expansion, by 2035 as approved in Order No. PSC-2023-0345-TRF-GU? Please explain.**

Company Response
Florida City Gas expects to fully recover the proposed program expansion by 2035.

4. **Please refer to the utility's response to Staff's First Data Request, No. 2. As the contractor's risk assessment report is now complete, please indicate if the utility's most recent Distribution Integrity Management Program risk assessment model is now available. If so, please provide a copy. If not, please explain why and indicate when FCG expects this assessment to be complete.**

Company Response
The Company's most recent Distribution Integrity Management Program Plan is provided at Exhibit B.

5. **Please refer to the utility's response to Staff's First Data Request, No. 5(a), Attachment B for the following questions.**
   a. **Please explain how these project cost estimates were determined.**

Company Response
The Company utilized historical costs from past Company program projects and other similar Company completed projects in order to establish a historical loaded run rate by proposed improvement type, corrected to future value for the potential for inflated construction costs that may occur during the 10-year program. Each run rate by project type was then extended against the planned projects for replacement each year, in order to obtain the expanded SAFE program costs by project category.

b. **Please indicate if these estimates are still accurate now that the contractor's risk assessment report is complete. If not, please provide a revised document with the updated project cost estimates, and provide an explanation of how these costs were determined.**

Company Response
Yes, the previously provided cost estimates are still accurate.

6. **Please refer to the contractor's risk assessment report for the following questions**
   a. **Of the 82 total span pipe segments in FCG's service territory, please identify the total number of span pipes the utility intends to replace, and identify the total number of span pipes that are considered moderate to high-risk. If these values are different, please explain why.**

Company Response

The Company intends on replacing all 82 span pipe segments throughout the 10 year expanded program. While certain span pipe segments demonstrate a higher relative risk amongst other span segments in the FCG system (based on past failures, age, potential impact radius, and population density class location), FCG believes all exposed spans represent levels of threats that warrant replacement via underground installation to mitigate risk. The Company will prioritize the spans that have the highest risk during the early years of the program life.

b. **Please provide a table identifying the estimated annual project costs by each proposed project category included in the contractor's risk assessment report for each year of the program term.**

Company Response

A table identifying the estimated annual project costs by each proposed project category has been included herein. Please refer to Exhibit C.

Exhibit A

Category	Project Name	2024				2025				2026				2027				2028				2029				2030				2031				2032				2033				2034				2035			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Obsolete	Xtrubed Steel Tubing + Bolted Tee Areas	X	X		X	X	X	X	X	X	X	X																																					
Obsolete	SR520 8in Replacement				X	X	X	X																																									
Span	Miami Spans/Suspended Pipe replacements (54 total)					X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Exposed	Brevard Mall Rooftop Meter Relocations							X				X																																					
Span	Brevard Spans/Suspended Pipe replacements (21 total)							X			X	X			X	X			X	X			X	X			X	X			X			X	X	X			X	X			X	X		X	X	X	
Span	PSL Spans/Suspended Pipe replacements (7 total)								X				X				X				X			X					X				X																
Obsolete	Stainless Residential MSAs									X	X	X	X												X			X	X	X	X	X	X					X	X	X	X	X	X	X	X	X	X	X	X
Obsolete	Eau Gallie Gate Station Renewal													X	X	X																																	
Obsolete	Titusville Gate Station Renewal																		X	X	X	X																											
Exposed	Exposed 12" HP Replacement at US27 / NW87AVE																						X																										
Obsolete	Cocoa & Vero Beach Rectifiers																						X																										
Exposed	Miami Rooftop Meter Relocations																							X				X			X				X														
Obsolete	OUC Gate Station Renewal																									X	X	X	X																				
Obsolete	Shorted Casing Renewals																												X	X		X			X				X										
Obsolete	Ryder 106 ST District Regulator Station																															X																	
Obsolete	Melbourne Gate Station Renewal																																X	X	X	X													
Obsolete	Odorant Tank Upgrade - South Miami Gate Station																																						X										
Obsolete	Substation 3 District Station Valve Replacements																																						X										
Obsolete	West Miami Gate Station Valve Replacements																																							X									
Obsolete	Odorant Tank Upgrade - Miami Airport Gate Station																																								X								
Obsolete	Opalocka Gate Station Valve Replacements																																										X						
Obsolete	Odorant Tank Upgrade - Lake Forest Gate Station																																												X				
Obsolete	Odorant Tank Upgrade - NW Hialeah Gate Station																																														X		

Exhibit B

DISTRIBUTION INTEGRITY MANAGEMENT PLAN

For Florida City Gas Distribution System

Current Plan: 2024

Approval Control Sheet	
Title: Distribution Integrity Management Plan	
Plan Effective Date: 08/02/2011	
Current Version – 01/01/2024	
Name & Title	**Date**
Engineering Manager – Integrity – Melissa Koenig	01/04/2024

REVISION CONTROL SHEET

Title: Distribution Integrity Management Plan

Section	Date	Comments
Entire	05/31/2013	The DIMP Plan was re-organized to follow the PHMSA inspection form and regulatory code.
Company Roles	05/31/2013	Further definition added to Section 1. Company Roles and who can participate in DIMP.
SME Determination	05/31/2013	Defined process to determine SME's used within the DIM Program.
Gaining Additional Information	05/31/2013	Defined process to identify and document data gaps in various systems used in the DIM Program.
Knowledge	05/31/2013	Added additional sources of data and how the information can be used.
Data Integrity Quality Assurance	05/31/2013	Defined processes to ensure quality of data used in the DIM Program.
Reporting Requirements	05/31/2013	Define process to compile information required for the Annual DOT report.
Potential Or Emerging Threat Identification	05/31/2013	Added process to identify, track and analyze potential and existing threats.
Corrosion Threat	05/31/2013	Reorganized sub-threats from pipeline material to type of corrosion, ie, external, internal, atmospheric, and stray.
Other Threats	05/31/2013	Add sub-threats to threat category.
Threat Identification	05/31/2013	Added sub-threats and definitions.
Risk Analysis Hierarchy	05/31/2013	Updated to include the Inactive Service Line Risk Assessment.
Inactive Service Line Risk Assessment	05/31/2013	The Florida rulemaking 25-12.045.1.C requirements.
Inactive Service Line Integrity A/A Actions	05/31/2013	The Florida rulemaking 25-12.045.1.C requirements.
Inactive Service Line Risk Assessment Records	05/31/2013	The Florida rulemaking 25-12.045.1.C requirements.
Performance Measures	05/31/2013	Added process to define and measures around performance measures.
Performance Measures	05/31/2013	Added provision for Elkton Gas not to be required to complete all non-mandatory metrics.
Threat Identification Process	05/31/2013	Added provision for Elkton Gas not to be required to complete all non-mandatory metrics.
Data Compilation	05/31/2013	The data compilation steps provide guidance to data collection.
Pipeline Integrity Risk Model Assessment	01/01/2014	The risk assessment section was updated based on the updated approach to the spatial risk analysis.
Damage Density Threat Assessment	01/01/2014	The damage density threat assessment section was updated based on the schedule of completion. Previously, this analysis was completed on a monthly basis. Now, this analysis is run on an as-needed basis.
Risk Assessment and Risk Hierarchy	01/01/2014	Updated the description for the 2.5 standard deviations being used. The 2.5 standard deviations used to document priority grids/areas represent 2.5 standard deviations about the average.
Company Roles	08/08/2014	Updated employee job titles to reflect current defined job titles within the organization.
Periodic Evaluation and Improvement – Plan Updating	08/08/2014	Updated the 'Plan Updating' section to more clearly define the process for requiring the two week approval process.

General Updates	01/01/2015	Updated terminology around "Priority Grids" to "Priority Areas".
New Definition	01/01/2015	Added new definition for Business District
Threat Identification	01/01/2015	Added new threat definitions – High Pressure Taps, Stubs, Jamison Fittings, Smith Blair Clamps, POSI Holds, , Rocky Backfill, Over Pressurization
State & Federal Annual Reporting Requirements	01/01/2015	Updated DIMP Plan distribution policy to state officials.
Approval Signoff	01/01/2015	Updated Approval Control Signoff with new titles.
Ranking of Risk	01/01/2015	Added a validation process for the risk ranking.
Ranking of Risk	01/01/2015	Added SME Risk Validation process.
Ranking of Risk	01/01/2015	Added PHMSA Audit Risk Assessment process
Identify and Implement Measures to Address Risk	01/01/2015	Added Subject Matter Expert Integrity A/A Actions process.
Identify and Implement Measures to Address Risk	01/01/2015	Added PHMSA Audit Risk Assessment A/A Action process.
Gaining Additional Information	01/01/2015	Removed technology survey requirement.
Risk Ranking	01/01/2015	Removed Damage Density Risk Ranking
Risk Assessment Process	03/30/2015	Updated location of where the risk assessment documentation is stored. Original location was set to the SharePoint site however it is now located on a system network drive.
Inactive Service Line Integrity A/A Actions	06/30/2015	Updated the location of where A/A actions are documented.
Purpose and Objectives - Definitions	01/01/2016	Added and updated the definition section.
Company Roles – Key Contacts	01/01/2016	Added and updated company roles and titles.
Company Roles – Subject Matter Experts	01/01/2016	Revised section
Timeline – Schedule of Procedures	01/01/2016	Revised procedure and task expectations to be completed up to one month after each respective quarter end.
Data Integrity Quality Assurance - Process	01/01/2016	Revised the GIS Data Validation section.
Reporting Requirements – Data Compilation	01/01/2016	Revised section
Threat Identification - Threats	01/01/2016	Revised threat definition's per PHMSA updates (May 2015 PHMSA release). This revision required some sub-threats to be placed in different threat categories. Added new sub-threats and definitions. Revised excavation section and added Delaware and Maryland.
Threat Identification Process	01/01/2016	Revised section
Potential or Emerging Threat Identification	01/01/2016	Revised section
Ranking of Risk – Objective and Process	01/01/2016	Removed section around Elkton not being on WMS. WMS has now been implemented for Elkton.
Periodic Evaluation and Improvement – Plan Updating	01/01/2016	Added description around the approval control sheet to indicate review of the previous year's appendices was completed by key contacts (per New Jersey and Maryland recommendations).

Objective and Process - Subject Matter Expert Integrity A/A Actions	01/01/2016	Revised section
Ranking of Risk – PHMSA Audit Risk Assessment – Risk Assessment Process	01/01/2016	Added Maryland and Delaware (explicitly added terminology to indicate both states are included).
Ranking of Risk – Pipeline Integrity Risk Model Assessment – Risk Assessment Process	01/01/2016	Revised terminology around the system filtering process.
Ranking of Risk - PHMSA Audit Risk Assessment	01/01/2016	Removed VP of Compliance and Technical Services responsibility.
Knowledge – Gaining Additional Information – Objective and Process	01/01/2016	Removed VP of Compliance and Technical Services responsibility.
Knowledge – Characteristics of Design, Operations and Environmental Factors	01/01/2016	Added LTA, Click and PeopleSoft
Identify and Implement Measures to Address Risks – Subject Matter Expert Integrity A/A Actions	01/01/2016	Removed likelihood of consequence score of five.
Ranking of Risk – System Level Threat Ranking	09/28/2016	Updated the variables used to calculate the System Level Threat Ranking.
Type and Location of Records	01/01/2017	Removed relative data grading process.
Integrity Management Program Record Summary	01/01/2017	Removed relative data grading process.
Data Quality Assurance Processes	01/01/2017	Updated take the time definition for GIS updates.
Data Compilation	01/01/2017	Removed Mobility from the data compilation section since the system is no longer used.
Threat Identification	01/01/2017	Updated Farm Tap and High pressure Tap Definitions.
Threat Identification	01/01/2017	Moved Service tap connection section from Equipment to Pipe, Weld, or Joint Threat.
Threat Identification	01/01/2017	Moved Cast Iron Bell & Spigot Joint from Other to Pipe, Weld, or Joint Threat.
Threat Identification	01/01/2017	Consolidated the Equipment sub-threats Equipment Failure with Equipment Malfunction
Threat Identification	01/01/2017	Consolidated the Incorrect Operations sub-threats Inadequate Safety Practices, Stripped Threads, and Construction/Installation defect into Failure to Follow Procedures.
Threat Identification Process	01/01/2017	Merged redundant steps for Threat Identification process
Potential or Emerging Threat Identification	01/01/2017	Merged redundant NOI process into the Identification Process.
Ad Hoc Processes	01/01/2017	Added semi-annual ad-hoc process to document significant studies performed by the DIMP group.

Subject Matter Expert Risk Assessment	01/01/2017	Removed bullet points that did not provide value to process.
Subject Matter Expert Risk Assessment	01/01/2017	Added minor verbiage to include pipeline materials and components to risk assessment process.
Purpose and Objective - Definitions	01/01/2018	Added Asset Repository.
Purpose and Objective - Definitions	01/01/2018	Removed Compliance Tracking System.
Purpose and Objective - Definitions	01/01/2018	Removed Customer Management (CMA) application
Purpose and Objective - Responsibility	01/01/2018	Added reference to Section 9: Document and Record Retention policy for retention policy.
Purpose and Objective – Key Contacts	01/01/2018	Added timing clarification “by the end of”.
Purpose and Objective – Key Contacts	01/01/2018	Updated Director of Compliance and Pipeline Risk Management Job Title
Purpose and Objective – Support Role	01/01/2018	Added Vice President, Operations Support position and definition.
Purpose and Objective – Support Role	01/01/2018	Added Director of System Operations position and definition.
Purpose and Objective – Subject Matter Experts	01/01/2018	Process clarification “end of Q2.”
Purpose and Objective – State Contacts	01/01/2018	Updated Q2 requirement to be annually.
Purpose and Objective – State Contacts	01/01/2018	Added timing clarification “by the end of”.
Purpose and Objective – Schedule of Procedures	01/01/2018	Updated Procedure Expectation table.
Knowledge – Program Awareness Initiatives	01/01/2018	Added new section for program awareness objectives.
Knowledge – Design, Operations, and Environmental Factors	01/01/2018	Added Asset Repository and Removed Compliance Tracking System definitions.
Knowledge – Gaining Additional Information	01/01/2018	Process has been updated to be more efficient and removed SharePoint references.

Knowledge – Data Quality Assurance Processes	01/01/2018	Removed DIMP initiation reference to GIS validation.
Knowledge – Data Quality Assurance Processes	01/01/2018	Removed topics for Quarterly Operations Meetings due to varying operational topics covered.
Knowledge – Data Compilation	01/01/2018	Added clarification for Elkton Gas to include Subject Matter Experts.
Knowledge – Data Compilation	01/01/2018	Geographic Information System, clarified process and responsibility.
Knowledge – Data Compilation	01/01/2018	Service Count determination, include Construction Operations in count determination
Knowledge – Data Compilation	01/01/2018	Excess Flow Valve Count Determination, clarifies a WMS query is needed.
Knowledge – Data Compilation	01/01/2018	Updated Compliance Tracking System with Asset Repository
Knowledge – Data Compilation	01/01/2018	Process clarification “end of Q2.”
Threat Identification – Object and Process	01/01/2018	Updated Threat definitions with PHMSA definitions.
Threat Identification – Sub threat Update	01/01/2018	Updated and reorganized sub threats among all threats.
Threat Identification – Composite Conditions or Materials	01/01/2018	Added new section for Composite Conditions or Materials. This includes definitions for threat Materials, Components, and Specific Situations/Events.
Threat Identification – Threat Identification, Investigation and Evaluation	01/01/2018	Added new process to identify and document new, potential or emerging threats.
Threat Identification – Adding New Threats to the Plan	01/01/2018	Added new section for adding threats to the Distribution Integrity Management Plan.
Threat Identification – Retiring Threats	01/01/2018	Added new section for retiring threats to the Distribution Integrity Management Plan.
Threat Identification – Threat Identification Process	01/01/2018	Removed old process due to new process.

Threat Identification – Threat Metric Requirements	01/01/2018	Removed redundant process to create metrics and who is responsible.
Threat Identification – Threat Metric Requirements	01/01/2018	Updated SharePoint process to document metric creation.
Threat Identification – Threat Metric Requirements	01/01/2018	Updated process for frequency and trend metrics.
Threat Identification – Potential or Emerging Threat Identification	01/01/2018	Removed process because it has been incorporated into the Threat Identification, Investigation and Evaluation process.
Risk Ranking – System Level Threat Assessment	01/01/2018	Updated process with numerous wording/process clarifications.
Risk Ranking – Subject Matter Expert	01/01/2018	Added detail to the subject matter Expert Risk Assessment and changed due date of product to be Q4.
Risk Ranking – PHMSA Audit Risk Assessment	01/01/2018	Updated process with numerous wording/process clarifications for key Contacts.
Periodic Evaluation and Improvement – Plan Updating	01/01/2018	Moved section for Approval Control of Plan.
Periodic Evaluation and Improvement – Plan Updating	01/01/2018	Created process for “Significant” Plan updates.
Document and Record Retention	01/01/2018	Process clarification and added detail to archive plans and appendices.
Threat Identification – Sub threat Update	7/31/2018	Added descriptions to: • Vehicular Damage (Road) • Loose Caps & Fittings (Buried) • O-Rings/Gaskets on Caps & Fittings • Broken Component • Damage Caused by Improper Backfill • Chemically Compromised Material (Non-Metallic)
Identify and Implement Measures to Address Risk	7/31/2018	Added ‘Keep Records’ which had been erroneously removed.
Gaining Additional Information	8/16/2018	Clarified attributes documented for Data Gaps.

Purpose and Objectives – Company Roles	10/25/2018	Changed Support Roles - Director of Standards, Compliance & QA to Director of Compliance and Pipeline Risk Management. Removed the following from job titles from Subject Matter Experts (titles no longer exist): • Director of Standards, Compliance & QA • Director of Asset Protection & Operations Process Improvement • Operations Improvement Senior Program Manage
General (All Sections)	11/14/2018	Updated with New Company Logo, Company Name
General (All Sections)	01/01/2019	Removed all references to “GAS”, “AGL”, “Atlanta Gas Light”, “Southern Company Gas”, “Elkton Gas”, “Chattanooga Gas” and all other non-Florida City Gas LDCs, and replaced with “Florida City Gas” or “FCG” to align with NextEra Energy divestiture
Purpose and Objective – Key Contacts	01/01/2019	Revised titles and responsibilities of all Key Contacts to align with current FCG representatives and removing all Southern Company Gas roles and titles that are no longer applicable due to NextEra Energy divestiture
Purpose and Objective – Support Role	01/01/2019	Revised titles and responsibilities of all Support Roles to align with current FCG representatives and removing all Southern Company Gas roles and titles that are no longer applicable due to NextEra Energy divestiture
Purpose and Objective – Subject Matter Experts	01/01/2019	Revised titles and responsibilities of all Subject Matter Experts to align with current FCG representatives and removing all Southern Company Gas roles and titles that are no longer applicable due to NextEra Energy divestiture
General (Several Sections)	01/01/2019	All references to different Southern Company Gas SharePoint sites were removed and replaced with one “DIMP SharePoint site”
Identify and Implement Measures to Address Risks – Leak Management Program	01/01/2019	Removed entire section under “Propane Leak Survey Program”, as Florida City Gas does not have any propane systems.
Identify and Implement Measures to Address Risks – Leak Management Program	01/01/2019	Removed references to “County wide safety plan”, as this was a Georgia specific program that is no longer applicable at Florida City Gas due to NextEra Energy divestiture
Document and Record Retention – Objective and Process	01/01/2019	Removed language that precisely identifies the folder structure, file name formatting and file location for the current and previous versions of the plan, as this location can change due to NextEra Energy divesture
Approval Control Signoff	01/08/2020	Updated Approval Control Signoff with the new Distribution Integrity Management Program Analyst
Approval Control Signoff	01/20/2020	Updated Edition version and Release Date
Purpose and Objectives – Key Contacts	3/20/2020	Updated Key Contacts to include the Distribution Integrity Management Program Analyst

Purpose and Objectives – Key Contacts	7/02/2020	Updated Key Contacts to new GM of Florida City Gas
Company Roles – Key Contacts	7/02/2020	Updated company titles
Periodic Evaluation and Improvement – Plan Updating	10/21/2020	Updated text to reflect the new GM of Florida City Gas
Scope – Definitions	10/21/2020	Removed all definitions in reference to Southern Gas Company applications and systems
Scope - Definitions	12/4/2020	Updated definitions to reflect Florida City Gas system changes
Company Roles – Key Contacts	03/28/2022	Updated Company titles and roles
Applications	03/28/2022	Removed applications no longer used.
Company Roles – Key Contacts	03/30/2022	Updated Company titles and roles
ALL entries above this line are previous to Chesapeake Utilities purchase of Florida City Gas		
General (All Sections)	12/22/2023	Updated with New Company Logo, Company Name
General (All Sections)	01/08/2024	Removed all references NextEra Energy and updated to Chesapeake Utilities – Florida City Gas (FCG) – All roles / departments updated
General (All Sections)	03/04/2024	DIMP reviewed

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Florida City Gas has developed the Distribution Integrity Management Program (DIMP) Plan based upon data gathered from various sources currently available to the Company. The Company has employed a process of evaluating the sources to determine their appropriateness for use within the program, as well as the means available for collecting and processing data of this sort, and, therefore believes that the data is reasonably accurate and reliable. However, technical limitations, human error, sampling methodology, equipment failure, and other aberrations could cause the data at times to be inaccurate or incomplete. Based on review, the Company does not believe that any such irregularities have a material impact on processes developed by the Company.

1) Purpose and Objectives

The objective of the Distribution Integrity Management Program (DIMP) is to comprehensively understand the physical integrity of the distribution system. Managing the integrity and reliability of the gas distribution system in compliance with CFR Part 192 requirements is a primary goal for the Company. The objective of this DIMP Plan is to establish the requirements to comply with CFR 49, Part 192, Subpart P, pertaining to integrity management for gas distribution pipelines.

This DIMP Plan is comprised of seven elements depicted in Figure 1-1.

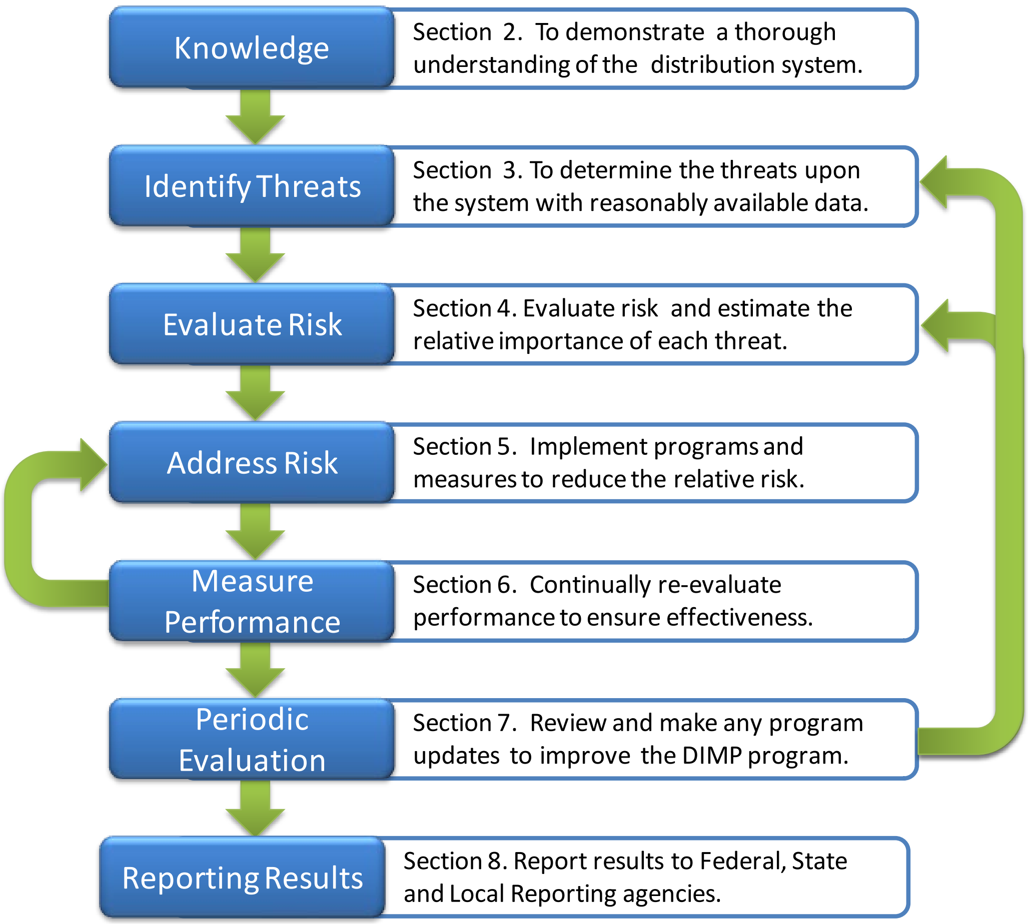

Figure 1-1 DIMP Elements

In addition to the key elements shown in Figure 1-1, this DIMP Plan establishes requirements for reporting of mechanical fitting failures in Section 8: Mechanical Fitting Reporting Requirements and maintaining records in Section 9: Document and Record Retention.

All key elements of this DIMP plan are in effect as of August 2, 2011.

A. Scope

i. Regulatory Reference: 192.1001

§ 192.1001

What definitions apply to this subpart?

The following definitions apply to this subpart:

Excavation Damage means any impact that result in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan or ***IM Plan*** means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart.

Integrity Management Program or ***IM Program*** means an overall approach by an operator to ensure the integrity of its gas distribution system.

Mechanical fitting means a mechanical device used to connect sections of pipe. The term “Mechanical fitting” applies only to:

(1) Stab Type fittings;

(2) Nut Follower Type fittings;

(3) Bolted Type fittings; or

(4) Other Compression Type fittings.

Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

ii. Definitions

The definitions provided in 49 CFR, §192.3 and §192.1001 shall apply to this DIMP Plan. The following additional definitions and acronyms shall also apply to this DIMP Plan.

A/A Action: Additional or Accelerated Action is a mitigative activity to the distribution system that reduces a threat upon the system. An A/A Action can include any action above Federal Standards or processes put in place to ensure added safety of the distribution system and accuracy of data gathered and can be measured by a performance measure.

Ad Hoc Process: Ad Hoc Processes are performed to document, analyze, target, and address specific and unique situations within the distribution system.

BCA Portal: Existing riser BCAs (create meter only WOs), administration screens, GIS map integration (and AE assignment), customer portal. From a reporting perspective it can export features for WOs and search results

Business District: The Company considers areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health or recreational purposes when defining its business districts. The Company also considers areas where gas and other underground facilities are congested under continuous street and sidewalk paving and extends to the building wall on one or both sides of the street. Further, any other area shall be considered that, in the judgment of the operator, should be designated as a business district.

Business Owner: The person or department responsible for the availability of data utilized in the DIM Program. This person or department has the ultimate responsibility for the performance of a business process, in realizing its objectives measured by key process indicators, and has the authority to make necessary changes.

Cathodic Protection Data Manager (CPDM): An electronic application used by the Corrosion Department for the purposes of cathodic protection (CP) compliance management. The information contained within CPDM pertains to the following: test point annual surveys, rectifier inspections, casings, exposed crossings, isolated services, CP system identification numbers, and cathodic protection facility locations. CPDM is a tool that is utilized by the Corrosion Department to support the DIMP Team with information relating to cathodically protected systems.

COF: Consequence of Failure

Collector: An application used by the field employees to complete work assigned from Maximo.

Contractor Quality Assurance (CQA): The quality assurance procedures followed by the Construction Operations Department to inspect, track and discipline gas installation contractors to ensure proper installation procedures are followed in accordance with the Company operational procedures manual.

Corporate Record Retention Policy: The policy by which records are defined and archived. This is a corporate policy.

Corporate Record Retention Schedule: The specific schedule or timeframe a record is maintained and assessable.

Distribution Integrity Management Program Files: Operator records, databases, and/or files that contain either material incorporated by reference in the Appendices of this DIMP Plan or outdated material that was once contained in this DIMP Plan Appendices but are now being retained in order to comply with record keeping requirements.

Distribution Integrity Management Program Plan (DIMP Plan): A written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with subpart P of 49 CFR Part 192. (Reference §192.1001)

Distribution Integrity Management Program (DIMP or DIM Program): An overall approach used by an operator to ensure the integrity of its gas distribution system. (Reference §192.1001)

Distribution Integrity Management Rule: 49 CFR, Part 192, Subpart P

DOT: Department of Transportation

Excavation Damage: Any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction of the facility including, but not limited to, the protective coating, lateral support, cathodic protection, or the housing for the line device or facility (reference §192.1001)

FCG: Florida City Gas.

FCG Leak Survey Manager App 2.0: An in-house work management system designed for scheduling and performing leak surveys.

Gas Quality: The established gas quality specifications a shipper shall meet when delivering natural gas.

GIS: Geographic Information System or a computer based mapping system

Hazardous Leak: A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous. This is a grade 1 leak. (Reference §192.1001)

IBM Maximo for Utilities (Maximo): An enterprise asset management solution that allows utilities to consolidate multiple work and asset management solutions into a single platform and database. A system capturing information regarding new construction records, pipeline maintenance activities, leak repairs, regulator station inspections, and other activities performed on the distribution system. Maximo is used by field service representatives (FSR) to assign tasks to be completed by field personnel.

IT: Information Technology

Integrity Management Plan or IM Plan: A written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this subpart. (Reference §192.1001)

Integrity Management Program or IM Program: An overall approach by an operator to ensure the integrity of its gas distribution system. (Reference §192.1001)

Irth: Ticket management solution of Florida.

LOF: Likelihood of Failure

Mechanical Fitting: A mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to stab type, nut follower, bolted or other compression type fittings. (Reference §192.1001)

Notice of Incident: This refers to an emergency notification defined in OPM Division II Section 5.

Notice of Probable Violation (NOPV): Formal written notice from a State Pipeline Staff detailing probable violations to specific section of the Code of Federal Regulation, which references a case number and an order of settlement.

NTSB: The National Transportation Safety Board

OPM: Operations Procedure Manual. As prescribed by PHMSA, the Minimum Federal Safety Standards Part 192.605, each operator of natural gas shall prepare and follow for each pipeline a manual of written procedures for conducting operations and maintenance activities.

PHMSA: Pipeline and Hazardous Materials Safety Administration

Plant Condition Report: A spreadsheet maintained by asset protection containing information about gas main and service locations that are difficult to locate due to varying reasons and requires investigation and possible mitigation.

Region: Areas within a distribution system consisting of mains, services, and other appurtenances with similar characteristics.

Risk: A relative measure of the likelihood of a failure associated with a threat and the potential consequences of such a failure.

Risk Model: The integration of facility data, operational data, SME input, and established algorithms to estimate the relative risk associated with a gas distribution system threat.

Scheduled Leak(s) for Repair: The PHMSA 7100.1-1 requires an operator to annually count the number of leaks scheduled for repair. These leaks are defined as grade 2 active leaks.

Small LPG Operator: An operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

Starnik: A customer management application. A financial system designed and historically used to capture customer information and meter information.

Subject Matter Expert (SME): An individual who is judged by the operator to have specialized knowledge based on their expertise or training.

Sub-Threat: A threat type within one of the primary threat categories specified in §192.1007(b)

Sunshine 811: The utility protection center for utilities located in Florida.

Supervisory Control Data Acquisition (SCADA): A system that collects data from various sensors and sends the data to a central computer that then manages and controls the data.

Ticket: A notification from the one-call center to the operator providing information of pending excavation activity that the operator is to locate and mark its facilities.

iii. Regulatory References: 192.1003

§ 192.1003 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005-192.1013 of this subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in § 192.1015 of this subpart.

iv. Objective and Process

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) amended the Federal Pipeline Safety Regulations on December 4, 2009 to require operators of gas distribution pipelines to develop and implement an integrity management program that includes a written integrity management plan.

The purpose of the DIM Program is to enhance safety by identifying and reducing gas distribution pipeline integrity risks. Operators must integrate reasonably available information about their pipelines to inform their risk decisions. The rule requires that operators identify risks to their pipelines where an incident could cause serious consequences and focus priority attention in those areas. The rule also requires that operators implement a program to provide greater assurance of the integrity of their pipelines.

The Distribution Integrity Management Program's approach was designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond previously established regulatory requirements. The SGA/NEGA framework document was used as a template for the DIMP Plan and Appendices.

This written DIMP Plan addresses the DIMP Rule which requires operators to develop and implement a DIM Program that addresses the following elements:

- Knowledge
- Identify Threats
- Evaluate and Rank Risks
- Identify and Implement Measures to Address Risks
- Measure Performance, Monitor Results, and Evaluate Effectiveness
- Periodic Evaluation and Improvement
- Report Results

Because of the significant diversity among distribution pipeline operators and pipelines, the requirements in the DIMP Rule are high-level and performance-based. The DIMP Rule specifies the required program elements but does not prescribe specific methods of implementation.

v. Regulatory Reference: 192.1005

§ 192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in § 192.1007.

vi. Objective and Process

The DIMP Plan is effective as of August 2nd, 2011 and shall be followed as long as distribution facilities remain in operation.

Florida City Gas DIMP complies with all elements of the regulatory requirements defined in CFR 192, Subpart P.

B. Responsibility

i. Knowledge of Content

The DIMP Plan is published with the intent of providing a key contact with the processes to execute the DIM Program. This includes, but is not limited to, identifying contacts and experts, defining analysis processes, and providing guidance.

ii. Care and Maintenance

The publication and accuracy of this manual involves the expenditure of considerable time and effort. In an effort to be a green product, the official DIMP Plan and appendices will be stored and archived electronically as defined in <u>Section 9: Document and Record Retention</u>. At any point, an electronic copy can be printed for review or archiving.

C. Company Roles

The purpose of this section is to describe key roles within the organization as it relates to the DIM Program. This includes the roles and responsibilities of key contacts, support roles and subject matter experts. This section also defines the requirements for a subject matter expert to be involved within the Distribution Integrity Management Program.

i. Key Contacts

A key contact is a Chesapeake Utilities employee or Florida City Gas employee who is familiar with the DIMP Plan and can provide guidance to the program. Additionally, key contacts can be identified by the Distribution Integrity Manager for further assistance in program development or communication.

- The key contacts identified in the DIMP Plan are listed in Appendix A: Reference of Key Contacts.
- A review of Appendix A: Reference of Key Contacts will be conducted annually by the end of Q1 by the Distribution Integrity Manager. This will include reviewing names, positions, company, phone, and email found in the key contact appendix. The Distribution Integrity Manager is only allowed to make edits to the contact information for key contacts found in the appendix, but cannot add or remove any key contacts without approval from the Vice President & General Manager of Florida City Gas.
    - The appendix shall include:
        - Name of Individual
        - Title of Individual
        - Phone Number
        - Email
    - All key contacts listed in Appendix A: Reference of Key Contacts are required to have a general description found below:

(1) General Manager of Florida City Gas

The General Manager of Florida City Gas is responsible for executive oversight of the DIMP Plan and to ensure the DIMP Plan processes are implemented by the organization in accordance with the DIMP and associated regulatory requirements. Responsibilities also include the executive oversight of leak, corrosion, damage prevention and other integrity related activities. Other roles for this position include:

- Responsible for the implementation and performance of the DIM Program
- Participates in the oversight of short-range and long-range plans for the program
- Responsible for the performance of initiatives developed by the DIM Program
- Ensures effective implementation of the DIM Program

(2) Lead Engineering Manager

The Lead Engineering Manager is responsible for the oversight and implementation of the DIM Program. Roles for this position include:

- Provides GIS guidance to the DIMP Team Participates in and is responsible for the oversight and evaluation of the DIM Program.

- Participates in the development of short-range and long-range plans for the program.
- Makes recommendations for proposed changes and revisions to the DIMP Plan.
- Ensures effective implementation of the DIM Program.

(3)Engineering Integrity Manager

The Engineering Integrity Manager has the responsibility for day-to-day program oversight and to ensure the plan is implemented effectively and is integrated with the Company's operating procedures. The Engineering Integrity Manager reports directly to the Lead Engineering Manager. This Plan assigns authority the Engineering Integrity Manager to develop and propose revisions to the plan. The Engineering Integrity Manager shall be able to delegate some or all of these tasks but is responsible for each task listed. Any tasks (defined below) delegated must be to a key contact or subject matter expert. Roles for this position include:

- Participates in the implementation and day to day activities of the DIM Program at the direction of General Manager of Florida City Gas and Lead Engineering Manager
- Develops and proposes changes and revisions to the DIM Plan
- Initiates communication with other departments within the Company
- Develops, proposes and coordinates A/A Actions and DIMP Related Actions with various departments within the Company
- Ensures completion of annual effectiveness reviews and plan re-evaluations
- Assists with reports to PHMSA and state safety regulators
- Monitors performance measures
- Assures plan compliance
- Analyzes threats
- Performs risk ranking
- Reviews and recommends exception requests

(4) Integrity Engineer

The Integrity Engineer reports directly to the Engineering Integrity Manager. The Inegrity Engineer is responsible for any task delegated to them by the Engineering Integrity Manager. Roles for this position include:

- Provides analytical and documentation support for the Engineering Integrity Manager
- Provides and prepares data for reports
- Compiles, analyzes and trends data from systems and sources for incorporation into DIMP

(5)Distribution Integrity Subject Matter Expert

A Distribution Integrity Subject Matter Expert shall be familiar with system related issues and participate in DIMP Related meetings.

- Participates in DIMP related meetings
- Identifies regional threats and consequences
- Distributes regional tasks, as needed, to subject matter experts
- Communicates the high level priorities of the DIM program

ii. Support Roles

Support roles provide the day to day support and guidance for activities related to the DIM Program. Additionally, a support role must comply with the SME requirements, but are not considered a key contact. These positions typically provide data, documentation, and guidance for the DIM program.

(1) Director of Operations Safety and Damage Prevention

- Communicates with State & Federal Regulators, trade associations and other external groups to identify potential and emerging threats
- Determines accelerated actions relating to Damage Prevention
- Oversee and direct the Quality Assurance inspection program
- Provides SME guidance on DIMP identified threats and risks

(2) Director of Operations Services

- Provides regulatory guidance to the DIMP Team
- Communicates with State & Federal Regulators, trade associations and other external groups to identify potential and emerging threats
- Standards & Procedure Quality Assurance
- Provides strategic direction for risk reducing programs
- Corporate liaison between regulatory agencies and Florida City Gas

(3) Compliance Manager

- Provides regulatory guidance to the DIMP Team
- Communicates with state & federal regulators, trade associations and other external groups to identify potential and emerging threats
- Corporate liaison between regulatory agencies and Florida City Gas
- Completes PHMSA and State reports
- Communicates with State & Federal Regulators, trade associations and other external groups to identify potential and emerging threats
- Executes or participates in the implementation of risk reducing programs
- Provides guidance and interpretations for business owners of regulatory rules and industry best practices

(4) Damage Prevention Manager

- Provides regulatory guidance to the DIMP Team
- Determines accelerated actions relating to Damage Prevention and ensures effective implementation of actions
- Provides data relating to damages for inclusion into the DIMP

(5) Engineering Integrity Manager

- Participates in engineering project reviews of DIM Program identified areas
- Verifies data integrity of GIS and CIS systems
- Develops and implements budgetary strategy of mitigative actions
- Provides engineering perspective on material performance and pipeline operations
- Communicates field identified threats to the DIMP Team
- Reviews material quality controls
- Communicates with the DIMP Team of potential and emerging threats and/or materials
- Provides research and expertise around specific DIMP related tasks or issues

- Provides GIS support to the DIMP Team
- Identifies and documents processes to capture, edit, and delete data in GIS
- Recognizes improvements to GIS, mobile, and asset technologies and provides implementation strategies
- Provides research resources to close data gaps

(6) Construction Services Manager

- Provides construction guidance to the DIMP Team
- Works with Pipeline Contractors to ensure the necessary data (test charts, drawings, etc) are created and provided to the GIS group for facility installations
- Help ensure safe and compliant installations of Company facilities
- Participates in the development of short-range and long-range plans for the program, relating to damages.
- Participates in the operational and system integrity related meetings
- Participates in annual effectiveness reviews

(7) Operations Manager

- Provides System Operations guidance to the DIMP Team
- Provides guidance to the design of regulator and tap stations
- Schedules leak surveys within compliance timeframes
- Provides leak survey's in response to DIMP Action Items
- Improves and streamlines leak survey processes
- Identifies potential and emerging threats found from Field Operations
- Recommends accelerated actions relating to System Operations
- Develops and implements budgetary strategy of mitigative actions
- Provides operational perspective on material performance and pipeline operations
- Communicates field identified threats to the DIMP Team
- Provides guidance to the design, installation, and maintenance of cathodically protected systems
- Researches and communicates corrosion related issues to the DIMP Team.
- Works with pipeline safety agencies to ensure compliance of inspections, readings and mitigative activities

(8) Integrity Engineer

- Provides analytical and documentation support for the Engineering Integrity Manager
- Provides and prepares data for reports
- Compiles, analyzes and trends data from systems and sources for incorporation into DIMP

iii. Subject Matter Experts

Subject Matter Experts (SME) are used throughout the DIM Program to provide firsthand experience about current and historical pipeline designs, operations, environment, and other factors.

A general definition of a SME is a person who has knowledge of the main, services, and/or appurtenances within the distribution system. A SME can be provided information from other employees, contractors, trade associations or outside sources but is responsible for the information that is disseminated to the DIMP Team and company. SME's are used to identify potential and emerging threats, ranking risks, and participate in developing mitigative activities.

- In addition to the key contacts and support roles identified above, the following positions have been determined to be potential subject matter experts and shall be considered in the DIM Program. Once a SME designation is granted to an employee, the designation can be considered perpetual for the employee.

    - Damage Prevention Specialist
    - Lead Engineering Manager
    - Engineering Design Manager
    - Designer
    - Compliance Manager
    - Safety Manager
    - Operations Manager
    - Integrity Technician
    - Integrity Supervisor
    - System Planning Engineer
    - GIS Specialist
    - GIS Analyst
    - GIS Supervisor
    - Measurement Technician
    - Operations Technician
    - Operations Supervisor

- A SME designation can be considered perpetual for the employee if he/she moves positions to a non-SME defined position. For example, the Construction Operations Manager can accept another position within the Company but shall be considered as a SME when reviewing excavation damages.
- A SME can be approved by the Engineering Integrity Manager
  if the individual's job title is not listed above but does provide knowledge or insight towards the DIM Program.
    - The DIMP Plan shall be updated to include the new job title following the <u>Section 7: Plan Updating</u> process.
- A SME who does not work for Chesapeake Utilities needs to be approved by the Engineering Integrity Manager. This shall include retirees or specialized contractors.
- The <u>Appendix A: Reference SME Qualifications</u> will be updated on an annual basis by the end of Q2.
- The Engineering Integrity Manager is responsible for maintaining <u>Appendix A: Reference SME Qualifications</u>. The annual record maintenance includes:
    - Adding, editing, or removing individuals from the SME qualification list.
    - Completing the following fields specific for each identified SME:
        - Job title: Former and/or current job title providing the SME designation.
        - Area of Experience: Defines a SME specialty and he/she can have multiple that apply. The following terms are used.
            - Construction, Engineering, Field, Information Technology, Regulatory, Analytics, Training

iv. *DEPARTMENTS AND TEAMS*

(1) DIMP Team

The DIMP Team is comprised of key contacts, support roles and subject matter experts. The DIMP Team is not a static team but rather utilizes specific employees for a variety of tasks and analyses. Accordingly, a DIMP Team is a specialized group of people addressing issues specific to the DIM program. To qualify as a DIMP Team, a manager or higher, from the Section 1: Departments and Teams will provide oversight and be responsible for the information disseminated from the DIMP Team.

(2) Engineering Department

The Engineering Department consists of both Engineering Integrity and Engineering Design and is responsible for the design of pipeline facilities according to applicable regulations and construction standards; planning, design and development of technical standards for pipeline facilities and operations; and also includes experts in the management of pipeline and pipeline facilities in the GIS environment. This department shall be consulted when needed for information on how to identify, analyze, and edit facilities in GIS. Additionally, production level maps shall be requested from the Engineering Department.

(3) Safety and Damage Prevention Department

The Safety and Damage Prevention Department is responsible for damage prevention activities and the quality assurance inspection program. It is responsible for tracking damages of pipeline facilities, and for the installation of pipeline facilities according to applicable regulations and construction standards.

(4) Compliance Department

The Compliance Department is responsible for ensuring that compliance is maintained with state, federal and corporate pipeline regulations and standards as well as the completion of the annual PHMSA reporting.

(5) Gas Control Department

The Measurement and System Operations Department is responsible for the installation, monitoring, and maintenance of cathodic protections systems. It is also responsible for the operation, inspection, and maintenance of regulator stations, critical valves, odorant injection and storage systems, large commercial and industrial meter sets, and expansion sleeves on above ground pipelines. Finally, it is responsible for Automation and Controls for the operation and maintenance activities associated with the Company's SCADA equipment.

(6) Operations Department

The Operations Department is responsible for the operation, monitoring, maintenance, and emergency response activities associated with the Company's pipeline facilities. It is also responsible for the installation, monitoring, and maintenance of cathodic protections systems; the operation, inspection, and maintenance of regulator stations, critical valves, odorant injection and large commercial and industrial meter sets; and for Automation and Controls for the operation and maintenance activities associated with the Company's SCADA equipment.

(7)Business Information Systems (BIS) Department

BIS provides support, development, and technical expertise with all systems. Enhancement requests for systems shall be communicated to the BISS Department so it can be reviewed and prioritized for a release.

D. STATE CONTACTS

- State contacts are to be documented in Appendix A: State Reporting. The Appendix A: State Reporting document information is to include:
    - State Regulatory Agency and Department;
    - State Contact and Position;
    - Address of State Agency;
    - Year the DIMP Plan has been sent; and
    - Document Reference
- Appendix A: State Reporting will be updated annually by the end of Q2.

E. TIMELINE

The DIM Program is updated on an annual basis and requires milestones to be completed throughout the year. The DIMP Plan is an integrity report of the previous year DOT calendar. For example, the 2011 DIMP Plan is a report of 2010 data. The final version will include documentation of system knowledge, identification of threats, risk analysis, implemented measures to reduce risk, performance measures and program re-evaluation.

i. SCHEDULE OF PROCEDURES

The completion of the quarter target date must be signed off by the Engineering Integrity Manager. If the Engineering Integrity Manager is unable to sign off on the Schedule of Procedures, a key contact within the Engineering or Compliance group must sign off. The procedure and task expectations as outlined below can be completed up to one month after each respective quarter end. The signoff of Schedule of Procedures demonstrates documentation and completion of tasks. Appendix A: Schedule of Procedures shall be updated every 4 ½ months, but at least four times each calendar year.

Quarter	Procedure Expectations
Q1 (Compile)	- Compile data from previous calendar year in accordance with the DOT's Form PHMSA F 7100.1-1 - Submit DOT Distribution annual report in accordance with Division II, Section 5.8 in the Company's Operations Procedures Manual (OPM)
Q2 (Analyze)	- Review data from previous DOT calendar year - Perform risk ranking to prioritize risks to the system - Finalize system knowledge, threat identification
Q3 (Develop)	- Develop appropriate accelerated & additional (A/A) actions - Develop and or prioritize pipeline replacement programs - Review DIM Plan for Program Effectiveness
Q4 (Finalize)	- Finalize Annual Risk Ranking Analysis - Finalize DIMP Plan metrics and appendices - Modify the forthcoming DIMP Plan to include any program improvements

The schedule of procedures provides major milestones to be accomplished throughout the year. Consequently, the quarter milestones do not prevent the incorporation of new information, threats, consequences, risks or information to be immediately integrated into the Distribution Integrity Program.

(1)Q1: Compile

The following steps occur in the first quarter of the year:

- Annual Pull of Active Leaks for DOT Annual Reporting & DIMP Metrics
- Annual Plan Updates
- Acquire & Prep Data for Analysis
- Data and Records Update
- DIMP Sign Off Sheet – Key Contacts
- DIMP Report Annual – DOT

- Summarize Evaluation & Improvement to Plan
- Plan Update to State
- Archive Data
- Q1 DIMP Plan Milestone Sign Off

(2)Q2: Analyze

The following steps occur in the second quarter of the year:

- Threat Identification Review Process
- Risk Ranking – System Threat Assessment
- Risk Ranking – Pipeline Integrity Risk Model
- Risk Ranking – Subject Matter Expert
- Risk Ranking – Inactive Services
- Begin to Create DIMP Plan Metrics
- Data Gaps and Plans
- Initial Review – Findings of Metrics and Risk Analysis
- DIMP Plan Metrics
- Q2 DIMP Plan Milestone Sign Off

(3)Q3: Develop

The following steps occur in the third quarter of the year:

- Recommend A/A Actions
- Review DIMP Plan Enhancements
- Review DIMP Plan for Program Effectiveness
- Q3 DIMP Plan Milestone Sign Off

(4)Q4: Finalize

The following steps occur in the fourth quarter of the year:

- Recommend and Review A/A Actions
- Finalize the Documentation of Implemented/Completed A/A Actions
- End of Year Review
- Q4 DIMP Plan Milestone Sign Off
- Publish DIMP Plan and Appendices for Year

ii. Deviation of Schedule

Any deviation from the schedule of procedures as prescribed in this DIMP Plan must document a key contact, explanation of delay, estimated and actual completion date to ensure responsibility and accountability of the delay. Deviations from the schedule of procedures require approval by the Director of Engineering and Integrity Management. The deviation from the schedule of procedures must be documented in Appendix A: Deviation of Schedule.

2) KNOWLEDGE

A. Regulatory Reference: 192.1007(a)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

B. Objective and Process

This section provides a background of general knowledge of Florida City Gas' infrastructure using available information such as the materials and type of construction, the operating conditions of the pipe or facility, and other relevant factors within the operating environment. This information is referred to as the "knowledge of the distribution system" and is the first of seven elements identified as an essential component of a distribution integrity management plan.

The objective of this section is to organize data and employee knowledge in a manner that ensures and demonstrates understanding and knowledge of the gas distribution pipeline. General knowledge of the system will assist the Company in identifying threats and establishing a risk evaluation of the distribution system.

i. Type and Location of Records

A summary of the existing records that are utilized by the DIM Program are documented in Appendix B.

- <u>Appendix B: Integrity Management Program Records Summary</u> This reference contains systems and records used in the DIM Program. The reference used in the appendix will be updated on an annual basis. This review will be conducted by the Distribution Integrity Management Program Engineering Leader. The information collected is to include:
  - Record Name: Provide Name of System or Record.
  - Record Type: Documents the format of the record. This can be multiple formats.
    - Database – D
    - Electronic Record – E
    - Paper Record – P
  - Location or Records: Document where the source record can be located.
    - Regional – Florida City Gas
    - Service Center – Service Center
  - Responsible: Identifies the business owner who uses the system to accomplish business tasks.
  - Utilization: How the data is used in DIM Program.
  - Data Characteristics: Document the intent of the record and how it is used within the DIM Program. A record source can include multiple descriptions.
    - Design –type of construction, inserted pipe, rehabilitated pipe method, materials, sizes, dates of installation, mains, services, etc.
    - Operating Conditions –pressure, gas quality
    - Environmental Factors –corrosive soil conditions, frost heave, land subsidence, landslides, washouts, wall- to-wall paving, population density, difficult to evacuate facilities, valve placement
    - Past Design – Retired gas main
    - Operations –O&M activities, field surveys, one call system notifications
    - Maintenance –Excavation damage

ii. Program Awareness Initiatives

Awareness of DIMP by all employees is an integral part of ensuring the safety and reliability of the Company's distribution system. All communication and training is distributed with the objective of providing continuous education to company employees.

- Communication between DIMP and other departments includes, but is not limited to:
    - Operations Meetings
    - Reference Materials
    - Training
- Topics may include, but are not limited to:
    - Data accuracy
    - Industry news / lessons learned
    - Distribution integrity management responsibilities
    - Safety
    - Field employee observations
    - Company records / databases
    - System mapping

C. Characteristics of Design, Operations, and Environmental Factors

The objective of this section is to assemble a comprehensive understanding of the Company's infrastructure using reasonably available information from past and ongoing system design, operations and maintenance activities. In addition, this plan will identify any additional information that is needed and provide a plan for acquiring that information over time through normal business activities.

The information referenced in this section shall be placed in Appendix B. The completed section demonstrates the regulatory requirement of "Knowledge of System."

- The DIMP Team will be responsible for compiling the information used in Appendix B.

i. *Regulatory Reference: 192.1007.(a).(1)*

192.1007.(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

ii. *Objective and Process*

Systems that provide the characteristics of the pipeline's design, operations and environmental factors that are necessary to assess the applicable threats and risks are documented herein, and included in the Section 2: Type and Location process.

(1) Pipeline's Design and Environmental Based Attributes

Geographic Information System (GIS): An electronic mapping and data storage system used to capture system information. The data contained within GIS is as follows: pipeline location, material, size, installation date, pressure, pipe diameter, test station locations, exposed crossings, service taps, residential/commercial propane tanks and other attributes. Additionally, GIS contains data relating to environmental factors such as; flood zones, business districts, wall-to wall paving, population density, difficult to evacuate facilities, military facilities, schools, churches, industrial parks, golf courses, park and recreational areas, and places of congregation. GIS also contains service address, city, name, service order number, pressure, tap size, tap location, length of service, size of service, size of main, depth of main, description of main location, material, and remarks.

(2) Operational Work Order and Tracking Records

The information contained within the following operational work order systems provides the data required to prepare the Annual PHMSA 7100.1-1 Report.

IBM Maximo for Utilities (Maximo): A system capturing information regarding new construction records, pipeline maintenance activities, leak repairs, regulator station inspections, and other activities performed on the distribution system. Maximo is used to create and track order completions.

Collector: An application used by the field employees to complete work assigned from Maximo.

Starnik: A customer management application that's primarily used for customer billing.

FCG Leak Survey Manager App 2.0: An in-house work management system designed for scheduling and performing leak surveys.

(3) Gas Controls

Supervisory Control Data Acquisition (SCADA): An IT system that collects data from various sensors and sends the data to a central computer. The information collected includes: metering, pressures, and temperature.

D. OVERVIEW OF PAST DESIGN, OPERATIONS AND MAINTENANCE

i. *REGULATORY REFERENCE: 192.1007.(A).(2)*

192.1007.(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(2) Consider the information gained from past design, operations, and maintenance.

ii. *OBJECTIVE AND PROCESS*

Information gained from past design, operations and maintenance is documented, or included by reference, in Appendix B & C. This data and information, if not already included in the various risk evaluations, shall be considered for incorporation or to be further evaluated by other processes.

(1) Operations and Maintenance

Contractor Quality Assurance (CQA) Program: An internal program to track contractor performance and quality. The information in this program includes inspection, tracking and discipline for construction activities specified in the program.

Critical Valve Inspection Records: The inspection form associated with critical valve inspections include; date, valve number, valve location, condition, tag, and color.

Odor Intensity Records: Records associated with odor odorant testing. This record contains: equipment used, serial number, test location, operating area, date, threshold values, intensity, and inspector.

Failure Investigations: Records associated with failure investigation as defined by 49 CFR 192 and as detailed in the Company Operating and Maintenance Procedures.

Subject Matter Experts: An individual who is judged by the operator to have specialized knowledge based on their expertise or training. The information provided by SMEs is typically, system knowledge, past design knowledge, repair maintenance knowledge, etc.

See Section 2: Characteristics of Design, Operations, and Environmental Factors for more systems capturing information specific to past design, operations, and maintenance.

(2) Leak Survey Records

FCG Leak Survey Manager App 2.0: An in-house system designed for capturing data during the leak survey process.

Maximo: The data contained within Maximo is as follows: survey grid, survey type, address, service center, discovery date, compliance date, grade, leak location codes, and atmospheric corrosion.

See Section 2: Characteristics of Design, Operations, and Environmental Factors for more systems capturing information specific to past design, operations, and maintenance.

(3) Excavation Information

Collector: used by the field to complete work assignments and track excavation damages from Maximo.

(4) Corrosion Records

Cathodic Protection Data Manager (CPDM): A module within the Pipeline Compliance System (PCS), an enterprise solution developed by American Innovations. The information contained within CPDM are annual reads, bi-monthly reads, isolated services, CP system identification numbers, test station locations, and rectifier locations. CPDM is utilized by the Corrosion Department to provide the DIMP Team with information relating to cathodically protected pipeline systems.

See Section 2: Characteristics of Design, Operations, and Environmental Factors for more systems capturing information specific to past design, operations, and maintenance.

(5) State and Federal Communications and Reporting

Notice of Probable Violation (NOPV): Formal written notice from a Pipeline Safety Agency detailing probable violations to specific section of the Code of Federal Regulation, which references a case number and an order of settlement.

National Response Center (NRC) Report: Telephonic communication to the national response center resulting in a report number when an incident has occurred which may meet the requirements of notification as defined by 49 CFR Part 191. This record can be withdrawn based on the results of the investigation or may require the submission of the PHMSA the Incident Report – Gas Distribution System Form.

PHMSA Annual Report PHMSA 7100.1-1: A report required to be submitted annually to PHMSA as defined by 49 CFR Part 192, contains the following information:

Part A – Operator Information

Part B – System Description

1. Miles of main and number of services by material and coating for steel
2. Miles of mains by material and diameter
3. Number of services by material and diameter and average service length
4. Miles of main and number of services by decade of installation

Part C – Total Leak and Hazardous Leaks Eliminated/Repaired During the Year by Cause

Part D – Excavation Damages and Tickets

Part E – Excess Flow Valve (EFV) and Service Valve Data

Part F – Leaks of Federal Land

Part G – Percent of Unaccounted for Gas

Part H – Additional Information

Part I – Preparer and Authorization Signature

PHMSA Incident Report PHMSA 7100.1: A report required to be submitted detailing a gas incident as defined by 49 CFR Part 191. The report is prepared on the Incident Report – Gas Distribution System Form. Information on this form includes:

Part A – Key Report Information

Part B – Additional Locations Information

Part C – Additional Facility Information

Part D – Additional Consequence Information

Part E – Additional Operating Information

Part F – Drug & Alcohol Testing Information

Part G – Apparent Cause (G1 - G8)

PHMSA Mechanical Fitting Failure Report 7100.1-2: Report required to be submitted annually to PHMSA as defined by 49 CFR Part 192, contains the following information:

Part A – Operator Information

Part B- Preparer and Authorization Signature

Part C – Mechanical Fitting Failure Data – which includes the following basic information: state, date of failure, mechanical fitting Involved, specify the type of mechanical fitting, leak location, year installed, year manufactured, provide decade installed (if year and manufacturer unknown), manufacturer, part or model number, lot number, other attributes, fitting material, two materials being joined, second pipe nominal size, apparent leak cause, and basic leak details.

(6) Legacy Systems and Records

Legacy Engineering Records: Records from past design and construction that are in paper format or electronic. The information in this record set includes the following: engineering guides, previous operating procedures manuals, purchase orders, historic construction records, pressure charts/readings, distribution tests data, and weld inspections. This information provides the engineering department who assists the DIMP Team with system knowledge to provide SME input, assist in evaluations of potential and emerging threats and in Ad Hoc Processes when needed. Additionally, this information can be useful for researching records in order to confirm or provide historic information.

Legacy As-Built Construction Drawings: Records from past construction that are in paper format or electronic. The information in this record set includes the following: date work started, date work completed, location, diameter, material, key, NOP, project type (i.e. new business, DOT, renewal, etc.), service center, county, project number, length, depth of cover, inserted pipe and casing, test pressure info, and cathodic protection info.

Legacy Pipe Inspection Reports: The information contained on these cards typically includes: house number, street, city/county, cross street, project number, line designation, size, material, coating, condition of coating, internal inspection, inspector name, date, and comments.

Gas Control Calibration Records: Previous electronic records associated with measurement and metering. The information is contained in the GMAS (GOS Database) and DataStream 7i and it includes information relating to metering and pressure. This information can be useful for researching records in order to confirm or provide historic information.

Legacy Gas Control Calibration Records: Historic records associated with measurement and pressure. The information contained within this record set includes: metering and pressure. This information can be useful for researching records in order to confirm or provide historic information.

Legacy Public Awareness Records: Records associated with public awareness as required by 49 CFR 192. These records contain the following information: dates, attendees, questionnaires, education materials, correspondence, etc.

Wall Maps / Plats: Historic mapping records these include paper maps and SAMS maps. The information contained within this record set includes: location, diameter, material, pressure and cathodic protection system identification number.

Regulator Station Inspection: The inspection form associated with regulator inspections includes; date, station name, station number, location, station housing, general station design, MAOP inlet, MAOP outlet, System Map, regulator make, regulator type, regulator size, connection, and spring range.

E. Gaining Additional Information

i. *Regulatory Reference: 192.1007.(a).(3)*

192.1007.(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example; design, construction, operations or maintenance activities).

ii. *Objective and Process*

- Data gaps are identified through the following processes:
  - Preparation of the annual risk ranking to assess threats to the system.
  - Identification of new or unknown threats.
  - Development of Ad Hoc Processes to address specific issues/threats.
  - Communication with regulators, professional organizations and trade groups.
  - Communication with documented SMEs.
- Data gaps are documented within Appendix B: Incomplete or Additional Information and include the following attributes:
  - Name: Identify the data or record needed.
  - Description: A description of the incomplete record and explanation of what shall be collected.
  - Type of Enhancement: This documents what component of a system needs to be improved. Multiple options can be chosen.
    - Process: The existing system can handle the enhancement but requires a change to a process.
    - Software: An existing or new software program needs to be modified or acquired to be able to capture the new information.
    - Hardware: An existing or new hardware platform needs to be modified or acquired to be able to capture the new information.
    - Data: The existing system has been enhanced or can otherwise handle the required data, but the data has not been captured or collected yet.
  - Status: This determines if the enhancement is actively being worked.
  - A review of the data gaps is conducted with the Distribution Integrity Manager and Director of Engineering and Integrity Management by the end of Q4.

F. Periodic Review and Refinement

i. Regulatory Reference: 192.1007.(a).(4)

192.1007.(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

ii. Objective and Process

- Refer to <u>Section 7: Periodic Evaluation and Improvement</u> in the DIM Plan for the process of periodic evaluation and improvement.

G. DATA CAPTURE FOR NEW CONSTRUCTION

i. REGULATORY REFERENCE: 192.1007.(A).(5)

192.1007.(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

ii. OBJECTIVE AND PROCESS

Data is continuously collected for both construction of new facilities, reconstruction of existing facilities and ongoing operations and maintenance. In particular, the standard or procedure that requires data capture for the location where the new pipeline is installed and the material of which it is constructed is contained in Division III, Section 3 of the OPM or Operations Procedures Manual.

(1)Pipeline Based Attributes

Geographic Information System (GIS) refers to the electronic mapping and data storage system used to capture system information. The data contained within GIS is as follows: pipeline location, material, size, installation date, pressure, pipe diameter, test station locations, exposed crossings, service taps and other attributes; service address, city, name, service order number, pressure, tap size, tap location, length of service, size of service, size of main, depth of main, description of main location, material, and remarks.

H. DATA INTEGRITY QUALITY ASSURANCE

i. *DATA QUALITY ASSURANCE PROCESSES*

- The DIM Program demands accurate and reliable information from a variety of sources. Below is a list of programs, technologies or systems that assist in validating the accuracy and completeness of data:
    - Maximo Business Warnings: Business warnings are part of the work order approval process for supervisors on activities related to the maintenance and operation of the pipeline and distribution appurtenances. Business warnings draw specific attention to predefined criteria, unique circumstances or user errors documented in the work order. A supervisor has to review all business warnings before a work order is approved.
        - Requests for additional business warnings shall be sent to the Information Technology Department. The Information Technology Department will prioritize the request into a future application release.
    - GIS Data Validation: Data from a variety of sources are cross checked to GIS to ensure the most accurate and reliable information is in GIS.
    - Take The Time: The Take the Time process allows the field and other employees to directly interact with the Engineering and Integrity Management Department to provide updates and correct issues found in GIS. The following scenarios provide the GIS Department with an email notification:
        - A field completed work order that indicates a discrepancy in GIS due to a field observation. Once the field order is field completed, it is sent for approval by the supervisor.
            - The supervisor must review the work order with the 'Update GIS' business warning.
                - The supervisor will decide if the Engineering and Integrity Management Department shall be notified by selecting 'Notify GIS'. This will send an email notification to the Engineering and Integrity Management Department
            - An investigation by the Engineering and Integrity Management Department will determine if updates to GIS are warranted.
        - Additionally, the field has access to a mobile GIS application. This application allows them to create red-lines of the information needing review. Once saved, the red-line is automatically sent to the Engineering and Integrity Management Department to be further investigated.
            - The red-line shall contain a description of the proposed update, including a contact name and phone number.
            - An investigation by the Engineering and Integrity Management Department will determine if updates to GIS are warranted.
        - An email shall be directly sent to the Engineering and Integrity Management Department when data gaps or inaccuracies are discovered by the field.
            - The email shall include a sketch or screen shot and detailed information about the data issue.

- An investigation by the Engineering and Integrity Management Department will determine if updates to GIS are warranted.
    - The Sr GIS Analyst is responsible for completing or closing a request.
    - The presentation includes metrics to gauge data and system integrity.
- Review of Operating and Maintenance Procedures (Audits and QA/QC Inspections)
    - Refer to OPM Division 1 Section 1.4.
- Completion Report Review of As-Builts; the Construction Services Department is responsible for verifying the information within the completion report package including the as-built drawing. Once the information has been verified as correct, the completion report package is sent to the GIS Team . The Engineering Integrity Department will perform a QA/QC of the completion report package to the standards defined in OPM Division 3 Section 3.
    - A request for additional information (RAI) will be sent out by the Engineering Integrity Department if the completion report package is lacking required information.
        - The RAI is sent to the Construction Operations Manager.
        - The completion report will not be posted to GIS until all information is accurate and included in the completion report package.
        - The Construction Operations Manager is responsible for closing any data gaps identified in the completion report package.
        - The Engineering Integrity Department is responsible for posting the completion report package to GIS.

I. Reporting Requirements

i. Data Compilation

- The DIMP Team is responsible for creating all metrics and references used in Appendix B & C.
    - The Engineering Integrity Manager is responsible for the accuracy of information displayed in the DIMP Appendices.
- The appropriate business owner is responsible for the source system information provided to the DIMP Team.
- The design, operating conditions and environmental factors are documented in Appendix B: Integrity Management Program Records Summary.
- The following data systems are queried on an annual basis in order to demonstrate knowledge of a pipeline's design and operations, and the environmental factors. Accordingly, this information is used to produce the metrics found in the DIMP Appendices. This is not the only information considered in the DIM Program but represents a dataset to replicate metrics found within the DIMP Appendices. The following instructions provide guidance to the data compilation process. The DIMP Team shall consider other data sources if they provide additional, more accurate, or supplemental information.

    - **Geographic Information System (GIS)** data is used throughout the DIMP Appendices to demonstrate understanding of pipeline location, material, size, installation date, pressure, test station locations, exposed crossings, and other attributes. GIS contains data relating to environmental factors such as; flood zones, business districts, wall-to wall paving, population density, difficult to evacuate facilities, military facilities, schools, churches, industrial parks, golf courses, park and recreational areas, and places of congregation. Gas mains from the GIS database are archived annually by the end of Q1.
        - This information is required for gas main mileage on the Annual PHMSA 7100.1-1 Report. This federal report is completed by March 15th unless an extension has been granted by PHMSA. This report is also submitted to the state.
        - An installation filter needs to be created to exclude any pipeline installed during Q1.
        - An analysis is run by the DIMP Team to attribute the gas main with PHMSA 7100.1-1 report designations. This includes material, size, and installation decade classifications.
        - This gas main mileage report is verified by Manager of Reliability Standards and Compliance before it is reported on the PHMSA 7100.1-1 annual report.
    - **Service Count Determination**
        - This task is coordinated by the Compliance Department on an annual basis for the PHMSA 7100.1-1 annual report.
            - The service count reported in B.1 of the previous year DOT Report is used as a baseline.

        - Construction Manager identifies services installed or retired by Company contractor crews.
        - By request, a query is run out of the Maximo database for the applicable year being reported that identifies services. A query is run out of the Maximo database for services installed by Company Distribution crews.
        - The services identified above are categorized as “new,” “retired,” or “replaced.”
            - The “new” service installs are added to the previous year report numbers. Note that “new” installs only consist of plastic and coated steel.
            - The “retired” services are subtracted from the previous year report numbers. The query does not identify if the retired services are protected or non-protected, so these are spread across the steel category based on the percentage of protected and non-protected main in the system.
            - The “replaced” services count does not change the total count of services, but is a balance of adding “plastic” and “protected coated steel” services and removing the legacy services (such as Copper and “un-protected steel”).
    - The final result is reported online within the PHMSA database.
- **Excess Flow Valve Count Determination**
    - This task is coordinated by the Compliance Department on an annual basis for the PHMSA 7100.1-1 annual report.
    - A query is run out of the Maximo database to identify all Excess Flow Valves (EFVs) installed by the Company under new business or pressure improvement projects.
    - A query is run out of the Maximo database for EFVs installed by Company Distribution crews.
        - The sum of these two values is used for the “Number of EFVs Installed this Calendar Year on Single Family Residential Services.”
    - The “Estimated Number of EFVs in System at the End of Year” is calculated by adding the above “current year EFV count” with the total reported in the previous year DOT report, Part E.
    - The final result is reported online within the PHMSA database.
- **Maximo**
    - Contains information specific to items requiring compliance or inspection intervals.

      Regulator Stations
        - The regulator station data is archived annually by Q2. This task is coordinated by the Distribution Integrity Manager and the DIMP Team.
        - This data shall only include regulator stations installed during the previous calendar year.

- See OPM Division 2 Section 4 for procedures to document leaks and leak repairs.
- To ensure leak repair orders are closed, approximately a month needs to transpire before an export can be requested.
- In general, leak repair and mechanical fitting repair information performed through distribution crews are documented through Maximo and are reported to PHMSA and State Regulatory Agencies. Leak repair data can be supplied by the DIMP Team or the IT Department.
  - The DIMP Team evaluates the information provided to identify and remove duplicative records
- Federal and State Leak Repair Reporting Requirements
  - All grade 1, 2, and 3 leak repairs are to be reported per PHMSA's definition of a leak as defined in the instructions for completing the PHMSA 7100.1-1 report.
    - This excludes non-hazardous leaks repaired by greasing and tightening.
  - To obtain a total of all leak repairs, the leak repair information must be consolidated with all work management systems containing leak repair information.
  - To verify leaks caused by excavation, cross checks are performed by the Compliance Department or Integrity Engineer to determine if any data gaps exist between reported damages and work order excavation damages. Differences are investigated.
  - All scrubbed data is also reviewed by the Engineering Integrity or Compliance Manager. A review of scrubbed data will include:
    - Reclassification of records with "Other" based on work order comments or other information
    - Reclassification of leak cause/sub cause based on work order comments or other information.
    - Reclassification of facility type based on leak location code, facility type, work order comments or other information.
  - The PHMSA 7100.1-1 annual report requires the reporting of leak repair information by March 15 for the previous year.
    - While the PHMSA 7100.1-1 annual report includes excavation damages that result in a leak under Part C, Part D also includes damages that do not result in a leak.
- Leak survey data can be supplied by the DIMP Team or IT Department.
  - The report includes leaks discovered through leak survey.
- The leak discovery count is reviewed by the Compliance Team or the Engineering Integrity Manager.
- Active leaks can be reported from Maximo.
  - The report includes all active leaks through the previous calendar year.
- Federal and State Leak Repair Reporting Requirements

- Grade 2 and 3 leaks are reported as leaks scheduled for repair on the PHMSA 7100.1-1

- **Damage Report**
  - The DIMP Team shall obtain a report of damage counts from the Damage Prevention department.
    - Damages will be compared against all Work Management Systems leak repair data to ensure all damages are reported.
  - The data provided by Damage Prevention Department will serve as the official dataset with sub-threats.
  - Work Management Systems and PeopleSoft should be analyzed for excavation damages that did not result in the loss of gas.
- **DOT Incident Reports** are compiled per CFR 191.5-9. These procedures are incorporated by reference in the OPM in Division II Section 5.
  - Incident reports are provided by the Compliance Department.
  - Federal and State Leak Repair Reporting Requirements
    - The Compliance Department reports these incidents within the guidelines provided in the OPM in Division II Section 5.
- **Total Locate Tickets**
  - Ticket volumes by service center or region can be acquired by the Operations Department, Damage Prevention Department or State One Call Center.

3) THREAT IDENTIFICATION

A. Regulatory Reference: 192.1007. (b)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline.

B. Objective and Process

The objective of this section is to identify existing and potential threats to the gas distribution pipeline. The following categories of threats shall be considered for each gas distribution pipeline:

- Corrosion Failure

  A leak caused by galvanic, atmospheric, stray current, microbiological or other corrosive action. A corrosion release or failure is not limited to a hole in the pipe or other piece of equipment. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is classified as corrosion. (Note: If the bonnet, packing, or other gasket has deteriorated to failure, whether before or after the end of its expected life, but not due to corrosive action, report it under a different cause category, such as Incorrect Operation for improper installation or Equipment Failure if the gasket failed)

- Natural Force Damage

  A leak caused by outside forces attributable to causes NOT involving humans, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds (Including damage caused by impact from objects blown by wind) or other similar natural causes. Lightning includes both damage and/or fire caused by a direct lighting strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by a lightning that results in damage to a gas distribution system asset which results in an incident.

- Excavation Damage

  A leak resulting directly from excavation damage by operator's personnel (oftentimes referred to as "first party" excavation damage) or by the operator's contractor (oftentimes referred to as "second party" excavation damage) or by people or contractors not associated with the operator (oftentimes referred to as "third party" excavation damage). Also, this section includes a release or failure determined to have resulted from previous damage due to excavation activity. For damage from outside forces OTHER than excavation which results in a release, use Natural Force Damage or Other Outside Force, as appropriate.

- Other Outside Force Damage

  A leak resulting from outside force damage, other than excavation damage or natural forces such as:
  - Nearby Industrial, Man-made or Other Fire/Explosion as Primary Cause of Incident (unless the fire was caused by natural forces, in which case the leak should be classified Natural Forces. Forest fires that are caused by human activity and result in a release should be reported as Other Outside Force).
  - Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation. Other motorized vehicles/equipment include tractors, mowers, backhoes, bulldozers and other tracked vehicles, and heavy equipment that can move. Leaks resulting from vehicular traffic loading or other contact (except report

as "Excavation Damage" if the activity involved digging, drilling, boring, grading, cultivation or similar activities.)

- Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels so long as those activities are not excavations activities. If those activities are excavation activities such as dredging or bank stabilization or renewal, the leak repair should be reported as "Excavation Damage."
- Previous Mechanical Damage NOT Related to Excavation. A leak caused by damage that occurred at some time prior to the release that was apparently NOT related to excavation activities, and would include prior outside force damage of an unknown nature, prior natural force damage, prior damage from other outside forces, and any previous mechanical damage other than that which was apparently related to prior excavation. Leaks resulting from previous damage sustained during construction, installation, or fabrication of the pipe, weld, or joint from which the release eventually occurred are to be reported under "Pipe, Weld, or Joint Failure." Leaks resulting from previous damage sustained as a result of excavation activities should be reported under "Excavation Damage" unless due to corrosion in which case it should be reported as a corrosion leak.
- Intentional Damage. Vandalism means willful or malicious destruction of the operator's pipeline facility or equipment. This category would include pranks, systematic damage inflicted to harass the operator, motor vehicle damage that was inflicted intentionally, and a variety of other intentional acts.
- Terrorism, per 28 C.F.R § 0.85 General Functions, includes the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives.
- Theft. Theft means damage by any individual or entity, by any mechanism, specifically to steal, or attempt to steal, the transported gas or pipeline equipment.

- Pipe, Weld or Joint Failure

  A leak resulting from a material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects or in-service stresses such as vibration, fatigue and environmental cracking. Material defect means an inherent flaw in the material or weld that occurred in the manufacture or at a point prior to construction, fabrication or installation. Design defect means an aspect inherent in a component to which a subsequent failure has been attributed that is not associated with errors in installation, i.e., is not a construction defect. This could include, for example, errors in engineering design. Fitting means a device, usually metal, for joining lengths of pipe into various piping systems. It includes couplings, ells, tees, crosses, reducers, unions, caps and plugs. Any leak that is associated with a component or process that joins pipe such as threaded connections, flanges, mechanical couplings, welds, and pipe fusions that leak as a result from poor construction should be classified as "Incorrect Operation." Leaks resulting from failure of original sound material from force applied during construction that cause a dent, gouge, excessive stress, or other defect, including leaks due to faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site that eventually resulted in a leak, should be reported as "Pipe, Weld or Joint Failure."

- Equipment Failure

  A leak caused by malfunctions of control and relief equipment including regulators, valves, meters, compressors, or other instrumentation or functional equipment. Failures may be from threaded components, flanges, collars, couplings and broken or cracked components, or from O-ring failures, gasket failures, seal failures, and failures in packing or similar leaks. Leaks caused by over-pressurization resulting from malfunction of control or alarm device; relief valve malfunction, and valves failing to open or close on command; or valves which opened or closed when not commanded to do so. If over-pressurization or some other aspect of this incident was cause by incorrect operation, the incident should be reported under "Incorrect Operation."

- Incorrect Operation

  A leak resulting from inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error. It includes leaks due to improper valve selection or operation, inadvertent over-pressurization, or improper selection or installation of equipment. It includes a leak resulting from the unintentional ignition of the transported gas during a welding or maintenance activity.

- Other Cause

  A leak resulting from any other cause not attributable to the above causes. A best effort should be made to assign a specific leak cause before choosing the Other cause category. An operator replacing a bare steel pipeline with a history of external corrosion leaks without visual observation of the actual leak, may form a hypothesis based on available information that the leak was caused by external corrosion and assign the Corrosion cause category to the leak.

C. CORROSION THREATS

Leaks caused by galvanic, atmospheric, stray currents, microbiological or other corrosive actions. A corrosion release or failure is not limited to a hole in the pipe or other piece of equipment. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is classified as corrosion. Below identifies the different metallic pipes installed for use in natural gas systems along with a brief narrative of its history, physical makeup, as well as reaction to the environment.

i. EXTERNAL CORROSION

External corrosion occurs due to environmental conditions on the outside of the pipe (e.g., from the natural chemical interaction between the exterior surface of the pipeline and the soil surrounding it). Typically, the exterior surface of a pipeline is coated in order to prevent the surrounding soil or other environmental condition from contacting the steel pipe, thus preventing the oxidation process. The components of the gas distribution system most vulnerable to this sub threat are bare steel mains and services and coated mains and services with holidays. Additionally, copper mains, services and copper service inserts have the potential to be vulnerable to corrosion depending on the circumstances. In addition, the oxidation process can be halted “electrically” on both bare pipelines as well as on pipelines that have been coated. When either or both of these protective measures break down, external corrosion can occur.

ii. INTERNAL CORROSION

Internal corrosion occurs due to chemical attack on the interior surface of the steel pipe from the commodities being transported within the pipeline. In some cases, the corrosive liquids may be contaminants such as water or other chemicals entrained or suspended within the commodity being transported. Typically, the commodity’s quality is controlled, internal coatings are applied, or corrosion inhibitors utilized to prevent internal corrosion. When one or more of these protective measures break down, internal corrosion can occur.

iii. ATMOSPHERIC CORROSION

The presence of a thin film of moisture on exposed steel gas mains, services, risers, and meter manifolds may subject these facilities to atmospheric corrosion. Steel pipe with inadequate coating that is exposed to marine atmospheres, high humidity, atmospheric pollutants, and agricultural chemicals may be particularly vulnerable to atmospheric corrosion.

Atmospheric corrosion identification and leak repair records are captured through the work order management systems and in Maximo during leak surveys.

D. Natural Force Threats

Leaks caused by outside forces attributable to causes NOT involving humans, such as earth movements, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperatures, thermal stresses, frozen components, high winds (Including damage caused by impact from objects blown by wind) or other similar natural causes. Lightning includes both damage and/or fire caused by a direct lighting strike and damage and/or fire as a secondary effect from a lightning strike in the area.

i. Ground Movement

Damage may result from shaking, liquefaction, and/or earth movement at the fault itself. The components of the gas distribution system most vulnerable to ground movement include areas where stress may be concentrated (elbows, fitting, valves, etc.), bell & spigot joints (cast iron and ductile iron mains), mechanical couplings, areas already degraded by corrosion, and poor welds and fusions.

ii. Animal or Insect Damage

Damage caused by any living non-human entity.

iii. Landslide

Landslides occur with the erosion of a surface usually caused by flooding. Landslides that undermine the soil support for piping may also be caused by sudden failure of adjacent water and sewage lines or other storm water control devices.

iv. Ice or Snow Related Damage

Damage or failure related to ice or snore buildup around above ground facilities. This includes but is not limited to: failures or damages caused by falling ice or snow, melting that results in water intrusion, or encapsulation.

v. Frost Line and Frost Heave

Ice/Frost heave occurs when the freezing of water saturated soil causes an expansion of the soil and an upward thrusting of the soil. Service territories with colder climates can experience frost lines that form at or below the depth of the buried gas mains and services. The resulting seasonal soil expansion can result in high loads and stress on the gas mains and services. The components of the gas distribution system most vulnerable to this sub threat are cast iron bell & spigot joints. Silty soils are often more prone to frost heave than clay or sandy soils.

A frost line that exists near the ground surface may also act to cause gas leaks to migrate longer distances and approach the foundations and outer walls of structures.

vi. Tree Related

Tree related leaks can include roots growing into the main or service and result in physically lifting or moving the pipe, thus applying increased stress that may result in a failure of a nearby fitting or the pipe itself.

vii. Heavy Rains or Flooding

Flooding may result in stresses and damage to gas mains and services as well as water intrusion into low pressure systems. Water intrusion may result in pressure outages and problems with regulation and metering equipment. Water levels that cover gas service regulators may also present safety risks.

Heavy rains may result is soil erosion, exposing gas mains and services to loading from stream flow or soil movement. High water levels may also exert damaging external forces to mains installed on bridges over water crossings.

viii. Lightning Related

Lightning includes damage and/or fire caused by a direct lightning strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by lightning that results in damage to a pipeline system asset.

ix. Rock Impingement

Point stress caused by rock contact that can lead to deformation, cracking and coating issues of plastic and metallic pipes. This includes backfill with rock, coral or other objects that can gouge or scrape the pipe.

x. Wind Related

Wind-blown debris commonly consists of roofing material, downed tree limbs, downed signs, downed power lines and poles, and wind-blown garbage. Above ground facilities are more susceptible to damage from this threat.

E. Excavation Damage Threats

Leaks resulting directly from excavation damages caused by earth moving or other equipment, tools or vehicles. Includes leaks from damage by operator's personnel (oftentimes referred to as “first party”) or by the operator’s contractor (oftentimes referred to as “second party”) or by people or contractors not associated with the operator (oftentimes referred to as “third party”). This also includes a release or failure determined to have resulted from previous damage due to excavation activity.

The State’s Administrative Code addresses procedures and responsibilities relating to damage prevention.

The website containing the administrative codes and laws for Florida:

- Sunshine 811 - http://www.sunshine811.com

i. Damage to Facility Within Tolerance

Persons engaging in blasting/excavating with mechanized equipment shall not damage, injure, or loosen any utility facility which has been marked

When excavating within the tolerance zone the excavator shall exercise reasonable care that shall include, but is not limited to, hand digging, pot holing, soft digging, vacuum excavation methods, pneumatic hand tools, and other generally accepted methods. For parallel excavation, the existing facility shall be exposed at intervals as often as necessary to avoid damages.

ii. Excavated Before Locate Ticket was Valid

The state issues valid locate tickets under different guidelines, typically two-three business days.

iii. Excavated Outside Locate Ticket Scope

When a locate request is made in accordance within the provisions of state administrative codes the excavator may conduct such activity provided the excavation information provided by the excavator in their locate ticket request details is followed.

iv. Excavated Without Valid Ticket

Prior to undertaking any excavation or demolition activities, it shall be the duty of each excavator to notify the approved notification center no less than the number of days outlined in the state administrative code.

v. Failure to Mark Facility

The operator did not locate the facility within the given time period. The number of days required is outlined in the state administrative code.

vi. *Failure to Preserve Marks*

Excavator shall, after commencement of excavation/demolition, protect and preserve the markings until the markings are no longer necessary for safe excavation. If the marking of the horizontal route of any facility is removed or is no longer visible the excavator shall stop excavation activities in the vicinity of the facility and shall notify the one-call center to have the route remarked.

vii. *Failure to Protect Unmarked Facilities*

An excavator shall not demolish in the requested locate area until all underground facilities have been marked or removed. Furthermore, an excavator shall avoid excavation in the locate request area until each facility operator has marked the facility or indicated no conflicts or for the time allowed for markings, whichever occurs first. If the operator has NOT marked its facility within the time allowed the excavator should refer to their respective states' administrative code.

Obtaining information as to the location of an underground facility from the operator does NOT excuse any excavator from performing an excavation in a careful and prudent manner, based on accepted engineering & construction practices nor does it excuse such excavator from liability for any damage or injury resulting from any excavation.

viii. *Inaccurate Company Records*

Gas distribution facilities may be mis-marked or left un-marked due to faulty records or maps.

ix. *Marking Error*

Gas distribution facilities may be mis-marked. This failure may be due to deficiencies in training, job execution, or equipment.

x. *Ticket Expired*

Locate tickets are considered valid for a certain amount of calendar days after request is made depending on each states' administrative code.

xi. *Unlocatable Pipe*

In general, facilities should be installed in a manner which will make them locatable using generally accepted locating equipment. Refer to the state administrative code for guidance with this threat.

xii. *Other*

Other root causes include the inability to locate a facility (e.g. no locating wire on plastic main), incorrect information provided to the one call center, deteriorated facilities, and previous damage. An analysis of the use of this criterion will determine if a new sub-threat needs to be added to the DIMP program.

F. Other Outside Force Damage Threats

Leaks resulting from outside force damages, other than excavation damages or natural forces. This includes nearby industrial, man-made or other fire/explosion. Damage by car, truck or other motorized vehicle/equipment NOT engaged in excavation activities. Damage by boats, barges, drilling rigs or other maritime equipment or vessels NOT engaged in excavation activities. Previous mechanical damage NOT related to excavation activities. Unintentional damage caused by other power equipment, such as mowers, tractors or other tracked vehicles, NOT related to excavation activities. Intentional damage/vandalism/terrorism, i.e. the willful or malicious destruction of the operator's pipeline facility or equipment.

i. Vehicular Damage (Road)

Damage caused to a pipeline or facility caused by a direct impact of road use vehicles. Above ground sections of gas mains, gas service lines, and regulator station piping may also be subject to damage by vehicular traffic and may require additional protection or relocation to mitigate the risk of damage that could result in a gas leak.

ii. Unintentional Human Error (Other Power Equipment, Etc.)

An unintentional damage to an above ground facility caused by human error. This typically involves the use of other power equipment, such as mowers, tractors or other tracked vehicles, NOT related to excavation activities.

iii. Vehicle or Vessel Damage (Non-Road)

Damage caused to a pipeline or facility caused by a direct impact of a marine vehicle. The marine vehicle can be drifting caused by natural or human error. Additionally, the marine vehicle can be operating under normal conditions and impact the pipeline or facility. Damages caused by marine vehicles during excavation activities will be considered "Excavation Damage". Furthermore, PHMSA issued advisory bulletin ADB-12-08 informing natural gas distribution system operators of the potential hazard of a train derailment damaging gas pipelines in the vicinity.

iv. Failure of Riser Structure

Damaged risers due to outside forces that cause accelerated corrosion. Anode-less risers are more susceptible to damage from this threat.

v. Vandalism or Theft

Gas valves and station equipment may be susceptible to vandalism that could result in the unsafe operation of a gas distribution system and may require actions to prevent or reduce the likelihood of such vandalism. Vandalism includes pranks, systematic damage to harass the Company, intentional motor vehicle damage, and any other intentional act that causes damage to the distribution system.

vi. *Fire or Explosion*

Fires and explosions can damage above-ground piping, risers, regulators, and/or meters, resulting in the release of natural gas that will provide additional fuel for the fire.

G. Pipe, Weld or Joint Threats

Leaks resulting from material defects within the pipe, components or joints due to faulty manufacturing procedures, design defects or in-service stresses such as vibration, fatigue and environmental cracking. Material defect means an inherent flaw in the material or weld that occurred in the manufacture or at a point prior to construction, fabrication or installation. Design defect means an aspect inherent in a component to which a subsequent failure has been attributed that is not associated with errors in installation, i.e., is not a construction defect. This could include, for example, errors in engineering design.

i. Brittle-Like Cracking on Plastic Pipe

PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s. General classifications of this pipe are Medium Density Polyethylene (MDPE) or High Density Polyethylene (HDPE).

ii. Cracked Plastic Cap

Cracked caps may indicate an inferior cap material. Generally, cracked caps related to the material leak cause are because of vintage plastic pipeline materials.

iii. Manufacturing Material Defect

A manufacturing material defect is an inherent flaw in the material or weld that occurred in the manufacturing or at a point prior to construction, fabrication, or installation.

iv. Engineering Design Defect

A design defect means an aspect inherent in a component to which a subsequent failure has been attributed that is not associated with errors in installation, i.e., is not a construction defect. This could include errors in engineering design or manufacturing design.

v. Transportation Damage

A transportation defect is a flaw in the material that occurred during the transportation of the material from the vendor's location or company supply location to the construction site. The defect typically occurs when the product is being loaded or unloaded for transport.

vi. Wrinkle Bend

A wrinkle bend is a type of pipeline deformation caused by the bending of steel pipe. Wrinkle bends designed after 1955 experience fewer issues because of better design principles with the turn wrinkle ratio or "mild ripples".

vii. Seam Weld

Seam weld leaks occur on the longitudinal pipe seam due to faulty manufacturing practices. A leak occurring on the seam weld may indicate a manufacturing and/or factory defect. Leaks caused by a seam weld failure may warrant an inventory review to identify the extent of the inferior pipeline/and or facilities.

viii. *Cast Iron Break*

The fracture or crack in the body of a cast iron component due to varying undetermined reasons.

ix. *Cast IRON BELL & Spigot Joint*

Cast iron joints, often referred to as bell and spigot, were the standard connection for legacy cast iron mains and manufactured as such. Over time this connection tends to fail for varying reasons. Leak repairs made to this joint are identified in this sub threat. No cast iron main or services exist in the FCG system.

x. *Loose Caps & Fittings (Buried)*

xi. *Buried caps or fittings can become loose due to multiple reasons.*

This can occur on the threaded area of the cap or fitting as well as the bolted area. This is often the failure cause of Mechanical Fittings.

xii. *O-Rings/Gaskets on Caps & Fittings*

O-Rings & Gaskets are types of seals that can fail on buried caps and fittings. This is often the failure cause of Mechanical Fittings.

H. Equipment Threats

Leaks caused by malfunctions of control and relief equipment including regulators, valves, meters, compressors, or other instrumentation or functional equipment. Failures may be from threaded components, flanges, collars, couplings and broken or cracked components, or from o-ring failures, gasket failures, seal failures, and failures in packing or similar leaks.

i. Equipment Malfunction

Equipment that has functioned improperly or abnormally.

ii. O-Ring/Gasket/Seal Failure

Equipment leak due to seal failures.

iii. Packing Failure

Equipment leak due to protective material failure.

iv. Threaded Component

Ridge wrapped around a joint or place of connection that has become loose or untightened.

v. Broken Component

Broken or cracked components on various types of equipment can cause failures.

I. Incorrect Operation Threats

Leaks resulting from inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error. It includes leaks that are associated with components or processes that join pipe such as threaded connections, flanges, mechanical couplings, welds, and pipe fusions that leak as a result from poor construction and unintentional ignition of the transported gas during a welding or maintenance activity. It also includes leaks due to improper valve selection or operation, inadvertent over pressurization, or improper selection or installation of equipment.

i. Failure to Use Procedures

The internal operating manual defines the procedures adequately to be able to conduct tasks at the minimum of federal, state, or local regulatory codes and standards and Company standards. The personnel did not follow the procedures during the installation, maintenance or repair on the distribution system.

ii. Fusion or Weld Failure

Failure or leakage of welded or fused joints may occur due to the use of improper or inadequate procedures, failure of field personnel to follow established procedures, weld or fusion equipment failure, or inadequate training.

iii. Damage to Pipe in Sewer (Cross-bore)

Trenchless technologies are utilized during the installation of mains and services. To ensure that proper clearances are maintained and that other facilities are not damaged, the location and depth of third party facilities must be determined. When proper procedures are not followed, a gas main or service may be accidentally cross-bored through a sewer line without the installation crew realizing it. At some later point in time, sewer maintenance activities may cut the gas line which may result in leaking gas entering the sewer line.

iv. Damage Caused by Improper Backfill

Failure to properly backfill a work hole may cause damage to natural gas distribution facilities and pipeline. All utilities and/or excavators must follow safety codes to note harm, damage, or weaken utilities in the area.

J. Other Threats

Other concerns that could threaten the integrity of the pipeline (other than those listed previously) also represent a threat to the gas distribution system. The Other category includes, but is not limited to, the weakening, deterioration, and/or failure of the pipeline or pipeline component resulting from any other cause, such as exceeding the service life, not attributable to the above causes. In addition, the other category shall be used when the leak was repaired or eliminated without uncovering the leak to determine the root cause such as abandoning or replacing the leaking pipeline facilities.

i. Abandoned or Replaced without Uncovering

Non-hazardous leaks identified on mains and/or services where retirement or replacement of the pipeline occurs and the leak was not repaired by conventional methods and tracked as such.

ii. Chemically Compromised Material (Non-Metallic)

Chemical or refined oil spills may produce significant risk to gas pipelines. These spills can seep through the soil and could make contact with distribution pipelines. Plastic pipe, and coal tar coating on metallic pipe, may be compromised should they come into contact with petroleum products.

iii. Other

The use of “other” as a threat and “other” as a sub-threat indicate a potential new threat. An analysis of the use of this criterion will determine if a new sub-threat needs to be added to the DIM Program.

K. Composite Conditions or Materials

The items included encompass specific components, materials, or occurrences where multiple threats and/or sub-threats may converge to create a failure or hazardous situation (i.e. Hurricane). The root causes associated with the prospective threats below are accounted for by the PHMSA threat categories and sub-threats defined above. However, these Composite Conditions or Materials allow the exploration of specific situations identified through a combination of industry and SME knowledge. These will be evaluated during the annual Subject Matter Expert Risk Assessment by the end of Q2.

i. Materials

1) Inner Tite

The Company has identified this type of cast iron as a specific sub threat due to it higher operating pressure and the rigid mechanical joint at connections resulting in an increased vulnerability to stress cracking.

2) Acrylonitrile-Butadiene-Styrene (ABS)

Acrylonitrile-Butadiene-Styrene (ABS) thermoplastic pipe has the potential for brittle like cracking. PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

3) Aldyl-A

Plastic pipe manufactured by several companies has the potential for brittle-like cracking dependent on the resin, pipe processing, and service conditions. PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

a. Early Vintage Aldyl-A

Plastic pipe typically installed prior to 1974 based on manufacturing resin changes with the greatest potential for brittle-like cracking.

b. Mid Vintage Aldyl-A

Plastic pipe typically installed 1974 – 1983 based on manufacturing resin changes with moderate potential for brittle-like cracking.

c. Late Vintage Aldyl-A

Plastic pipe typically installed 1983-1990 based on manufacturing resin change with low potential for brittle-like cracking

4) Polybutylene (PB)

Polybutylene (PB) has the potential for brittle like cracking. PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

5) Poly-vinyl Chloride PVC

Polyvinyl chloride pipe has the potential for brittle like cracking. PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

6) Drisco 8000

PHMSA Advisory bulletin ADB-12-01 identifies Drisco Pipe 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation.

7) Vintage Black Plastic

Black plastic pipe typically installed during the 1970s with potential for brittle-like cracking.

8) Century Products (MDPE 2306)

Century Utility Products Inc. produced and sold medium density polyethylene (MDPE) plastic pipe and fittings that utilized a resin lacking adequate resistance to brittle-like cracking and is prone to a relatively short life when subjected to high local stress concentrations. PHMSA issued advisory bulletin ADB-99-02 in March of 1999 informing natural gas distribution system operators of the potential brittle-like cracking vulnerability of plastic pipe installed between the 1960s and early 1980s.

ii. Components

1) Valves

Many valves are vital to the safe operation of a gas distribution system. Primary valve functions are to introduce or stop gas flow, to control flow direction, and to regulate flow or pressure.

2) Regulators

Based on functionality, regulators will be categorized as either: 1) service regulators or 2) district regulator station regulators. Regulator types may be further categorized as direct-operated (spring-operated) and pilot-operated. Direct-operated regulators are most accurate in lower pressure and lower gas flow ranges. Pilot-operated regulators are preferred for high-flow rates or when precise pressure control is required.

Gas service regulators are used to reduce the gas pressure prior to flowing into the gas meter and customer houseline or commercial fuel line. Both types of regulators, direct-operated and pilot-operated, are used to serve residential and commercial customers based on the application and the specified operating parameters.

3) Mechanical Fittings

Mechanical fittings provide a fast, reliable alternative to making repairs and have been used successfully for many years. However, these can become a leak source if not properly installed or manufactured improperly.

4) **Drip**

A drip may be a potential leak source at the flanged end connections or at the drain fitting located on the body of the component. Drips are typically encountered on the low pressure cast iron distribution systems. Further, a drip may become full at times and potentially disrupt the flow of adequate gas supply to customers located downstream of a drip.

5) **Relief or Other Pressure Limiting Devices**

A relief can be a relief valve, monitor regulator, or rupture disk type device designed to control pressure build-up by providing a release of pressure at a designated set point. This pressure release, such as natural gas venting to the atmosphere or second (monitor) regulator taking over control shall the primary regulator fail, is vital to the safe operation of Company facilities and to ensure the protection of all connected, downstream piping and equipment.

Based on functionality, relief devices will be categorized as either: 1) full relief valve 2) alarm or partial relief valve 3) or monitor relief. Like regulators, relief types may be further categorized as direct-operated (spring-operated) or pilot-operated. Direct-operated reliefs are most accurate in lower pressure and lower gas flow ranges. Pilot-operated reliefs are preferred for high-flow rates or when precise pressure control is required.

A relief device may be found in piping at regulator stations, meter sets, compressor equipment, LNG facilities, and on pressure vessels. Refer to Regulator definition section for possible leak threats.

6) **Delrin Insert Tap Tees**

PHMSA Advisory bulletin ADB-07-01 specifies Delrin insert tap tees as being susceptible to premature brittle-like cracking.

7) **Plexco Service Tee Celcon Caps**

PHMSA Advisory bulletin ADB-07-01 identifies Plexco Service Tee Celcon (polyacetal) Caps as being susceptible to premature brittle-like cracking.

8) **Dresser POSI-HOLD**

A boltless joining system providing seal and restraining pipe connections for any combination of steel and plastic gas main. In specific scenarios these fittings have needed additional restraint to minimize the risk of failure.

9) **Jamison Insertion Tapping Tees**

This tapping tee allows for the insertion of a tracer wire into the pipeline to be able to locate. These tapping tees will be monitored for integrity.

10) **Smith - Blair Clamps on Plastic Pipe**

The Smith – Blair clamps for temporary repair on plastic pipeline is not recommended by the manufacturer. A bulletin was provided by the manufacturer to emphasize the importance of not using this clamp on plastic permanent repairs.

iii. *Specific Situations / Events*

1) Pipe Installed in Casing

Pipes installed in casings may be electrically shorted to the casing wall, shielding from effective cathodic protection current. Contact between the casing and pipe may result from improperly installed end seals, settlement of the pipe relative to the casing, failed spacers, and welding or other material inside the casing. Water may also accumulate in the casing due to ineffective seals or atmospheric condensation. As a result, pipes installed in casing may experience a higher rate of corrosion and leakage.

2) Inactive Service Lines

Inactive service lines are non-active premises with an active gas line. These types of service lines may have increased risk because of excavation and maintenance threats.

3) Rear Lot Main

Rear lot main are main lines laid in the back of properties. These lines can be difficult to locate and maintain because of non-traditional utility location and other physical obstructions.

4) Isolated Services

A service that is not electrically connected to main and is separately protected.

5) Unprotected Services

An unprotected service is a metallic service that is separated from cathodically protected main or by being in between other non-metallic service parts that do not need cathodic protection.

6) Gas Lamps/Gas Lights

Light fixtures found on private property.

7) Over Pressurization

An elevation of distribution system pressure beyond the allowable build-up beyond MAOP by pipeline safety regulations and the Company OPM. The over pressurization could compromise the integrity of facilities.

8) Distribution Exposed Main

Below ground main that over time has been exposed.

9) Mechanically Coupled Pipe

Historically installed metallic gas main connected using mechanical couplings.

10) Gas Quality

The quality of natural gas is a result of an agreement between the provider and the customer. Due to the nature of natural gas and the transportation mechanism, the quality of the delivered product is primarily determined by the pipeline operator and posted in the 'General Terms and Conditions: Gas Quality section of the pipeline operators tariff under informational postings on the pipeline operators website.

Utility operators have a need to know the expected range of quality of the fuel being delivered to them and ideally to have some control over the variability of that fuel to assure compliance with regulations, to protect their investment in generating equipment, and to be able to meet the needs of their customers.

11) Leak by Stray Current

Stray current may cause corrosion when it flows from an outside source onto a steel gas main or service at one location and then exits the steel distribution system into the earth at another location as it completes a circuit back to the power source. Corrosion occurs at the location where the current exits the steel distribution system at coating holidays or sections of bare steel. The most common sources of stray current include transit systems, impressed current systems operating on other structures, and high voltage transmission systems.

12) Grub Worm

Grub worms typically reside within the first foot of top soil and have been known to eat through shallow PE service lines causing leaks. Consequently, mains are generally not affected by grub worms. No geographical trends have been identified with these leak occurrences.

13) Thermal Expansion and Contraction

Thermal Expansion/contraction means the leak occurred due to stresses acted on the pipeline facilities as a result to a change in temperature.

14) Hurricane

A hurricane is a severe, rotating tropical storm with heavy rains and cyclonic winds exceeding 74 mi (119 km) per hour. In addition to the threats from heavy rain and flooding previously described, high winds from hurricane can cause damage from airborne debris, uprooted trees, toppled telephone poles, etc. Aboveground gas facilities in the path of such an event are at a greater risk to damage.

15) Tornado

A tornado is violently rotating column of air that comes in contact with the surface of the earth. High winds from tornados can cause damage from airborne debris, uprooted trees, toppled telephone poles, etc. Aboveground gas facilities in the path of such an event are at a greater risk to damage.

16) Other Natural Disasters

Significant natural events can impact the distribution system by putting unusual strain and circumstances on the pipeline and facilities. Natural events include significant geological, hydrological, or climatic events not previously listed.

17) Emergency Excavate – No Locate

In general, an emergency excavation can occur when one or more of the following conditions exist:

- The unforeseen excavation, which, if not performed, could present a danger to life, health or property.

- The excavation is required to repair a service outage.
- An unstable condition exists which may result in any of the conditions listed above (for example, a leak in any service or main, or a fault in a primary or secondary wire and/or cable).

Persons engaging in emergency excavation shall give notice of the emergency excavation as soon as practical.

18) Stubs

A stub is a remnant of an existing pipeline that has been shortened, diverted or reconfigured but still remains active. These locations may be unknown and pose an excavation risk because the possible lack of documentation and knowledge for the location of these facilities. Although stubs occur on both mains and services, many more service stubs exist and can be more difficult to locate. The OPM has been updated to minimize the occurrences of future state stubs.

19) Service Tap Connection

Service Tap Connections are typically made by installing a tapping tee on the main by welding, heat fusion process or mechanical application.

a. *Farm Tap*

Farm tap is defined as a service line where its common source of supply is from a transmission pipeline located upstream of a Distribution Center.

b. *High Pressure Service Tap*

A service line with a pressure greater than 60 psig and is not a farm tap.

20) Pre-1940 Oxy-Acetylene Girth Welds

Prior to the mid-to-late 1930s, the welding of joints on larger diameter steel gas lines was performed using oxy-acetylene gas welding. These joints may be more prone to leakage and failure than the electric arc welding techniques used today for pipe diameters greater than 4 inches.

21) Arc Burn

A leak sustained from an electric arc either by the extreme heat it produces or through radiation. A metallurgical notch, caused by ground clamps or from striking an arc on the base metal at any point other than:

- in the weld groove, or
- The immediate surface next to the groove that will be covered by the weld cap.

22) Propane

Unlike natural gas propane is heavier than air. Propane gas tends to drop or sink to lower elevations. There is the potential for propane to collect in lower lying areas, this is taken into consideration when evaluating propane gas as a sub threat. No propane systems exist in the FCG system.

L. Threat Identification, Investigation, and Evaluation

i. *Regulatory Reference: 192.1007. (b)*

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

An operator must consider reasonably available information to identify existing and potential threats. Sources of data can include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

ii. *Objective and Process*

There are many types of threats to the distribution system that may require identification, investigation, and evaluation. Some threats may not require all components of this process and their utilization is up to the discretion of the Distribution Integrity Manager. The threat identification, investigation, and evaluation (TIIE) process is dynamic and may be adjusted to address each threat as needed. Threats to our system include, but are not limited to:

- Specific threats that require further investigation to determine courses of action
- Threats that are not currently identified
    - Potential Threats
    - Emerging Threats
- Threats that do not fit within our defined sub-threat categories
- Threats that are identified but require further research
- Missing information identified through data gaps

Not all communicated concerns will be documented through the TIIE process. If through a combination of industry, system, and SME knowledge, DIMP determines that the concern has been adequately addressed by an existing threat and does require further investigation, the concern will not be added to the TIIE process. Additionally, over-generalized threats, such as materials as a whole, will not be included.

The threat identification, investigation, and evaluation process is utilized to enable consideration of all threats not explicitly stated within this Plan and to allow for the investigation of specific threats within the distribution system. The identification of a new threat may result in the threat's incorporation into already existing sub-threats, the identification of new Composite Conditions or Materials, the creation of an A/A, or the identification of a data gap. All entries in the DIMP SharePoint site will be reviewed at the end of the quarter in which they were added. Additionally, all active entries will be reviewed quarterly. This process is Effective April 1st, 2018.

iii. *Identification Process*

Sources that may be used to identify threats are varied but can be classified as coming from internal or external sources. Internal threat sources are those that are identified by an individual or process within the Company. They include the SME Risk Assessment, reviews of work order data, Notice of

Incidents (NOI), and notifications from FCG employees. Examples of external sources include, but are not limited to, National Transportation and Safety Board (NTSB) Reports and Recommendations applicable to pipeline accidents, NTSB bulletins and letters, PHMSA advisory bulletins, NOIs, communications as a result of membership in a gas association, and industry publications.

- PHMSA and NTSB advisory bulletins
  - All PHMSA and NTSB advisory bulletins will be documented in Appendix C.
    - This will include bulletins that may or may not apply to FCG.
  - A review of PHMSA and NTSB bulletins shall be conducted on a quarterly basis.
- If a threat has been identified, the source of the threat, internal or external, will be communicated to the DIMP team.

iv. Ad Hoc Threat Investigation

Ad hoc threat investigations are used when a situation arises where new information becomes available, additional details and/or investigation are needed to verify a perceived threat, or further defining of potential threats are required. Typically, the strategy is developed based on the unique characteristics of the situation and reasonably available data.

- The DIMP Team must determine if an ad hoc threat investigation is applicable and if enough information exists to adequately analyze the issue.
  - If limited or no data exists to perform the ad hoc process, then the data gap must be documented in accordance with <u>Section 2: Gaining Additional Information</u>.
- The ad hoc threat investigation is completion configurable to address the issue of concern. Report types can include, but are not limited to:
  - Spatial analysis
  - Tabular analysis – pivots and graphs
  - Various data integrations
  - Written report(s)
- This analysis does not need to conform to <u>Section 4: Rank of Risk</u>. This analysis does not need to constitute a formal risk analysis and may not have elements of likelihood or consequence.
- The results of the ad hoc threat investigation will be shared with the appropriate departments as identified during the threat identification, investigation, and evaluation process.
- The Engineering Integrity Manager or designate will be responsible for ensuring the documentation of the ad hoc threat investigation(s) within the DIMP files.

v. Evaluation Process

- When a threat is identified, the information provided shall include, but is not limited to:
  - Threat Name
  - Threat Description
  - Source
  - Date Identified

    - Geographic Extent
    - DOT Threat Category
    - Sub-Threat
    - Actions Taken
- If data systems currently do not collect the necessary information to evaluate the potential or emerging threat, a data gap will be documented and steps to capture the information will be initiated.
- If a potential or emerging threat has been previously investigated or identified, this shall be documented.
    - The DIMP Team will determine if a potential or emerging threat has already been identified, considered, or investigated previously.
        - This may include similar situations and any previous investigations
        - This may also include investigations conducted by FCG
- If a potential or emerging threat has not been previously identified, considered, or investigated, an ad hoc threat investigation will be conducted.
- If an ad hoc threat investigation indicates that a previously unidentified threat exists, the threat will be added to the plan as described in Section 3: Adding New Threats to the Plan.
- If an ad hoc threat investigation determines that submitted details were inaccurate or incomplete, and no new threat has been discovered this will be documented.
    - This may include situations where the ad hoc threat investigation determined that the threat had been previously identified.
- At the end of each quarter:
    - All active investigations will be reviewed.
    - All investigations completed within the same quarter will be reviewed.
- The Engineering Integrity Manager or designate is responsible for ensuring the compilation of the threats

M. Adding New Threats to the Plan

This section describes the process of adding new threats to the DIM Plan after they have been identified using the process outlined in Section 3: Threat Identification, Investigation, and Evaluation. The addition of a new sub-threat is not necessarily required by the identification of a new threat in Section 3: Threat Identification, Investigation, and Evaluation. The identification of a new threat may result in the threat's incorporation into already existing sub-threats, a new Composite Material or Condition, the creation of an A/A, or the identification of a data gap, among other options. The DIMP Team will document the results of the threat identification, investigation, and evaluation process.

- If a threat has been determined to be representative of a new sub-threat under PHMSA / FCG threat categories:
  - New sub-threats may be added to the Plan as soon as they have been identified and approved.
    - The Subject Matter Expert and System Level Risk Assessments do not need to be rerun when a new threat is added unless determined to be required by Engineering Integrity Manager.
- If a threat is determined to be categorized as a Composite Material or Condition:
  - The threat will be evaluated and reviewed during the Subject Matter Expert Risk Assessment with other composite materials and conditions.
- New threats added to the Plan must be reviewed and approved by the Engineering Integrity Manager or designate by the end of Q1.

N. Retiring Threats

This section describes the process of retiring threats from the DIM Plan after they have been identified using the process outlined in Section 3: Threat Identification, Investigation, and Evaluation. The retirement of a sub-threat is not necessarily preceded by the identification of a new threat. Threats may be retired for many reasons including, but not limited to:

- System improvement
- Environmental changes
- PHMSA threat category definition revisions
- Investigation results

Previously identified threats will be archived in the Distribution Integrity Management Program Files.

- If a threat has been determined to no longer be present in the Company's distribution system:
    - A sub-threat or composite material or condition may be retired from the plan.
- Threats retired from the plan must:
    - Be reviewed and approved by Key Contacts by the end of Q1.

O. Threat Metric Requirements

The purpose of the threat metrics is to provide the key contacts with an annual review of the data to review trends. This is a tool to monitor the integrity of the system over a 5-year period of time. SMEs review the metrics and include this knowledge with their overall system knowledge when ranking risks on the system.

- This section defines the requirements for metrics found in Appendix C.
- The metrics and references listed below are updated or completed and included in the DIMP Appendices on an annual basis by the end of Q2.

APPENDIX B: System Knowledge
REFERENCE: Integrity Management Program Record Summary
REFERENCE: Incomplete or Additional Information
METRIC: 10 Year DOT Reported Total Mileage Of Main and Number of Services
METRIC: 10 Year DOT Reported Mileage Of Main By Material
METRIC: 10 Year DOT Reported Number of Services By Material
METRIC: System Design by Operating Pressure
METRIC: Summary of Main Material Types and Decade Installed
METRIC: Miles of Mains by Material and Diameter
METRIC: Number of Service by Material and Diameter
METRIC: Number of EFVs
METRIC: Main Mileage by Material and Service Center
METRIC: Number of Regulator Stations by Regulator Manufacturer and Type
APPENDIX C: Identify Threats
METRIC: 10 Year DOT Reported Leaks by Cause on Mains
METRIC: 10 Year DOT Reported Leaks by Cause on Services
METRIC: DOT Reportable/Significant Gas Incidents by Cause
METRIC: DOT Reportable/Significant Gas Incidents Summary by Year
METRIC: Number of Hazardous Leaks Either Eliminated or Repaired, Categorized by Cause
METRIC: DOT Reported Excavation Damages Trend
METRIC: Number of Excavation Total Tickets
METRIC: Number of Worked Tickets
METRIC: Number of Hazardous Leaks Either Eliminated or Repaired , Categorized by Material
METRIC: Total Amount of Discovered Leaks By Leak Location Code and Grade
METRIC: Number of Active Leaks by Survey Type and Grade
METRIC: Active Leaks by Facility Type and Service Center
METRIC: Corrosion Threat
METRIC: Corrosion Frequency
METRIC: Natural Forces Threat
METRIC: Natural Forces Frequency
METRIC: Excavation Damage Threat
METRIC: Outside Force Threat
METRIC: Outside Force Frequency

APPENDIX C: Identify Threats
METRIC: Material & Weld Threat
METRIC: Material & Weld Frequency
METRIC: Equipment Failure Sub-Threat Trend
METRIC: Equipment Failure Sub-Threat Frequency
METRIC: Equipment Leaking Component
METRIC: Equipment Leaking Component Frequency
METRIC: Mechanical Fittings
METRIC: Incorrect Operation Threat
METRIC: Incorrect Operation Frequency
METRIC: Other Threat
METRIC: Other Frequency
METRIC: Cross Bore Frequency

- The process to replicate the metrics shall include source, query, filters, pivots, and other requirements.
    - This should include:
        - LDC Name: The abbreviation of the local distribution company.
        - DIMP Year: The year the metric was published in the DIMP Appendices.
        - Name: Name of metric in DIMP Appendices.
        - Original Data Source: The sources that were used to compile the information.
        - File Location: The folder location where the file is stored.
        - File Name: The name of the file.
        - Pivot Sheet: If a pivot table exists, where is it located in the spreadsheet.
        - Pivot Filter: Identify any filter to limit the information being displayed.
        - Pivot Row labels: This will create row labels and generally helps with the final presentation of data.
        - Pivot Column Labels: This will create column labels and generally helps with the final presentation of data.
        - Pivot Values: Identify if the information is counted or summed to be able to get to the core number.
        - Additional: Any additional information that could be useful in re-recreating metrics found in the DIMP Appendices Knowledge or Threat section.
    - The data should be updated by the end of the Q2 of every DIMP year.

- The threat metrics found in the DIMP Appendices must use a frequency and trend metric for each primary threat. All primary threats, as defined by Part 192, will be represented in the Appendix C with threat metrics.
    - The metrics use the data compiled with the processes defined in Section 2: Data Compilation.
        - The appendix will include two types of metrics per primary threat.
            - The Frequency Metric for all primary threats except excavation requirements are defined below:
                - This metric includes leak repairs from the previous year.

    - If applicable, a quantity field shall be associated to the leak repair material or locate ticket type. This will provide the ability to normalize the data. For example, 1 leak on 10 miles of cast iron main. If a threat is subject to an entire area, the entire system mileage or service count shall be given.
    - Total leak repair count distributed by facility type and sub-threat.
    - Frequency of Failure
        - Main Leaks per Mile
        - (Service Leaks / Services) * 100
        - Total Leaks/Facility Mile
            - Facility Mile is main mileage plus the number of services multiplied by average service length
    - An example is below:

Threat / Sub-Threat	Year							
	Quantity		Leaks Repaired			Frequency of Failure		
	Miles Main	# Services	Mains	Services	Meter	Main Leaks/Mile	(Service Leaks / Services) * 100	Total Leaks / Facility Mile(mains & svcs)
Corrosion (All)								
Bare Steel								
Cast Iron								
Coated Steel								
Galvanized Steel								

- The Frequency Metric for the Excavation threat requirements are defined below:
    - This metric includes leak repairs from the previous year.
    - If applicable, a quantity field shall be associated to the leak repair material or locate ticket type. This will provide the ability to normalize the data. For example, 1 leak on 10 miles of cast iron main. If a threat is subject to an entire area, the entire system mileage or service count shall be given.
    - Total leak repair count distributed by facility type and sub-threat.
    - Frequency of Failure
        - Main Damages per 1000 Tickets
        - Main Damages Per Mile
        - Service Damages Per 1000 Tickets
        - (Service Damages/Service Count)*100
        - Total Damages Per 100 Worked Tickets
    - An example is below:

Threat / Sub-Threat	Year										
	Quantity			Leaks Repaired			Frequency of Failure				
	Worked Tickets	Miles Main	# Services	Mains	Services	Meter	Main Damages per 1000 Tickets	Main Damages Per Mile	Service Damages Per 1000 Tickets	(Service Damages / Services) * 100	Total Damages Per 1000 Worked Tickets
Excavation (All)											
Valid Ticket											

Mislocate by Contract Locator											
No Ticket											
Hand Tool											
Invalid Ticket											
Incorrect Records or Maps											
Deteriorated Marking											
Pipeline Could Not Be Located											
Contractor Working for Company											
Ticket Outdated											
Failure to Perform Test Hole											
Failure to Maintain Clearance											
Previous Damage - Non-corrosion											
Improper Backfill Practices											
Failure to Respond to Locate Contractor											
Failure to Use Hand Tools											

- The Trend Metric for all primary threat requirements are defined below:
  - The leak repairs are broken out by threat, sub-threat and year. This will include 6 years' worth of leak repair data.
  - The average field is calculated by summing the 5 years prior to the previous year. This average is not to include the previous year leak repair count because this skews averages. For example, when the DIMP year is represented by 2012 than the baseline is determined by the following algorithm:

    (2007+2008+2009+2010+2011)/5
  - Some datasets may not have five years' worth of data to determine an average. In these cases, use as many years as possible to determine the average.
  - An example is below:

Threat / Sub-Threat	Leak Ratio					
	2007	2008	2009	2010	2011	Average
Natural Forces (All)						
Ground Movement						
Grub Worm						
Ice						
Lightning						
Other (Explain)						

4) RANKING OF RISK

A. Regulatory Reference: 192.1007. (c)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following element:

(c) Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

B. Objective and Process

A multi-tiered approach to risk evaluation and threat ranking has been developed to evaluate the risks associated with the distribution pipeline. This more sophisticated risk analysis approach has been created to better understand and react to threats occurring in the system. This approach ensures all threats and the potential consequences are considered and addressed in a manner appropriate with the threat.

i. Risk Analysis Hierarchy

A risk analysis hierarchy has been provided to allow for macro and micro understanding of threats in the system. Accordingly, the risk analyses provide different perspectives where threats may be identified and addressed. The risk analysis hierarchy can also be used to strategically identify emerging threats through the system threat assessments and to tactically attack those threats through the results of the local risk assessments.

Risk Evaluation	System / Local	Updated	Description
System Level Threat Assessment	System	Annually	The System Level Threat Assessment is a high level ranking mechanism to identify the top threats throughout the system. Furthermore, this analysis includes the ranked sub-threats within each threat category.
Subject Matter Expert Risk Assessment	System/Local	Annually	The Subject Matter Risk Assessment provides an ongoing process of understanding what factors affect the risk posed by threats to the gas distribution system and where they are relatively more significant than others. Additionally, this assessment allows for non-leak centric or very specific threats to be assessed by subject matter experts.
PHMSA Audit Risk	System/Local	Annually	A list will be created of the top 10 risk to the

Risk Evaluation	System / Local	Updated	Description
			system. This list will be determined by Key Contact Review and be comprised from the System Level Threat Assessment and the Subject Matter Expert Risk Assessment. This approach will ensure that leak volumes and SME expertise is considered when determining the top risks to the distribution system.
Pipeline Integrity Risk Assessment	Local	Annually	The Pipeline Integrity Risk Assessment is a comprehensive spatial risk analysis to identify specific areas in our system to address risk. This risk analysis considers the pipeline threats, Corrosion, Natural Force, Material & Weld, Equipment, Incorrect Operations, Other, Excavation, Outside Force, Below Ground Services, Active Leaks, & Hazardous leak repair history. The consequence factor has been determined by the geographical location and attributes of the pipeline. Although this risk analysis considers all threats, the threat weights have been set to locate areas where the pipeline and/or facilities are subject to structural risks. The output of the Pipeline Integrity Risk Assessment will be

Risk Evaluation	System / Local	Updated	Description
			Prioritized Areas for replacement or other mitigative activities.
Inactive Services Risk Analysis	Local	Annually	The Inactive Service Line Risk Assessment has been designed to prioritize the removal of all inactive service lines for FCG. This analysis is completed on an annual basis and examines multiple risk factors.

C. System Level Threat Assessment

The System Level Threat Assessment is designed to objectively rank threats and sub-threats on the distribution system. This should be used as a macro level tool to assist in prioritizing actions to the systems top threats.

i. Risk Assessment Process

The System Level Threat Assessment is based on the current reportable leak repair count and is completed annually by the end of Q2. The System Level Threat Assessment is included by reference in Appendix D.

ii. Risk Assessment

The System Level Threat Assessment assigns a risk score for each sub-threat calculated based on the percentage of leak repairs by facility type, trend of leak repairs, and percentage of leaks that are hazardous. Consequently, only sub-threats with greater than or equal to 1% of the total leak repairs by facility type are included in the System Level Threat Assessment.

The System Level Threat algorithm is:

Sub-Threat Risk = LOF ** COF*

*LOF = Leak Repair Facility Ratio * Leak Repair Trend*

COF = Percent Hazardous

Risk Factor	Definition
Leak Repair Facility Ratio	*Current Year Leak Repairs by Sub Threat and Facility Type / Current Year Total Leak Repairs by Facility Type* • Values are scaled from 0-1. • Facility Types are broken out by main, service, and meter. • Only sub-threats with greater than or equal to 1% of the total leak repairs by facility type are included in the System Level Threat Assessment.
Leak Repair Trend	*Current Year Leak Repairs / Five Year Average.* • 200% (2) should be applied for trends greater than or equal to 200%. • A value of 1 is assigned to sub-threats with a five-year average of 0. • Values are scaled from 0-1.
Percent Hazardous	*Six Year Total Hazardous Leak Repairs / Six Year Total Leak Repairs* • The population includes leak repairs from the five-year historical count and current reportable year.

iii. Risk Assessment Validation

- The Key Contacts knowledge, previous results, and supporting data shall provide validation of the assessment.

- Any SME Risk Assessments adjustments shall be included in the DIMP Appendices by the end of Q4.
- Any change based on feedback from Key Contacts will also be incorporated into the DIMP Appendices.

D. SUBJECT MATTER EXPERT RISK ASSESSMENT

Risk analysis is an ongoing process of understanding what factors affect the risk posed by threats to the gas distribution system and where they are relatively more significant than others. The primary objectives of the evaluation and ranking of gas distribution pipeline risk are:

i. RISK ASSESSMENT PROCESS

The SME Based Risk Evaluation considers the cause and consequence of pipeline materials, components and threats to the distribution system. This SME based approach ensures all threats are considered and ranks the threats based on the risk value. This approach includes a detailed discussion led by the DIMP Team with local SME's to identify localized conditions. The SME discussion and initial assessment is completed on an annual basis and should be completed by the end of Q2.

Florida City Gas will perform the SME Risk Assessment at the service center level.

A composite SME Risk Assessment will be created using the SME Risk Assessment. This will include a weighted average of the risk score. This will represent the composite risk score for FCG. The weight of each region or service center will be based on the gas main mileage within the area.

The Subject Matter Expert Risk Assessment shall be finalized by the end of Q3.

ii. RISK ASSESSMENT

SMEs will supply a value for each pipeline material, component and threat using the following ranks:

Rank	Scale
No	Threat is not present in system.
Low	Threat poses a minimal risk.
Mod	Threat poses a moderate risk.
High	Threat poses a high risk.

The DIMP Team will compare the SME supplied values for each pipeline material, component and threat to leak repair and other available information to determine values of Likelihood and Consequence of Failure:

a. Likelihood of Failure:

Rank	Scale
0	Threat is not present in system.
1	Minimal probability of leak occurring
2	Low probability of leak occurring
3	Moderate probability of leak occurring
4	Moderate to high probability of leak occurring
5	High probability of leak occurring

b. Consequence of Failure:

Rank	Scale
0	Threat is not present in system.
1	Minimal consequence to the surrounding population
2	Low consequence to the surrounding population
3	Moderate consequence to the surrounding population
4	Moderate to high consequence to the surrounding population
5	High consequence to the surrounding population

Risk of Failure. ROF is the product of the assigned values for Likelihood and Consequence:

Risk = Likelihood * Consequence

iii. *RISK ASSESSMENT VALIDATION*

- The Key Contacts knowledge, previous results, and supporting data shall provide validation of the assessment.
- Any SME Risk review and adjustments shall be included in the DIMP Appendices by the end of Q4.
- Any change based on feedback from Key Contacts will also be incorporated into the DIMP Appendices.

E. PHMSA Audit Risk Assessment

The PHMSA Audit Risk Assessment will be a composite from the System Level Threat Assessment and the Subject Matter Expert Risk Assessment. Accordingly, the System Level Threat Assessment is a leak centric analysis and the Subject Matter Expert Risk Assessment allows for non-leaking or locally specific risks to be ranked. Therefore, the PHMSA Audit Risk Assessment will ensure the benefits from both assessments are maximized into a consolidated list of the top ten risks to the distribution system.

i. Risk Assessment Process

The PHMSA Audit Risk Assessment will be completed annually by the end of Q4.

The Subject Matter Expert Risk Assessment and System Level Threat Assessment shall be used by the Key Contacts to determine the PHMSA Audit Risk Assessment.

The Key Contacts will finalize the ranking of the top ten risks.

- The Lead Engineering Manager shall have the discretion to resolve any variances between the Key Contacts to finalize the top ten risks.

This list shall serve as the top risks to the system when requested by state, federal or other regulatory authorities.

ii. Risk Assessment

- Provide a ranked list of the top ten risk sub threats. The number one ranked item will be the highest risk and the number ten will be the lowest risk.

- The threat rank, primary threat, and sub-threats shall be listed in the DIMP Appendices by the end of Q4.
    - No relative score attribute is required, just a ranking of risks.

iii. Risk Assessment Validation

The ranked list developed by the Key Contacts shall be based on data from the System Level Threat Assessment or the Subject Matter Expert Assessment.

Key Contacts have a strong understanding of Distribution Integrity and their participation on the PHMSA Audit Risk Assessment will provide direct validation of the ranked threats.

Historical PHMSA Audit Rankings shall be used to help validate the ranking.

Validation of the PHMSA Audit Risk Assessment will also provide validation to the System Level Treat Assessment and the Subject Matter Expert Risk Assessment.

F. Pipeline Integrity Risk Model Assessment

Risk analysis is an ongoing process of understanding what factors affect the risk posed by threats to the gas distribution pipeline and where they are relatively more significant than others. The primary objectives of the evaluation and ranking of gas distribution pipeline risk are:

- Consider each applicable current and potential threat
- Consider the likelihood of failure associated with each threat, LOF
- Consider the potential consequences of such a failure, COF
- Estimate and rank the risks (i.e. determine the relative importance) posed to the pipeline
- Consider the relevance of threats in one location to other areas
- Identify priority areas to assign mitigative measures

i. Risk Assessment Process

The current process used for Risk Assessment (the evaluation and ranking of risk) shall be documented, on the system network for DIMP. The risk analysis is to be completed on an annual basis; as it has been defined in the Schedule of Procedures. Prior risk assessment processes shall be retained and stored in the Distribution Integrity Management Program files. Please see document and record retention for the location of records. The spatial analysis is conducted for FCG.

The risk assessment process assesses a relative risk score for all gas mains in the system (as of the last day of the previous year). System footage and leak history are used to further filter the systems. Filtered gas main systems scoring 2.5 standard deviations above the average will be reviewed and assigned a mitigative activity. These activities will be documented in Appendix E of this DIMP Plan. Additionally, gas main systems scoring outside the 2.5 standard deviation will be manually reviewed for threat anomalies.

ii. Risk Assessment

The current risk assessment (cause, consequence, and resultant risk ranking) shall be documented, or included by reference, in Appendix D.

The FCG risk analysis was designed in accordance with CFR sub-part P 192.1007 (c). The regulations mandate all distribution pipeline operators to “Evaluate and rank risk”. The regulation stipulates the risk analysis must consider corrosion failure, natural force damage, excavation damage, other outside force damage, pipe/weld or joint failure, equipment failure, incorrect operation, other cause, and any other potential threat to the system. These threats also include sub-threats which represent a better understanding of the influencing risk factors upon the distribution system.

The risk model is geospatially aware which means the cause and consequence scores are unique to the geographical location of the pipeline. For example, large and high pressure pipelines in an urban area have a higher consequence of failure score. Cast Iron pipelines will have a higher likelihood of failure score where cast iron corrosion leaks have occurred. Therefore, the risk model uses both the attributes of the pipeline and leak repair data while considering the physical location of the data to produce geographically accurate risk scores.

The risk analysis was built using model builder and Python scripting functionality in ESRI ArcMap. Although this tool was built with the same technology as ESRI's DIMP model, the FCG risk model is significantly different.

Risk characteristics of consequence of failure (COF) identify population density, business district, pressure and diameter from the following sources:

- Population Density:
  The building point layer is used to determine population density. Both the number of structures within proximity and the average distance between main and structure is considered.
- Leak Survey (Business Districts):
  The leak survey layer is used to determine business districts. These business districts are used to identify areas of consequence.
- Gas Main:
  The risk analysis relies on attributes of the gas main for pressure, age, and diameter of pipeline.

Prior risk assessment results shall be retained and stored in the Distribution Integrity Management Program files.

iii. RISK HIERARCHY

(1) Product Risk

The product risk is a product of the likelihood and consequence. The relative risk has been normalized and will have scores from 0-1. A higher risk score means the pipeline is more at risk.

iv. RISK ASSESSMENT VALIDATION

After completion of the Pipeline Integrity Risk Analysis, the results are inspected by the Distribution Integrity Management team to ensure proper data classification and criteria. This includes a thorough review of risk scores associated to the gas main and Priority Areas and an assessment of leak repairs causing the elevated score. The risk assessment review process includes an investigation of high threat areas and is documented in Appendix D.

The results of the Pipeline Integrity Risk Analysis are also validated through SME review and an engineering analysis of the system continuity. The system engineering analysis combines local SME knowledge, PHMSA advisories of historically and newly identified problematic systems and gaps within those systems to identify and categorize systems for replacement.

Pipelines historically prone to performance issues from the system engineering analysis are compared to the high ranking pipeline segments from the Pipeline Integrity Risk Assessment within the priority areas greater than 2.5 standard deviations above the average. This validation process is performed to confirm materials and systems historically prone to performance issues fall within the priority areas and all high ranking pipeline segments from the pipeline integrity risk model within the priority areas are a one to one match to the materials and systems identified in the system engineering analysis.

Details related to this review are located in Section 5: Identify and Implement Measures to Address Risk. Segments such as these may be pushed to replacement or other mitigative actions based on review of the Pipeline Integrity Risk Assessment and other available data or field investigation. Additionally, the risk analysis validation creates an understanding of the system to better assign appropriate mitigative activities during development of risk based A/A Actions.

G. INACTIVE SERVICE LINE RISK ASSESSMENT

Regulatory Reference: Florida Rule 25-12.04I.1

(c) Annual risk assessments shall be made for all service lines that have been inactive for more than one year.

1. The annual risk assessments shall identify potential threats and shall rank risks using the operator's Distribution Integrity Management Plan developed pursuant to 49 C.F.R. 192, Subpart P (2011) which is incorporated by reference in Rule 25-12.005, F.A.C. The annual risk assessments shall include the following required elements of the operator's Distribution Integrity Management Plan in identifying threats: Presence of excess flow valves, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, excavation damage experience, and any other data deemed relevant by the operator.

i. RISK ASSESSMENT PROCESS

The Inactive Service Line Risk Assessment has been designed to identify and prioritize at-risk inactive service lines for Florida City Gas. This analysis is completed on an annual basis by the end of the 2nd quarter and examines multiple risk factors associated with an inactive service line.

ii. RISK ASSESSMENT

The risk factors used for prioritizing the removal of all inactive service lines have been provided below.

(1) Risk Factors Examined

a. Age Factor
   - This is assigned for each individual inactive service line
   - Determine the duration the service line has been inactive
b. Active Leak Factor
   - This is assigned for each individual inactive service line
   - Determine if any active leaks exist on the inactive service line
c. Repaired Leak Factor
   - This is assigned for each individual inactive service line
   - Determine if any repaired leaks have occurred since the service has become inactive
d. Excess Flow Valve (EFV) Factor
   - Excess Flow valve factors are assigned per neighborhood/leak survey grid to indicate if areas are known to have installed EFV's
e. Material Factor
   - Material factors are assigned per neighborhood/leak survey grid to indicate inactive service line materials that exist
f. Surveillance and Patrolling Factor
   - This is assigned for each individual inactive service line
   - Determines if any abnormal operation condition exists

(2) Prioritizing Inactive Services

- All inactive service lines are prioritized based on all listed factors:
  1. Age Factor
  2. Leak Factor
  3. Damage Ratio Factor
  4. Material Factor

5. Abnormal Operation Condition Factor
6. Excess Flow Valve Factor

(3)Risk Calculations

- The risk calculation is based on the threat factor weighting.
- All services with an AGE of 10 will be exempt from risk calculation since these have already been prioritized by the legislation.

5) IDENTIFY AND IMPLEMENT MEASURES TO ADDRESS RISKS

A. Regulatory Reference: 192.1007. (d)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

B. Objective and Process

The objective of this section is to define activities that will improve pipeline integrity. Accordingly, actions can be created at the macro level to address system-wide threats. These System Level A/A Actions will generally be administered at a program level. This would include actions such as Bare Steel/Cast Iron replacement program, enhanced Leak Survey program and Meter Protection program. Additionally, actions can be tailored at the local level to address results specific to local or service center level. This would include tactical actions such as pipeline replacement prioritization and accelerated leak surveys.

i. System Level Integrity A/A Actions

System Level Threat Actions are generally designed program level pipeline or facility initiatives. These A/A Actions include: Bare Steel Replacements, Cast Iron Replacements, Bollard Installation Program, etc. When applicable, System Level Threat Actions should have performance measures associated to them and the threat or program being addressed. The associated performance measures will assist in determining the effectiveness of the A/A Actions. It is important to note, System Level Threat Actions require system wide data accumulation and may require longer periods of time to gauge the effectiveness of the program.

The System Level Threat Assessment (Risk Evaluation) will be reviewed annually by SME's to determine if System Level Threat A/A Actions should be implemented. This process is to be completed by Q4 of the DIMP calendar.

ii. Subject Matter Expert Integrity A/A Actions

Subject Matter Expert Risk Assessment Actions are generally designed program level pipeline or facility initiatives. These A/A Actions include: Bare Steel Replacements, Cast Iron Replacements, Bollard Installation Program, etc. When applicable, Subject Matter Expert Risk Assessment Actions should have performance measures associated to them and the threat or program being addressed. The associated performance measures will assist in determining the effectiveness of the A/A Actions. It is important to note, Subject Matter Expert Risk Assessment Actions require system wide data accumulation and may require longer periods of time to gauge the effectiveness of the program.

- FCG shall follow the Subject Matter Expert Integrity A/A Actions Process.
    - The Subject Matter Expert Integrity A/A Actions will be documented in the DIMP Appendices by Q4.
    - The Subject Matter Expert Assessment (Risk Evaluation) will be reviewed annually, by the end of Q4, to help determine if System Level Threat A/A Actions should be implemented.
    - Any sub-threat or component with a likelihood of failure score of 5 at a region or service center will have a documented A/A Action.
        - A sub-threat A/A Action can be consolidated if it occurs on many of the components or facilities.

  - A sub-threat – component A/A Action does not need to be listed more than once if it occurs in multiple service centers. It shall be noted that it occurs in many areas.
    - For example, crossbores occur in multiple service centers but can be listed once for an A/A Action.

- Any sub-threat or component with an aggregated risk score of 15 or higher will have a documented Subject Matter Expert Integrity A/A Action.

iii. PHMSA Audit Risk A/A Actions

All of the risks identified in the PHMSA Audit Risk Assessment shall include an A/A Action.

The PHMSA Audit Risk Assessment A/A Actions will be documented in the DIMP Appendices by Q4.

- The threat rank, primary threat, and sub-threats shall be listed in the DIMP Appendices.
- The A/A Actions must also include the performance measures associated to the A/A Actions.
- A template of the form is below:

Threat Addressed, Measure to Reduce Risk, and Performance Measure

For the top five highest ranked risks from the operator's risk ranking list the following:

- Primary threat category (corrosion, natural forces, excavation damage, other outside force damage, material or weld, equipment failure, incorrect operation, and other concerns)
- Threat subcategory (GPTC threat subcategories are acceptable. Try to be specific. Example, failing bonnet bolts of gate valve, manufacturer name, model #)
- Measure to reduce the risk (list the one measure the operator feels is most important to reducing the risk)
- Associated performance measure

Rank	Primary Threat Category*	Threat Subcategory, as appropriate	Measure to Reduce Risk	Performance Measure
1.				
	Comments			
2.				
	Comments			
3.				
	Comments			
4.				
	Comments			
5.				
	Comments			

* Corrosion, Natural Forces, Excavation Damage, Other Outside Force Damage, Material or Weld, Equipment Failure, Incorrect Operation, Other Concerns

iv. *Priority Area Integrity A/A Actions*

Targeted areas are identified with the Pipeline Integrity Risk Assessment model to assign specific remedial actions to ensure pipeline integrity and public safety. These efforts are specifically designed to find priority areas and to mitigate risk.

The risk score associated with each area is not a quantitative score for failure but rather a qualitative measure of the presence of threats within a geographical area. Therefore, a statistical approach using standard deviation from mean to select Priority Areas will be utilized. A final determination to use 2.5 standard deviations from mean ensures that the most significant areas are objectively selected. Accordingly, this threshold was determined to be adequate based on the distribution of scores into logical scoring groups.

A SME may also add areas, pipelines, or segments based on SME knowledge to the list of identified areas. The SME added areas, pipelines, or segments will follow the same requirements of implementing measures to reduce risk as an area identified through the spatial risk analysis. A SME evaluation of the PIRM (PIRM/PRP SME Evaluation) with regards to prioritization must be completed and justified in order to make these changes.

A/A Actions for the Priority Areas are to be implemented for the following year or have a documented date of when the action is scheduled. This can include prioritization of Priority Areas over a multi-year project, such as a pipeline replacement project/program.

The Priority Areas with associated A/A Actions are referenced in Appendix E.

v. *Inactive Service Line Integrity A/A Actions*

(1) Regulatory Reference: Florida Rule 25-12.045. C.3

Inactive service lines that are identified in the annual risk assessments as potential threats with a high-risk ranking shall be retired and physically abandoned within six months after completion of the annual risk assessment.

(2) Integrity A/A Actions

A review of the Inactive Service Line Risk Assessment will determine if additional actions are warranted. This procedure to address actions for the Inactive Service Line Risk Assessment is only applicable for Florida City Gas.

Based on best operational judgment, A/A Actions shall be developed. If A/A Actions are warranted, they are to be identified and documented within the Company's Customer Management Application. The A/A Actions of retirement are to be completed by the end of the assessment year because the Inactive Service Line Risk Assessment is completed at the end of Q2.

C. Leak Management Program

The Leak Management Program is established in Division II Section 4 of the Operations Procedure Manual.

i. *Description of Existing Programs*

A summary of the key elements of the Leak Management Program are documented in OPM Division II Section 4.

Key Elements of Leak Management	OPM Reference
Leak Detection	Division II, Section 4.1
Leak Grading/Classification	Division II, Section 4.4-4.5
Leak Compliance	Division II, Section 4.6
Evaluation of Leak Survey	Division II, Section 4.3
Leak Detection Tool Calibration	Division II, Section 4.8

ii. *Leak Survey Process & Technology*

A pipeline will be surveyed on 1 to 5 year intervals based on material, type, condition, location, and other characteristics of the pipeline. Consequently, more frequent survey intervals can also be defined as identified in DIMP. As areas are surveyed, the leak survey technician will record the presence of a leak on the GIS mobile app. This information is synced and uploaded to GIS Web which serves as a central repository for reporting and leak survey management.

iii. *Leak Compliance Process & Technology*

As survey leaks are found they pass through Maximo and flow into the compliance tracking system. A compliance date is automatically calculated based on the jurisdiction and grade of the leak. The compliance dates for leaks include repair, re-evaluation, and recheck.

All customer call in leaks are treated as emergency orders and require immediate attention. If not repaired immediately, the leak will be graded as a Grade 2 or 3 and entered into Maximo for future tracking and scheduling based on the leak grade. If repaired promptly and there is residual gas, the repaired leak will be entered into Maximo so that a recheck can be scheduled by the leak compliance system.

iv. *Leak Repair/Re-evaluation Process & Technology*

As the leak compliance date approaches, a work order is generated to either the above or below ground work order management system. The activity performed on the leak is recorded in the work order system. The completion of the work order passes back into the leak compliance system to document the repair date and schedule any future activities such as a recheck or re-evaluation.

v. *Key Performance Metrics & Analysis of Effectiveness*

The Leak Management Programs key performance metrics (those that establish program effectiveness) shall be documented, or included by reference, in Appendix F. Prior documentation shall be retained and stored in the Distribution Integrity Management Program files.

vi. *Locate, Evaluate, Act, Keep, Self-Assess (L.E.A.K.S.)*

Florida City Gas has a leak management program outlining the following five key elements (as specified by the Gas Piping Technology Committee guidance).

- **L**ocate the leaks in the distribution system
  - This process is outlined in OPM Division II, Section 4: Leak Surveys, Investigations and Reports.
- **E**valuate the actual or potential hazards associated with these leaks
  - This process is outlined in OPM Division II, Section 4: Leak Surveys, Investigations and Reports.
- **A**ct appropriately to mitigate these hazards
  - This process is outlined in OPM Division II, Section 4: Leak Surveys, Investigations and Reports.
- Keep records
  - This process is outlined in OPM Division II Section 4: Leak Surveys, Investigations and Reports
- **S**elf-assess to determine if additional actions are necessary to keep people and property safe
  - Leak data, including sub-causes, is further reviewed during the annual risk ranking.
  - Special ad hoc investigations are performed when more information is needed to adequately rank the threat to the system.

D. Risk Reducing Programs

i. Description of Existing Risk Reducing Programs

The following programs have been identified as risk reducing programs. These programs are referenced in the OPM.

Program Name	Program OPM Reference
Damage Prevention	Division II, Section 3
Public Awareness	Division II, Section 3: Division II, Section 14:
Leak Surveys Investigations and Reports	Division II, Section 4
Corrosion Control Monitoring	Division II, Section 8
Continuing Surveillance	Division II, Section 1
Patrolling and Inspection of Gas Systems	Division II, Section 2
Repair and Replacement	Division II, Section 6
Investigation of Failures	Division II, Section 7
Valve Inspection and Maintenance	Division II, Section 11
Regulator Stations, Pressure Gauges and Tele-metering	Division II, Section 12
Customer Meter and Regulator Inspections	Division II, Section 13
Emergency Manual	Division II, Section 22

6) Measure Performance, Monitor Results, and Evaluate Effectiveness

A. Regulatory Reference: 192.1007. (e)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(e) Measure performance, monitor results, and evaluate effectiveness.

B. Standard Performance Measures

i. Number of Hazardous (Grade 1) Leaks Either Eliminated or Repaired, per §192.703(c), Categorized by Cause

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- This performance measure only includes hazardous (grade 1) leak repairs and primary leak cause.
- Performance Measure requirements:
    - The previous year's leak repair count.
        - The count of hazardous leak repairs by primary leak cause and facility type is required for the PHMSA F 7100.1-1 annual report.
    - The baseline is based on a five year moving average.
        - This average is not to include the previous year leak repair count because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm: (2007+2008+2009+2010+2011)/5
        - The baseline is determined for mains, services, main & service, and primary leak causes.
        - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
    - The percentage difference from the baseline is calculated as:
        - ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
    - The Engineering Integrity Manager or designate is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
    - Steps to consider when reviewing performance measure effectiveness:
        - The previous year leak count shall be equal to or less than the baseline average to be considered favorable.
        - When the previous year leak repair count is higher than the baseline average it shall be considered for adjustments to existing A/A Actions to improve the A/A Action effectiveness.

- Special considerations shall be given for low volumes of leak repair counts because the percentage from baseline can appear exaggerated.
    - For example, a main leak repair count from a baseline average 1 to a previous year count of 2 is a 100% increase but is not be a significant increase.
- It is important to be familiar with the A/A Actions when evaluating Performance Measures.
    - A/A Actions can take many years before a benefit is seen in the leak repair counts. A pipeline replacement program can take years before the performance measures are met.
    - Some A/A Actions can cause a negative impact to performance measures.
        - For example, an increased leak survey frequency on bare steel or cast iron could increase the amount of discovered leaks that will eventually be reported as repaired leaks.

- Since these will be reviewed as part of the Section 5: Identify and Implement Measures to Address Risk Process, a calibration for A/A Actions shall be considered when annually identifying A/A Actions based on the Distribution Integrity Risk Ranking.

ii. *Number of Excavation Damages Count & Rate*

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- This performance measure only includes excavation damage repairs and damage sub causes.
- Performance Measure requirements:
    - The previous year's excavation damage count and rate
        - The count of excavation damage repairs is required for the PHMSA F 7100.1-1 annual report.
        - The Damage Rate is determined as follows:
          (Damage Count / Total Ticket Count) *1000
    - The baseline is based on a five year moving average.
        - This average is not to include the previous year excavation damage repair count and damage rate because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm:
          (2007+2008+2009+2010+2011)/5
            - The baseline average shall be rounded to a whole number.
        - The baseline is determined for mains, services, main & service, and damage sub causes.
        - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
    - The percentage difference from the baseline is calculated as:
        - ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
    - The Engineering Integrity Manager or designate is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
    - Steps to consider when reviewing performance measure effectiveness:
        - The previous year excavation damage count or damage rate shall be equal to or less than the baseline average to be considered favorable.
        - When the previous year damage ratio is higher than the baseline average it shall be considered for adjustments to existing A/A Actions to improve the A/A Action effectiveness.

- It is important to be familiar with the A/A Actions when evaluating measure performance.
  - A/A Actions can take many years before a benefit is seen in the excavation damage counts.

- Since these performance measures will be reviewed as part of the Section 5: Identify and Implement Measures to Address Risk Process, a calibration for existing A/A Actions shall be considered when annually identifying A/A Actions based on the Distribution Integrity Risk Ranking. This process is also considered in the Section 7: Periodic Evaluation and Improvement.

iii. *Number of Excavation Tickets*

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- This performance measure only includes excavation damage repairs and damage sub causes.
- Performance Measure requirements:
  - The previous year's total ticket count.
    - The count of total locate tickets is required for the PHMSA F 7100.1-1 annual report.
  - The baseline is based on a five year moving average.
    - This average is not to include the previous year total locate count because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm: (2007+2008+2009+2010+2011)/5
      - The baseline average shall be rounded to a whole number.
    - The baseline is determined for mains, services, main & service, and damage sub causes.
    - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
  - The percentage difference from the baseline is calculated as:
    - ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
  - The Distribution Integrity Manager is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
  - Steps to consider when reviewing performance measure effectiveness:
    - An increase or decrease in total tickets does not indicate any performance measure issue.
    - Total tickets are used to normalize damage counts.

iv. *Number of Leaks either Eliminated or Repaired, Categorized by Cause*

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.

- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- This performance measures all leak repairs and primary leak cause.
- Performance Measure requirements:
    - The previous year's leak repair count.
        - The count of all leak repairs by primary leak cause and facility type is required for the PHMSA F 7100.1-1 annual report.
    - The baseline is based on a five year moving average.
        - This average is not to include the previous year leak repair count because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm: (2007+2008+2009+2010+2011)/5
            - The baseline average shall be rounded to a whole number.
        - The baseline is determined for mains, services, main & service, and primary leak causes.
        - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
    - The percentage difference from the baseline is calculated as:
        - ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
    - The Engineering Integrity Manager is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
    - Steps to consider when reviewing performance measure effectiveness:
        - The previous year leak count shall be equal to or less than the baseline average to be considered favorable.
        - When the previous year leak repair count is higher than the baseline average it shall be considered for adjustments to existing A/A Actions to improve the A/A Action effectiveness.
            - Special considerations shall be given for low volumes of leak repair counts because the percentage from baseline can appear exaggerated.
                - For example, a main leak repair count from a baseline average 1 to a previous year count of 2 is a 100% increase but is not be a significant increase.
            - It is important to be familiar with the A/A Actions when evaluating measure performance.

  - A/A Actions can take many years before a benefit is seen in the leak repair counts. A pipeline replacement program can take years before the performance measures are met.
  - Some A/A Actions can cause a negative impact to performance measures.
    - For example, an increased leak survey frequency on bare steel or cast iron could increase the amount of discovered leaks that will eventually be reported as repaired leaks.
- Since these will be reviewed as part of the Section 5: Identify and Implement Measures to Address Risk Process, a calibration for A/A Actions shall be considered when annually identifying A/A Actions based on the Distribution Integrity Risk Ranking.

v. *NUMBER OF HAZARDOUS (GRADE 1) LEAKS EITHER ELIMINATED OR REPAIRED, PER §192.703(C), CATEGORIZED BY MATERIAL*

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- This performance measure only includes hazardous (grade 1) leak repairs and primary material. When possible, materials shall be identified as bare steel, galvanized steel, coated steel, MDPE, HDPE, MD Aldyl-A, HD Aldyl-A, cast iron, and copper.
- Performance Measure requirements:
    - The previous year's leak repair count.
        - The count of hazardous leak repairs by primary material and facility type is required per 192.703(c). This report is not required on the DOT annual report.
    - The baseline is based on a five year moving average.
        - This average is not to include the previous year leak repair count because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm: (2007+2008+2009+2010+2011)/5
            - The baseline average shall be rounded to a whole number.
        - The baseline is determined for mains, services, main & service, and material.
        - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
    - The percentage difference from the baseline is calculated as:
        - ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
    - The Engineering Integrity Manager or designate is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
    - Steps to consider when reviewing performance measure effectiveness:
        - The previous year leak count shall be equal to or less than the baseline average to be considered favorable.
        - When the previous year leak repair count is higher than the baseline average it shall be considered for adjustments to existing A/A Actions to improve the A/A Action effectiveness.

- Special considerations shall be given for low volumes of leak repair counts because the percentage from baseline can appear exaggerated.
  - For example, a main leak repair count from a baseline average 1 to a previous year count of 2 is a 100% increase but is not be a significant increase.
- It is important to be familiar with the A/A Actions when evaluating measure performance.
  - A/A Actions can take many years before a benefit is seen in the leak repair counts. A pipeline replacement program can take years before the performance measures are met.
  - Some A/A Actions can cause a negative impact to performance measures.
    - For example, an increased leak survey frequency on bare steel or cast iron could increase the amount of discovered leaks that will eventually be reported as repaired leaks.

- Since these will be reviewed as part of the Section 5: Identify and Implement Measures to Address Risk Process, a calibration for A/A Actions shall be considered when annually identifying A/A Actions based on the Distribution Integrity Risk Ranking.

C. Additional Performance Measures

i. *Sub-Threat Performance Measures*

(1) Measure Performance

- The Distribution Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The DIMP Team is responsible for completing the performance metrics in the DIMP Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness by the end of Q3.
- Each primary threat will have a performance measure based on leak repair counts. The performance measure shall include:
    - The previous year's leak repair count for each threat with sub causes.
        - These performance measures are not reported to PHMSA or the State Pipeline Staff.
    - The baseline is based on a five year moving average.
        - This average is not to include the previous year leak repair count because this skews averages. For example, when the DIMP year is represented by 2012 then the baseline is determined by the following algorithm: (2007+2008+2009+2010+2011)/5
        - The baseline average shall be rounded to a whole number.
        - Some datasets may not have five years of data to determine an average. In these cases, use as many years to determine the average.
        - The baseline is determined for mains, services, main & service, and primary leak causes.
    - The percentage difference from the baseline is calculated as:
        i. ((Previous Year Count – Baseline)/Baseline) *100
- Refer to Section 2: Data Compilation for steps to collect the information.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
    - The Engineering Integrity Manager or designate is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness is determined by examining the baseline average as compared to the previous year count.
    - Steps to consider when reviewing performance measure effectiveness:
        - The previous year leak count shall be equal to or less than the baseline average to be considered favorable.
        - When the previous year leak repair count is higher than the baseline average it shall be considered for adjustments to existing A/A Actions to improve the A/A Action effectiveness.

- Special considerations shall be given for low volumes of leak repair counts because the percentage from baseline can appear exaggerated.
    - For example, a main leak repair count from a baseline average 1 to a previous year count of 2 is a 100% increase but is not be a significant increase.
- It is important to be familiar with the A/A Actions when evaluating measure performance.
    - A/A Actions can take many years before a benefit is seen in the leak repair counts. A pipeline replacement program can take years before the performance measures are met.
    - Some A/A Actions can cause a negative impact to performance measures.
        - For example, an increased leak survey frequency on bare steel or cast iron could increase the amount of discovered leaks that will eventually be reported as repaired leaks.

- Since these will be reviewed as part of the Section 5: Identify and Implement Measures to Address Risk Process, a calibration for A/A Actions shall be considered when annually identifying A/A Actions based on the Distribution Integrity Risk Ranking.

ii. Customized Performance Measures

(1) Measure Performance

- The Engineering Integrity Manager is responsible for the accuracy of numbers displayed in the metrics in the Appendix F: Measure Performance, Monitor Results, & Evaluate Effectiveness.
- The Engineering Integrity Manager shall have the ability to add any additional performance measure metrics.
- Performance measure metrics shall be completed by the end of Q3.

(2) Monitor Results

- Key contacts are to annually review this performance measure by the end of Q3. This includes;
  - The Engineering Integrity Manager or designate is responsible for conducting the meeting.

(3) Evaluate Effectiveness

- Effectiveness shall be at the discretion of the key contacts since the customized performance measure is not defined.

7) Periodic Evaluation and Improvement

A. Regulatory Reference: 192.1007.(f)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(f) Periodic Evaluation and Improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

B. Purpose and Objectives

The objective of this section of the plan is to periodically re-evaluate threats and risks on the entire pipeline and periodically evaluate the effectiveness of its program. This written integrity management plan shall be reviewed annually and updated as required to reflect changes and improvements that have occurred in process, procedures and analysis for each element of the program. This annual process constitutes as a DIM Program evaluation.

i. Process For Review

The review process shall determine the deletions, additions, and modifications of the forthcoming DIMP Plan. The Engineering Integrity Manager will track enhancement requests internally and will publish approved changes by Q4 for the upcoming DIMP Plan. This internal review process is recommended to fully investigate the impact of the changes to the DIMP Plan

- Additional requests may be included in the current DIMP year plan based on priority and Distribution Integrity Manager.
- All elements of the DIM Program are open for review to ensure continual improvement of the DIM Program.
- Appendix G: Periodic Evaluation and Improvement documents major changes to the DIMP Plan.
- Appendix D: Evaluate and Rank Risk shall contain modifications to the risk analysis process.

ii. Items to Review

An annual review of the following items must be completed every year by Q4 for the upcoming DIMP Plan:

- General Information (Contacts, Action Schedules, Definitions)
- Incorporate new system information used in Section 2: Characteristics of Design, Operations, and Environmental Factors and Section 2: Characteristics of Past Design, Operations, and Maintenance.
- Identify additional information needed to fill data gaps due to missing, inaccurate, or incomplete records
- Evaluation of threats documented in Section 3: Threat Identification.
- Evaluation of risks documented in Section 4: Ranking of Risk.
- Review assigned A/A Actions defined through Section 5: Identify and Implement Measures to Address Risk.
- Review performance measures and their effectiveness defined in Section 6: Measurement Performance, Monitor Results, and Evaluate Effectiveness.
- Any other items deemed necessary

C. Plan Updating

i. General Updates and Revision Control

All changes to the written plan, inclusive of material from the appendices, shall be recorded on the Revision Control Sheets within the Plan and Appendices. The revision notes must include section, date, and comments to help with the change management of the documents. The requirements of document revisions apply to all sections of the DIMP Plan and Appendices.

ii. Approval Control

The Plan approval control sheet requires key contacts to approve the DIMP Plan by the end of Q1 of each DIMP year. Consequently, updates made to the DIMP Plan throughout the year will not require an update to the approval control sheet.

Additionally, the approval control sheet indicates that key contacts have reviewed the previous year's appendices. This is to ensure that key contacts have reviewed all metrics within the appendices that have been completed through Q4 of the previous year.

iii. Significant Plan Updates

A significant update is defined as a change to the plan that fundamentally changes the processes and tasks required to be completed throughout the annual completion of the program. This can include, but is not limited to, a new risk analysis, or a new threat identification process. Examples of non-significant updates include, but are not limited to, the identification of a new threat, clarification of a process, or a job title update.

- Once notified of a significant update, all key contacts will be given two weeks to review proposed plan changes.
    - The proposed changes can be applied to the DIMP Plan sooner when all key contacts agree with the changes.
    - If no comments are made within two weeks of the review, all updates shall be deemed accepted by the Engineering Integrity Manager.
        - A final approval shall be given by the General Manager of Florida City Gas.
    - If comments are made, all key contacts shall have a meeting to discuss the updates.
        - Once updates are finalized by the DIMP Team, another meeting shall be conducted to approve the new plan.
        - All key contacts are required to approve the plan.
    - The General Manager of Florida City Gas has final authority of any DIMP Plan change and shall have the ability to approve, override, and require any change requests. This includes:
        - The ability to immediately approve a proposed DIMP Plan without consensus from other key contacts.

8) REPORTING RESULTS

A. Regulatory Reference: 192.1007.(g)

192.1007 A written integrity management plan must contain procedures for developing and implementing the following elements:

(g) Report results. Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by § 191.11. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

B. STATE & FEDERAL ANNUAL REPORTING REQUIREMENTS

The following measures shall be reported annually, by March 15, to PHMSA as part of the annual report required by 49 CFR, § 191.11:

- Number of grade 1 leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), per § 192.703(c), categorized by main/service and by cause of leak.

- Number of excavation damages

- Number of excavation tickets (receipt of information by the Company from the notification center)

- Total number of leaks either eliminated or repaired, categorized by main/service and by cause of leak.

The plan will be made available for review upon request or during regular scheduled system inspections. The method of review can be electronically or hard copy. See Section 1: State Contacts for the contact information for the state pipeline safety authority.

9) DOCUMENT AND RECORD RETENTION

A. Regulatory Reference: 192.1011

§ 192.1011 What records must an operator keep?

An operator must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

B. Objective and Process

The following records shall be retained in the DIM Program files.

- The most current as well as prior versions of this written DIMP Plan
- Documents supporting knowledge of facilities
- Documents supporting threat identification
- Documents supporting risk evaluation and ranking
- Documents supporting the identification and implementation of measures to address risks
- Documents supporting measurement of performance, monitoring results and evaluating effectiveness
- Effectiveness reviews
- Annual reports to PHMSA (as required by §191.11) and state pipeline safety authorities
- Mechanical Fittings Failure Reports
- Documents supporting the FCG Inactive Service Line Risk Assessment under Florida Rule 25-12.045. C.2

- Documentation demonstrating compliance with the requirements of 49 CFR, Part 192, Subpart P shall be retained for at least 10 years. System data retention requirements are included by reference in Appendix H: Record Retention and Location.
- All records documented in Appendix B: Integrity Management Program Records Summary shall be maintained for at least ten years or as defined in 192.1011.
    - The Corporate Record Retention Schedule shall be updated as needed to ensure records indicated on Appendix B: Integrity Management Program Records Summary has a corresponding record with the record retention policy.
- Current and historical versions of the official written DIMP Plan and Appendices are archived after updates are made in accordance with Section 7: Plan Updating.
- Supporting documents and data utilized in the DIMP Plan are archived on an annual basis. The file location of source documents can be located in Appendix H: Record Retention and Location.

The record listing can be referenced in Appendix H: Record Retention and Location.

Exhibit C