INDIANA GAS COMPANY, INC.

d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.

A CENTERPOINT ENERGY COMPANY

(VECTREN NORTH)

IURC CAUSE NO. 45468

DIRECT TESTIMONY

OF

SARAH J VYVODA

MANAGER, TRANSMISSION & STORAGE INTEGRITY MANAGEMENT

ON

TRANSMISSION AND STORAGE INTEGRITY MANAGEMENT, AND OTHER COMPLIANCE PROGRAMS

SPONSORING PETITIONER'S EXHIBIT NO. 5,

ATTACHMENTS SJV-1 THROUGH SJV-2

Glossary of Acronyms

AGA	American Gas Association
API RP 1171	American Petroleum Institute Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs
API RP 1173	American Petroleum Institute Recommended Practice 1173
ASME	American Society of Mechanical Engineers
ASV/RCV Proposed Rule	Valve Installation and Minimum Rupture Detection Standards Notice of Proposed Rulemaking
ASVs	Automated Shut-Off Valves
CenterPoint	CenterPoint Energy, Inc.
CPCN	Certificate of Public Convenience and Necessity
DIMP	Distribution Integrity Management Program
Gaps	Missing or Unavailable Data
GIS	Geographical Information System
GPAC	Gas Pipeline Advisory Committee
HCAs	High Consequence Areas
IFR	Interim Final Rule
IURC	Indiana Utility Regulatory Commission
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MOC	Management of Change
NACE	National Association of Corrosion Engineers
NPRM	Notice of Proposed Rulemaking
NTSB	National Transportation Safety Board
O&M	Operations and Maintenance
OQ	Operator Qualification
PEF	Performance Evaluation Form
Petitioner or Vectren North or The Company	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc.
PHMSA	Pipeline and Hazardous Materials Safety Administration
Pipeline Safety Act	Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011
RCVs	Remote-Controlled Valves
SGA	Southern Gas Association
SGTGL Rule	Safety of Gas Transmission and Gathering Lines Rule
SIMP	Storage Integrity Management Program
SMEs	Subject Matter Experts
SMS	Safety Management System
Storage Integrity Final Rule	Safety of Underground Natural Gas Storage Facilities Final Rule
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
TIMP	Transmission Integrity Management Program
Vectren	Vectren Corporation
Vectren Ohio	Vectren Energy Delivery of Ohio, Inc.
Vectren South	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.

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DIRECT TESTIMONY OF SARAH J VYVODA

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sarah J Vyvoda. My business address is 211 NW Riverside Drive, Evansville, Indiana, 47708.

Q. By whom are you employed?

A. I am employed by Vectren Corporation ("Vectren"), a wholly-owned subsidiary of CenterPoint Energy, Inc. ("CenterPoint").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner", "Vectren North" or "the Company"), which is a subsidiary of Vectren.

Q. What is your role with respect to Petitioner Vectren North?

A. I am Manager of Transmission and Storage Integrity Management for CenterPoint, which is the ultimate parent company of Vectren North. I have the same role with two other utility subsidiaries of Vectren – Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. Please describe your educational background.

A. I received a Bachelor of Science in chemical engineering from Rose-Hulman Institute of Technology in 2004.

Q. Please describe your professional experience with the Company.

A. I have been employed with Vectren Corporation ("Vectren") and CenterPoint in various roles since April 6, 2009. Prior to moving to my current role as CenterPoint's Manager of Transmission and Storage Integrity Management in February 2019, I was Vectren's Director of Gas System Integrity for two years. Additionally, I have held roles as Vectren's Chief Engineer of Gas Asset Integrity Management, Manager of Transmission Integrity Management, and Transmission Integrity Management Engineer.

Q. What are your present duties and responsibilities as Manager of Transmission and Storage Integrity Management?

A. In my current role as Manager of Transmission and Storage Integrity Management, I am responsible for reducing risks to transmission and storage assets by executing the transmission and storage field integrity management programs for the entirety of CenterPoint. This includes development and implementation of data collection, threat and risk assessment, integrity assessment, remediation action, and preventive and mitigation action plans for transmission and storage assets. I participate on internal steering committees to identify and mitigate risks to our natural gas systems. Additionally, I monitor pipeline safety regulations and industry events related to natural gas distribution, transmission and storage assets. My responsibilities also include industry engagement through membership in various associations including the

American Gas Association ("AGA"), Southern Gas Association ("SGA"), National Association of Corrosion Engineers ("NACE"). Additionally, my role requires monitoring and participating in the pipeline safety rulemaking and guidance issuance processes.

Q. Have you ever testified before the Indiana Utility Regulatory Commission?

A. Yes. Most recently, I provided testimony in Vectren South's gas rate case under Cause No. 45447. Additionally, I provided testimony in Vectren's Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") proceedings under Cause No. 44430-TDSIC-6 through -13 (Vectren North) and Cause No. 44429-TDSIC-6 through -13 (Vectren South). In addition to those on-going causes, I provided testimony on behalf of Vectren North and Vectren South in Cause No. 44971 seeking a certificate of public convenience and necessity ("CPCN") for compliance projects to meet the regulatory requirements of the new Safety of Underground Natural Gas Storage Facilities Rule ("SIMP Final Rule").

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will describe a subset of the Company's Compliance Programs that have been enhanced to comply with new and changing federal pipeline safety regulations since the last rate case. Specifically, these are the aforementioned TIMP, SIMP, Facility Damages program, Safety Management System ("SMS"), and Operator Qualification ("OQ") and Training program. Additionally, my testimony will address the impact of DIMP on the Company's integrated pipeline safety programs and risk reduction efforts. Petitioner's Witness Kate D. Porter will fully address DIMP pipeline safety requirements and impact to the Company's investments in her testimony. My testimony will: (1) provide a brief history of these programs; (2) describe the federal pipeline safety regulations establishing the compliance need and requirements for these programs; (3) provide an update on new and changing federal pipeline safety regulations that have required enhancement to these programs since the last rate case; (4) describe the requirements to comply with these programs; and (5) provide a basis for how these programs contribute to on-going capital and operations and maintenance ("O&M") investment of the Company.

Q. Are you sponsoring any attachments in this proceeding?

A. Yes. I am sponsoring the following attachments in this proceeding:

- <u>Petitioner's Exhibit No. 5</u>, **Attachment SJV-1**: Gas Transmission Integrity Management Plan Version 2020.1.
- <u>Petitioner's Exhibit No. 5</u>, **Attachment SJV-2**: Storage Integrity Management Program Version 2020.2.

Q. Were these attachments prepared by you or under your supervision?

A. Yes, they were.

Q. Please summarize the Company's enhancements to the pipeline safety compliance programs since the last rate case described in your testimony.

A. As a result of evolving pipeline safety regulations issued by PHMSA, the Company was required to enhance its pipeline safety programs since the last Vectren North rate case.[1] Specifically, the Company enhanced existing pipeline safety programs

[1] Vectren North Rate Case 2007/2008 Cause No. 43298

including the DIMP, TIMP, Facility Damages program, and OQ and Training program. Additionally, the Company implemented an SMS in response to PHMSA advisory bulletins and recommendations and industry best practices. In response to a recent new rulemaking, the Company also implemented a SIMP. Collectively, these programs comprise the Company's Compliance Programs within this filing. In order to comply with the federal pipeline safety regulations issued by PHMSA, the Company has invested in both capital and O&M compliance projects to reduce risks to natural gas assets under these Compliance Programs. The Compliance Programs require on-going investment to maintain the program compliance by executing annual prescriptive compliance activities and reporting, and plan and execute risk reduction projects such as integrity assessments and asset replacement projects. These activities result in costs within the test year and future years.

Q. How is your testimony organized?

A. My testimony is organized in the following sections:

Background of the Company's pipeline safety Compliance Programs;

- Overview of the pipeline safety Compliance Programs and activities;
- Discussion of recently published pipeline safety regulations;
- Enhancements to the Company's pipeline safety Compliance Programs resulting in additional and on-going investment;
- Compliance Program O&M activities that make up the O&M expenses within the test year; and
- Capital Compliance Plan impact resulting from the Company's pipeline safety Compliance Programs.

II. BACKGROUND

Q. Please provide an overview of the Company's pipeline safety Compliance Programs.

A. The Company's Compliance Programs drive the planning and execution of projects the Company is required to complete to comply with federally mandated pipeline safety regulations, including those pursuant to the TIMP, SIMP, and other assorted pipeline safety rules. Under the Compliance Programs, the Company must engage in activities including gathering and enhancing asset data used to determine existing threats to the system; conducting risk assessments to identify threats to the integrity of the system; completing inspections; remediating conditions found during assessments, evaluation and implementation of preventative and mitigating measures to minimize future threats; and maintaining ongoing risk mitigation plans to monitor threats and reduce risks. The preventative and mitigating measures include focus on efforts to reduce damages to pipeline facilities and the qualification of operating personnel. Additionally, the implementation of an SMS is included to address overarching risks of people, assets and the public as required by pipeline safety regulations and recommended practice. The Compliance Programs result in compliance project activities to reduce risk. These projects are dynamic based on risk assessment, and in many ways are interdependent. Risk assessment processes required by the integrity programs, SMS, and other Compliance Programs are used to create the project scopes and resource plans.

Q. Has the Company enhanced its Compliance Programs since the last rate case?

A. Yes. Since the last rate case filed in late 2007 with an order issued in 2008, the

Company has been required to enhance its Compliance Programs to continue to comply with existing pipeline safety program requirements, and new and changing PHMSA pipeline safety regulations. Specifically, the integrity management programs require the application of continuous improvement and program effectiveness assessments to ensure risk reduction activities are effectively reducing the risk of failure of the Company's assets. The Compliance Program enhancements have resulted in continued capital and O&M investments to maintain the programs, plan mitigation efforts, and execute pipeline safety compliance projects. The Compliance Program enhancements are discussed further later in my testimony in Section III: Compliance Programs Overview. The impact of the PHMSA pipeline safety regulation publications is discussed later in my testimony in Section IV: Impact of Recently Published Pipeline Safety Regulations.

Q. Does the Company manage O&M for these compliance projects at the project level?

A. While the Company endeavors to manage costs at the project level, the Compliance Program requirements drive the plan initiatives, timing and priorities. Many factors make managing costs at the project level challenging. The main factor is that the Compliance Programs and resulting project activities are focused to reduce risk, are dynamic based on risk assessment, and in many ways are interdependent. Risk assessment and continuous improvement required by the integrity programs, SMS, and other Compliance Programs are used to create the project scopes and resource plans. The project scopes and resource plans have potential to impact each O&M Compliance Project priority and scope due to the interdependencies. Examples of interdependencies include the impact of enhanced facility damages data on distribution asset risk assessment, or the impact of distribution leak reporting and response evaluation on operator qualifications and training for leak investigation. Therefore, the Company manages the costs at the Compliance Program level.

III. COMPLIANCE PROGRAMS OVERVIEW

Q. Please describe the TIMP requirements.

A. The Company's TIMP originated in 2004 in response to PHMSA's publication of the first integrity management requirements for transmission assets. This rulemaking established 49 CFR Part 192, Subpart O which specifies how pipeline operators must identify, prioritize, baseline assess and re-assess, evaluate, repair and validate the integrity of gas transmission pipelines located within High Consequence Areas ("HCAs"). Additionally, this subpart specifies the program requirements to continually gather transmission asset information, identify threats, conduct risk assessment activities, and implement mitigative actions to reduce transmission asset risk of failure. Under these regulatory requirements, the Company established its TIMP which includes compliance with the aforementioned areas, the process to measure and report program effectiveness and enhance the program based on the program effectiveness results. The Company's TIMP has been significantly modified to meet additional transmission integrity regulations published by PHMSA in 2019 under the Safety of Gas Transmission and Gathering Lines Rule[2] ("SGTGL Rule"). The impact of this additional rulemaking is discussed later in my testimony in Section IV: Impact

[2] https://www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment

of Recently Published Pipeline Safety Regulations.

Q. Please describe the SIMP requirements.

A. The Company's SIMP was created in 2016 to comply with PHMSA's 49 CFR Part 192, Pipeline Safety: Safety of Underground Natural Gas Storage Facilities Interim Final Rule ("IFR")[3] which in turn incorporates by reference the American Petroleum Institute Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs ("API RP 1171"). The Company's SIMP is executed through collaborative efforts between the Company's Storage Integrity Management, Reservoir Engineering, and Storage Operations departments and support functions required to comply with the IFR. Due to these rulemakings beginning in 2016, PHMSA requires storage field operators to develop, implement, and continuously improve a SIMP to ensure safety of their natural gas underground storage facilities. The Company's SIMP plan describes how to perform threat identification and relatively rank risks to underground storage wells and assets, conduct site assessments and well-logging to identify integrity defects, and address the results of those assessments through remediation, prevention, monitoring, mitigation and emergency response. Additionally, the plan includes a management of change ("MOC") process, training requirements and compliance documentation requirements. Recently, PHMSA published the Safety of Underground Natural Gas Storage Final Rule[4] ("Storage Integrity Final Rule") on February 12, 2020, formalizing

[3] https://www.federalregister.gov/documents/2016/12/19/2016-30045/pipeline-safety-safety-of-underground-natural-gas-storage-facilities#:~:text=Under%20the%20interim%20final%20rule%2C%20all%20intrastate%20transportation-related,filed%20with%20PHMSA%20pursuant%20to%2049%20U.S.C.%2060105.

[4] https://www.federalregister.gov/documents/2020/02/12/2020-00565/pipeline-safety-safety-of-underground-natural-gas-storage-facilities

the requirements for underground natural gas storage safety. The impact of the SIMP Final Rule is discussed further in Section IV: Impact of Recently Published Pipeline Safety Regulations.

Q. Has the Company implemented an SMS?

A. Yes. In 2015, the Company implemented an SMS in compliance with American Petroleum Institute Recommended Practice 1173 ("API RP1173"). API RP1173 describes ten elements required for a successful SMS. They are:

- leadership and management commitment,
- stakeholder engagement,
- risk management,
- operational controls,
- incident investigation, evaluation and lessons learned,
- safety assurance,
- management review and continuous improvement,
- emergency preparedness and response,
- competence, awareness and training, and
- documentation and record keeping.

The Company has addressed all ten of the SMS elements, and each element is in various stages of implementation. CenterPoint implemented a dedicated department to support managing and executing the SMS requirements upon the merger in 2019. This department includes a staff of nine focused on risk information collection, risk register management, "bow-tie" analysis, control testing, governance, communication and reporting.

Q. Please describe how the Company's SMS contributes to pipeline safety and risk reduction.

A. In alignment with the integrity management programs, the Company's SMS requires the collection of risks identified from personnel working on, and around, gas assets or the supporting work processes to be populated in a risk register. The risks are then ranked by the personnel, reviewed by a technical committee, and a threshold is established to define and prioritize the risks to address along with mitigating actions. Multiple cycles of identifying and ranking risks to gas assets, employee safety, and system operations have been completed to update the Company's risk register as part of the SMS for gas pipeline safety activities. Similar to the cross-department collaboration required to execute the integrity management programs, various Company subject matter experts ("SMEs") participate in the SMS risk discussions and phases of the risk identification process, including personnel from gas operations, engineering, gas contractors, safety, compliance, damage prevention, human resources, and information technology. The current pipeline risk mitigation programs and projects are linked to risk register items, policies and procedures, and strategic planning through a detailed risk assessment process, or "bowtie analysis," that maps each risk to its mitigation plan. Key performance indicators and metrics have been identified and evaluated to measure effectiveness of those mitigation plans. Additionally, the Company's SMS executes a multi-tiered governance structure to promote visibility to safety and compliance performance from the field to the boardroom. The structure provides support for implementing risk reduction activities as part of incident investigations and lessons learned activities. The impact of SMS on the Company's risk mitigation investments is discussed further in Section VIII: Enhancement of Compliance Programs, Risk Assessment, and Impact to the

Company's Required Investment.

Q. Have state regulators charged with enforcement of the federal regulations further emphasized the importance of using a pipeline safety management system to support compliance with safety regulations?

A. Yes. Consistent with guidance from the PHMSA, the Commission's Pipeline Safety Division has informed the Company that adoption of a safety control framework that ensures the planning, doing, checking, and adjusting continuous improvement steps are in place should be an integral part of compliance and pipeline safety programs. As a key stakeholder in the safety of our pipeline systems, the Company regularly engages with the Commission's Pipeline Safety Division on the implementation of its safety management system, and continues to update the Commission's Pipeline Safety Division through scheduled discussion of the status of its risk management process and the development of mitigation plans for the risks identified as the highest risks and other significant risk reduction programs, such as distribution and transmission integrity management, linked together by SMS. The progress of this activity and the linkage to the TIMP, DIMP and SIMP programs demonstrates the continued value of the SMS.

Q. Do industry associations support the implementation of SMS?

A. Yes. Specifically, AGA supports the implementation of SMS as a complement to existing pipeline safety programs. In May 2019, the members of AGA established a commitment to enhance pipeline safety by implementing an SMS over a three-year period. The Company participated as a member of the AGA pilot group for SMS implementation. As a leader in SMS implementation, the Company actively shared best practices, lessons learned, and safety culture enhancements at AGA conferences and other industry discussions.

Q. Please describe the Company's Facility Damages program.

A. The focus of the Facility Damages program is to increase overall public safety by helping ensure compliance with 49 CFR 192.614, 49 CFR 192.616, and Indiana Code ch. 8-1-26. The Company's Facility Damages program, overseen by the damage prevention department, was formed in 2015. The damage prevention team manages the risk of third-party damage to the Company's assets by educating excavators on pipeline safety requirements, training safe excavation practices, damage reporting, one call locate management, and public awareness. The damage prevention team documents and investigates each facility damage, assigns a root cause, performs a corrective action, and utilizes that data to help drive training and identify improvement opportunities. Additionally, the Company uses contract locate vendors to perform our locate requests through the One Call center and holds periodic meetings to monitor key performance metrics, such as quality and on time performance. The Facility Damages program is supported by the company's Public Awareness program focusing on communication of pipeline safety requirements and best practices to emergency responders, public officials and the public. While ensuring compliance with the public awareness rule, this program also provides a focused effort to create campaigns, messaging and targeted distribution to educate the excavation stakeholders. The program has proven to be effective in increasing awareness, providing education and changing behaviors to reduce utility damages.

Q. Please describe the Company's OQ and Training program.

A. The Company's OQ and Training program is designed to meet the regulations and applicable amendments in 49 CFR Part 192 Subpart N. The intent of the regulations is for operators to ensure a qualified workforce is performing the tasks required to design, construct, operate, and maintain natural gas systems and reduce the likelihood and consequence of incidents caused by human error. The core function of the OQ and Training program is to establish, execute and track qualification requirements and training for individuals performing the identified covered tasks from the regulations, PHMSA guidance, and industry best practices for both internal employees and contract personnel performing work on the natural gas system. Covered tasks are identified based on a four-part test as outlined in 49 CFR 192.801, which requires the evaluation of processes to determine a reasonable cause to verify qualifications, the span of control of certain functions, and managing, documenting and communicating change. The OQ and Training program requires significant recordkeeping and reporting processes to manage and track the training materials and status of qualifications for the expansive workforce required to operate and maintain the Company's natural gas system. As pipeline safety programs evolved, PHMSA has included in its new regulations additional qualification and training requirements as a risk reduction measure to address industry failures contributed to by human error. As a result, the Company has expanded the number of covered tasks and performance evaluations ("PEFs") required for training and qualification and identified additional personnel and processes required under the program. The impact of expanding the OQ and Training program to meet additional pipeline safety regulations is discussed further in Section IV: Impact of Recently Published Pipeline Safety Regulations.

Q. Do the Compliance Programs and required activities result in O&M expenses within the test year?

A. Yes, the O&M expenses required to continue execution of the Compliance Programs are included in the test year. Petitioner's Witness Ryan D. Moore supports the unadjusted test year O&M expense level, including the O&M expenses related to the Compliance Programs as described in my testimony. Additional detail of the planned compliance activities that make up these costs within the test year is included later in testimony in Section IX: Compliance Programs O&M Activities within the test year.

Q. Do the Compliance Programs and required activities also result in capital investments within the test year?

A. Yes, the capital investments required to continue execution of the Compliance Programs are included in the test year. Petitioner's Witness Steven A. Hoover provides further detail on the capital Compliance Plan supporting the Compliance Programs.

IV. IMPACT OF RECENTLY PUBLISHED PIPELINE SAFETY REGULATIONS

Q. Has PHMSA issued new pipeline safety regulations since the Company's last base rate case?

A. Yes. Industry pipeline events continue to drive PHMSA to respond with increased pipeline safety regulations and enforcement. PHMSA has continued sharing its plans and drafted proposed regulations with the industry. These regulations impact the Company's need to invest in the replacement or upgrade of its infrastructure, as well as increase O&M expenses to execute new or modified programs to comply with pipeline safety regulations. PHMSA, acting on congressional mandates and recommendations from the National Transportation Safety Board ("NTSB"), the Office of Inspector General, and the General Accounting Office, continues preparing new or modified regulations to address these mandates and safety recommendations. Since the Company's last base rate case, PHMSA has issued pipeline safety regulations regarding the safety of gas transmission pipelines and underground natural gas storage assets, as well as numerous advisory bulletins, such as those in response to the San Bruno and Merrimack Valley incidents, providing guidance to operators to continue to enhance their pipeline safety Compliance Programs.

V. SAFETY OF GAS TRANSMISSION AND GATHERING LINES RULE

Q. Please describe the timing and nature of the SGTGL Rule.

A. On March 18, 2016, PHMSA published a Notice of Proposed Rulemaking ("NPRM") for the SGTGL Rule, docketed as PHMSA-2011-0023, which proposed to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. The SGTGL Rule was divided into three phases for publication: Phases 1 and 2 concern gas transmission lines and Phase 3 impacts gathering lines. Phase 1 of the SGTGL Rule was published in the Federal Register on October 1, 2019 and became effective July 2, 2020.

Q. Please describe the compliance requirements associated with the SGTGL Rule published October 1, 2019.

A. The SGTGL Rule is categorized as a significant rulemaking by PHMSA under their rulemaking and standards processes, meaning the modifications to existing transmission integrity regulations and additional requirements have significant impact to TIMP operators' processes and plans. This rulemaking is PHMSA's response to the 2010 San Bruno transmission pipeline safety event and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("Pipeline Safety Act"). Within the Pipeline Safety Act, PHMSA was charged with research efforts and industry coordination to enhance the transmission integrity management regulatory requirements to prevent a similar event from occurring elsewhere. This first phase of the SGTGL rulemaking is the result of those efforts. Additional phases are pending that will impact transmission integrity regulations further and integrity requirements for gathering lines. PHMSA has communicated that Phase 2 is planned for tentative publication mid-year 2021.

The SGTGL Rule impacts areas beyond enhancing requirements in 49 CFR 192 – Subpart O – Transmission Integrity Management and includes requirements for design and construction of transmission facilities, operator qualification and training, reporting to PHMSA, and standards incorporated by reference. However, the scope of the rulemaking impacts only transmission pipelines. The main enhancement areas to the transmission integrity management requirements include: MAOP reconfirmation, material property verification, transmission asset record quality and retention requirements, moderate consequence area ("MCA") assessments, and response criteria to integrity threats. The modifications and additional requirements from the SGTGL Rule have been incorporated into CenterPoint's Gas Transmission Integrity Management Plan (GTIM) 2020.1 revision. Please see Petitioner's Exhibit No. 5, Attachment SJV-1: Gas Transmission Integrity Management Plan Version 2020.1 for the plans and procedures supporting CenterPoint's TIMP compliance.

Q. Will additional compliance requirements set forth in the SGTGL Rule drive new or expanded activities as part of the ongoing Compliance Plan?

A. Yes. In order to comply with the SGTGL Rule, increases to both the O&M Compliance Plan beginning in 2020 and the capital Compliance Plan estimated to begin in 2021 are required. The additional compliance requirements include:

- revisions to the TIMP plan;
- definitions and quality control process to maintain traceable, verifiable and complete transmission asset records;
- identification of MCAs;
- extension of the assessment schedule to include MCA assessments;
- creation and execution of a material verification plan and testing;
- execution of maximum allowable operating pressure ("MAOP") record re-verification per the prescriptive requirements of the rule;
- revisions to the design and construction standards;
- extension of the operator qualification and training plan to cover additional tasks included in the new rule; and
- updating various manuals to incorporate refined reporting requirements, standards updates and links to support the TIMP plan changes.

Activities to comply with the SGTGL Rule were initiated in 2020 and will continue into 2021 and future years. The O&M costs associated with executing these activities are projected in the test year costs in Petitioner's Witness Moore's direct testimony. The capital plan impact is addressed in Petitioner's Witness Hoover's direct testimony.

Q. Will the incremental TIMP compliance activities drive increases in the ongoing TIMP O&M and capital investment?

A. Yes. Ongoing TIMP capital and O&M costs are required to support the implementation and execution of enhanced transmission integrity management program requirements from the SGTGL Rule.

VI. SAFETY OF UNDERGROUND NATURAL GAS STORAGE RULE

Q. Please describe the publication and changes in compliance requirements from the Storage Integrity Final Rule?

A. PHMSA published the Storage Integrity Final Rule in the Federal Register on February 12, 2020. The effective date of this rule, since it was preceded by the IFR, is March 13, 2020. The Storage Integrity Final Rule solidified the requirements of storage integrity management by incorporating API RP 1170 and 1171 as written and specifying certain compliance requirements and timelines for enforcement. The Storage Integrity Final Rule contains a clear definition of underground natural gas storage assets clearly noting the line of demarcation between transmission and storage assets as the well head. Additionally, PHMSA provided clarification and prescriptive compliance dates for activities such as the annual program review, integrity baseline and reassessment activities, federal reporting, and storage asset documentation requirements. Specifically, the SIMP Final Rule requires operators to complete baseline well-logging assessments within seven (7) years of the effective date of March 2020. Additionally, PHMSA established a prescriptive reassessment interval of seven (7) years, requiring operators to reassess the integrity of wells on a seven (7) year frequency. Currently, AGA and industry are seeking clarification regarding this requirement as many operators accepted well-logging assessments that met the API requirements prior to the IFR as baseline assessments that may already have met the seven (7) year interval requirement. This is the case with the Company's SIMP and well-logging reassessments as the Company chose to conduct well integrity assessments prior to the issuance of the IFR. As a result, certain well integrity reassessments are required to be conducted as soon as practical. Additionally, PHMSA established, consistent with the TIMP and DIMP programs, an annual program review requirement that shall not exceed 15 months in interval. PHMSA modified the SIMP reporting requirements from the IFR in the Storage Integrity Final Rule. The IFR previously required the reporting of any well work potentially impacting the reservoir pressure 60 days prior to execution. PHMSA clarified this requirement in the Storage Integrity Final Rule by defining well work and updating the reporting portal for operator notification submissions. Lastly, PHMSA adopted the documentation quality and retention requirements in the transmission integrity management regulations for storage asset documentation requiring most documentation to be retained for the life of the asset. Attached is the Company's Storage Integrity Management Program Version 2020.2 in Petitioner's Exhibit No. 5, Attachment SJV-2.

Q. Will additional compliance requirements set forth in the Storage Integrity Final Rule drive new or expanded activities as part of the ongoing investments?

A. Yes. Specifically, the Company has updated the baseline well integrity assessment plan and schedule, as well as the reassessment plan and schedule to comply with the

Storage Integrity Final Rule. The Storage Integrity Final Rule requires baseline assessment targets of 50% of wells within four years of the program implementation, 100% of wells complete within seven years of the program implementation, and reassessments due on a seven-year interval from the time of baseline assessment. The plan and schedule changes required to meet these requirements increased the number of wells that the Company must assess annually by SIMP resulting in additional O&M expenses and capital investment. Additional activities to comply with the Storage Integrity Final Rule include revising the Company's SIMP plan to incorporate the changes in requirements from the IFR to the Storage Integrity Final Rule. The Company determined that only minor revisions were required to the SIMP plan to meet the Storage Integrity Final Rule compliance. Additional preventive and mitigative measure requirements to collect information on storage assets to support risk assessment and additional monitoring requirements also contribute to the increased O&M expense. The O&M costs of continuing to comply with these regulations are included within the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

VII. PHMSA PROPOSED REGULATORY CHANGES

Q. Are there any proposed changes to pipeline safety regulations?

A. Yes, in addition to the recently published SGTGL Rule and Storage Integrity Final Rule, PHMSA continues to propose additional pipeline safety regulations to reduce the risk to natural gas assets. In response to recent pipeline safety events where pipeline isolation was delayed increasing the consequence of the rupture, in February

2020, PHMSA issued a Notice of Proposed Rulemaking ("NPRM") regarding Valve Installation and Minimum Rupture Detection Standards ("ASV/RCV Proposed Rule") under Docket No. PHMSA-2013-0255. Most recently, on October 14, 2020, PHMSA published an NPRM regarding class location change allowances and requirements entitled Class Location Change Requirements under Docket No. PHMSA-2017-0151.

Q. Please describe the ASV/RCV Proposed Rule requirements.

A. The ASV/RCV Proposed Rule requires operators to install ASVs and RCVs going forward as they install new or replace segments of existing transmission lines. Additionally, the rule specifies minimum valve spacing requirements, response times to activate the valves and achieve isolation, valve testing requirements, and failure investigation requirements. Currently, the ASV/RCV Proposed rule is completing the Gas Pipeline Advisory Committee ("GPAC") process to review comments and finalize the rule requirements and language. The publication of this rule is expected in late 2020 or early in 2021. The proposed implementation timeline is 24 months to allow for the update of the necessary design, construction, and emergency response policies and procedure. Implementation of the requirements will include impact to both the Company's O&M and capital pipeline safety investments to complete the policy and procedure updates, expand the scope of transmission capital projects to include the design and installation of ASV/RCVs, obtain the necessary resources and monitoring technology and systems to remotely operate the valves for testing and emergency response, and enhance the failure investigation processes.

Q. **Please describe the Class Location Change Requirements NPRM**.

A. The Class Location Change Requirements NPRM, previously an advance notice or proposed rulemaking, proposes amendments, based on feedback from the comment period, to the requirements for gas transmission pipeline segments that experience a change in class location. Under the existing regulations, pipeline segments located in areas where the population density has significantly increased must perform one of the following actions: reduce the pressure of the pipeline segment, pressure test the pipeline segment to higher standards, or replace the pipeline segment. This proposed rule would add an alternative set of requirements operators could use, such as periodic assessment and monitoring based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location.

Q. Does the United States government continue to support PHMSA and the evolution of pipeline safety regulations?

A. Yes. In June 2019, the Department of Transportation began the legislative process for the Pipeline Safety Act reauthorization. The reauthorization is in-progress with bills from both the House and the Senate. The Pipeline Safety Act progress has extended into 2020 and recently passed through the Senate in August 2020. The Pipeline Safety Act is heavily influenced by recent events, including the Merrimack Valley natural gas distribution event which resulted in one loss of life. The proposed act includes numerous components, including: public awareness, community right-to-know information requirements, modernizing data collection through technology; pipeline construction and permitting review; updating reporting thresholds; updating criminal penalties; and expansion of several program requirements including operator qualification requirements; overpressure protection; management of change; and additional distribution and transmission pipeline safety requirements. Timing of approving the Pipeline Safety Act is not specific as it is dependent on passing through the House and Office of Management and Budget approval processes.

VIII. ENHANCEMENT OF COMPLIANCE PROGRAMS, RISK ASSESSMENT, AND IMPACT TO THE COMPANY'S REQUIRED INVESTMENT

Q. Has the Company enhanced or implemented additional Compliance Programs since the last rate case?

A. Yes. Consistent with the continuous improvement requirements of pipeline safety Compliance Programs, and in response to expanding PHMSA pipeline safety regulations, the Company has enhanced its TIMP, DIMP, Facility Damages and OQ and Training Compliance Programs. Additionally, as stated earlier in my testimony, the Company has implemented its SIMP in compliance with the SIMP Final Rule, and its SMS in compliance with PHMSA safety recommendations and industry best practices.

Q. Please describe the evolution of the integrity management programs and asset risk assessment.

A. TIMP was the first pipeline safety program to require asset risk assessment. Transmission risk assessment, which is the evaluation of the likelihood of failure times the consequence of failure for an asset, was focused on specific threats to transmission pipelines located within HCAs. HCAs are areas along the pipeline located around high population density or in proximity of critical facilities such as schools, hospitals or prisons. The results of this risk assessment were used to prioritize pipeline integrity assessments to assess the riskiest top 50% of HCAs by December 17, 2007 and the remaining 50% of HCAs by December 17, 2012. Once baseline assessments were complete, the risk assessment results are used to identify threats outside of HCAs to investigate, remediate, and adjust reassessment intervals for HCA assessments based on changing threat information.

DIMP followed TIMP in implementation of asset risk assessment in 2009. Initially, distribution risk models were simplistic as the regulations were less prescriptive than TIMP regulations and the available data to support likelihood of failure analysis was much less than that for transmission lines due to less stringent record retention and quality requirements. Many operators, including Vectren North, relied upon leak history data and distribution asset location proximity to population to determine risk. A requirement of DIMP is for operators to "know the system" by performing records research, data reconciliation, field investigations and SME interviews. For the first five (5) years of DIMP implementation, a main area of focus for the Company was on data capture and data quality improvements. Once data availability and reliability were improved for distribution assets, the Company launched an initiative to enhance distribution risk assessment by creating asset-based risk models using the additional available data sets to determine likelihood and consequence of failure.

In 2017, to comply with the SIMP Final Rule, the Company implemented its storage asset risk assessment process specific to the threats and causes of failure with storage wells, reservoirs and facilities. The Company has completed validation of the storage asset-based risk models and subsequent model and data enhancements through well-logging assessments, records data mining and SME interviews to improve the data necessary to conduct the storage risk assessment activities. The Company is updating its SIMP risk model and is implementing a revised model in 2020.

As part of the continuous improvement of the integrity management programs, the Company continues to identify enhancements through conducting annual program reviews, effectiveness evaluations, and lessons learned exercises to focus on risk assessment process enhancements and the implementation of best practices across each area of risk.

Q. Please describe the enhancements in gas asset data used for risk modeling and assessment.

A. The Company has focused on gas asset data enhancements through many ongoing initiatives such as adoption of more advanced data analytics tools and enhanced data quality initiatives, including the identification of missing or unavailable data ("gaps"), for risk modeling enhancements. Targeted data improvement areas include distribution asset characteristics, asset location accuracy, field data collection process and quality evaluation, leak data quality evaluation and enhancement, data gap identification and damage prevention data evaluation.

The process for creating and evaluating the effectiveness of asset-based risk models for all asset types includes a data evaluation and validation phase. During that phase, data necessary to support the determination of likelihood and consequence of failure for the model is sourced and aggregated into one complete data set. Conflicts in data are identified and reconciled by developing a conservative set of rules to determine the prevailing value. Gaps are identified, evaluated and mitigated, if applicable, by applying conservative assumptions, interviewing SMEs, performing records research, and field data investigation. Additionally, data gaps where it is impractical to mitigate prior to the necessity of a risk evaluation are escalated in the model output in order to facilitate their impact to overall risk evaluation and prioritize their mitigation. Gap mitigation plans continue to be identified, prioritized and scheduled for continuous ongoing data improvement to support risk assessment.

Q. Has the Company continued to enhance its SMS program elements and processes?

A. Yes. As part of the continuous improvement "plan, do, check and adjust" process of pipeline safety and Compliance Programs, the Company continues to enhance its SMS. The Company continues to hold continuous improvement events with stakeholders representing each of the risk input areas to improve the risk register process, risk ranking, risk mitigation assignment criteria and control testing. The event identified many enhancements to the risk register process that are actively being completed.

Additionally, the Company's SMS implementation requires a MOC process as one of its ten required elements. The MOC process requirements include: (1) maintaining a procedure to identify and execute changes to an operator's programs, policies, and procedures impacting pipeline safety; (2) maintaining a method for identifying potential risks associated with changes; and (3) identifying and obtaining any required approvals prior to implementation of a change. The MOC team has taken responsibility for process enhancements that are being implemented in support of the continuous improvement requirements of SMS. Documentation and recordkeeping;

and competence, awareness, and training process enhancements continue to be re-evaluated.

Q. Please describe the enhancements to the Facility Damages program.

A. Consistent with the Compliance Program evolution to continue to address risk reduction to the Company's gas assets, the Facility Damages program has been enhanced to prevent and mitigate third-party damage incidents. Specifically, the department was expanded to include Damage Prevention Specialists to focus attention on excavators and others working along pipelines and monitor for correct locates and safe digging practices. Additionally, the locator performance management program was enhanced to conduct audits and track metrics associated with accurate, on-time, and root-cause of locates resulting in damages. Training programs and materials were created for locators and excavators to provide on-going education of pipeline safety requirements, safe digging practices, and lessons-learned from damage investigations. These program elements require on-going resources and maintenance per the continuous improvement processes of pipeline safety compliance to support facility damage risk reduction.

Q. Please describe the enhancements to the OQ and Training program.

A. As pipeline safety guidance continued to be issued around OQ and Training programs, many newly published regulations included requirements to enhance the Company's OQ and training programs. Additionally, guidance was received in collaboration efforts with the Commission's Pipeline Safety Division to continue to enhance the robustness of the OQ and Training program PEFs, training material, and tracking. As a result, the Company expanded the number of PEFs for operations and maintenance tasks that require OQ. Specifically, the Company added 32 covered tasks to the OQ and Training program and implemented the training of those tasks over a three-year period. The department was expanded to include a performance evaluator role to support the PEF training and effectiveness evaluation. In response to the training requirements from the SIMP Final Rule, a trainer dedicated to supporting storage operators OQ and performance training was recently added in 2020. As part of the continuous improvement process, the Company continues to investigate efficiencies in tracking and analyzing the required OQ and training metrics as part of the program review requirements.

IX. COMPLIANCE PROGRAM O&M ACTIVITIES WITHIN THE TEST YEAR

Q. Please describe the TIMP O&M compliance activities that make up the costs within the test year.

A. The TIMP activities scheduled to occur in the test year include the on-going integrity assessments, preventive and mitigative measures, and programmatic compliance projects necessary to comply with the transmission integrity management regulations. Specifically, two in-line inspection integrity assessments will be conducted. This includes cleaning the pipeline for inspection and running deformation and metal loss detection tools to detect and evaluate any defects that may be present in the pipelines. Additionally, any defect warranting mitigation resulting from the in-line inspection tool results will be evaluated by direct examination and repaired as necessary. The preventive and mitigative measures scheduled for 2021 include:

- installing pipeline markers to denote MCAs;

- rehabilitating transmission stations;
- monitoring internal corrosion gas constituents;
- evaluating the installation of RCV's to isolate the system in the event of rupture to reduce the consequence of a pipeline safety event;
- maintaining and clearing rights-of-way located in HCA and MCA to support emergency response, additional patrols and aerial leak surveys;
- conducting records research for pipeline, station and appurtenance data, and transmission pressure systems to support the maximum allowable operating pressures ("MAOP") documentation and risk assessment;
- conducting monthly aerial surveys of pipelines to identify potential third-party activity and encroachments;
- researching and managing identified encroachments to the pipeline rights-of-way through the integration of project tracking software and geographical information system ("GIS") updates that improve visibility to the threat;
- communicating to customers and the public regarding safe practices around transmission rights-of-way, integrity management project areas and the safety benefits of conducting an integrity assessment program; and
- responding to emergent integrity threats per the risk assessment process.

The programmatic compliance projects, annual activities required to maintain TIMP program compliance with the pipeline safety regulations, planned for 2021 include activities required to support TIMP annual compliance and comply with the SGTGL Rule. The annual compliance activities include:

- evaluating HCA, MCAs and class locations;
- completing annual regulatory reporting;
- evaluating the changes in asset risk; and

- measuring program effectiveness.

The programmatic activities to comply with the SGTGL Rule include:

- identifying pipelines with deficient traceable, verifiable, and complete pressure test records;
- developing an MAOP reconfirmation program and scheduling pipelines with deficient MAOP records for mitigation, such as pressure testing, pipe replacement, or field investigation;
- developing material verification pipeline testing standards and processes; and
- continuing revisions to the TIMP plan forms and compliance management workflows impacted by the SGTGL Rule additional requirements.

Additionally, the Company is enhancing its transmission asset risk assessment process by implementing a quantitative risk model. PHMSA has urged operators to continue to enhance their risk assessment processes to address threats more thoroughly that have caused recent pipeline failures, such as geotechnical hazards and circumferential cracking. The implementation of the quantitative risk model requires data collection and algorithm development through an iterative tuning process that is planned for 2021. The specific TIMP O&M costs within the test year are based on historical cost analysis and individual project estimates. These O&M costs are included within the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

Q. Please describe the SIMP O&M compliance activities that make up the costs within the test year.

A. The SIMP activities planned for 2021 include conducting well-logging integrity assessment, executing the necessary programmatic compliance activities, and continuing to reduce risk through preventive and mitigative measures. In 2021, the Company plans to prepare 29 wells for well-logging assessment and conduct the integrity assessments. Additionally, any conditions discovered from the well-logging assessments requiring mitigation will be remediated. Programmatic activities including emergency response training, program effectiveness review, risk model enhancements, and implementation of compliance workflow management processes are planned. Additionally, on-going preventive and mitigative measures including data collection on plug and abandoned wells, well monitoring, site inspections, and well-treatments will be completed. Lastly, the Company plans to continue to enhance the OQ and Training requirements to support a competent and qualified workforce executing the storage operations and maintenance tasks. The specific SIMP O&M costs within the test year are based on historical cost analysis and individual project estimates. These O&M costs are included in the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

Q. Please describe the SMS O&M compliance activities that make up the costs within the test year.

A. SMS activities planned to occur during 2021 test year include continuing to collect risks, conducting bow-tie assessments, monitoring the identified process controls, maintaining the risk register, and continuing risk reduction discussions using the governance process. Additionally, activities include reassessing the evolving maturity of the Company's SMS implementation by conducting a safety culture survey, implementing the API Maturity Model and conducting the maturity model assessment. The Company plans to evaluate the SMS implementation using a peer review process.

Third-party SMS certification is also being investigated for the support staff. The SMS O&M costs are included within the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

Q. Please describe the Facility Damages O&M compliance activities that make up the costs within the test year.

A. In 2021, the Damage Prevention program will continue to:

- perform damage investigations and complete the required regulatory reporting;
- implement corrective actions to remediate damages as they occur;
- train excavators and first responders on state and federal pipeline safety laws and best practices;
- conduct job site visits to monitor locator and excavation contractors;
- increase public awareness on pipeline safety damage prevention laws, both state and federal, and safe digging practices;
- maintain the single-point of contact for company related damage prevention inquiries;
- conduct locator quality auditing, metric tracking, and lessons-learned exercises; and
- attend local damage prevention council meetings.

The Facility Damages O&M costs are included within the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

Q. Please describe the OQ and Training O&M compliance activities that make up the costs within the test year.

A. Regarding OQ and Training, in 2021 the Company plans to continue evaluating employee performance of the required covered tasks, manage compliance data and conduct the necessary training to maintain a competent and qualified workforce. The Company estimates over 4,944 performance evaluations will be completed in 2021. The Company will continue to manage and maintain the necessary PEF and training data and complete the required compliance reporting. Additionally, activities include developing additional training simulations and tools for materials, fittings, plastic pipe fusion, welding, destructive testing, and equipment, and training company performance evaluators are planned. The OQ and Training O&M costs are included within the test year O&M expenses in Petitioner's Witness Moore's direct testimony.

X. COMPLIANCE PROGRAM IMPACT ON THE CAPITAL COMPLIANCE PLAN

Q. Does the Company manage the capital Compliance Plan at the project level?

A. No. While the Company endeavors to manage costs at the project level, the Compliance Program requirements drive the plan initiatives, timing and priorities. The capital Compliance Plan is comprised of individual projects driven by the Company's Compliance Programs. The Company reviews costs at the project level, however the Compliance Programs requirements and dynamic risk reduction process drive the plan initiatives, timing and priorities making managing the capital plan at the project level impractical. Many factors contribute to the challenges of managing the capital plan costs at the project level. Mainly, as mentioned previously regarding the O&M costs associated with the Compliance Programs, the Compliance Programs and resulting compliance project activities are focused on risk reduction and are therefore dynamic based on risk assessment process. The risk assessment prescriptive compliance requirements, and continuous improvement actions required by the integrity programs, SMS, and other Compliance Programs are used to create the project scopes and resource plans. The project scopes and resource plans have potential to impact each O&M Compliance Project priority and scope due to the interdependencies. Additionally, risk reduction and compliance driven activities, such as integrity assessments, are interdependent. Examples of interdependencies include the requirement to assess a transmission pipeline by in-line inspection to adequately address the threats resulting in a retrofit project that includes the scope of mitigating exposures identified from the SMS risk identification process. Due to the dynamic nature and interdependencies from the risk reduction process, the Company manages the costs at the Compliance Program level rather than the individual project level.

Q. How are capital projects identified and prioritized within the capital Compliance Plan?

A. Capital projects are identified from performing operations and maintenance activities, construction activities, or evaluations of risk to gas assets from the Compliance Programs, including:

- asset risk assessment,
- integrity assessment findings,
- operations and maintenance findings,
- emergent abnormal operating conditions,
- SMS risk register reports,
- field investigation of threats, and
- construction projects.

Once a potential need for a project is identified, the next step is to determine the project priority first by evaluating whether the project: (1) is an immediate compliance or safety issue to address as soon as possible, or (2) can be scheduled in future years. If the project addresses an immediate compliance or safety issue, the scope for remediation is determined along with a high-level preliminary estimate and the project is submitted for stakeholder discussion to include in the current year work and resource plan. Stakeholders include representatives from gas operations, integrity management, and gas engineering. Certain projects, such as plastic pipe exposures, are determined to nearly always be emergent as they are easily susceptible to failure due to third-party damage. Most projects are determined to not be necessary to address as an immediate compliance or safety issue and are scoped and scheduled using a collaborative process between the integrity management department and gas engineering, coordinating with additional stakeholders to determine the scope of remediation, high-level preliminary estimate, and target year of completion. Many criteria are considered when determining a project scope and schedule, including:

- compliance due dates,
- asset-based integrity management risk score,
- applicable threats,
- asset type,
- vintage,
- pressure,
- in-line inspectability,
- long-lead items or permits,
- material availability,
- system issues or constraints, and

- SME risk information.

Q. How have the enhancements in data collection and data quality impacted asset risk assessment and prioritization of capital projects within the capital Compliance Plan?

A. Individual capital projects make-up the capital Compliance Plan discussed in Petitioner's Witness Hoover's direct testimony. Pipeline safety regulations have required the implementation of enhancements to record quality and retention requirements, data collection, and reporting requirements over time with the most stringent now being the addition of the integrity management programs and asset risk assessment. As those regulations evolved, the Company's data collection processes and data storage methodologies developed organically to meet each additional requirement. This led to gas asset records and data being stored and retained inconsistently and in different locations, systems and to different standards throughout the lifecycle phases of an asset, from scope, design, procurement, construction, operation, maintenance, assessment and retirement.

As gas asset data improvements are made, this data is evaluated and added to the asset-based risk models. During the evaluation phase, trends in data are recognized, such as a change in the frequency of maintenance work orders, damages or failures. These trends are evaluated as part of the integrity management programs and the results are validated with field operations, gas engineering, gas system planning and other personnel familiar with the condition of gas assets. The results of the evaluation may identify additional threat mitigating projects for prioritization in the project scoping, estimating and prioritization process. Significant changes in threats may cause a reprioritization of projects, for example, when a project risk increases, and the project is scheduled to be executed sooner than originally planned to mitigate the higher risk. Additionally, discovery of emergent threats from operations and maintenance activities and the integrity management programs continues to impact the risk model results and project plans. At least annually, risk models are run using the most recent data available and changes in risk are validated and evaluated for mitigation driving the creation or reprioritization of mitigation projects. The improved data is maintained in systems that are accessed for many of the operations, maintenance and construction practices performed by the company leading to more accurate scopes of work, field response, asset locating and system performance monitoring.

Lastly, as pipeline safety incidents continue to occur, PHMSA and the National Transportation Safety Board ("NTSB") issue guidance to operators to enhance their programs to prevent such events. The Company reviews this guidance as it is available and enhances its programs to identify and mitigate pipeline safety risks.

Q. How has the implementation of SMS impacted the capital Compliance Plan?

A. The implementation of the SMS risk register has identified the need for accurate and available gas asset data and records as part of its risk register item analysis. Bowtie analyses and mitigation plans have been created to address the risk register items associated with improving gas asset data and records quality and availability. This has supported a focused data improvement and data governance strategy evaluation through a series of initiatives including a baseline assessment of gas asset data sources, stewards, gap analysis, and data management of change process.

As part of the implementation of the communication plan for SMS, the Company visited each operating center and met with personnel to discuss the elements of a safety management system, the status of implementation, relevant risk register items to the operating center and the status of mitigation of those items, as well as overarching systemic risks and mitigation progress. During those visits, feedback was gathered from personnel that adjusted scores within the risk register, updated mitigation status of items and added items to the risk register. Mitigative actions required to address SMS risks may result in additional projects or the reprioritization of projects within the capital Compliance Plan. Additionally, SMS continues to receive information regarding asset threats during the annual risk register review process. Information collected from this process is passed to the appropriate integrity management department, such as feedback on specific project scopes within the compliance plan, changing operating conditions such as increasing leak severity or frequency, and troublesome working conditions when performing repairs. This department then evaluates the impacted risk factors, compliance project scopes, estimates and prioritization and makes changes to reflect the impact to the asset risk based on operations feedback.

Q. Please describe how the Company determines the type of integrity assessment that is required and how that influences the scope of a project.

A. Integrity assessment methods are determined by their applicability to address the identified threats on the pipeline to be assessed. Certain threats may only be addressed by specific assessment methods. For example, unstable manufacturing and construction threats require pressure testing to determine stability and cased pipe must be assessed by pressure testing or in-line inspection as the casing inhibits the survey methods used for external corrosion direct assessment on the carrier pipe. The TIMP department determines assessment methods by reviewing the results of the threat evaluation performed during the preassessment of the pipeline. Pipeline characteristics, operational and maintenance data are reviewed and evaluated against prescribed threat criteria to determine which threats apply to the pipeline segment. The assessment method is then selected based on the identified threats to the pipeline segment. Regulations prescribe which methods may be used to assess integrity threats per the American Society of Mechanical Engineers ("ASME") B31.8S Managing System Integrity of Gas Pipelines referenced by the integrity management regulations. The assessment methods allowed to address identified threats were modified under the new regulatory requirements set forth in the SGTGL Rule, emphasizing the need to conduct in-line inspection assessments and increasing the need to retrofit the transmission pipelines for in-line inspectability by the next assessment date.

Q. Do the capital projects within the capital Compliance Plan support compliance with TIMP?

A. Yes. Annually, the Company runs the transmission integrity management risk model using the most up-to-date information on assets and evaluates the output to identify any changes in threats to the system, specifically focusing on HCAs scheduled for upcoming assessment. The risk results along with the scheduled assessment methods are reviewed to ensure all identified threats may be addressed by the selected assessment method or if a change in assessment method or a complimentary assessment method is required to address all threats.

Certain assessment methods require preparation work in the form of a capital compliance project, such as retrofitting a pipeline for in-line inspection, removing a pipeline casing and/or pipeline replacement. Once the assessment method is selected to adequately address the identified threats from the preassessment and risk model evaluation, project scopes are created, prioritized and scheduled to facilitate the execution of the assessment method by the compliance due date. To efficiently address the mitigation of risk on the asset to be assessed, the project area is reviewed for additional compliance work and the scope is expanded to address that work at the same time. For example, the mitigation of exposures will be included in the project scope to retrofit a pipeline for in-line inspection as it is the most efficient use of resources to address the work at the same time with the same crew and eliminate the need for an additional outage on the system.

Q. Can the Company's risk assessment process and the type of threat that is being assessed that requires modification of existing infrastructure also result in new or additional capital projects within the capital Compliance Plan?

A. Yes. Many of the capital projects are performed to support the required assessment of transmission pipelines within HCAs, and now MCAs. As a result, the scope of some projects may be adjusted to allow for the completion of the assessments. Project schedules may be altered as assessments identify areas within our system that require immediate mitigation. The effectiveness of in-line inspection runs may drive additional areas of modification that are necessary to continue to make the Company's transmission system in-line inspection compatible. Equipment installation to comply with integrity threat monitoring requirements may also be necessary, such as gas chromatograph installation to monitor threats related to gas quality and composition. Finally, more frequent inspections and patrols may identify additional threats to be mitigated through compliance projects.

Additionally, the Company has been working on validating its MAOP data to support the SGTGL Rule requirement to assess pipeline MAOPs for complete, traceable and verifiable pressure test records. Without such records, the Company could be forced to shut down its pipeline operation. Beginning in 2020, project scopes are being reviewed to ensure compliance with the requirements for MAOP reconfirmation and material property verification set forth in the recently published SGTGL Rule effective July 2020.

Q. Has the Company updated its Transmission Modernization capital Compliance Plan as a result of continued risk assessment?

A. Yes. Projects on the Transmission Modernization capital Compliance Plan have been reprioritized and adjusted as a result of assessing the output of our risk models based on new information about our systems, assets, operational issues, growth to our system, external timing requirements and input resulting from completed projects. Risk models are updated annually to reflect the new information, which drives an evaluation and adjustment of the capital projects. The updated risk results identify new projects and change the scope, timing and prioritization of other projects. Further discussion on the capital projects driven from the risk assessment process is included in the direct testimony of Petitioner's Witness Hoover.

Q. Can the results of storage risk analysis and assessment impact the Storage Capital Plan?

A. Yes. Similar to how the transmission integrity risk analysis and assessment processes impact the scope and prioritization of existing projects and identify threats requiring emergent capital projects, so too does the SIMP risk assessment process. The

Company conducted a baseline risk assessment for storage assets in 2017 to establish the priority of capital projects within the plan. The risk assessment is updated at least annually, and additional information is incorporated based on operations and maintenance activities, well-logging assessments and data mining. The risk results are used to confirm or adjust the prioritization of projects within the schedule to ensure the highest risks are addressed first. The risk analysis results and findings from the well-logging assessments are further evaluated at least annually to ensure emergent capital projects are scoped and scheduled if they are necessary to remediate threats and findings discovered through the assessment process. Additionally, the Company has identified through its reservoir analysis and storage operations well-logging feasibility analysis, modifications necessary to complete well-logging assessments or monitor existing threats. The Company continues to complete well-logging assessments to establish a baseline of integrity conditions for each well. This information contributes to the change in risk assessment and drives the well-remediation activities and prioritization. The site preparation, well modification and remediation projects flow through the ongoing process of scoping, estimating and prioritizing within the storage capital plan as discussed in Petitioner's Witness Hoover's direct testimony and attachments.

Q. Has the Company updated its capital Compliance Plan as a result of continued SIMP risk assessment?

A. Yes. As results are available from integrity assessments and well-logging, remediation activities are identified and prioritized. These activities include the plug and abandonment of certain wells with severe corrosion defects and the installation of casing liners to remediate less severe integrity conditions. Also, the loss of capacity to inject and withdraw from the storage field due to well integrity remediations such as abandoning and retiring a well from service may drive the need to construct a new well to regain the capacity. The impact to the capital project plan is discussed further in Petitioner's Witness Hoover's direct testimony.

XI. CONCLUSION

Q. Please summarize your position on the Company's integrity management programs and related compliance projects.

A. Pipeline safety regulations require the Company to develop and implement integrity management programs for its transmission, distribution and storage systems. The regulations require that the integrity management program include specific elements, that the Company assess threats to pipeline integrity and that the Company take action to remediate or mitigate such threats. The Company has developed such programs and plans, conducted the assessments in a manner consistent with the regulations, and has undertaken specific projects to manage pipeline integrity. All of this has been performed under the oversight of, and in cooperation with, the IURC Pipeline Safety Division.

Q. Please summarize your position on the timing of the O&M and capital expenditures required by the integrity management programs.

A. The Company's management of pipeline integrity prior to the implementation of 49 C.F.R. 192 subparts (O) and (P) and the Storage Integrity Final Rule was consistent with applicable regulations and was based on sound engineering practices and standards. For many years the Company has been monitoring asset integrity, performing necessary repairs and replacing higher-risk facilities. The integrity management projects discussed in my testimony represent an acceleration of pipeline integrity expenditures in order to comply with the prescriptive and evolving integrity management regulations based on the Company's knowledge and experience from designing, constructing, operating, and maintaining its system.

Q. Do you have a final summary?

A. Yes. The Company's integrity management programs, related integrity management projects, and project schedules are reasonable. The costs associated with the integrity management programs are directly related to the safe operation of the transmission distribution and storage systems, in compliance with state and federal law, and should be recovered from ratepayers as requested in this rate case.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

CAUSE NO. 45468

VERIFICATION

I, Sarah J. Vyvoda, affirm under the penalties of perjury that the forgoing representations of fact in my Direct Testimony are true to the best of my knowledge, information and belief.

Sarah J. Vyvoda

Sarah J. Vyvoda

Dated: December 18, 2020

Gas Transmission Integrity Management

GTIM-Plan

2020.1

Table of Content

Appendices

<<END>>

GTIM-01-002 Identification of Consequence Areas

PURPOSE: To provide a standardized approach for determination of High Consequence Areas (HCA) and Moderate Consequence Areas (MCA).

REFERENCES: 49 CFR 192.903; 49 CFR 192.905; 49 CFR 192.951; 49 CFR 192 Appendix E;

SECTIONS:

- General
- Site Information
- Determination of Consequence Areas
- Documentation

1.0 GENERAL

1.1 *High Consequence Areas* are identified using either Method 1 or Method 2 as defined in 49 CFR 192.903.

An area established by one of the methods described below:

(Method 1) An area defined as:

(i) A Class Location 3 under 49 CFR 192.5; or

(ii) A Class Location 4 under 49 CFR 192.5; or

(iii) Any area within a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet, and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) The area within a potential impact circle containing an identified site.

(Method 2) The area within a potential impact circle containing

(i) 20 or more buildings intended for human occupancy, unless prorated as described in paragraph 4 of the definition in §192.903 applies; or

(ii) An identified site.

1.1.1 CNP utilizes Method 2 for determining High Consequence Areas except for TX pipeline systems; TX uses Method 1.

1.1.2 As a prudent operator, CNP exercises judgment in HCA determination, and at times, may conservatively designate a non-HCA pipeline segment as an HCA.

1.1.3 During the initial HCA identification process, Local Operations were able to provide or gather thorough information on Identified Sites.

1.1.3.1 CNP solicited feedback in a good-faith effort to gather information from Public Officials during its initial HCA identification as required by 49 CFR Part 192. CNP found that Public Officials gave limited feedback and therefore developed methods for collecting the information more reliably and consistently.

1.1.3.2 CNP engages with public officials through its design and construction, land services, and encroachment management activities to gather knowledge of activity occurring around transmission pipelines.

1.2 *Moderate Consequence Areas* are areas outside of HCAs that have a PIR containing either:

- Five or more buildings intended for human occupancy; or
- Any portion of the paved surface, including shoulders, of a designated interstate, freeway, or expressway, as well as any other principal arterial roadway with four (4) or more lanes[1].

Note: CNP may choose to add a buffer distance to the Potential Impact Radius (PIR) calculation to compensate for centerline inaccuracies and assess HCAs and MCAs conservatively.

The buffer distance may be decreased or eliminated as the accuracy of centerline data improves or when field measurements, from the pipeline centerline to the Identified Site, are recorded for the line segments.

2.0 SITE INFORMATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Annually perform a transmission pipeline HCA and MCA evaluation. Review for:

- Visual markings and signs indicating a new or changed identified site information; and
- New construction within 220 yards (200 meters) of the pipeline.

2.1.2 Incorporate additional information on Identified Sites within 660 feet of pipeline center as appropriate from sources including but not limited to:

- Normal operating and maintenance activities;
- Feedback from Local Operations;
- Aerial photographs;
- Public Officials with safety or emergency response or planning responsibilities;
- Geospatial analyses;
- Work orders;
- Assessment documentation; and
- Third-Party providers.

2.1.3 Create a work order to correct HCA and MCA or structure attributes in GIS.

Note: Incorporate new HCAs and MCAs into the assessment schedule calendar within one (1) year of discovery.

3.0 DETERMINATION OF CONSEQUENCE AREAS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Review and confirm information that could affect HCA and MCA determination:

- PIR;
- MAOP changes;

[1] As defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1; https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf.

- Diameter changes;
- De-rating or up-rating of the pipeline;
- Commodity changes;
- New pipeline installation;
- Pipeline reroutes or removal;
- Pipe centerline corrections;
- New construction within the ROW;
- Changes in use of existing dwellings and structures;
- Changes in occupancy of existing dwellings and structures;
- Removal or abandonment of existing dwellings and structures;
- Paved arterial roadway with four (4) or more lanes, freeway, interstate, or expressway including shoulders; and
- Expansion of existing roadways.

3.1.2 Annually determine the extents of the HCA or MCA.

3.1.2.1 Confirm GIS updates are complete before continuing with this determination.

3.1.2.2 Using the appropriate geospatial tools, execute the determination of HCAs and MCAs.

3.1.2.2.1 For HCA identification: An algorithm determines the areas of consequence by calculating the PIR using the formula listed in GTIM-14-001 “Glossary”.

3.1.2.2.2 For MCA identification: An algorithm determines the areas of consequence by calculating the impact areas with building structures and roads per the definition of MCA listed in GTIM-14-001 “Glossary”.

3.1.2.3 Follow the CNP Integrity Management processes for determination and updating HCA and MCA locations.

4.0 DOCUMENTATION

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Record the changes to HCA and MCA extents in GIS or another appropriate database.

4.1.2 Record new HCAs and MCAs; include the following information:

- Segment name and description;
- Pipe diameter;
- MAOP;
- Location of HCA or MCA;
- Description of HCA or MCA;
- HCA or MCA extents;
- PIR;
- Buffer, if any;
- Discovery date; and
- Determination method.

4.1.3 Create a work order to incorporate all HCA and MCA information into GIS or other appropriate tracking databases.

4.1.3.1 Spot check GIS updates to confirm that changes are integrated and correct.

4.1.4 Report any new or modified HCAs and MCAs to the GTIM Manager for assignment and scheduling of assessments in the appropriate assessment calendar.

4.1.5 Document HCAs and MCAs on GTIM-90102 “HCA Survey Worksheet”.

- Total HCA footage for each operating company;
- Total HCA footage for interstate pipelines (e.g., Kentucky);
- Total HCA footage for the CNP system;
- Total MCA footage for each operating company;
- Total MCA footage for interstate pipelines (e.g., Kentucky); and
- Total MCA footage for the CNP system.

4.1.5.1 GTIM-90102 is a cumulative worksheet. Append data to the previous year’s documentation.

4.1.6 Maintain historical HCA and MCA information for the life of the pipeline system.

4.1.6.1 Annually export a file of the HCAs and MCAs recorded in GIS or another appropriate database.

4.1.6.2 Archive the exported file in the appropriate IM file with a timestamp.

4.1.6.3 Prepare maps of the HCA and MCA extents and should include, at a minimum, the following:

- The preparer of the map;
- Date prepared;
- Description of the pipeline segment;
- Aerial photograph backgrounds with creation date;
- Pipe location accuracy;
- PIR;
- Buffer, if any; and
- HCA or MCA identifier.

4.1.6.4 Archive the maps in the appropriate IM file.

4.2 Responsibility: GTIM Engineer or designee

4.2.1 Annually, schedule a meeting with all stakeholders to confirm the addition of new HCAs and MCAs on the appropriate assessment schedule calendar.

4.2.1.1 During this meeting, review the assessment schedule calendar to identify new transmission lines to be evaluated for HCAs and MCAs.

4.2.1.2 Update the Revision History of the assessment schedule calendar.

4.2.1.3 Create a Change Management entry documenting the review of the assessment schedule calendar.

<<END>>

GTIM-02-001 Data Gathering and Research

PURPOSE: To establish a standardized method for gathering pipeline data.

REFERENCES: 49 CFR 192.917; ASME/ANSI B31.8S-2004, Section 2.3; NACE SP0502-2010;

SECTIONS:
- Background
- Preparation
- Data Gathering
- Documentation

1.0 BACKGROUND

1.1 The gathering of pipeline information related to its physical pipeline characteristics and attributes, construction circumstances and methods, current class location, operation and maintenance activities, tests, inspections, established MAOP, and other events, features, and external data as necessary for the assessment of risk and for performing integrity assessments.

Note: This procedure deals with large-scale data collection efforts, including the continual integration of data from Integrity Management activities and processes. For pipeline segments not documented with traceable, verifiable, and complete (TVC) records, consider opportunistic methods for obtaining the required data element information.

2.0 PREPARATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Identify the pipeline segments to evaluate.

2.1.2 Define the scope of the data gathering.

2.1.2.1 Define the scope of data gathering using example data element tables in industry-standard documents, such as ASME/ANSI B31.8S-2004 and NACE SP0502-2010.

2.1.3 Based upon the scope, prepare a data collection template (i.e., GTIM-90300 “Data Collection Form”.

2.1.3.1 Consider the following when preparing a data collection template, including, but are not limited to:

- A checklist to document and track the data sources;
- Material information;
- Construction and installation information;
- Corrosion control history;
- Operating data;
- Leak and failure data;
- Prior assessment data;
- Repair and maintenance activities;
- Gas Quality records;

- Recent industry incidents;
- Facility Damage records (e.g., Third-Party, Weather, soil stability, seismic events, etc.); and
- Encroachment incidents.

2.1.3.2 The use of other data collection templates requires the approval of the GTIM Manager.

2.1.4 Assign personnel to the Data Collection Team.

2.1.5 Provide the data collection form to the Data Collection Team.

3.0 DATA GATHERING

3.1 Responsibility: Data Collection Team

3.1.1 Using available data, identify segments for each pipeline. Segments may be defined based on work orders, coating type, diameter, etc.

3.1.1.1 Correlate the segment identification with the appropriate databases.

3.1.2 Complete a Data Collection Form for each segment.

3.1.3 Perform research of records and files to locate any missing data.

3.1.3.1 Sources of data may include, but are not limited to:

- Work orders;
- Maintenance orders;
- Pipeline system maps;
- O&M forms (i.e., incident reports, safety-related condition reports, pipe exams, etc.);
- 3rd party service provider reports/data;
- One-Call records;
- Subject Matter Experts;
- Material requisition sheets;
- Field/hand-written notes;
- Material certifications;
- Assessment records;
- Design/engineering reports;
- Technical evaluations; and
- Manufacturer equipment data.

3.1.4 Document any data assumption made on the Data Collection Form and include the rationale for each assumption.

3.1.5 For each data element, make a copy of the root source of information.

3.1.6 If consulting a Subject Matter Expert, document:

- His or her name;
- Current job title; and
- Date interviewed.

4.0 DOCUMENTATION

4.1 Responsibility: Data Collection Team

4.1.1 Create a data packet for each segment. Include copies of root source information and the Data Collection Form.

4.1.2 If data gathered from a prior assessment requires revision during a current Pre-Assessment, complete a new page 1 for the GTIM-90300.

4.2 Responsibility: GTIM Engineer or designee

4.2.1 Integrate the data according to GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

4.2.2 Retain completed data packets for the life of the pipeline system.

<<END>>

GTIM-02-003 MAOP Origination

PURPOSE: To establish a standardized method for determining the Maximum Allowable Operating Pressure (MAOP) for pipeline segments for inclusion in the IM Program.

REFERENCES: 49 CFR 192.619; 49 CFR 192 Subpart J; 49 CFR 192 Subpart K; ASME/ANSI B31.8-2007;

SECTIONS:

- General
- Preparation
- Determining the Design Pressure
- Determining with Test Pressure
- Determining with Historical Operating Pressure
- Determining with "Grandfather" Clause *(obsolete)*
- Additional Considerations
- Determining the MAOP
- MAOP Changes and Updates

1.0 GENERAL

1.1 49 CFR 192 requires establishing a Maximum Allowable Operating Pressure (MAOP) for each distinct segment of a pipeline.

1.1.1 CNP does not, as a standard operating condition, operate pipelines that exceed the established MAOP.

1.2 CNP retains records used to establish the MAOP of each pipeline segment for the life of the pipeline.

1.2.1 Beginning July 1, 2020, all records used in the establishment of a segment's MAOP, will be documented with traceable, verifiable, and complete (TVC) records, including the segment's characteristics and attributes, (i.e., including diameter, wall thickness, seam type, and grade) and component ratings (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.).

1.2.1.1 GTIM-14-001 "Glossary" contains definitions for Traceable Records, Verifiable Records, and Complete Records.

1.3 Any pipeline segment without a TVC documented MAOP requires MAOP reconfirmation per GTIM-02-004 "MAOP Reconfirmation".

1.4 CNP does not utilize any alternative MAOPs outlined in 49 CFR 192.620.

2.0 PREPARATION

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Identify the pipeline segments for evaluation.

2.1.1.1 Applicable, are segments with (TVC) records for pipe and component material properties, with new information.

2.1.2 Verify the following minimum data is available:

- Outside pipe diameter;
- Wall thickness;

- The manufacturing process of pipe (seam type);
- Test pressure;
- Temperature;
- Class location;
- Pipe grade or Specified Minimum Yield Strength; and
- Pressure ratings of pipeline appurtenances.

2.1.2.1 As necessary, collect additional information per procedure GTIM-02-001 “Data Gathering and Research”.

2.1.2.2 Include a GTIM-90201 “MAOP Origination” form for each segment or system to calculate the MAOP.

2.1.2.2.1 Obtain the copy from previously created MAOP documentation, and update with current or additional information, as necessary.

2.1.2.2.2 If a previous copy does not exist, create a document for each segment or system.

3.0 DETERMINING THE DESIGN PRESSURE

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Determine the Design Pressure for steel pipe components using the following design formula:

$$P = \left({}^{(2 \times S \times t)}/_{D} \right) \times F \times E \times T$$

where:

P = Design pressure in pounds per square inch gauge *(psig)*
S = Specified minimum yield strength (SMYS) of material *(psi)*
t = Nominal wall thickness of the pipe *(inches)*
D = Outside diameter of the pipe *(inches)*
F = Design factor based on Class Location of the pipeline as given in the following table:

Table 02-003-1: Derived from ASME/ANSI B31.8-2007, Table 841.1.6-1 Basic Design Factor

Class Location	Design Factor *(F)*
1	0.72
2	0.60
3	0.50
4	0.40

E = Longitudinal joint factor:

1.00 *(for seamless, electric resistance welded, submerged, or double submerged arc welded, electric fusion welded, and electric flash welded pipe)*

0.60 *(for furnace butt welded pipe and “other joint types” in pipe 4-inches or less outside diameter)*

0.80 *(for “other joint types” in pipe over 4-inches outside diameter)*

0.60 *(for pipe 4-inches or less outside diameter if longitudinal joint type cannot be determined)*

0.80 *(for pipe over 4-inches outside diameter if longitudinal joint type cannot be determined)*

T = Temperature derating factor:

1.000	*(for gas temperature of 250˚F or less)*
0.967	*(for gas temperature of 300˚F)*
0.933	*(for gas temperature of 350˚F)*
0.900	*(for gas temperature of 400˚F)*
0.867	*(for gas temperature of 450˚F)*

(For intermediate temperatures, determine the derating factor by interpolation.)

3.1.1.1 Enter the design pressure for steel pipe on line A.1 of GTIM-90201 "MAOP Origination".

3.1.1.1.1 Where more than one calculated pressure exists for a system, enter the lowest value.

3.1.1.1.2 Attach the calculation(s) showing all information to GTIM-90201.

3.1.2 Determine the design pressure for "other components". Other components may include but are not limited to:

- Valves;
- Flanges;
- Fittings;
- Mechanical couplings;
- Leak clamps;
- Instruments;
- Odorizers;
- Overpressure protection devices; and
- Regulators.

3.1.2.1 Determine the design pressure for other pipeline system components from sources such as:

- ANSI[1] (formerly ASA[2]);
- ASTM[3] (e.g. D2513, D2517);
- ASME[4];
- MSS[5];
- Similar class designations;
- Manufacturer's specifications; and
- Literature.

3.1.2.1.1 Retain copies of all information for each type of component installed.

3.1.2.2 Attach a separate sheet to GTIM-90201 and list the design pressure for each type of component, as necessary.

[1] American National Standards Institute.
[2] American Standards Association.
[3] American Society for Testing and Materials.
[4] American Society of Mechanical Engineers.
[5] Manufacturers Standardization Society of the Valve and Fittings Industry, Inc.

3.1.2.3 Enter the lowest pressure on the appropriate line (A.2 through A.12) of GTIM-90201.

3.1.2.3.1 For components not installed, indicate “N/A”.

3.1.2.3.2 For system components where the design pressure rating cannot be determined, show as “unavailable” on GTIM-90201.

3.1.2.3.2.1 When any system component is “unavailable”, determine and execute an action plan to perform additional evaluations.

3.1.2.3.3 Notify GTIM Manager.

Note: Pay special attention to pressure regulators. Use the inlet pressure rating – this will vary depending upon orifice size.

4.0 DETERMINING WITH TEST PRESSURE

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Determine if the line has been pressure tested to 49 CFR 192 Subpart J requirements.

4.1.1.1 Applicable test reasons:

- Conducted after initial construction;
- Laterals;
- Services connected to the original pipe; and
- Replacement pipe.

4.1.1.1.1 The lowest test pressure from any of the above tests determines the MAOP.

4.1.1.1.2 Attach records for all the above tests to GTIM-90201.

4.1.1.2 For steel pipe, divide the test pressure by the factor from the following table:

Table 02-003-2: 49 CFR 192.619(a)(2)(ii) Table 1

		***Factor** *(F) (or an onshore segment)*		
Class Location	**Installed before (Nov. 12, 1970)**	**Installed after (Nov. 11, 1970) and before July 1, 2020**	**Installed on or after July 1, 2020**	**Converted under 49 CFR 192.14**
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

***** For offshore pipeline segments installed, uprated, or converted after July 31, 1977, and not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated, or converted after July 31, 1977, and located on an offshore platform or a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

4.1.1.2.1 Enter the lowest value on GTIM-90201 line B.1.

4.1.1.3 Confirm documentation of the pressure test(s) date(s).

4.1.1.4 With multiple pressure tests, work with the most recent test results.

4.1.1.5 Attach a record of the pressure test to GTIM-90201.

4.1.1.5.1 Enter “unavailable” on the GTIM-90201 and explain on an attachment, if a record of a pressure test is unlocatable.

4.1.1.5.2 Determine and execute an action plan to perform additional evaluations when a record is unlocatable.

4.1.1.5.3 Notify GTIM Manager.

5.0 DETERMINING WITH HISTORICAL OPERATING PRESSURE

5.1 Responsibility: GTIM Engineer or designee

Note: Pay special attention to pressure regulators. Use the inlet pressure rating – this will vary depending upon orifice size.

5.1.1 Review records (i.e., pressure charts, regulator station inspection reports showing inlet or outlet pressures, telemetry data, or similar) to determine the highest operating pressure between July 1, 1965, and July 1, 1970.

5.1.1.1 If no records are available, a notarized statement attesting to the operating pressure during that period by a person in charge of pipeline operations may be acceptable at the discretion of the regulatory agencies that have jurisdiction.

5.1.2 Enter the highest historical operating pressure on GTIM-90201 line C.1.

5.1.3 The historical operating pressure limit on MAOP may be overridden by:

- A pressure test conducted after July 1, 1965, or
- An uprating in compliance with 49 CFR 192 Subpart K;
  - The most recent pressure test or uprating controls.

5.1.3.1 Complete a new MAOP Origination GTIM-90201 for the applicable segment or system with the new parameters whenever one of these activities takes place.

6.0 DETERMINING WITH “GRANDFATHER” CLAUSE (OBSOLETE)

6.1 The use of the ‘Grandfather’ clause is obsolete.

6.1.1 The ‘Grandfather’ clause allowed setting the MAOP for transmission pipeline segments based on historical pressures, even if that pressure exceeded the design pressure rating. See §192.619(a)(3).

6.2 PHMSA requires MAOP Reconfirmation for all pipeline segments currently utilizing the grandfather clause for MAOP determination. MAOP Reconfirmation activities will occur before July 2, 2035.

7.0 ADDITIONAL CONSIDERATIONS

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Review all criteria used to determine the MAOP.

7.1.2 Determine if a lower pressure due to safety considerations is warranted. Consult with Gas Control and Gas Supply.

7.1.2.1 Safety considerations include, but are not limited to:

- History of Leaks;
- Corrosion issues;
- Equipment problems; and
- %SMYS reduction.

7.1.2.2 As appropriate, set the MAOP at the value that is considered the maximum safe pressure.

7.1.2.3 Enter this value on GTIM-90201, line E.1 and attach documentation rationalizing the reason for the lower pressure.

7.1.2.3.1 This pressure must be less than that determined from section 3.0 “Determining the Design Pressure”, section 4.0 “Determining with Test Pressure”, and section 5.0 “Determining with Historical Operating Pressure”.

8.0 DETERMINING THE MAOP

8.1 Responsibility: GTIM Engineer or designee

8.1.1 After determining the appropriate pressure limit in each category, select the lowest value from GTIM-90201 lines A.13, B.1, C.1, D.1, and E.3 as the MAOP.

8.1.2 Enter this pressure on line F.1 of GTIM-90201.

8.1.3 Sign and date the GTIM-90201 and attach all support documents.

8.1.3.1 Include supporting documentation for all categories reviewed.

8.1.4 Store this file for the life of the pipeline or system.

8.1.5 Review the segment(s) MAOP(s).

8.1.6 Determine the system MAOP based upon the lowest segment MAOP in that system.

9.0 MAOP CHANGES AND UPDATES

9.1 Responsibility: Gas Transmission Engineering or Local Operations or designee

9.1.1 As new information becomes available, provide the GTIM Engineer a copy of all records.

9.1.1.1 New information includes:

- New maintenance records;
- Pressure tests;
- Updated as-builts;
- Upratings; and
- New projects.

9.2 Responsibility: GTIM Engineer or designee

9.2.1 Review provided information from other departments to determine if MAOP changes are merited.

9.2.2 When merited, establish the new MAOP utilizing GTIM-02-004 “MAOP Reconfirmation”.

9.2.2.1 Complete a new GTIM-90201 “MAOP Origination” for the applicable segment or system with the new parameters whenever one of these activities takes place.

9.2.3 Communicate all MAOP changes to all applicable departments including, but not limited to:

- Engineering;
- Local Operations; and
- Gas Control.

<<END>>

GTIM-02-004 MAOP Reconfirmation

PURPOSE: To establish a method for reconfirming the Maximum Allowable Operating Pressure (MAOP) of all applicable transmission pipeline segments per 49 CFR 192.624.

REFERENCES: 49 CFR 192.624;

SECTIONS:

- General
- Planning and Scheduling
- Reconfirmation Method Selection
- MAOP Reconfirmation Methods
- Reconfirmation Plan Review
- Documentation

1.0 GENERAL

1.1 PHMSA requires the MAOP Reconfirmation of all applicable pipeline segments within an onshore steel transmission pipeline system per §192.624. Specific activities include:

1.2 Completion of all MAOP Reconfirmation activities according to the following schedule:

- Develop and document a plan for completing all MAOP Reconfirmation actions by July 1, 2021.
- Include a schedule for tracking the completion of at least 50% of the pipelines' mileage by July 3, 2028, and 100% by July 2, 2035.
- Completion of all MAOP Reconfirmation activities should occur as soon as practicable or within four (4) years after meeting a condition of §192.624(a), whichever is later.

Note: If operational and environmental constraints limit CNP's ability from meeting the above deadlines, CNP may petition for an extension of the completion deadlines by up to one (1) year by submitting a request to PHMSA per GTIM-13-001 "Required Notifications to Regulatory Agencies".

2.0 PLANNING AND SCHEDULING

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Review the Pressure Testing and Material records of all pipeline segments using the most current HCA, MCA, and Class Location data to determine applicability.

2.1.1.1 Applicable pipeline segments include:

- Segments without traceable, verifiable, and complete (TVC) records, located in a High Consequence Area (HCA), or in Class 3 or Class 4 location; and
- Segments currently utilizing the 'grandfather clause' for MAOP determination, which are greater than or equal to thirty percent (30%) of the Specified Minimum Yield Strength (SMYS), and located in one of the following areas:
  - A High Consequence Area (HCA);
  - A Class 3 or Class 4 location; or
  - A Moderate Consequence Area (MCA) that accommodates inspection using instrumented inline inspection tools.

2.1.1.2 Material properties and attribute records include:

- Diameter;
- Wall thickness;
- Grade (i.e., Minimum Yield Strength (SMYS), Ultimate Tensile Strength (UTS)); and
- Seam type.

2.1.1.3 Add applicable pipeline segments to the MAOP Reconfirmation plan and include the following details:

- Pipeline name;
- Applicable pipeline segment extents;
- Estimated segment mileage;
- Reason for performing reconfirmation; and
- Date of discovery, if after July 1, 2020.

2.1.2 Create a schedule prioritized by risk after identifying all applicable pipeline segments.

2.1.3 Indicate 50% of the total mileage for MAOP Reconfirmation completion before July 3, 2028.

3.0 RECONFIRMATION METHOD SELECTION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Consider the following factors when selecting the MAOP Reconfirmation method:

- Availability or feasibility of required equipment (i.e., pig launchers and receivers, in-line inspection tool capabilities, and availability);
- System constraints;
- Budgetary constraints;
- Time constraints;
- Stakeholder input and recommendations;
- Opportunistic testing (i.e., bundling with other planned integrity or O&M work); and
- Customer impact.

3.1.2 Evaluate the suitability of each method described in the next section, including the benefits and limitations associated with each method. Refer to GTIM-03-001 “Assessment Method Selection”, and other method selection documentation for guidance.

3.1.3 For each identified pipeline segment in the plan, select a recommended method of reconfirmation and consult with stakeholders to finalize the selection, then add the following to the plan.

- The recommended reconfirmation method;
- Stakeholder input and recommendations;
- Material verification requirements (note opportunistic and planned material testing);
- Any opportunities to bundle reconfirmation with other planned capital or O&M work on the pipeline segment(s) such as proximity, planned replacement, modification, or improvement projects, or scheduled integrity assessments; and
- The planned reconfirmation year.

4.0 MAOP RECONFIRMATION METHODS

4.1 Responsibility: GTIM Engineer or designee

Note: MAOPs established using Method 2, or Method 5 allows future uprating of the pipeline segment per Subpart K.

4.1.1 *Method 1 - Pressure Testing*. Method 1 consists of performing a Subpart J Pressure Test and verifying material properties records per the following requirements:

4.1.1.1 Conduct a Subpart J Pressure Test where the MAOP is equal to the test pressure divided by the greater of either 1.25 or the relevant class location factor in Table 04-004-1 below.

4.1.1.2 Determine if TVC records for material properties supporting diameter, wall thickness, seam type, and grade exist.

4.1.1.2.1 If any of the above material properties lack TVC records, during the Pressure Test work, obtain the missing records by applying the appropriate testing or sampling requirements to establish TVC records per GTIM-02-010 “Material Verification” as soon as practical.

4.1.1.2.2 Test the line pipe materials cut out from the test manifold sites at the time of the pressure test.

4.1.1.2.3 If the pressure test fails, test any removed pipe from the failure location per the requirements of GTIM-02-010 “Material Verification”.

Table 02-004-1: Class Location Factor for MAOP Determination

		Factors*, segment--		
Class Location	**Installed before (Nov. 12, 1970)**	**Installed after (Nov. 11, 1970) and before July 1, 2020**	**Installed on or after July 1, 2020**	**Converted under §192.14**
1	1.10	1.10	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.40	1.50	1.50	1.50
4	1.40	1.50	1.50	1.50

* For offshore pipeline segments installed, uprated or converted after July 31, 1977, and not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated, or converted after July 31, 1977, and located on an offshore platform or a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

4.1.2 *Method 2 - Pressure Reduction*. Method 2 consists of limiting the pipeline segment to an MAOP of no greater than the highest actual operating pressure[1] sustained by the pipeline during the five (5) years preceding October 1, 2019, divided by the greater of 1.25 or the relevant class location factor in Table 02-004-1, by reducing pressure as necessary.

[1] The highest actual sustained pressure reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment, or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location). Referenced as “historical pressure” for the remainder of this procedure.

4.1.2.1 For pipeline segments with a class location change, determine if TVC records for material properties supporting diameter, wall thickness, seam type, and grade (minimum yield strength and ultimate tensile strength) exist.

4.1.2.1.1 If TVC records do not exist, reduce the pipeline segment MAOP as follows to:

- For location changes from Class 1 to Class 2, divide the historical pressure by 1.39.
- For location changes from Class 2 to Class 3, divide the historical pressure by 1.67.
- For location changes from Class 3 to Class 4, divide the historical pressure by 2.00.
- For location changes from Class 1 to Class 3, divide the historical pressure by 2.00.

4.1.2.2 When considering a less conservative pressure reduction factor or a longer look-back period, the operator must notify PHMSA per GTIM-13-001 “Required Notifications to Regulatory Agencies” no later than seven (7) calendar days after establishing the reduced MAOP.

4.1.3 *Method 3 - Engineering Critical Assessment (ECA)*. Conduct Method 3 according to GTIM-02-006 “Engineering Critical Assessment (ECA)”.

4.1.4 *Method 4 - Pipe Replacement*. Replace the pipeline segment.

4.1.5 *Method 5 - Pressure Reduction for Pipeline Segments with Small Potential Impact Radius*. Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP by:

- Reducing the MAOP to the historical pressure divided by 1.1;
- Conducting patrols to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation per O&M 17.34 “Transmission Line Patrols” or CNP O&M XVII-A “Patrolling/Transmission Lines”; and
- Performing leakage surveys per O&M 17.33 “Transmission Line Leak Survey” or CNP O&M XIX “Leak Surveys/Transmission Lines” at intervals not to exceed those in Table 02-004-1.

Table 02-004-2: §192.624(c)(5)(ii) Table 1

Class Locations	Patrols	Leakage Surveys
(A) Class 1 and Class 2	3½ months, but at least four (4) times each calendar year	3½ months, but at least four (4) times each calendar year
(B) Class 3 and Class 4	3 months, but at least six (6) times each calendar year	3 months, but at least six (6) times each calendar year

4.1.6 *Method 6 - Alternative Technology*. Method 6 allows for the use of an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. When electing to use an alternative technology, provide notification to PHMSA per GTIM-13-001 “Required Notilfications to Regulatory Agencies”.

5.0 RECONFIRMATION PLAN REVIEW

5.1 Responsibility: GTIM Engineer or designee

5.1.1 At least annually, review the most current HCA, MCA, and Class Location data to determine applicability.

5.1.1.1 Applicable pipeline segments include:

- Segments without traceable, verifiable, and complete (TVC) records, located in a High Consequence Area (HCA), or in a Class 3 or Class 4 location; and
- Segments currently utilizing the 'grandfather clause' for MAOP determination, which are greater than or equal to thirty percent (30%) of the Specified Minimum Yield Strength (SMYS), and located in one of the following areas:
  - A High Consequence Area (HCA);
  - A Class 3 or Class 4 location; or
  - A Moderate Consequence Area (MCA) that accommodates inspection using instrumented inline inspection tools.

5.1.1.2 Material properties and attribute records include:

- Diameter;
- Wall thickness;
- Grade (i.e., Minimum Yield Strength (SMYS), Ultimate Tensile Strength (UTS)); and
- Seam type.

5.1.1.3 Add newly identified applicable pipeline segments to the MAOP Reconfirmation plan and include the following details:

- Pipeline name;
- Applicable pipeline segment extents;
- Estimated segment mileage;
- Reason for performing reconfirmation; and
- Date of discovery.

5.1.1.4 For each of the newly identified pipeline segments in the plan, select a recommended method of reconfirmation and consult with stakeholders to finalize the selection, then add the following to the plan per section 3.0.

- The recommended reconfirmation method;
- Stakeholder input and recommendations;
- Material verification requirements (note opportunistic and planned material testing);
- Any opportunities to bundle reconfirmation with other planned capital or O&M work on the pipeline segment(s) such as proximity, planned replacement, modification, or improvement projects, or scheduled integrity assessments; and
- The planned reconfirmation year.
  - Complete reconfirmation before July 2, 2035, or within four (4) years after the pipeline segment date of discovery, whichever is later.

6.0 DOCUMENTATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Update the MAOP reconfirmation plan upon completion of each pipeline segment.

6.1.1.1 Maintain the document's revision history or log each change according to GTIM-11-001 "GTIM Change Management".

6.1.2 Retain all records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken related to the procedure for the life of the pipeline.

<<END>>

GTIM-02-006 Engineering Critical Assessment (ECA)

PURPOSE: To establish material strength and the MAOP of pipeline segments in lieu of pressure testing and the other MAOP Reconfirmation methods.

REFERENCES: 49 CFR 192.632;

SECTIONS:

- General
- Review Historical Documentation
- Determine Remaining Defects
- ECA Analysis
- Documentation

1.0 GENERAL

1.1 An Engineering Critical Assessment (ECA) is a method for reconfirming the MAOP of applicable pipeline segments known as 'Method 3'.

1.2 Analyses and calculations performed as part of this procedure should use pipe and material properties documented with traceable, verifiable, and complete records (TVC).

1.2.1 GTIM-14-001 "Glossary" contains definitions for Traceable Records, Verifiable Records, and Complete Records.

1.2.2 If TVC records are not available, obtain the undocumented data using GTIM-02-010 "Material Verification" as soon as practical and use conservative assumptions when performing the ECA.

1.3 Subject Matter Experts (SMEs) or industry experts will assess the validity of this process based on the documentation produced during this process.

1.3.1 Engage industry experts to support the ECA method selection and process, as necessary.

1.3.2 Document all evaluations, any assumptions used, the rationale for selections used, and conclusions for the ECA process. Include the following with all ECA documentation produced:

- Name of the reviewer;
- Date of evaluation, assumption, or action; and
- A detailed conclusion.

2.0 REVIEW HISTORICAL DOCUMENTATION

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 For the applicable pipeline segments, review the following documentation compiled over the life of the pipeline to determine defects remaining in the pipe, or that could remain in the pipe.

- Threats;
- Loadings and operational circumstances relevant to those threats, including along the pipeline right-of-way;
- Outcomes of the threat assessments;
- Relevant mechanical and fracture properties;
- In-service degradation or failure processes;

- Initial and final defect size relevance; and
- Quantify the interacting effects of threats on any defect in the pipeline.

2.1.1.1 Data sources include but are not limited to:

- The results of all tests;
- Direct examinations;
- Destructive testing results;
- Other pertinent information related to pipeline integrity, including:
    - Close interval surveys;
    - Interference surveys required for corrosion control;
    - Root Cause Analyses of prior incidents;
    - Prior pressure test leaks and failures;
    - Other leaks;
    - Pipe Inspections;
    - Prior integrity assessments, including those assessments conducted outside of High Consequence Areas; and
    - Coating surveys.

3.0 DETERMINE REMAINING DEFECTS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 To assess the defects remaining in the pipeline segment, select one (1) of the three (3) assessment methods.

- Evaluate a previous Subpart J compliant Pressure Test;
- Perform an In-Line Inspection; or
- Use “other technology”.

3.1.2 Evaluating a previous Subpart J compliant Pressure Test to assess the defects remaining in a pipeline segment:

3.1.2.1 Review the documentation applicable to the pipeline segments, described in section 2.0 above, in combination with the documentation from the previous Subpart J Pressure Test to determine the defects that could have survived the Pressure Test.

3.1.2.1.1 If TVC records are not available for any analysis of a defect, always use conservative assumptions, and unless verified using in situ direct measurements, account for uncertainties and tool variances when analyzing the reported results of the defect dimensions.

3.1.2.2 Predict how much the defects have grown since the date of the pressure test, according to GTIM-05-005 “Predictive Failure Pressure”.

3.1.2.3 Select the most severe defect that could have survived the Pressure Test and remains in the pipe at the time of this ECA.

3.1.2.3.1 Document the use of TVC records or assumptions.

3.1.2.4 Calculate the remaining life for the pipeline segment and establish a re-assessment interval using GTIM-05-005 “Predictive Failure Pressure” and GTIM-06-001 “Determining Reassessment Intervals”.

3.1.3 Perform an In-Line Inspection (ILI) assessment to identify the defects remaining in a pipeline segment.

3.1.3.1 Select the NACE SP0102 compliant ILI tools necessary to detect:

- Wall loss;
- Deformation from dents;
- Wrinkle bends;
- Ovalities;
- Expansion;
- Seam defects;
- Cracking;
- Selective seam weld corrosion;
- Longitudinal, circumferential, and girth weld cracks;
- Hard-spots, if applicable;
- Hard-spot cracking; and
- Stress corrosion cracking.

3.1.3.2 Include a tool that can detect girth weld defects if a reportable incident, attributed to a girth weld failure, occurred since the pipeline’s most recent Subpart J Pressure Test.

3.1.3.3 Create and use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction-related anomalies.

3.1.3.3.1 Use enough data points to validate tool performance at the same or better statistical confidence level provided in the tool specifications.

3.1.3.4 Follow existing ILI procedures for identifying defects outside the tool performance specifications.

3.1.3.5 Evaluate the assessment results.

3.1.3.5.1 Confirm the assessment results meet the requirements of GTIM-03-015 “Non-HCA Assessments” and GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

3.1.3.5.2 Apply the most conservative limit of the tool tolerance specifications to ensure results conservatively account for the accuracy and reliability of the ILI process, the in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of the defect dimensions.

3.1.3.5.3 Perform confirmation tests to ensure the accuracy of the defect types and pipe material vintage evaluated by the ILI and in-the-ditch examination tools.

3.1.3.5.4 Account for inaccuracies in evaluations and fracture mechanics models for predicted failure pressure determinations.

3.1.3.6 Remediate all anomalies detected by the ILI assessment.

4.0 ECA ANALYSIS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Perform the ECA analysis as follows.

4.1.1.1 The material properties required to perform an ECA analysis are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable.

4.1.1.2 If the Specified Minimum Yield Strength (SMYS) or actual material yield and ultimate tensile strength are not known or not documented by traceable, verifiable, and complete records, assume 30,000 psi or determine the material properties using GTIM-02-010 “Material Verification”.

4.1.1.2.1 For any cracks or crack-like defects remaining in the pipe or that could remain in the pipe, determine the predicted failure pressure of each defect using GTIM-05-005 “Predictive Failure Pressure”.

4.1.1.2.2 For any metal loss defects not associated with a dent, including corrosion, gouges, scrapes, or other metal loss defects that could remain in the pipe, determine the predicted failure pressure per GTIM-05-005 “Predictive Failure Pressure”.

4.1.1.2.2.1 Applicable only with corrosion regions that do not penetrate the pipe wall more than 80 percent of the wall thickness.

4.1.1.2.2.2 Use conservative assumptions for metal loss dimensions (length, width, and depth).

4.1.1.2.3 For gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, determine the predicted failure pressure per GTIM-05-005 “Predictive Failure Pressure” using appropriate failure criteria and justification of the criteria.

4.1.1.2.3.1 Document and justify the appropriate failure criteria used to predict the failure pressure.

4.1.1.3 Evaluate defects for interaction, and if found, use the most limiting predicted failure pressure.

4.1.1.3.1 Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage.

4.1.1.3.2 Document all evaluations and any assumptions made during the analysis of interacting defects.

4.1.1.4 Establish the MAOP of the pipeline segment at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe.

4.1.1.4.1 Divide the lowest predicted failure pressure by the greater of 1.25 or the relevant class location factor in Table 02-006-1 below.

Table 02-006-1: Class Location Factor for MAOP Determination

Class Location	Installed before (Nov. 12, 1970)	Factors*, segment--		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under §192.14
1	1.10	1.10	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.40	1.50	1.50	1.50
4	1.40	1.50	1.50	1.50

* For offshore pipeline segments installed, uprated or converted after July 31, 1977, and not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated, or converted after July 31, 1977, and located on an offshore platform or a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

5.0 DOCUMENTATION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Retain all records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken per the requirements of this process for the life of the pipeline.

<<END>>

GTIM-02-007 Applying the Transmission Line Definition

PURPOSE: To establish a standard method for identifying transmission pipelines.
REFERENCES: 49 CFR 192.3; 49 CFR 192.901;
SECTIONS:
- Definitions
- Applying the Transmission Line Definition
- Documentation

1.0 DEFINITIONS

1.1 A *Transmission Line* refers to a pipeline, other than a gathering line, where any of the following applies:

- Transports gas from a gathering line or storage facility to a:
  - Distribution Center
    - Defined as a regulator station with odorized gas; or
    - Defined as a town border station (city gate).
  - Storage Facility
    - Defined as an underground storage facility; or
    - Defined as a pipeline system due to the line pack potential within the pipeline system.
- A large volume customer that is not downstream from a distribution center. (Large volume customers, such as factories, power plants, and institutional users of gas, receive volumes of gas similar to a distribution center.)
  - Operates at a hoop stress pressure of 20% or more of SMYS; or
  - Transports gas within a storage field.
- Transports gas within a storage field.

2.0 APPLYING THE TRANSMISSION LINE DEFINITION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Review the layout of the pipeline and determine the inlet source(s) of gas and the delivery points.

2.1.1.1 Locate information about the pipeline on updated system maps and in other appropriate databases.

2.1.2 Determine if the pipeline transports gas under any of the conditions listed in section 1.1. If so, the pipeline is considered a transmission pipeline.

2.1.2.1 Obtain updated maps or information from other appropriate databases to determine these conditions.

2.1.2.2 Verify listed conditions with operations personnel (SMEs) as required.

2.1.3 Determine if the pipeline has an MAOP that is greater than 20% SMYS. If so, the pipeline is considered a transmission line.

2.1.4 Determine if the pipeline transports gas within a storage field. If so, the pipeline is considered a transmission line.

3.0 DOCUMENTATION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Complete a GTIM-90207 “Transmission Line Definition” form for documenting the results to categorize a pipeline as a Transmission Line.

3.1.2 Submit the completed Transmission Line Definition form to the GTIM Manager for approval.

3.1.3 Retain GTIM-90207 for the useful life of the pipeline in the IM file.

<<END>>

GTIM-02-010 Material Verification

PURPOSE: To establish a standardized method for verifying the physical characteristics and attributes of pipelines.

REFERENCES: 49 CFR 192.607; 49 CFR 192.632; 49 CFR 192.712; API Spec 5L-2013; ASTM A370-2009;

SECTIONS:

- General
- Material Property Testing of Line Pipe
- Component Pressure Rating
- Sampling
- Documentation

1.0 GENERAL

1.1 PHMSA requires retaining material properties and attributes in traceable, verifiable, and complete (TVC) records for all steel transmission line pipe and associated components for the life of the system.

1.1.1 GTIM-14-001 “Glossary” contains definitions for Traceable Records, Verifiable Records, and Complete Records.

1.1.1.1 Review guidance documents containing expanded TVC definitions and the determination of TVC records.

1.2 For buried and aboveground assets without material properties and attributes TVC records, CNP plans to opportunistically conduct non-destructive or destructive tests, examinations, and assessments while performing excavations at the following opportunities: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance activities, and excavations that are associated with replacements or relocations of pipeline segments removed from service, as able.

1.2.1 Tests, examinations, and assessments will be appropriate for verifying the material properties and attributes.

1.2.2 CNP will make a best-effort attempt to verify applicable assets during emergent and non-planned work.

1.3 Records for the physical line pipe characteristics and attributes, include, but are not limited to:

- Diameter;
- Wall thickness;
- Grade (e.g., yield strength, ultimate tensile strength, etc.); and
- Seam type.

1.4 Verification of non-line pipe components material properties includes valves, flanges, fittings, fabricated assemblies, and other pressure-retaining components and appurtenances that are:

- Larger than 2 inches in nominal outside diameter,
- Material grades of 42,000 psi (Grade X-42) or greater, or
- Appurtenances of any size directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

1.4.1 Components not requiring TVC records include components in:

- Compressor stations;
- Meter stations;
- Regulator stations;
- Separators;
- River crossing headers;
- Mainline valve assemblies;
- Cross-connections with isolation valves from the mainline pipeline; and
- Valve operator piping.

Note: §192.107(g) restricts the use of material properties determined from either destructive or non-destructive testing to justify raising the grade or specification of the material unless the original grade or specification was unknown with an assumed yield strength of 24,000 psi.

Note: TVC records established by this procedure include Charpy v-notch toughness values needed to meet the requirements of the Engineering Critical Assessment (ECA) method for MAOP Reconfirmation and the fracture mechanics calculations in predicting failure pressure.

2.0 MATERIAL PROPERTY TESTING OF LINE PIPE

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Non-destructive testing methods and tools used to determine material properties require:

- Validation by a Subject Matter Expert (SME) based on a comparison with destructive test results on the material of comparable grade and vintage;
- Conservatively account for measurement inaccuracies and uncertainties using reliable engineering tests and analyses; and
- Usage of properly calibrated test equipment for comparable test materials.

2.1.1.1 When using non-destructive testing methods and tools to determine the Specified Minimum Yield Strength (SMYS) and Ultimate Tensile Strength (UTS) for the material properties of line pipe, at each location, conduct tests at a minimum of five (5) places in at least two (2) circumferential quadrants of the pipe for, at minimum, a total of ten (10) test readings at each pipe cylinder location.

2.1.2 Destructive testing includes a set of tests of material properties for SMYS and UTS conducted on each test pipe cylinder removed from each test location per the requirements of API Spec 5L and ASTM A370.

2.1.2.1 When cutting out samples from a line pipe for destructive testing, follow the instructions in the Cutout Protocol and Chain of Custody form.

2.1.3 Ensure non-destructive and destructive test results meet TVC requirements.

2.1.4 Retain all documentation in the IM file for the life of the pipeline.

2.1.5 Create a work order to incorporate updated information in GIS.

3.0 COMPONENT PRESSURE RATING

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Establish and document the ANSI rating or pressure rating (per ASME/ANSI B16.5) for material properties and attributes for non-line pipe components without TVC records based on the documented manufacturing specification for the components.

3.1.1.1 If specifications are not known, visually inspect the component for the manufacturer's stamped, marked, or tagged material pressure ratings, and material type to establish the pressure rating through planned and opportunistic excavations.

3.1.1.1.1 Trace the component's specifications and identification to the manufacturer's manual or catalog for the installation year of the component.

3.1.1.1.2 Review any installation work orders for traceability and verification.

3.1.1.2 All field investigations of component properties and attributes must include adequate documentation to meet TVC requirements. At a minimum, in the field, collect and document the following to verify the pressure rating of a component:

- Component type and function;
- Component material;
- Pipeline name or system that component is attached to;
- Location description;
- GPS coordinates for the component, sub-centimeter is preferred;
- All component markings;
- Photographs of component, location, and all markings;
- Date of field investigation;
- The method used to determine the pressure rating; and
- The component's pressure rating.

4.0 SAMPLING

4.1 Responsibility: GTIM Engineer or designee

4.1.1 To verify material properties and attributes for a population of multiple, comparable pipeline segments with defined start and endpoints, without traceable, verifiable, and complete records, use a sampling program according to the following requirements:

4.1.1.1 Define separate populations of similar segments of pipe for each combination of the following material properties and attributes:

- Nominal wall thicknesses;
- Grade;
- Manufacturing process;
- Pipe manufacturing dates; and
- Construction dates.

4.1.1.1.1 If the dates between the manufacture or construction of the pipeline segments exceed two (2) years, do not consider those segments the same vintage when defining a population under this section.

4.1.1.1.1.1 The pipeline segments need not be continuous.

4.1.1.1.1.2 The total population mileage is the cumulative mileage of pipeline segments in the population.

Note: Not all segment populations within a pipeline may be missing TVC records.

4.1.1.1.2 Utilize available data sources to assist in discerning between populations, including but not limited to previous direct examinations, pipeline modifications, surveys, or material investigations.

4.1.1.2 For each population defined, determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities for damage prevention, until completion of the lesser of the following:

- One excavation per mile rounded up to the nearest whole number; or
- 150 excavations if the population is more than 150 cumulative miles.

4.1.1.2.1 CNP may elect to take a sample at the beginning and end of a segment within the population and every mile in-between for a population less than 150 miles.

4.1.1.2.2 Prior tests conducted using this procedure to verify the physical characteristics and attributes of a pipeline segment within this population, count as one sample or excavation toward this determination.

4.1.1.3 If the excavations identify properties that are inconsistent with available information, expectations, or assumed properties used for operations and maintenance in the past, inform the GTIM Manager.

4.1.1.3.1 If CNP elects to continue with sampling, CNP will establish an expanded sampling program or an alternative statistical sampling approach.

4.1.1.3.1.1 The expanded sampling program or an alternative statistical sampling approach will use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid.

4.1.1.3.1.2 Before using an expanded sampling program or an alternative statistical sampling approach, CNP will notify PHMSA according to GTIM-13-001 “Required Notifications to Regulatory Agencies”.

4.1.1.4 Document each sample population with the names of the included line segments and extents, and the material properties of each sample population.

5.0 DOCUMENTATION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Create a work order to incorporate information into GIS or other applicable databases.

5.1.2 Retain all records for the life of the pipeline.

5.1.3 When updating pipeline segments or components with properties determined with this procedure, create a log entry per GTIM-11-001 “GTIM Change Management”.

<<END>>

GTIM-02-020 Determination of Stable Threats

PURPOSE: To establish a standardized method for identifying when potential manufacturing and construction threats are stable or non-stable for steel transmission lines.

REFERENCES: 49 CFR 192.917; ASME/ANSI B31.8S-2004, Section 6.3.2; GRI-04/0178-2004;

SECTIONS:
- Background
- Historical Record Review
- Determination of Stable Threats for Lines with a Valid Subpart J Pressure Test
- Determination of Stable Threats for Lines without a Valid Subpart J Pressure Test
- Annual Review
- Integrity Assessments

1.0 BACKGROUND

1.1 Construction and Manufacturing threats can be considered stable or non-stable.

1.1.1 Construction threats and Manufacturing threats represent potential weak points or locations of 'increased vulnerability' for risk of failure. These types of threats typically remain stable until interacting with other conditions, increasing the likelihood of failure and instability.

1.1.1.1 Post-installation pipeline segments subjected to hydrostatic pressure testing satisfying the criteria of Subpart J of at least 1.25 times MAOP, and that have not experienced a reportable incident attributable to a manufacturing or construction defects since that test are considered stable.

1.1.1.1.1 Incidents that revert stable threats to non-stable threats include:

- Incidents caused by an original manufacturing-related defect, or construction-, or installation-, or fabrication-related defects;
- MAOP increases; or
- Stress increases leading to cyclic fatigue.

1.2 Pressure Testing is the only acceptable assessment method to determine the stability of these types of threats.

2.0 HISTORICAL RECORD REVIEW

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Identify the pipeline segment(s) for evaluation, typically located within a Consequence Area.

2.1.2 Determine if Manufacturing threats or Construction threats for the pipeline are stable or non-stable. Refer to procedure GTIM-02-021 "Threat Identification".

2.1.2.1 If Manufacturing or Construction defects are considered stable, no further analysis is required.

2.1.3 Determine if the covered segment(s) has a valid Subpart J pressure test.

2.1.3.1 Verify records documenting the Subpart J pressure test exist and are complete.

2.1.4 For pipelines without a valid Subpart J pressure test, determine the discovery date of the Consequence Area.

2.1.4.1 Use the original discovery date of the Consequence Area where the boundaries have expanded.

2.1.4.2 Use the original discovery date of the Consequence Area if the covered segment was identified, removed, and then re-identified as a Consequence Area.

2.1.4.3 Review the historical pressure records for the five (5) years preceding the discovery of the covered segment(s).

Note: Use the most current Subpart J pressure test to establish stability for newly identified Consequence Areas. Reviewing the five (5) year operating pressure history is not required.

2.1.4.4 Pressure Testing information formats including but not limited to:

- Spreadsheets;
- Databases; and
- Paper records.

2.1.4.5 Request the assistance of Gas Measurement, Gas Control, and subject matter experts (SMEs) as appropriate.

2.1.4.6 If records are not available for the five (5) years preceding the discovery of the Consequence Area, document an alternative means of obtaining a five (5) year historical operating pressure.

2.1.5 Identify the highest operating pressure for the five (5) years preceding the discovery of the Consequence Area, referred to as the “Historical 5-Year Operating Pressure”.

2.1.6 Identify any seam failures that have occurred anywhere in the pipeline system (i.e., covered and non-covered segments).

2.1.6.1 For each seam failure, identify the following:

- Seam type (i.e., ERW, lap welded);
- Pipe manufacturer; and
- Pipe vintage.

2.1.6.2 Subject Matter Experts are an acceptable source of information.

3.0 DETERMINATION OF STABLE THREATS FOR LINES WITH A VALID SUBPART J PRESSURE TEST

3.1 Responsibility: GTIM Engineer or designee

3.1.1 For each covered segment with a valid Subpart J pressure test, review the operating pressure since the last Subpart J pressure test.

3.1.2 Determine if the operating pressure has exceeded MAOP since the last Subpart J pressure test. Include abnormal operating conditions.

3.1.3 Determine if this pipe or a pipe with similar pipe characteristics in the system has experienced seam failures. (See section 2.1.6.)

3.1.4 Determine if stresses leading to cyclic fatigue or other loading conditions have increased since the last Subpart J pressure test.

3.1.4.1 Stresses may include, but are not limited to:

- Pressure cycling;
- Frequent blasting operations; and
- Ground movement.

3.1.4.2 If this information is undocumented, consult with Subject Matter Experts (SMEs) or other acceptable sources of information and analysis.

3.1.4.2.1 For covered segments with blasting activities occurring within 600 feet of the PIR, perform an annual review of seismograph data and verify the threshold value did not exceed two (2) inches/second for peak particle velocity during blasting activities.

3.1.4.2.2 Contact SMEs to determine if there have been any occurrences of ground movement (i.e., seismic activity, or removal of supporting backfill).

Note: Per the paper GRI-04/0178 "Effects of Pressure Cycles on Gas Pipelines" by John F. Kiefner and Michael J. Rosenfeld, cycling typically is not an integrity issue on natural gas pipelines; therefore, CNP has adopted a similar position.

When deemed appropriate by the SME, CNP will perform further analysis on stresses related to blasting operations and ground movement. SMEs determine on a case-by-case basis when further analysis is necessary.

3.1.5 When any of the above conditions are applicable, consider the Manufacturing and Construction threats on pipelines with a valid Subpart J pressure test to be non-stable. For example, if the MAOP has been exceeded since the last Subpart J pressure test, consult with SMEs to determine if the pressure exceedance warrants considering the threat non-stable.

3.1.5.1 For each applicable pipeline, complete GTIM-90204 "Stable Threats", section 2, "Pressure Test History".

3.1.6 Document the SME review on GTIM-90204, including reasoning and final determination on the threat stability.

3.2 Responsibility: Subject Matter Expert (SME)

3.2.1 Consider manufacturing and construction defects subjected to a valid Subpart J pressure test to be stable and expected not to fail while in-service as long as there is no interacting threat that may increase the likelihood of instability and failure.

3.2.1.1 Review the pipeline segment for interacting threats, such as the following:

- Wet, sour gas;
- Over pressurization;
- Stress corrosion cracking (SCC);
- Selective seam corrosion; and
- Soil instability.

3.2.1.2 For pipeline segments carrying wet, sour gas, review the stability of manufacturing defects that may be susceptible to hydrogen cracking and hydrogen blistering.

3.2.1.3 Consider pipeline segments that have experienced pressure excursions of five-percent above the validated MAOP to be at minimal risk for failure.

3.2.1.4 For lap-welded pipe, ERW pipe, or flash-welded pipe, determine if there is a risk of SCC, selective seam corrosion, soil instability, or washout.

3.2.2 Consider manufacturing threats as non-stable if interacting threats exist, and no mitigation for those risks is in place.

3.2.3 Consider manufacturing threats to be stable at MOP less than or equal to 80 percent of the Subpart J test pressure and absence of interacting threats.

3.2.4 Confirm the stability of construction defects (e.g., girth-weld defects and fabrication weld defects) with the absence of external forces, stresses, or strains imposed on the pipeline segment.

3.2.4.1 Review conditions that may impose unusual longitudinal strain on the pipeline segment.

3.2.4.2 For segments containing mechanical couplings, acetylene girth welds, wrinkle bends or girth welds of questionable quality, determine the risk of soil movement.

3.2.5 Document the SME review on GTIM-90204, and include reasoning and final determination on the threat stability.

3.3 Responsibility: GTIM Engineer or designee

3.3.1 For lines with a valid Subpart J pressure test, consider Manufacturing and Construction stable threats for the covered segment(s) if all the following criteria apply:

- Operating pressure history meets one of the following two (2) conditions:
    - The operating pressure has not exceeded MAOP since the last Subpart J pressure test;

    <u>or</u>

    - The operating pressure has exceeded MAOP since the last Subpart J pressure test, and the SME Review determined there is no detriment to line stability.
- Stresses leading to cyclic fatigue have not increased since the last Subpart J pressure test; and
- The pipeline does not have physical characteristics similar to other pipelines in the system experiencing seam failure.

3.3.2 If Manufacturing or Construction threats are non-stable, prioritize the Consequence Area as a high-risk segment and schedule accordingly in the assessment schedule calendar.

3.3.3 Document if the threat is stable or non-stable for each covered segment in GTIM-90204, section 1, “Consequence Areas”.

3.3.4 Document the results of each covered segment review on GTIM-90209 “Threat Analysis”.

4.0 DETERMINATION OF STABLE THREATS FOR LINES WITHOUT A VALID SUBPART J PRESSURE TEST

4.1 Responsibility: GTIM Engineer or designee

4.1.1 For each applicable Consequence Area without a valid Subpart J pressure test, review the operating pressure records for the years after the discovery of the Consequence Area.

4.1.2 Determine if the operating pressure has exceeded the “Historical 5-Year Operating Pressure” for the Consequence Area.

4.1.2.1 Include abnormal operating conditions.

4.1.3 Determine if the pipe has similar pipe characteristics to any other pipes in the system that have experienced seam failures, or characteristics that have contributed to pipeline failures within industry. (See section 2.1.6.)

4.1.4 Determine if stresses leading to cyclic fatigue for the HCA have increased since the installation of the pipeline.

4.1.4.1 Refer to section 3.1.4.2, including the Note, for additional cyclic fatigue information.

4.1.5 For each applicable pipeline, complete GTIM-90204 “Stable Threats”, section 3, “Operating History”.

4.1.6 For lines without a valid Subpart J pressure test, consider Manufacturing and Construction threats as stable if all of the following criteria apply:

- The operating pressure has not increased above the “Historical 5-Year Operating Pressure” since the discovery of the Consequence Area;
- Stresses leading to cyclic fatigue have not increased since the discovery of the Consequence Area; and
- The pipeline does not have physical characteristics similar to other pipelines in the system experiencing seam failure.

4.1.7 If Manufacturing or Construction threats are non-stable, prioritize the Consequence Area as a high-risk segment and schedule accordingly in the assessment schedule calendar.

4.1.8 Document if the threat is stable or non-stable for each covered segment in GTIM-90204, section 1, “Consequence Areas”.

4.1.9 Document the results of each covered segment review on GTIM-90209 “Threat Analysis”.

5.0 ANNUAL REVIEW

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Annually review all Consequence Areas with stable Manufacturing and Construction threats. Refer to GTIM-06-005 “Reassessments”.

5.1.1.1 Obtain a copy of the original completed GTIM-90204 “Stable Threats”.

5.1.1.2 Review the appropriate pipeline information to determine if any criteria per section 3.0 “Determination of Stable Threats for Lines with a Valid Subpart J Pressure Test” have changed.

5.1.2 If any of the criteria have changed, re-classify the Manufacturing threat or the Construction threat as a non-stable threat.

5.1.2.1 Update GTIM-90204 “Stable Threats”.

5.1.2.2 Update GTIM-90209 “Threat Analysis”.

5.1.2.3 Select Pressure Test as the method of reassessment

5.1.2.4 Update the assessment schedule calendar as needed.

6.0 INTEGRITY ASSESSMENTS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Perform a pressure test on all Consequence Areas with the Manufacturing or Construction threat identified as non-stable.

6.1.1.1 Perform the test at a test pressure that maximizes the reassessment interval. Refer to GTIM-06-001 “Determining Reassessment Intervals”.

6.1.2 Consider all Manufacturing and Construction threats to be stable upon completion of a successful and valid Subpart J pressure test.

Note: Pipeline segments with non-stable Manufacturing or Construction threats that require MAOP Reconfirmation, must conduct the MAOP reconfirmation per §192.624(c)(3) “Method 3” using an Engineering Critical Assessment (ECA) to establish the material strength and MAOP of the pipeline segment.

<<END>>

GTIM-02-021 Threat Identification

PURPOSE: To establish a standardized method for identifying threats on pipeline segments.

REFERENCES: 49 CFR 192.917; ASME/ANSI B31.8S-2004, Section 2.2;

SECTIONS:

- General
- Identify Time-Dependent Threats
- Identify Static Threats
- Identify Time-Independent Threats
- Interactive Threats
- Documenting Identified Threats
- Identifying Threats for Stations
- New and Changed Consequence Areas
- Periodic Review

1.0 GENERAL

1.1 Threat categories delineated by time-related defect types are Time-Dependent, Static (or Stable), and Time-Independent.

- Time-Dependent:
  - External Corrosion;
  - Internal Corrosion; and
  - Stress Corrosion Cracking.
- Static (or Stable):
  - Manufacturing-related defects;
    - defective pipe seam; and
    - defective pipe.
  - Construction (welding/fabrication related) defects;
    - defective pipe girth weld;
    - defective fabrication weld;
    - wrinkle bend or buckle; and
    - stripped threads/broken pipe/ coupling failure.
  - Equipment:
    - gasket O-ring failure;
    - control/relief equipment malfunction;
    - seal/pump packing failure; and
    - miscellaneous.
- Time-Independent:
  - Third-Party/Mechanical Damage;
    - damage inflicted by first, second, or third parties (instantaneous/immediate failure);
    - previously damaged pipe (delayed failure mode); and
    - vandalism.

- Incorrect Operational procedure;
- Weather-related and Outside Force;
  - cold weather;
  - lightning;
  - heavy rains or floods; and
  - earth movements.

1.2 If the data used to identify a specific threat is suspect or insufficient:

1.2.1 The threat is assumed to exist and applies to the entire segment.

1.2.2 Segment risk assessments use conservative data value assumptions or are assigned a higher priority.

1.2.3 Usage of pipeline segments with known and similar conditions as a basis for threat determination is acceptable.

Note: The unavailability of information is not a justification for the exclusion of a threat from the integrity management program.

2.0 IDENTIFY TIME-DEPENDENT THREATS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Identify the Consequence Areas for evaluation.

2.1.1.1 CNP always considers External Corrosion a threat to each covered segment.

2.1.1.1.1 Complete GTIM-90209 “Threat Analysis”, “Section 3 - Analysis of External Corrosion Threat”.

2.1.1.2 Determine if Internal Corrosion is a threat to the covered segment.

2.1.1.2.1 Always look for signs of internal corrosion on pipeline segments undergoing ECDA and during any direct examinations as part of that assessment process.

2.1.1.2.2 Consider the following factors, as well as other information on the pipeline system, while determining if internal corrosion is a threat on the line:

- Results of assessments in nearby Consequence Areas;
- Gas Chromatograph reports (i.e., sour or wet gas);
- Leak history and root causes;
- CP monitoring equipment;
- Storage fields and independent producers with no other supporting information;
- Sags, sharp bends, or other features that may hold corrosive elements; and
- Other documentation and information sources.

2.1.1.2.3 Complete GTIM-90209, “Section 4 - Analysis of Internal Corrosion Threat”, to assist in determining whether internal corrosion should be considered a threat to the covered segment.

Note: In a continuous effort to identify threats on all covered segments, CNP will continue to look for internal corrosion (IC) as a part of our ECDA and ILI assessments, as well as during routine O&M activities. In the event IC is determined a threat, CNP will perform an appropriate integrity assessment on the most likely region(s) for IC, as well as evaluating like and similar conditions if applicable.

2.1.1.3 Consider the following factors to determine if Stress Corrosion Cracking (SCC) is a threat to the Consequence Area.

- Age of pipe;
- Operating %SMYS;
- Range of temperature;
- Distance downstream from the closest compressor;
- Coating type;
- Hydrostatic testing history;
- Evidence of SCC on this pipeline or other similar pipelines; and
- A history of failures or leaks due to SCC.

2.1.1.3.1 Identify as near-neutral SCC threat if meeting all three (3) of the following conditions:

- Operating stress level (MAOP) greater than 60% of SMYS;
- Coating other than Fusion Bonded Epoxy (FBE); and
- Age of pipe greater than ten (10) years.

2.1.1.3.2 Identify as high-pH SCC threat if meeting all five (5) of the following conditions:

- Operating stress level (MAOP) greater than 60% of SMYS;
- Coating other than Fusion Bonded Epoxy (FBE);
- Age of pipe greater than ten (10) years;
- Operating temperature greater than 100°*F*; and
- Less than twenty (20) miles downstream from the nearest compressor station.

2.1.1.3.3 When evidence of SCC is found anywhere on a line, identify SCC as a threat to the Consequence Area.

2.1.1.3.4 If a leak or failure attributed to SCC occurs anywhere on a line, identify SCC as a threat to the Consequence Area.

2.1.1.3.5 Complete GTIM-90209, “Section 5 - Analysis of Stress Corrosion Cracking Threat”.

Note: If an in-service leak or rupture attributable to SCC occurs anywhere on a pipeline (covered or non-covered segments), conduct a hydrostatic test within twelve (12) months. Refer to GTIM-04-064 “SCCDA Direct Examination and Post-Assessment”.

Note: If a pipeline is susceptible to either high-pH SCC or near-neutral SCC, confirm the collection of data relevant to SCC at all excavation sites, for any reason (i.e., assessments or maintenance activities), in both covered and non-covered segments. This data includes, but is not limited to, information on coating anomalies and disbonded coating.

3.0 IDENTIFY STATIC THREATS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Identify the Consequence Areas for evaluation.

3.1.1.1 Determine if any of the following conditions are present that may adversely affect Manufacturing defects for the Consequence Area.

- Low-frequency electric resistance weld (LF-ERW) pipe;
- Electric flash weld (EFW) pipe;
- Lap welds;
- Hammer welds;
- Butt welds;
- Joint factor less than 1.0 (including but not limited to lap welds, hammer welds, and butt welds); or
- Cast iron pipe.

3.1.1.1.1 If a longitudinal seam type is unknown for pipe installed before 1979, use a conservative assumption that the manufacturing defect threat does exist.

Note: CNP uses an installation date of 1979, conservatively, as opposed to 1970, to account for any pre-1970 manufactured pipe installed as late as 1979.

3.1.1.1.2 Complete GTIM-90209, “Section 6 - Analysis of Manufacturing Defects Threat”.

3.1.1.2 Determine if any of the following conditions are present that may adversely affect Construction defects for the Consequence Area.

- Mechanical couplings;
- Acetylene girth welds; or
- Wrinkle bends.

3.1.1.2.1 Complete GTIM-90209, “Section 7 - Analysis of Construction Defects Threat”.

3.1.1.3 If Manufacturing or Construction defects are identified as a threat, determine whether these threats are stable.

3.1.1.3.1 Refer to procedure GTIM-02-020 “Determination of Stable Threats”.

3.1.1.3.2 Complete GTIM-90204 “Stable Threats”.

3.1.1.3.3 Determine if the threat stability has changed from the previous threat analysis.

3.1.1.3.3.1 If the threat stability has changed from the previous threat analysis, attach supporting documentation, such as an SME Stability Analysis, and pressure charts.

3.1.1.4 Use the following resources to determine if the threat of Equipment defects exist for the Consequence Area.

- Applicable O&M forms;
- Maintenance work orders;
- Quality Assurance records; and
- Emergent issues records.

3.1.1.4.1 Consider the following attributes relating to the equipment on the pipeline:

- Year of Installation;
- Manufacturer;
- Regulator valve failure information;
- Relief valve failure information;
- Flange gasket failure information;
- Overpressure protection failure information;
- Regulator set point drift;
- Relief set-point drift;
- O-Ring failure information;
- Seal/packing failure information;
- Mainline valve (if inaccessible or troublesome); and
- Blow-down properly configured.

3.1.1.4.2 Determine if any of the following conditions exist, identify the Equipment defects as a threat:

- Failed regulator valve (still in-service) located in an area impacting the Consequence Area;
- Failed relief valve (still in-service) anywhere on the line;
- Repeated history of failed flange gaskets;
- Repeated history of failed O-rings; or
- History of failed overpressure protection.

3.1.1.4.2.1 At the discretion of the Subject Matter Expert, all locations containing equipment with a history of failures (i.e., a particular style or model) may be susceptible to an Equipment threat regardless of whether the failure occurred in that Consequence Area.

3.1.1.4.2.2 Include equipment outside the Consequence Area that can impact that Consequence Area (e.g., an upstream valve) in all Equipment threat analyses.

3.1.1.4.3 Complete GTIM-90209, “Section 8 - Analysis of Equipment Defects Threat”.

Note: An equipment failure is defined either as the failure of the equipment to perform the intended task or as equipment operating outside of the manufacturer’s specified tolerances.

4.0 IDENTIFY TIME-INDEPENDENT THREATS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Identify the Consequence Areas for evaluation.

4.1.1.1 CNP always considers Third-Party Damage to be a threat to each covered segment.

4.1.1.1.1 Review the following to determine if Third-Party Damage or Mechanical Damage is a threat to the Consequence Area unless a casing or concrete protective barrier covers the entire Consequence Area.

- Form 3112 “Gas Damage Report”;
- Form 3375 “Pipeline Location Record”; and
- GTIM-90802 “Transmission Encroachment”.

4.1.1.1.2 If the line has evidence of active Third-Party Damage, Mechanical Damage, or encroachments, document the information on GTIM-90209, “Section 9 - Analysis of Third-Party Damage Threat”, in the comments field.

4.1.1.1.3 Complete GTIM-90209, “Section 9 - Analysis of Third-Party Damage Threat”.

4.1.1.2 The threat of Incorrect Operations exists if any of the following exists for the pipeline:

- Leaks or failures attributed to incorrect operation;
- Identification of Incorrect Operating procedures;
- Recorded incident(s) of personnel failing to follow documented procedures, which resulted in a leak or equipment failure; or
- Overpressure protection equipment Incorrectly setup.

4.1.1.2.1 Consult with Subject Matter Experts to determine, on a case-by-case basis, if implemented procedural corrections eliminate the Incorrect Operations threat.

4.1.1.2.2 Failure of personnel to follow documented procedures constitutes a threat not only for the segment in question but also for all potentially affected lines; thus, all lines on which the person worked may be susceptible to improper operations.

4.1.1.2.3 Complete GTIM-90209, “Section 10 - Analysis of Incorrect Operations Threat”.

4.1.1.3 Consider the following factors to determine if Weather-Related, Outside Forces, or Cyclic Fatigue are threats to the Consequence Area:

- Susceptible to non-stable slopes, soil liquefaction, sinkholes, or wash-outs;
- Susceptibility to frost heave (depth of cover less than frost line);
- Known seismic (e.g., earthquakes) or flood hazards;
- Piping susceptible to lightning strikes;
- Blasting activity within 600 feet of the PIR (refer to O&M 9.38 “Blasting” or CNP O&M XV “Damage Prevention”); and
- Crosses a body of water.

4.1.1.3.1 The threat of Cyclic Fatigue exists if the following conditions are present:

- Significant pressure cycling; or

- Other loading conditions (including ground movement, and unsupported pipe span(s)) could lead to a failure of deformation, including a dent or gouge, crack, or other defects in the covered segment.

4.1.1.3.2 Complete GTIM-90209, “Section 11 - Analysis of Outside Force Threat”.

5.0 INTERACTIVE THREATS

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Update GTIM-90209 “Threat Analysis” with interactive threats after considering the following interactive threats:

5.1.1.1 External Corrosion and Third-Party/Mechanical Damage:

- Third-Party Damage or Mechanical Damage to the pipe or coating creates a likely spot for accelerated External Corrosion.
- Prior wall loss due to severe External Corrosion reduces the pipeline’s ability to withstand Third-Party Damage and Mechanical Damage.

5.1.1.2 Weather-Related/Outside Force and Construction Defects:

- Weather-Related or Outside Force damage typically exacerbates Construction defects before damaging the rest of the pipeline. Areas of concern include acetylene welds, wrinkle bends, and mechanical couplings.

5.1.1.3 Outside Force/Manufacturing:

- Earth movements can cause damage to steel pipelines installed as late as 1979, depending upon the manufacturing process.
- Pressure cycling can activate manufacturing defects.

6.0 DOCUMENTING IDENTIFIED THREATS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Document the identified threats in GTIM-90209, “Section 2 - Summary of Threats”.

7.0 IDENTIFYING THREATS FOR STATIONS

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Refer to GTIM-90210 “Threat Analysis – Stations and Equipment” for stations.

7.1.1.1 Complete a form for each station.

8.0 NEW AND CHANGED CONSEQUENCE AREAS

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Identify and document threats per this procedure for newly identified and changed Consequence Areas.

8.1.1.1 Complete this review no later than one (1) year after the discovery of the Consequence Area.

8.1.2 Report the Consequence Area(s) for inclusion in the assessment scheduling calendar.

9.0 PERIODIC REVIEW

9.1 Responsibility: GTIM Engineer or designee

9.1.1 On an annual basis, review the identified threats per the requirements of GTIM-06-005 “Reassessments”.

9.1.2 Retain all meeting minutes, attendance sheets, and management approval documentation in the IM file.

<<END>>

GTIM-02-022 Risk Assessment and Prioritization

PURPOSE: To establish a standardized method for prioritizing Integrity Assessments based on Risk Assessment program results and Subject Matter Expertise.

REFERENCES: 49 CFR 192.917; ASME/ANSI B31.8S-2004, Section 5;

SECTIONS:

- Background
- Risk Model Development
- Data Management
- Risk Assessment
- Annual Risk Review
- Documentation

1.0 BACKGROUND

1.1 CNP initially used Sewall's RiskCalculator™ risk assessment model to prioritize threats for each High Consequence Area (HCA) and schedule baseline assessments for completion by December 17, 2012.

1.1.1 After using Sewall's RiskCalculator™ risk assessment model to prioritize assessments for each HCA, CNP utilized SMEs and no longer used Sewall's RiskCalculator™ risk assessment model.

1.1.2 CNP completed 100 percent of the baseline assessments before December 17, 2012, as required by 49 CFR Part 192 for all identified HCAs.

1.2 Newly identified Consequence Areas are scheduled for assessment upon discovery, prioritized according to a risk-based analysis, and assessed within ten (10) years of the discovery date.

1.3 CNP currently utilizes GeoFields RiskFrame® Modeler to prioritize assessments for each Consequence Area.

2.0 RISK MODEL DEVELOPMENT

2.1 To comply with 49 CFR 192 Subpart O and its incorporation of ASME/ANSI B31.8S-2004, CNP subject matter experts (SMEs) selected GeoFields RiskFrame® Modeler as a relative risk-ranking model.

2.1.1 The objectives of the Risk Assessment program include:

- Prioritize covered segments for assessment and preventive and mitigative measures.
- Determine the effectiveness of preventive and mitigative measures
- Determine the most effective preventive and mitigative measures
- Provide a consistent decision-making process for applying resources
- Determine effectiveness or need for other integrity assessment technologies

2.2 The risk algorithms for the model were developed jointly by CNP and GeoFields personnel.

2.2.1 The model incorporates construction data, operating data, and pipeline survey data to determine a quantitative estimate of failure probabilities and failure consequences along each pipeline.

2.3 Outlined in the document “GeoFields RiskFrame® Modeler Design and Workshop Notes” are the factors and datasets incorporated into the Risk Model.

2.3.1 At a minimum, this document includes all threats listed in ASME/ANSI B31.8S-2004. Refer to GTIM-02-021 “Threat Identification” for more detailed information.

2.3.1.1 Each threat category is weighted based on CNP SME input and statistical trends across the industry for serious and significant incidents.

2.3.2 Some factors without associated data are included in the Risk Model to account for threats and events that have not occurred in CNP’s system to date.

2.3.3 Per ASME/ANSI B31.8S-2004, the GeoFields RiskFrame® Modeler considers interactive threats.

2.3.3.1 GTIM-02-021 discusses interactive threats.

2.4 The GeoFields RiskFrame® Modeler risk scoring incorporates formulas for:

- Risk of Failure (ROF);
- Likelihood of Failure (LOF);
- Consequence of Failure (COF); and
- Interactive Threats Equation (IAE).

3.0 DATA MANAGEMENT

3.1 **Responsibility:** GTIM Engineer or designee

3.1.1 Collect data relevant to Risk Assessment per GTIM-02-001 “Data Gathering and Research”. Data collected may include, but not limited to:

- Pipeline Design;
- Pipeline Construction;
- External Data Sets (i.e., population, roadway, earth movement, and environmental data);
- Data collected during routine operations and maintenance activities; and
- Integrity assessment results.

3.1.1.1 New information is captured continually per GTIM-02-001 and incorporated into the RiskFrame® datasets.

3.1.2 Identify and evaluate all potential threats for each Consequence Area per GTIM-02-021.

3.1.2.1 At a minimum, include the datasets specified in ASME/ANSI B31.8S-2004, Appendix A.

3.1.2.2 Complete a GTIM-90209 “Threat Analysis” per the requirements of GTIM-02-021 “Threat Identification” for each newly identified Consequence Area and ongoing risk assessment.

3.1.3 Review the higher risk scores and compare the last risk run results with known data or algorithm changes.

3.1.3.1 Identify pipeline segments containing low-frequency electric resistance welded (ERW) pipe, lap-welded pipe, or flash-welded pipe.

3.1.3.1.1 Consider Consequence Areas on these lines high-risk if there is a history of seam failure, or the line exceeded the maximum operating pressure experienced during the preceding five years.

3.1.3.2 Identify pipelines at risk from stress corrosion cracking, or soil instability, or cyclic fatigue.

3.1.3.2.1 Consider Consequence Areas on these lines high-risk if the line exceeded the maximum operating pressure experienced during the preceding five years or an increase of the line's MAOP.

3.1.4 Ensure data incorporated into the RiskFrame® datasets is the most current, available information to produce the most accurate and valid risk results.

3.1.4.1 Create a work order to correct data in GIS.

3.1.5 Capture data from other CNP databases needed for manual insertion or verification of the Risk Assessment program.

3.1.6 Maintain data in GeoFields to be incorporated into the Risk Assessment.

4.0 RISK ASSESSMENT

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Run the Risk Assessment once each year to calculate risk scores.

4.1.1.1 Dynamic segmentation divides each pipeline into several smaller segments based on the segment's specific characteristics allowing assignment of risk to the smaller segments. The risk score for the entire pipeline then becomes the highest risk score of the individual segment on the pipeline.

4.1.1.2 Compare risk results with the risk results from the previous year.

4.1.1.2.1 Document significant risk score changes if the variation in risk resulted from changes made to the risk model algorithm.

4.1.1.2.2 Evaluate the emergence of new threats and remediations, contributing to the change in risk.

4.1.2 Perform "What If" scenarios to validate the risk scores, if necessary.

4.1.2.1 Re-run the Risk Assessment, if necessary.

4.1.3 Use risk scores to prioritize HCA and MCA segments.

4.1.3.1 Address all HCAs and MCAs on a priority basis, including newly identified Consequence Areas and Consequence Areas with substantial risk increases when scheduling integrity assessments and selecting preventive and mitigative measures.

4.1.4 Re-evaluate the integrity assessment schedule calendar as needed to address high-risk HCAs and MCAs.

4.1.4.1 Notify the GTIM Manager of significant changes to the integrity assessment schedule to determine if notification to PHMSA and other regulatory agencies, per GTIM-13-001 "Required Notifications to Regulatory Agencies", is necessary.

4.1.5 Retain risk result datasets within GeoFields.

4.2 Responsibility: GTIM Manager or designee

4.2.1 Notify PHMSA and other regulatory agencies per GTIM-13-001 "Required Notifications to Regulatory Agencies", if necessary.

4.2.1.1 Significant changes to the integrity assessment schedule include changing the primary method for determining HCA and MCA locations or reducing the number of HCA or MCA miles to be assessed in a particular year by more than 25 percent.

4.2.1.2 Adjustments to project schedules to meet customer commitments, balance Local Operations resources, or manage expenditures, do not constitute a significant change unless, in doing so, meets the criteria outlined above.

5.0 ANNUAL RISK REVIEW

5.1 Responsibility: Integrity Management Team and Subject Matter Experts (SMEs)

5.1.1 Review Risk Model algorithms, annually, during the third and fourth quarters.

5.1.2 Evaluate risk score results generated in the second quarter to identify trends and new threats.

5.1.2.1 Confirm the weightings and percentages assigned to each variable category and rule are accurately represent the risk associated with the pipeline system or modify to provide a more accurate representation of the system.

5.1.2.1.1 Recommend new or revised data gathering to achieve substantial improvement in risk assessment, when identified.

5.1.2.2 Perform “What If” scenarios to validate the risk scoring and results, if necessary.

5.1.3 Make changes to the risk model algorithm or the risk assessment process as required.

5.1.3.1 When a changing the Risk Model, record a Change Management per GTIM-11-001 “GTIM Change Management”.

5.1.3.2 Notify GTIM Engineers of changes made to the Risk Model to ensure the scores and recalculated.

5.1.4 Assess the effectiveness of the Risk Assessment process.

5.1.4.1 Recommend improvements as necessary.

5.1.4.2 Assign follow-up actions to specific personnel and document.

6.0 DOCUMENTATION

6.1 Responsibility: Integrity Management Team and Subject Matter Experts (SMEs)

6.1.1 Maintain the Risk Assessment algorithms and risk results in GeoFields’ datasets.

6.1.2 Maintain a copy of the original Risk Model results for the HCAs identified before December 17, 2004, in the IM file.

6.1.3 Document the annual Risk Model Review and retain documentation in the IM file.

6.1.3.1 Documentation may include the following but are not limited to:

- Signoff and attendance sheets;
- Meeting minutes;
- Assigned action items; and
- Follow-up activities.

<<END>>

GTIM-03-001 Assessment Method Selection

PURPOSE: To establish a standardized method for determining assessment methods on covered segments.

REFERENCES: 49 CFR 192.921; 49 CFR 192.710; 49 CFR 192.937;
ASME/ANSI B31.8S-2004, Sections 6.2-6.4;

SECTIONS:
- Background
- Identify Assessment Segments
- Select the Assessment Method

1.0 BACKGROUND

1.1 Assessing the integrity of the line pipe in each covered segment occurs by applying one or more of the following methods depending on the threats to which the covered segment is susceptible.

- Pressure Test;
- Spike Hydrostatic Pressure Test;
- In-Line Inspection;
- Direct Assessment;
- Excavation and in situ Direct Examination;
- Guided Wave Ultrasonic Testing, or
- Other Technology.

1.2 "Other Technology" assessments require approval from the Pipeline and Hazardous Materials Safety Administration (PHMSA) at least ninety (90) days in advance of using the other technology.

1.2.1 Refer to procedure GTIM-13-001 "Required Notifications to Regulatory Agencies".

2.0 IDENTIFY ASSESSMENT SEGMENTS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 When appropriate, consider assessing multiple covered segments on a single line or combining multiple lines into a single assessment using the same method(s) based on the following:

- The consistency of the identified threats for all covered segments;
- Required assessment method(s); and
- Budget constraints.

3.0 SELECT THE ASSESSMENT METHOD

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Review the identified threats for each of the covered pipeline segments, per GTIM-02-021 "Threat Identification".

3.1.2 Evaluate the suitability of each method for addressing the identified threats, including the benefits and limitations associated with each method for assessing the threats to the covered segments(s).

3.1.2.1 Refer to “Table 03-001-1: Threats Addressed by Assessment Method; Benefits and Limitations”.

Table 03-001-1: Threats Addressed by Assessment Method; Benefits and Limitations

Assessment Method	Threats Addressed	Restrictions and Special Considerations	Benefits	Limitations
Pressure Test *(PT)*	External Corrosion		Historically proven effectiveness, widespread use, and flexibility for addressing large number of threats;	• Pass/Fail test; it does not provide detailed information about the condition of the pipeline; • Must meet requirements of 49 CFR 192 Subpart J to be a valid integrity assessment (e.g., test duration); • The line must be taken out of service during the test; • It is not always possible to maintain an alternate product supply to all customers during the test; • The reassessment interval is determined by the ratio of the test pressure to MAOP; • Requires drying the pipeline internally upon completion; • Proper disposal of water used for hydrostatic tests may be cost-prohibitive;
	Internal Corrosion			
	Other Environmentally Assisted Corrosion Mechanisms			
	Stress Corrosion Cracking			
	Third-Party / Mechanical Damage			
	Manufacturing and related defects *(including ERW, EFW, and other pipe seam concerns)*; Construction-related defects	Pressure tests are the only method suitable for addressing active manufacturing or construction threats;		
Spike Hydrostatic Pressure Test	Stress Corrosion Cracking			• Conduct inspections of lines operating at a hoop stress level of 30 percent or more of SMYS according to §192.506; • The line must be taken out of service during the test; • It is not always possible to maintain an alternate product supply to all customers during the test; • Requires drying the pipeline internally upon completion; • Proper disposal of water used for hydrostatic tests may be cost-prohibitive;
	Manufacturing and related defects *(including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects)*;			
In-Line Inspection *(ILI)*	External Corrosion	Use MFL or TFI ILI tools to detect external metal loss;	Detailed In-Line Inspection results provide useful data for assessing the condition of the pipeline; A single run can assess long pipeline segments;	• Cannot address active Manufacturing or Construction threats; • A successful ILI tool run requires the line to meet minimum geometry and flow conditions. Typical requirements include long radius bends and a velocity range of 4 - 7
	Internal Corrosion	Use MFL or TFI ILI tools to detect internal metal loss;		

Assessment Method	Threats Addressed	Restrictions and Special Considerations	Benefits	Limitations
	Third-Party / Mechanical Damage *(including dents, gouges, and grooves)*	Use geometry or caliper ILI tools to detect Third-Party / Mechanical Damage in the form of dents; Align ILI data with known encroachment information to address the Third-Party / Mechanical Damage threat;	Internal Mapping Unit (IMU) tools are available to obtain three-dimensional GPS coordinates of the pipeline segment;	mph. Removal of short radius bends or valves that restrict internal equipment passage may be cost-prohibitive; • Lines without ILI pig launching or receiving facilities equipped with pressure-relieving devices requiring construction or modification which may be cost-prohibitive; • Temporary launchers and receivers, equipped with pressure-relieving devices, may be used but will also require modifications; • Multiple tool runs (i.e., caliper and metal loss tools) may be necessary to detect all anomaly types applicable to the identified threats; • Limited detection of SCC cracks; • Determine reassessment intervals by the ratio of the predicted failure pressure to MAOP;
	Material Cracking and crack-like Defects *(e.g.,* Stress Corrosion Cracking*, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks)* Hard Spots with cracking	Ultrasonic shear wave tool or transverse flux tool; Detection limits may not be appropriate for very small SCC cracks;		
Direct Assessment *(DA)*	External Corrosion		ECDA provides an assessment of the External Corrosion threat, taking many aspects of external corrosion, including cathodic protection levels and coating condition, into consideration; Utilized in both indirect and direct inspections of the pipeline; ICDA provides an assessment of the Internal Corrosion threat through both indirect examination (modeling) and direct examination; No service interruption;	• Cannot address active Manufacturing or Construction threats; • More than one direct assessment method may be required to address all applicable threats; • Each direct examination method requires multiple excavations in each region. Multiple excavations can be labor-intensive and cost-prohibitive; • ICDA is not valid for use on lines transporting wet gas; • Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed;
	Internal Corrosion			
	Third-Party Damage	Must integrate ECDA indirect inspection data with foreign crossing and encroachment information to address Third-Party / Mechanical Damage;		
	Stress Corrosion Cracking			

Assessment Method	Threats Addressed	Restrictions and Special Considerations	Benefits	Limitations
Excavation and in situ Direct Examination *(Visual Examination)*	*(Select the non-destructive examination method(s) appropriate for the threat. methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse-wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI))*		Allows for visual examination, and direct measurement of anomalies;	• Direct examinations can be labor-intensive and cost-prohibitive;
Guided Wave Ultrasonic Testing *(GWUT)*	External Corrosion Internal Corrosion	May require approval in advance of using this method (“other technology”) from the Pipeline and Hazardous Materials Safety Administration (PHMSA). Refer to GTIM-13-001;	Detects internal and external metal loss; Allows cost-effective inspection of difficult locations *(e.g., insulated line with minimal insulation removal; corrosion under supports without need for lifting; inspection at elevated locations with minimal need for scaffolding; inspection of road crossings and buried pipes;)*	• Must conform to the criteria defined in 49 CFR Part 192 Appendix F, or this method is considered an “other technology” requiring PHMSA approval in advance of use; • All defect indications above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced within specified deadlines; • Interpretation of data is highly operator dependent; • Difficult to find small pitting defects; • Not very effective at inspecting areas close to accessories; • Can't find gradual wall loss; • GWUT may not be used to assess shorted casings;
Other Technology	*Determine on a case-by-case basis*	Obtain approval in advance of using the other technology from the Pipeline and Hazardous Materials Safety Administration (PHMSA) for any “other technology” assessments. Refer to GTIM-13-001;	Benefits determined on a case-by-case basis;	• Requires PHMSA notification; • Limitations determined on a case-by-case basis.

3.1.3 Determine whether a single method or a combination of methods is required to address all identified threats for the covered segment(s).

3.1.3.1 A combination of Direct Assessment methods (i.e., ECDA and ICDA) may be required to address all threats.

3.1.4 Consider the following factors when selecting an assessment method:

- Availability or feasibility of required equipment (i.e., pig launchers and receivers, in-line inspection tool capabilities, and availability);
- System constraints;
- Budgetary constraints;
- Time constraints; and
- Customer impact.

3.1.5 Document the rationale for the method selected on the corresponding method Pre-Assessment form.

3.1.6 Consider other transmission facilities in the area during the pre-assessment when determining the assessment extent.

3.1.6.1 Pipeline characteristics, operating history, or other factors may warrant informational inspections or examinations outside covered segment boundaries.

3.1.7 Document the assessment method or combination of methods for each assessment in the Baseline/Reassessment Assessment Plan (BRAP) or other assessment schedule calendar, as applicable.

3.1.8 If a method other than Pressure Test, Spike Test, ILI, Direct Assessment, Direct Examination, or GWUT is selected, (an “Other Technology”), notify jurisdictional authorities in advance of using the other technology.

3.1.8.1 Refer to GTIM-13-001 “Required Notifications to Regulatory Agencies”.

3.1.9 Refer to GTIM-13-003 “Special Permits (Waivers)” when a required assessment method is not feasible due to customer interruption, tool availability, and ability to maintain product supply.

<<END>>

GTIM-03-002 Baseline / Reassessment Assessment Plan

PURPOSE: To establish a standardized method for creating and updating the Integrity Management Baseline/Reassessment Assessment Plan.

REFERENCES: 49 CFR 192.911; 49 CFR 192.919; 49 CFR 192.921; 49 CFR 192.710;

SECTIONS:

- Background
- Prioritize and Schedule Assessments
- Document the Baseline/Reassessment Assessment Plan
- Annual Review and Update

1.0 BACKGROUND

1.1 A Baseline/Reassessment Assessment Plan was created based on covered segment risk priority and scheduled assessment method.

1.1.1 Assessment methods are determined based on identified threats and pipeline specific considerations, such as in-line inspectability. Refer to procedure GTIM-03-001 "Assessment Method Selection".

1.1.2 The Baseline/Reassessment Assessment Plan combines CNP's Baseline Assessment Schedule and legacy Vectren's Baseline and Long-Range Assessment schedules.

2.0 PRIORITIZE AND SCHEDULE ASSESSMENTS

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 All initially identified HCAs were scheduled for a baseline assessment and completed before December 17, 2012.

2.1.1.1 Each assessment segment was ranked based on the Total Risk score.

2.1.1.2 CNP completed 100 percent of the baseline assessments before the December 17, 2012 deadline, as required by 49 CFR Part 192 for all identified HCAs.

Note: As a prudent operator, CNP exercises judgment in HCA and MCA determination, and at times, may conservatively designate a non-covered pipeline segment as an HCA or MCA.

2.1.2 For new HCAs and MCAs, perform a threat analysis per GTIM-02-021 "Threat Identification" and GTIM-02-020 "Determination of Stable Threats", and schedule for baseline assessment in the appropriate assessment calendar.

2.1.2.1 Schedule new HCAs for baseline assessment within ten (10) years of discovery.

2.1.2.2 For MCAs meeting the following conditions, prioritize pipeline segments based on risk and schedule initial assessments as soon as practicable, within ten (10) years of meeting the conditions, but no later than July 3, 2034. Consider aligning the MCA assessments with existing HCA scheduled assessments, when practical.

2.1.2.2.1 Conditions required for assessing of MCA segments:

- Operates at a MAOP of greater than or equal to 30% SMYS;
- Located in Class 3 or Class 4;

- Accommodates internal inspection tools (i.e., “smart pigs”); and
- Are not located in a high consequence area.

2.1.2.2.2 Consider using assessments conducted before July 1, 2020, on applicable MCA segments, as the initial MCA compliant assessment if the assessment met the Subpart O requirements of Part 192 for in-line inspection at the time of the assessment.

2.1.2.2.2.1 If using a prior assessment as an initial assessment, schedule the reassessment according to section 4.1.1.3.2.

3.0 DOCUMENT THE BASELINE/REASSESSMENT ASSESSMENT PLAN

3.1 Responsibility: GTIM Engineer or designee

3.1.1 The Baseline/Reassessment Assessment Plan, the assessment schedule calendar, includes the following information:

- Total HCA or MCA footage covered by the assessment;
- Begin and end measure points for each assessment segment;
- Threats identified for each covered segment;
- Date threats identified/reviewed;
- Total Risk score for each covered segment (not required for newly identified covered segments);
- Assessment method(s) to be used based on identified threats;
- Assessment method(s) selection justification;
- Assessment year scheduled; and
- Each scheduled assessment’s status.
    - Not Started;
    - In Progress;
    - Complete;

4.0 ANNUAL REVIEW AND UPDATE

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Annually review the assessment schedule calendar.

4.1.1.1 Confirm the assessment schedule calendar is up-to-date with new information, applicable threats, and risks that may require changes to the segment prioritization, scheduled dates, or assessment methods.

4.1.1.1.1 Refer to GTIM-02-021 “Threat Identification” and GTIM-02-022 “Risk Assessment and Prioritization”.

4.1.1.2 Update ‘in-progress’ and ‘completed’ assessment statuses.

4.1.1.2.1 Incorporate all changes in methods, tools, and statuses, include the assessment completion date if known.

4.1.1.3 Schedule reassessments of completed assessments.

4.1.1.3.1 For HCA segments, schedule the reassessment per GTIM-06-001 “Determining Reassessment Intervals”.

4.1.1.3.1.1 If a reassessment interval is greater than seven (7) years, schedule an interim assessment or a full assessment to occur before the end of the seventh-year.

4.1.1.3.2 For MCA segments, schedule the reassessment to occur within ten (10) years.

4.1.1.3.2.1 Consider a shorter reassessment interval based upon the types of anomalies, operational, material, and environmental conditions found, or as necessary to ensure public safety.

4.1.2 Document all changes in the Revision History section of the assessment schedule calendar and complete change management activities.

4.1.2.1 Retain the assessment schedule calendar in the IM file for the life of the program.

<<END>>

GTIM-03-003 Pressure Testing

PURPOSE: To provide consistent direction for performing pressure testing as required for Integrity Management assessments.

REFERENCES: 49 CFR 192 Subpart J; 49 CFR 192 Subpart O; 49 CFR 192.921; 49 CFR 192.179; 49 CFR 192.506; ASME/ANSI B31.8-2007; ASME/ANSI B31.8S-2004, Appendix A;

SECTIONS:

- General
- Pre-Assessment
- Work Planning
- Performing the Pressure Test
- Failure Identification
- Reassessment Intervals
- Preventive and Mitigative Measures
- Performance Measures
- Feedback and Continuous Improvement
- Changes and Internal Communications
- Post-Assessment Documentation

1.0 GENERAL

1.1 Pressure testing is an assessment method used to address threats identified on covered segments within the Integrity Management Program.

1.1.1 Pressure testing is suitable for addressing time-dependent threats such as External Corrosion, Internal Corrosion, Stress Corrosion Cracking, and other environmentally assisted corrosion mechanisms.

1.1.2 Pressure tests are also suitable for addressing Third-party Damage, Manufacturing threats, Construction threats, and potential pipe seam defects.

1.1.2.1 Pressure tests are the only method suitable for addressing active (non-stable) construction or manufacturing defects.

1.2 Conduct Pressure Testing per 49 CFR 192 Subpart J.

1.3 Pressure testing consists of three phases:

- Pre-Assessment;
- Pressure Testing; and
- Post-Assessment.

2.0 PRE-ASSESSMENT

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Complete a pre-assessment for the pipeline segment(s) to be pressure tested.

2.1.1.1 Perform a site visit to verify HCA, MCA, and Identified Site locations if necessary.

2.1.1.1.1 Create a work order to correct HCA, MCA, or structure information in GIS, if necessary, and then re-evaluate the HCA and MCA extents with the corrected information.

2.1.1.1.2 Prepare aerial maps of the assessment extents.

2.1.1.2 Document the pipeline threat information on GTIM-90209 “Threat Analysis”.

2.1.1.3 Document the assessment extents on GTIM-90310 “Pressure Test”.

2.1.1.3.1 Include the HCA or MCA footage and the total assessed footage.

2.1.1.4 Determine the feasibility of performing a pressure test. Document the justification on GTIM-90310 “Pressure Test”.

2.2 Responsibility: GTIM Engineer and Gas Transmission Engineering or Gas Operations

2.2.1 Select test pressures that maximize the reassessment interval, when appropriate.

2.2.1.1 Refer to procedure GTIM-06-001 “Determining Reassessment Intervals”.

2.2.2 Document the maximum and minimum test pressures on GTIM-90310 “Pressure Test”.

2.2.3 Document the test duration on GTIM-90310 “Pressure Test”.

2.2.3.1 Use an 8-hour minimum pressure test duration with pipeline integrity assessments.

2.2.4 Select and document the test medium on GTIM-90310 “Pressure Test”.

2.2.4.1 If water is the test medium:

2.2.4.1.1 Examine the elevation gradient to determine the length and number of test sections, and to ensure the test pressure is within specified limits.

2.2.4.1.2 Maintain the minimum test pressure at the highest elevation location.

2.2.4.1.3 The highest pressure at the lowest elevation must remain below the maximum test pressure.

2.2.4.1.4 Confirm the manufacturer’s hydrostatic test limitations for valves, testing materials, and other prefabricated components (such as pig traps, manifolds, flanges, etc.).

2.2.4.1.5 Develop a dewatering plan for drying each segment.

2.2.5 Perform an engineering-analysis to determine if a spike test is appropriate based on information gathered during the Pre-Assessment and Threat Analysis.

2.2.5.1 If a spike test is deemed appropriate and selected, perform the spike test according to §192.506.

2.2.5.1.1 Requirements of §192.506 include:

- Pipeline operating at a hoop stress level at or greater than 30% SMYS;
- Test medium must be water;
- Baseline test pressure must meet the pressure specified in §192.619(a)(2);
- The test must maintain pressure at or above the baseline test pressure for at least 8 hours;
- After the test-pressure stabilizes at the baseline pressure, and within the first two (2) hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS; and
- This pressure must be held for at least 15 minutes after the spike test pressure stabilizes.

2.2.5.2 Document the following on GTIM-90310:

- Test selection justification;
- Minimum and maximum test duration;
- Test pressure;
- Test %SMYS at highest stress location and lowest stress location; (Generally, this will be at the low point and high point in the test segment, unless the pipeline attributes vary along the test segment.); and
- Maximum (do not exceed) pressure.

2.2.6 Document any preparations required on GTIM-90310 before performing the test.

2.2.6.1 Complete required line modifications before testing begins to achieve the desired test pressure.

2.2.6.2 Preparation activities may include, but are not limited to:

- Line modifications (reroutes, bypasses);
- Addressing customer supply issues;
- Removal of obstructions (regulators, valves);
- Installation of equipment (weld caps, blind flanges);
- Worker safety, public safety, and environmental precautions;
- Installation of temporary separators or filters on farm-taps or other laterals, if needed; and
- Inform customers and emergency responders of pending activities.

2.2.6.3 Attach details of required preparation activities.

2.2.7 Determine if field validation is required.

2.3 Responsibility: GTIM Engineer or designee

2.3.1 Maintain the Pre-Assessment documentation for the useful life of the pipeline segment.

2.3.2 Create a work order if known data attributes need correction in GIS.

2.3.3 Conduct a Pre-Assessment approval meeting.

2.3.3.1 Document the date of the meeting, attendees, the discussion items, and any follow-up.

3.0 WORK PLANNING

3.1 Responsibility: Gas Transmission Engineering and GTIM Engineer

3.1.1 For a pressure test due to an in-service leak or rupture attributable to Stress Corrosion Cracking, perform the pressure test according to ASME/ANSI B31.8S-2004, Appendix A3.4.2.

3.1.2 Develop a work plan per the requirements of 49 CFR 192 Subpart J and O&M 11.0 “Pressures”.

3.1.2.1 Include the following materials and any pertinent information received from Gas Transmission Engineering or Gas Operations.

- Form 3142 “Pipe and Appurtenance Test Data (Greater Than 60 psig MAOP)”;
- Maps of the pipeline;

- Form 3185 “Systems Operations Plan” (see form 3185SWI “System Operation Plan - Standard Work Instructions” for guidance);
- Form 3187 “Pre-Construction Walkthrough”;
- Form 3141 “Purging Record”;
- Environmental protocols; and
- Dewatering Plan.

3.1.3 Notify Gas Operations personnel of the line segments scheduled for assessment.

3.1.4 Consult with Gas Control and Gas Operations to determine system effects while the line is down for the pressure test.

3.1.5 Engage the CNP environmental team to obtain permits and for the disposal of test media per CNP environmental safety policies.

3.1.6 Prepare Dig Plan packets per GTIM-04-026 “Dig Plan Preparation” for full Integrity Management direct examination(s) at pre-test excavation sites, if applicable.

3.1.6.1 Indicate if field validation of the pressure test is required.

3.1.6.2 Direct examination is only necessary if required for pressure test preparations.

3.1.7 Attach supporting documentation to GTIM-90310 “Pressure Test”, as appropriate.

3.2 Responsibility: GTIM Engineer or designee

3.2.1 Confirm the following documentation is prepared, or complete as applicable, and attached to the Work Plan:

- GTIM-90310 “Pressure Test”, the Pre-Assessment section;
- GTIM-90300 “Data Collection Form”;
- Map of assessment extents;
- Aerial Maps;
- GTIM-90441 “Dig Plan Summary” for each location;
- GTIM-90501 “Response Schedule”;
- GTIM-90901 “Performance Measures”;
- Form 3142 “Pipe and Appurtenance Test Data (Greater Than 60 psig MAOP)”;
- Maps of the pipeline;
- Form 3185 “Systems Operations Plan” (see form 3185SWI “System Operation Plan - Standard Work Instructions” for guidance);
- Form 3187 “Pre-Construction Walkthrough”;
- Form 3141 “Purging Record”;
- Environmental protocols; and
- Dewatering Plan.

3.3 Responsibility: GTIM Manager or designee

3.3.1 Confirm the pressure test Work Plan meets the requirements of 49 CFR 192 Subpart J.

3.3.2 Approve the Work Plan and return documentation to the GTIM Engineer.

3.4 Responsibility: GTIM Engineer or designee

3.4.1 Provide copies of the Work Plan to the Gas Transmission Engineer and the GTIM Field Supervisor or GTIM Field Inspector.

4.0 PERFORMING THE PRESSURE TEST

4.1 Responsibility: GTIM Field Supervisor or GTIM Field Inspector and Pressure Testing Crew

4.1.1 Prepare for the preparation excavations per the requirements of GTIM-04-027 “Direct Examination Preparation”, if applicable.

4.1.1.1 Coordinate the direct examination(s) with the Pressure Testing Crew.

4.1.1.2 Perform the direct examinations per the Dig Plan.

4.1.2 Evaluate and document findings during the Direct Examination phase per the requirements of GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

4.1.3 Document all results of each direct examination and any remedial activities on GTIM-90418 “Pipeline Inspection for Direct Examinations”. Attach additional sheets as necessary.

4.1.4 Repair any anomalies found during the excavation, according to O&M 16 “Repairs” or CNP O&M XX “Transmission Pipeline Repair”.

4.2 Responsibility: GTIM Engineer or designee

4.2.1 Create a work order to incorporate or update data attributes in GIS which result from activities such as:

- All data collected during bell hole digs and direct examinations (i.e., GTIM-90418, etc.);
- Any pipeline modifications made;
- Pipe attributes collected or observed during assessments that are not currently correct in GIS.

4.2.2 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

4.3 Responsibility: GTIM Field Inspector or designee

4.3.1 Complete the required forms in the Dig Plan. Send the following completed forms to the GTIM Field Supervisor for review and submission to the GTIM Engineer.

- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- GTIM-90441 “Dig Plan Summary”;
- GTIM-90471 “Magnetic Particle Inspection Report”, if applicable; and
- Form 3020 “Excavation Repair Report”.

4.4 Responsibility: Pressure Testing Crew or Local Operations

4.4.1 Perform the pressure test per the Work Plan and Gas Transmission Engineering guidelines.

4.4.2 Hold the test pressure in the specified pressure range for the specified duration.

4.4.2.1 Extend test periods, if necessary, to accommodate work schedules or other conditions as warranted by CNP.

4.4.3 Do not add pressure to the pipeline segment without the approval of Gas Transmission Engineering.

4.4.4 Note all variations on the chart.

4.4.5 Record all deviations from the Work Plan.

4.5 Responsibility: GTIM Field Inspector or designee

4.5.1 If the work plan stipulates, coordinate monitoring the pressure testing for validation.

4.5.2 Document all deviations from the Work Plan on GTIM-90310.

4.5.3 Review and approve all pressure test results before dewatering.

4.5.3.1 If deemed necessary, approval of the pressure test results may occur off-site.

4.5.3.2 Review deviations and notify affected parties per GTIM-11-001 “GTIM Change Management” and GTIM-13-002 “Internal Communications”.

4.6 Responsibility: Pressure Testing Crew or Local Operations

4.6.1 Dispose of the test medium per CNP environmental safety policies.

4.6.2 Confirm completion of restoration to damaged ROWs or other properties caused during the dewatering process.

4.6.3 For hydrostatic tests, remove moisture from the line segment per a dewatering plan.

4.6.4 Assemble and attach to the Work Plan the documentation from the pressure test. Documentation must include, at a minimum:

- Test medium;
- Test pressure;
- Test duration;
- Test date and time;
- Pressure recording chart and pressure log;
- The volume of the test medium used and added during the test;
- Pressure versus volume plot, if applicable;
- Recorded pressure at high and low elevations;
- Elevation at the location where test pressure recorded;
- Name of person(s) conducting test and their company;
- Environmental factors (ambient temperature, raining, snowing, windy, etc.);
- Manufacturers of the line pipe, valves, etc., if known;
- Pipe specifications (e.g., SMYS, diameter, wall thickness, etc.), if known;
- Clear identification of features within each test section; and
- Describe any leaks or failures and their dispositions.

4.6.4.1 Documents include, but are not limited to, the following:

- Drawings, sketches, and photos;
- Pressure charts;
- Temperature charts;
- Calibration certifications; and

- System Operation Plan.

4.6.5 Provide copies of the documentation to the GTIM Field Inspector.

4.6.6 Retain all of the original documentation from the test and supporting documentation in the Gas Transmission Engineering Work Order file. Retain color copies in the IM file for the useful life of the pipeline.

4.7 Responsibility: GTIM Field Inspector or designee

4.7.1 Review the Work Plan and test documentation from Gas Transmission Engineering.

4.7.2 Document all deviations from the Work Plan on GTIM-90310.

4.7.3 Complete the Pressure Test section of GTIM-90310.

4.7.3.1 Record the pressure test results, including the maximum and minimum pressures achieved and durations.

5.0 FAILURE IDENTIFICATION

5.1 Responsibility: Pressure Testing Crew

5.1.1 When a pressure test indicates that a leak may be present, do not tie-in the pipe segment to the gas system until the leak has been located, repaired, and all pressure testing requirements met.

5.1.1.1 If a pipe rupture occurs, retain all damaged pipe and appurtenances in a secure location for failure analysis.

5.1.1.2 Notify the GTIM Engineer of the pressure test failure. Refer to section 5.3 in this document.

5.1.1.3 Lower or remove all the test pressure to a safe level while performing repairs on the exposed pipe.

Note: If the leak is too small to locate, consult with Integrity Management. Consider adding P&M activities to monitor line leakage.

5.1.2 After repair completion, re-perform the pressure test per the requirements of this procedure.

5.1.2.1 Any previously obtained elapsed testing time before the failure and repair or replacement does not count toward the minimum required test duration.

5.1.3 Complete all required documentation, including, as applicable:

- Form 3112 “Gas Damage Report”;
- “Facilities Damage Transmission Supplemental” form; and
- Form 3105 “Pipe Exam”.

5.1.4 Provide copies of all repair documentation to the GTIM Field Inspector.

5.1.5 Retain all original documentation in the Gas Transmission Engineering work order file and color copies in the IM file for the useful life of the pipeline.

5.2 Responsibility: GTIM Field Inspector or designee

5.2.1 Complete GTIM-90310 and GTIM-90418 “Pipe Inspection Direct Examination”.

5.2.1.1 Include documentation of any required follow-up activities.

5.2.2 Attach all supporting documentation, including repair documents to GTIM-90310, as applicable.

5.2.3 Provide all documentation to the GTIM Field Supervisor for review and submission to the GTIM Engineer.

5.3 Responsibility: GTIM Engineer or designee

5.3.1 Perform root cause analysis, per GTIM-04-012 “Root Cause Analysis”, on all pressure test failures.

5.3.1.1 If the root cause of the pressure test failure is corrosion, refer to procedure GTIM-08-005 “Evaluating Similar Conditions”.

5.3.2 Review all documentation for completeness.

5.3.3 Attach GTIM-90421 “Root Cause Analysis” documents to GTIM-90310.

5.3.4 Create a work order if known data attributes need correction in GIS.

6.0 REASSESSMENT INTERVALS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Calculate the reassessment interval per GTIM-06-001 “Determining Reassessment Intervals”.

6.1.1.1 Document the reassessment interval on GTIM-90310.

6.1.2 If applicable, update GTIM-90501 “Response Schedule” to document any remediation activities and required response times.

6.1.3 For scheduling purposes, assign a tentative assessment method for the next scheduled assessment.

6.1.4 Add Reassessments, Confirmatory Direct Assessments, Scheduled Conditions, and other remediation activities to the assessment schedule calendar.

7.0 PREVENTIVE AND MITIGATIVE MEASURES

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Create a new GTIM-90209 “Threat Analysis” (Post-Assessment) with the following information:

- Newly identified threats;
- Elimination of threats; and
- Changes to existing threat documentation.

7.1.1.1 Refer to GTIM-02-021 “Threat Identification”.

7.1.1.2 Create a work order to incorporate any modified attributes.

7.1.2 Review the Preventive and Mitigative (P&M) Measures implemented for the applicable covered segment(s).

7.1.2.1 Consider implementing additional P&M measures. Refer to GTIM-08-004 “Identify Preventive and Mitigative Measures”.

7.1.2.2 Complete GTIM-90804 “Preventive and Mitigative Measures”.

8.0 PERFORMANCE MEASURES

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Document Performance Measures on GTIM-90901 “Performance Measures”.

8.1.1.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

8.1.1.2 Document the total HCA miles or total MCA miles assessed.

9.0 FEEDBACK AND CONTINUOUS IMPROVEMENT

9.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

9.1.1 Request feedback from project participants (i.e., Gas Transmission Engineering, Local Operations, Corrosion Control, etc.). Feedback topics should include, but are not limited to:

- Failure identification;
- Failure analysis;
- Root-cause analysis;
- Remediation activities;
- In-process evaluations;
- Scheduled and monitoring follow-ups; and
- Reassessment intervals.

9.1.2 Solicit “lessons learned” from project participants upon completion of the pressure test.

9.1.2.1 Consider addressing the following in the “lessons learned” communications.

- Things that went well during the process;
- Areas for improvement; and
- Modifications needed to the Pressure Testing procedures.

9.1.2.2 If appropriate, invite feedback from the Service Provider(s).

9.1.2.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

9.1.3 Document feedback and continuous improvement activities on GTIM-90310 “Pressure Test”.

9.2 Responsibility: GTIM Engineer or designee

9.2.1 Review the results of the feedback and determine additional areas of improvement.

9.2.2 If applicable, initiate a change request according to GTIM-11-001 “GTIM Change Management” for each additional P&M recommendation, and any other potential process improvement.

9.2.2.1 Initiate, if applicable, a CNP Management of Change request for publishing any modifications to GTIM-Plan procedures.

9.2.3 Summarize the repairs made and describe any required or recommended follow-up activities on a GTIM-90424 “Summary Report to Local Operations”.

9.2.3.1 Send GTIM-90424 to Local Operations and Corrosion Control.

10.0 CHANGES AND INTERNAL COMMUNICATIONS

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Confirm the submission of all change management requests. Document the submission confirmation date on GTIM-90310.

10.1.2 Confirm data collected from field activities matches data recorded on the GTIM-90300 “Data Collection Form” during the pre-assessment phase of this assessment.

10.1.2.1 If the field activities data is different from the data on form GTIM-90300, update the form, and create a work order to update the GIS data.

11.0 POST-ASSESSMENT DOCUMENTATION

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Perform a 100% quality check of all requested GIS updates. Document the date confirmed on GTIM-90310.

11.1.2 Confirm completion of Post-Assessment documentation. Documentation includes, but is not limited to, the following:

- GTIM-90209 “Threat Analysis”;
- GTIM-90310 “Pressure Test”;
- GTIM-90418 “Pipeline Inspection Direct Examination” (for each dig location);
- GTIM-90421 “Root Cause Analysis”;
- GTIM-90424 “Summary Report to Local Operations”;
- GTIM-90471 “Magnetic Particle Inspection Report”;
- GTIM-90501 “Response Schedule”;
- GTIM-90804 “Preventive and Mitigative Measures”;
- GTIM-90901 “Performance Measures”;
- GTIM-91101 “Pipeline Event Evaluation”;
- GTIM-91102 “Integrity Change Management Record”;
- Calibration certifications;
- Drawings, sketches, and photos;
- Pipeline Elevation Profile;
- Aerial Maps;
- Map of assessment extents;
- Form 3105 “Pipe Exam”;
- Form 3141 “Purging Record”;
- Form 3142 “Pipe and Appurtenance Test Data (Greater Than 60 psig MAOP)”;
- Form 1021 “Job Safety Briefing Form”;
- Pressure and temperature charts and logs;
- Remaining Strength calculations;
- Form 3020 “Excavation Repair Report”;
- Form 3112 “Gas Damage Report”; and
- “Facilities Damage Transmission Supplemental” form.

11.1.3 Conduct a meeting with the GTIM Manager to review the Post-Assessment documentation and obtain approval.

11.1.4 Once the Post-Assessment is approved, the pressure test process is considered complete.

11.1.5 Confirm all assessment documentation is stored in the IM file within 30 days of completing the Post-Assessment process.

<<END>>

GTIM-03-004 Pigging - Cleaning

PURPOSE: To establish a standardized method for the use of cleaning pigs when used in preparation for other internal inspection tools to perform an Integrity Assessment.

REFERENCES: 49 CFR 192.921; 49 CFR 192.750; ASME/ANSI B31.8S-2004, Section 6;

SECTIONS:

- Background
- Preparing for the Pig Run
- Launching and Receiving the Pig
- Sampling
- Documentation

1.0 BACKGROUND

1.1 Cleaning a pipeline increases the pipeline's operating efficiency and facilitates internal inspection of pipelines with an In-Line Inspection tool.

1.1.1 Pigging operations may involve one or all of the following processes based on pipeline conditions:

- Regular sweeping of the pipeline to remove liquids or solids;
- Periodic liquids removal; or
- Cleaning of a pipe's inside surface with scrapers or brushes.

2.0 PREPARING FOR THE PIG RUN

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Coordinate with the GTIM Field Supervisor, and the Service Provider to determine the type of cleaning to be utilized and the frequency of line cleaning. Consider the following:

- Historical and expected contaminants (i.e., dust, scale, paraffin, etc.);
- Previous pigging results;
- The volume of contaminants historically removed from the line;
- Consider the ability to capture and separate contaminates during a cleaning; and
- The presence of corrosives.

2.1.2 Modify the cleaning tool configuration when appropriate to find the most effective cleaning design for the line segments' operating conditions.

2.1.3 Equip the launcher and receiver with a device capable of safely relieving pressure in the barrel.

2.1.4 Coordinate with Gas Control to evaluate reductions in flow efficiency that may be the result of liquids or solids build up in pipelines.

2.1.5 Collect and review any concerns with stakeholders of liquids entering other parts of the system from laterals and take-offs as a result of the cleaning process.

2.2 Responsibility: GTIM Field Supervisor or designee

2.2.1 Schedule cleaning pigs as required for:

- Solids removal; and
- Liquids removal.

2.2.1.1 Confirm GTIM-90302 “Report of Cleaning Pig Operations” is completed for each cleaning application.

2.2.1.2 Restock cleaning pigs and other equipment as needed.

2.3 Responsibility: GTIM Field Supervisor or designee

2.3.1 Coordinate with safety and environmental departments to review and discuss:

- Safety concerns; and
- Environmental issues.

2.3.2 Refer to CNP safety and waste disposal policies.

2.4 Responsibility: Local Operations or GTIM Field Inspector or designee

2.4.1 Review the pigging plan with all involved parties, which may include a dry run if needed.

2.4.2 Confirm the pipeline is ready for the pig run by:

- Removing all sample probes;
- Verifying bypass valves are in the ‘closed’ position to prevent the pig from stopping;
- Verifying the pig launcher valve is closed; and
- The pig receiver gate is open.

2.4.3 Photograph the cleaning pig before launching.

3.0 LAUNCHING AND RECEIVING THE PIG

3.1 Responsibility: Local Operations or GTIM Field Inspector or designee

3.1.1 Confirm the successful launch of the pig by using one of the following methods:

- Geophones;
- Transmitter signal;
- Visual examination of pig signal; or
- Pipeline Pressure Gauges.

3.1.2 When detecting a large volume of liquids in the pipeline, notify Gas Control to allow Gas Control the opportunity to adjust the flow.

3.1.2.1 Allow time to confirm liquid handling equipment and personnel are in place.

3.1.3 Verify the pig has been received and has cleared the pig receiver gate by one of the following processes:

- Geophones;
- Transmitter signal;
- Personal observation (listening for pig); or
- Examination of the pig signal.

3.1.4 Remove the pig from the receiver assembly.

3.1.5 Photograph the pig after removal.

3.1.6 Collect material and liquid samples, if present, using the proper extraction, storage, and transportation techniques.

3.1.7 Measure the volume of contaminants removed from the pipeline and document on GTIM-90302 “Report of Cleaning Pig Operations”.

Note: Take samples used to analyze pipeline liquids from the receiver barrel.

3.1.8 Consult with the GTIM Field Supervisor and the ILI Service Provider to determine the need for additional cleaning runs or other adjustments.

4.0 SAMPLING

4.1 Responsibility: GTIM Field Supervisor or designee

4.1.1 Sample and test fluids and solids after the first cleaning run.

4.1.1.1 When performing multiple cleaning pig runs, sampling is only necessary with the first run.

4.1.2 Obtain as much sample as possible in the container, at least 250 ml (recommended), and perform the necessary field measurements as recommended by the Environmental Department with a minimum amount of sample.

4.1.2.1 When collecting samples, make sure to completely fill the sample container to remove any air from it and then immediately close the container.

4.1.2.2 Do not contaminate the sample by touching the inside surfaces of the container.

4.1.3 Measure the temperature of the liquids using a thermometer.

4.1.4 Perform all field tests immediately after obtaining the sample, particularly the tests for bacteria.

4.1.4.1 Perform the following field tests on aqueous liquids in the following order:

- Sulfate Reducing Bacteria;
- Acid Producing Bacteria;
- pH;
- Alkalinity;
- Dissolved H_2S; and
- Dissolved CO_2.

4.1.4.2 Perform a field test for sulfate-reducing and acid-producing bacteria per procedure GTIM-04-011 “Field Testing for Microbiologically Influenced Corrosion Bacteria”.

4.1.4.3 Test the pH of the liquid with pH test paper.

4.1.4.4 Perform the alkalinity testing on the sample with the appropriate field test kit, per the instructions included with the kit.

4.1.4.5 Obtain the appropriate Hydrogen Sulfide (H_2S) field-test kit (Hach Field Test Method).

4.1.4.5.1 Perform the Hach Field Test Method by following the instructions included in the kit.

4.1.4.6 Obtain the appropriate field test kit for testing dissolved carbon dioxide (CO_2).

4.1.4.6.1 Perform the field test per the instructions provided with the kit.

4.1.4.6.2 Dissolved CO_2 needs to be measured immediately after the sample is collected. Dissolved CO_2 test kits measure the amount of CO_2 in the test solution at the time of testing.

4.2 Responsibility: GTIM Field Supervisor or designee

4.2.1 Arrange for a qualified laboratory to perform a comprehensive analysis of the liquids.

4.2.2 Contact the laboratory before collecting the sample.

4.2.2.1 The laboratory performing the analytical work can provide pre-cleaned containers containing the appropriate preservatives accompanied by pertinent Material Safety Data Sheets (MSDS).

4.2.2.2 The laboratory should provide specific sample collecting instructions.

4.2.3 Confirm the laboratory explains any solids found in the fluid and tests the sample for the following items:

- Iron (mg/L);
- Manganese (mg/L);
- Barium (mg/L);
- Strontium (mg/L);
- Chlorides (mg/L);
- Sulfates (mg/L);
- Sulfide (ppm or mg/L);
- Silicon (mg/L);
- Chemical Residuals (i.e., corrosion inhibitors, biocides, etc.); and
- Total Dissolved Solids or Specific Conductance.

4.2.4 When directed by the GTIM Field Supervisor or when the following may be an issue, instruct the laboratory to test for the following:

- Glycols, Methanol, and other organic compounds of interest; and
- Hydrocarbons.

4.3 Responsibility: Local Operations or GTIM Field Supervisor or designee

4.3.1 If solids are present, use a sterile spatula or knife to collect a sample of the solid material.

4.3.1.1 Test these solids in the field:

- Sulfate Reducing Bacteria;
- Acid Producing Bacteria;
- pH;
- Carbonate (qualitative analysis only); and
- Sulfide (qualitative analysis only).

4.3.2 Test the sample for bacteria per GTIM-04-011 “Field Testing for Microbiologically Influenced Corrosion Bacteria”.

4.3.3 Test the pH of the solid with pH test paper.

4.3.4 Test for carbonates and sulfides.

4.3.4.1 Field-testing for carbonates and sulfides confirms the presence of the substances but does not indicate the quantities present.

4.3.4.2 Add a couple of drops of 1.0 hydrochloric acid (with a concentration range of (0.005 - 0.16 mg of H_2S/L) to a large “pea-size” amount of the solid in a test tube.

4.3.4.2.1 If the sample effervesces or if active bubbling occurs, carbonate is present.

4.3.4.2.2 If a “rotten egg” odor is detected coming from the barrel of the test tube, sulfide salts are present.

Note: Hydrochloric acid is extremely corrosive. Use extreme caution when handling. Review the Material Safety Data Sheet before use and wear the appropriate designated personal protective equipment.

4.4 Responsibility: GTIM Field Supervisor or designee

4.4.1 As appropriate, submit a sample of the solids to a qualified laboratory for comprehensive laboratory analysis.

4.4.2 Contact the laboratory before collecting the sample.

4.4.2.1 The laboratory can provide pre-cleaned containers containing the appropriate preservatives accompanied by pertinent MSDS Sheets.

4.4.2.2 The laboratory should provide specific sampling instructions.

4.4.3 Instruct the laboratory to monitor the following items:

- Iron (mg/kg);
- Manganese (mg/kg);
- Barium (mg/kg);
- Strontium (mg/kg);
- Chlorides (mg/kg);
- Sulfates (mg/kg); and
- Sulfides (mg/kg).

4.5 Responsibility: GTIM Field Supervisor or designee

4.5.1 Label all samples collected for laboratory analysis to include the following:

- Sample location identification information;
- Date and time of the sample collection; and
- Name of the sample collector.

4.5.2 Send all samples to a qualified laboratory for analysis.

4.5.2.1 Obtain a list of approved laboratories from the Environmental Department.

4.5.2.2 Instruct the laboratory on what tests to perform.

4.5.3 Take proper care before shipping the sample(s).

4.5.3.1 Wrap all samples with bubble wrap, foam peanuts, and other padding material in such a manner that containers are separated and will not break.

4.5.3.2 Special-shipping or transportation requirements are necessary for samples containing non-stable or pyrophoric-prone sulfides.

5.0 DOCUMENTATION

5.1 Responsibility: GTIM Field Supervisor or designee

5.1.1 Review the results of all field tests and laboratory analyses.

5.1.2 If MIC is present, notify the GTIM Engineer.

5.2 Responsibility: GTIM Engineer or designee

5.2.1 Review the results of the data.

5.2.2 Consult with subject matter experts to develop a plan of action when MIC is present.

5.2.3 Develop appropriate Action Plans as necessary.

5.2.4 Recommend changes to the cleaning method or frequency as needed.

5.2.5 Maintain GTIM-90302 “Report of Cleaning Pig Operations” in the IM file.

5.2.6 Provide a copy of the GTIM-90302 “Report of Cleaning Pig Operation” to the Environmental Department.

<<END>>

GTIM-03-005 In-Line Inspection Pre-Assessment

PURPOSE: To establish a standardized method for the assessment of a pipeline using In-Line Inspection (ILI) tools to gather data for the detection and identification of pipeline anomalies.

REFERENCES: 49 CFR 192 Subpart O; ANSI/ASNT ILI-PQ-2005; ASME/ANSI B31.8S-2004, Section 6; NACE SP0102-2010; API Std 1163-2013; NACE Publication 35100-2000;

SECTIONS:

- Background
- ILI Feasibility
- HCA, MCA, and Identified Site Review
- Data Collection and Review
- ILI Tool Selection
- Pre-Assessment Documentation

1.0 BACKGROUND

1.1 In-Line Inspection (ILI) tools are also known as “intelligent” or “smart” pigs.

1.2 ILI is a methodology used to assess multiple threats on a pipeline. The effectiveness of the ILI process depends on the appropriateness of the tool for the stated inspection objectives.

1.2.1 Typically, ILI is an appropriate assessment method for external corrosion, internal corrosion, stress corrosion cracking, third-party damage, and mechanical damage.

1.2.2 ILI can be useful for mapping, locating, and identifying various pipeline features and anomalies such as:

- Pitting and general corrosion;
- Cracking including stress corrosion cracking;
- Longitudinal and girth weld defects;
- Dents and gouges;
- Pipe deformation and ovality;
- Hard spots;
- Valves, tees, fabricated assemblies; and
- Pipeline segments less than 15-feet in length.

1.2.3 ILI assessments are typically not considered valid for assessing:

- Non-stable Manufacturing defects; and
- Non-stable Construction defects.

1.3 ILI Assessment consists of four phases:

- Pre-Assessment;
- In-Line Inspection Tool Run;
- Direct Examination; and
- Post-Assessment.

Note: To maintain and demonstrate the safety, integrity, and reliability of CNP transmission pipelines, CNP is retrofitting many transmission pipelines to be 'Internal Inspection ABLE'.

1.3.1 If applicable, Pre-Assessment documentation may include information from:

- In-Line Inspection Feasibility studies; and
- Pipeline modifications (i.e., retrofits).

2.0 ILI FEASIBILITY

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Gather, review, and verify data from various internal and external sources to determine if pipeline equipment and appurtenances will permit the passage of an internal tool. Data sources include, but are not limited to:

- GIS;
- Previous assessment documentation; and
- Any previous ILI feasibility studies performed on these segments.

2.1.1.1 Review the pipeline characteristics to determine if segments are capable of internal inspection with ILI tools. Consider the following:

- Internal pipe diameter changes (tool passage restrictions);
- Protruding devices, probes, and coupons (tool damage and passage restrictions);
- Wall thickness changes (speed control influences);
- Short radius or back-to-back bends (tool passage restrictions);
- Reduced bore valves and fittings (tool passage restrictions);
- Field bends and bends at crossings (tool passage restrictions of certain types and sizes of tools);
- Internal coatings (abrasive tools may damage coatings);
- Taps, branch connections, or back-to-back tees (prevent proper propelling of internal fluids or gases);
- Unbarred branch connections, mainline drips, and outlets equal to or greater than 50% of the pipeline nominal diameter (device restraint at openings); and
- Adequate pressure and flow available to propel the tool without exceeding the pipeline's MAOP:
  - Consider options to control tool speed (i.e., variable bypass tools);
  - Tools such as Circumferential MFL and Dual Diameter may require pressure greater than the pressure required for standard MFL tools of the same size.

2.1.2 Review pipeline launching and receiving facilities. Consider the following:

- Using existing facilities or arrange for construction of temporary facilities;
- Adequate workspace around the facilities;
- Adequate barrel lengths for the potential tool(s);
- Appropriately sized kicker lines for tool propulsion; and

- Properly sized fittings, and tool indicators, for venting, tool bypass, line equalization, fluid collection, and drainage.

2.1.3 Review the pipeline environment. Consider the following:

- Specialized work plans to address the use of tied or tethered tools, pulled and pushed through short segments of a pipe; and
- Tools compatible with the pipeline's operating temperatures and pressures.

2.1.4 Review pipeline product. Consider the following:

- Is product flow sufficient to propel the tool at recommended velocities?
- Can the pipeline system adequately relieve/consume the pressure downstream of the tool?
- Ability to identify impacted customers in the event of a flow restriction or stoppage?
- Are there any corrosive fluids which can damage inspection tools?
- Perform cleaning runs to remove debris before the ILI run?

2.1.5 Consult with Gas Control and Gas System Design to verify the required flow rates and system characteristics for the pipeline to be inspected.

2.1.6 Document feasibility on GTIM-90313 "In-Line Inspection - Pre-Assessment".

3.0 HCA, MCA, AND IDENTIFIED SITE REVIEW

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Perform a site visit to verify covered segment boundaries and the locations of Identified Sites if necessary.

3.1.2 Create a work order if known HCA, MCA, or structure information needs correction in GIS.

3.1.3 Prepare aerial maps of the covered segments for the pipeline, including extents.

3.1.4 Document the assessment segment information for the pipeline on GTIM-90313 and GTIM-90209 "Threat Analysis".

4.0 DATA COLLECTION AND REVIEW

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Perform data collection per GTIM-02-001 "Data Gathering and Research".

4.1.2 Review and update the GTIM-90300 "Data Collection Form" for the pipeline segment(s) to be assessed.

4.1.3 Review the applicable threats to each pipeline segment.

4.1.3.1 Refer to GTIM-02-021 "Threat Identification" and complete GTIM-90209.

4.1.4 Establish goals for the ILI run and document on GTIM-90313. Goals can include the following:

- Detection of anomalies;
- Location of pipeline features;
- Accuracy and resolution requirements;
- The ability of the tool to discern between anomalies;
- Tool speed; and

- Capable of identifying pipeline segments less than 15-feet in length.

4.1.5 Collect and review pipeline information. Types of data may include, but are not limited to:

- As-built pipeline alignment and profile drawings;
- Purchasing records of pipe, valve, fittings, etc.;
- Weld and joint length records;
- Construction detail drawings;
- Survey books and notes;
- Previous pigging runs;
- Prior line inspection and repair records;
- Third-party construction records such as foreign crossings;
- Subject Matter Expert operating and construction experience;
- Customers affected by ILI;
- One-way feeds (i.e., filter fittings, bypass piping); and
- Existing Preventive and Mitigative (P&M) Measures.

4.1.5.1 Refer to GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

4.1.6 Review data from previous In-Line Inspections, if applicable.

4.1.6.1 Confirm the accurate integration of the following into GIS:

- Centerline data;
- AGM data;
- Valve location data;
- Repairs/mitigative actions performed;
- Unity Plot data; and
- Any other significant applicable findings.

4.1.7 Document information gathered on GTIM-90300 and GTIM-90312 “ILI Pre Assessment Questionnaire”.

4.1.8 Create a work order, if known data attributes need correction in GIS.

4.1.8.1 Example: No casing identified in GIS, and yet through pre-assessment research, such as as-built records or actual observation, determines that a casing does exist.

4.1.9 Document the rationale for the method selection on GTIM-90313 “In-Line Inspection - Pre-Assessment”.

5.0 ILI TOOL SELECTION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 In addition to the Inertial Mapping Unit (IMU) tool type, select other types of tools to run based on the identified goals and objectives of the inspection, matching relevant pipeline attributes and expected anomalies with the capabilities and performance of the specific set of ILI tools listed below.

Note: Running multiple tool types improves the sizing accuracy, identification of anomalies, characterization of interacting threats, and data alignment.

Conduct assessments with tethered or remotely controlled tools, not explicitly discussed in NACE SP0102-2010, provided they comply with those sections of NACE SP0102-2010 that are applicable.

Table 03-005-1: ILI Technology Systems[1]

Inspection Technology	Tool Description / Capability	Propulsion Method
Magnetic Flux Leakage *(MFL)*	• Oldest and most widely used technology for metal loss indications such as corrosion and gouges; • Limited sizing accuracy for irregular geometries such as dents; • High-resolution MFL tools can detect circumferential indications; • Limited detection capabilities for mill defects such as laminations or inclusions; • Detects previous repairs with steel sleeves or ferrous markers;	• Free Swimming; • Tethered; • Robotic;
Caliper / Geometry	• Used for ovality and dent detection and sizing due to construction flaws, soil movement, and third-party damage; • Used for detecting damage to the line involving deformation of the pipe cross-section; • Tools range from single-channel gauging pigs to multi-channel caliper pigs; • Pre- MFL tool usage to verify pipeline bore and bend radii allows safe passage of the ILI tool;	• Free Swimming; • Tethered; • Robotic (subject to vendor and tool size);
MFL/Transverse Flux Inspection *(TFI)*	• Identifies and measures metal loss; • Used to determine the location and extent of longitudinally-oriented corrosion; • Useful for detecting seam-related corrosion; • Cracks and other defects can be detected, though not with the same level of reliability; • Detection and sizing of cracks and crack-like defects; • May be able to detect axial pipe wall defects - such as cracks, lack of fusion in the longitudinal weld seam, and stress corrosion cracking - that are not detectable with conventional MFL and ultrasonic tools; • Lower Probability of Detection for tight cracks; • Limited detection capabilities for mill defects such as laminations or inclusions; • Detects previous repairs with steel sleeves or ferrous markers;	• Free Swimming • Tethered

[1] Adapted from NACE SP0102-2010 “In-Line Inspection of Pipelines”, Table 1: “Types of ILI Tools and Inspection Purposes”.

Inspection Technology	Tool Description / Capability	Propulsion Method
Compression Wave Ultrasonic Testing *(CWUT)*	• Measures pipe wall thickness and metal loss; • The successful deployment of a UT tool is dependent upon pipe cleanliness, specifically the removal of paraffin build-up within the pipe; • The use of a cleaning pig is recommended before use of UT tools; • Detection and sizing of metal loss, including narrow axial external corrosion; • Detection and sizing of laminations and inclusions; detection of other mill anomalies; • UT tools are liquid-coupled tools. Run either in a liquid slug or a completely liquid-filled line;	• Free Swimming
Shear Wave Ultrasonic Testing *(SWUT)*	• Most reliably detects longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking); • Shear Wave UT is categorized as a liquid coupled tool. It uses shear waves generated in the pipe wall by the angular transmission of UT pulses through a liquid coupling medium (oil, water, etc.). The angle of incidence obtained in pipeline steel is adjusted such that a propagation angle is 45 degrees; • Run either in a liquid slug or a completely liquid-filled line; • Appropriate for longitudinal crack inspection;	• Free Swimming
Inertial Mapping Unit *(IMU)*	• Mapping tools provide pipeline coordinates and can also be used to detect and size bends, dents, sharp dents, wrinkle bends, and buckles; • Coordinates provided to sub-cm accuracy is preferred;	• Free Swimming • Tethered

6.0 PRE-ASSESSMENT DOCUMENTATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Perform a 100% quality check of all requested GIS updates.

6.1.2 Confirm completion of the following forms:

- GTIM-90209 “Threat Analysis”;
- GTIM-90300 “Data Collection Form”;
- GTIM-90312 “ILI Pre-Assessment Questionnaire”; and
- GTIM-90313 “In-Line Inspection - Pre-Assessment”.

6.1.3 Retain forms and supporting documentation in the IM file.

6.1.4 Conduct the Pre-Assessment approval meeting.

6.1.5 Communicate scope and schedule to the GTIM Field Supervisor when the Pre-Assessment phase has been completed and approved.

<<END>>

GTIM-03-006 In-Line Inspection and Data Analysis

PURPOSE: To establish a standardized method for performing an In-Line Inspection (ILI) and analysis of the data.

REFERENCES: 49 CFR 192 Subpart O; ASME/ANSI B31.8S-2004, Section 6; NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:

- Background
- ILI Assessment Preparation
- Performing the In-line Inspection
- Field Review of Inspection Data
- Post-Run Verification
- Preliminary Indications
- Evaluation of In-line Inspection Tool Results
- Review of Preliminary Report
- Evaluating ILI Data for Dents
- Third-Party Damage
- Determination of Validation Examination Locations
- Dig Plan Preparation
- In-Line Inspection and Data Analysis Documentation

1.0 BACKGROUND

1.1 The In-Line Inspection phase consists of performing the tool run, evaluation of the inspection data, and the development and approval of a direct examination plan.

2.0 ILI ASSESSMENT PREPARATION

2.1 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

2.1.1 Coordinate the project with internal stakeholders per procedure GTIM-03-011 “In-Line Inspection Tool Run Preparation”.

2.1.2 Coordinate the placement of aboveground markers per GTIM-03-011.

2.1.3 Review approved Pre-Assessment documentation for any changes that may have occurred along the pipeline between completion of the Pre-Assessment and the time of the ILI tool runs.

2.1.3.1 If applicable, amend the approved Pre-Assessment documentation and review it with the GTIM Manager.

2.1.3.2 If modifying the approved Pre-Assessment document, create a change management record per GTIM 11-001 “GTIM Change Management” documenting the changes.

3.0 PERFORMING THE IN-LINE INSPECTION

3.1 Responsibility: GTIM Field Supervisor or designee

3.1.1 Verify the Service Provider personnel qualifications on-site before commencing work.

3.1.2 Before beginning the tool run(s), review the survey acceptance criteria with the Service Provider.

3.1.2.1 Refer to the contract specifications and GTIM-12-001 “In-Line Inspection Data Acceptance” for guidance.

3.1.2.2 Confirm the resolution of the mapping data will be adequate.

3.1.2.3 In some cases, the GTIM Field Supervisor, GTIM Engineer, and the Service Provider may mutually agree that different survey acceptance criteria are appropriate. If such a case exists, agree on the criteria and document the new criteria on GTIM-90314 “In-Line Inspection and Data Analysis”.

3.1.2.4 Failure of a tool run to meet the acceptance criteria may result in a rerun of the tool.

3.1.3 Test the data recording unit’s operability before beginning each tool run.

3.1.4 Coordinate the In-line Inspection per the established tool run schedule and GTIM-03-011.

3.1.5 Follow the tool run schedule for running the tools and controlling the product flow during the tool run.

3.1.5.1 Communicate any deviations from the existing tool run schedule (i.e., multiple runs, running additional tools, etc.) to the appropriate stakeholders.

3.1.6 Before placing a tool in the pipeline, photograph each tool.

3.1.7 If the service provider conducts a radiation survey, document the radiation levels before and after each ILI tool run on GTIM-90314.

3.2 Responsibility: GTIM Field Inspector or designee

3.2.1 Run cleaning pigs as required.

3.2.1.1 Refer to GTIM-03-004 “Pigging - Cleaning” for additional information on the collection and sampling of solids and liquids removed from the pipeline.

3.2.1.2 Multiple cleaning tool runs may be required.

3.2.1.3 Document the cleaning pig runs on GTIM-90302 “Report of Cleaning Tool Operations”.

3.2.2 Run tools with gauge plates and caliper tools as required.

3.2.2.1 Evaluate the results of the gauge and caliper tool run(s) and resolve any pipeline concerns before running additional In-line Inspection tool(s).

3.2.3 Take photographs of each tool before and after each run.

3.2.4 Notify the GTIM Field Supervisor and GTIM Engineer of any significant issues.

3.2.5 Monitor and document the tool speed using GTIM-90303 “ILI Tool Above Ground Marker Log”.

3.2.5.1 Record other related, pertinent information on GTIM-90303 “ILI Tool Above Ground Marker Log”.

3.2.5.1.1 Record the time that the tool passes each AGM in military time.

3.2.5.1.2 Calculate the tool velocity between each benchmarked location on GTIM-90303.

3.2.5.2 Confirm pressures and tool speed recommended by the Service Provider and agreed upon by CNP. ILI tools typically travel between four (4) and seven (7) mph.

4.0 FIELD REVIEW OF INSPECTION DATA

4.1 Responsibility: GTIM Field Supervisor or designee

4.1.1 Inspect the tool after removal from the pipeline.

4.1.1.1 Look for physical damage to the sensors per GTIM-12-001 “In-Line Inspection Data Acceptance”, section “1.0 Sensors”.

4.1.2 Document the review on GTIM-90314.

5.0 POST-RUN VERIFICATION

5.1 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

5.1.1 Before releasing the ILI Service Provider from the job site, confirm completion of the following:

- Verify tool is operational and functioning;
- All specified locations (e.g., AGMs) were identifiable;
- Document the electronic raw data file size;
- Receipt of odometer footage; and
- Tool damage documentation, if applicable.

5.1.1.1 Review the data quality assessment report for acceptance, sent by the Service Provider, usually within 24 hours.

6.0 PRELIMINARY INDICATIONS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Request the Service Provider provides notification to the GTIM Field Supervisor or GTIM Engineer of any indications requiring attention before the issuance of the Preliminary Report. Indications include:

- Wall loss greater than or equal to 80%, factoring in the Service Provider’s tool tolerance;
- Any dent with a depth greater than 6% of the pipeline diameter (e.g., dent with a depth greater than 0.50 inches for a pipeline diameter less than the Nominal Pipe Size (NPS) of 12);
- Any dents with wall loss.

6.1.2 Determine if any of the preliminary indications should be considered ‘Immediate’ indications.

6.1.3 Review all preliminary ‘Immediate’ indications with the GTIM Manager to determine a plan of action.

6.1.3.1 If remediation will likely require a large section of pipe to be repaired or replaced, engage Gas Transmission Engineering to perform remediation.

7.0 EVALUATION OF IN-LINE INSPECTION TOOL RESULTS

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Confirm the Service Provider provides the Preliminary Report within thirty days (30) after tool removal.

7.1.1.1 Refer to GTIM-12-001 “In-line Inspection Data Acceptance” for details on the ILI tool run acceptance criteria.

7.1.2 Complete the appropriate section of GTIM- 90314.

8.0 REVIEW OF PRELIMINARY REPORT

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Review the Preliminary Report provided by the ILI Service Provider.

8.1.2 Confirm the report meets all specifications outlined in the contract.

8.1.3 Review the Preliminary Report for any indications with a severity that requires action before the expected date of the Final Report.

8.1.4 Review the Preliminary Report for accuracy and completeness.

8.1.4.1 Correct all inaccuracies and identify any missing data.

8.1.4.2 Provide the Preliminary Report revisions to the Service Provider for correction.

8.1.5 When data is complete and accurate, send the Preliminary Report to all appropriate stakeholders.

8.2 Responsibility: GTIM Engineer or designee

8.2.1 Review and approve the acceptance of the In-Line Inspection Preliminary Report per the specifications outlined in the contract and GTIM-12-001.

8.2.1.1 Record the receipt and approval dates on GTIM-90314.

8.2.2 Create a work order and attach the accepted Preliminary Report data for entry into GeoFields.

8.2.2.1 If this is the first In-Line Inspection on this pipeline segment, (baseline ILI), utilize the ILI SurveyLoad <u>macro</u> alignment process to load ILI data.

8.2.2.2 If this is not the first In-Line Inspection on this pipeline segment, verify the integration of previous into GeoFields, and then utilize the ILI SurveyLoad <u>micro</u> alignment process for data integration.

8.2.3 Retain In-Line Inspection data in GeoFields and the IM file.

8.2.3.1 Utilize previous ILI data in subsequent ILI runs.

8.2.4 Utilize GeoFields' RiskFrame® Analyst to evaluate the ILI report data and create dig sheets.

8.2.4.1 If the GeoFields' RiskFrame® Analyst cannot generate the dig sheets, request creation of dig sheets from the ILI Service Provider or another applicable software.

9.0 EVALUATING ILI DATA FOR DENTS

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Respond to dents per the requirements of GTIM-05-001 "Addressing Conditions Found During an Integrity Assessment".

9.1.2 Review the Preliminary ILI Report for dents or gouges located within covered segments.

9.1.2.1 Identify the dent indications that occur on the upper two-thirds (2/3) of the pipe between the 8-o'clock and 4-o'clock positions.

9.1.3 Using GIS, compile a list of encroachments and foreign-line crossings within the covered segment(s).

9.1.4 Review One-Call activity through the on-line database or other CNP One-Call ticket resources for evidence of increases in Third-Party or Mechanical Damage threats.

9.1.5 Discuss the reliability of the encroachment and foreign-line crossing data with Local Operations.

9.1.5.1 If reliable data is not available, gather information about encroachment and foreign-line crossing locations from Subject Matter Experts (SME).

10.0 THIRD-PARTY DAMAGE

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Using data from GIS and information from SMEs, compare encroachment and foreign-line crossing data with the dent indications.

10.1.2 Identify locations where a dent is within ten (10) feet of the outside edge of an encroachment area.

10.1.2.1 Document the review for locations with a dent on GTIM-90314.

10.1.2.1.1 If no suitable locations exist, no further action is required.

10.1.2.2 For each dent indication not scheduled for evaluation, either:

- Arrange for excavation and evaluation of the indication; or
- Assume Third-Party damage caused the dent; and
  - Evaluate the need for additional Preventive and Mitigative measures.

10.1.2.2.1 If the dent is assumed to be caused by Third-Party Damage, provide notification to the Land Services Encroachment Manager per CNP policies.

10.1.2.2.2 Refer to GTIM-08-002 “Finding Evidence of Encroachment” and document on GTIM-90802 “Transmission Encroachment”.

10.1.3 Document the review for Third-Party Damage on GTIM-90314.

11.0 DETERMINATION OF VALIDATION EXAMINATION LOCATIONS

11.1 Responsibility: GTIM Engineer or designee

11.1.1 If the Preliminary Report does not contain any “Immediate” indications, performing validation digs before receiving the Final Report is not required.

11.1.1.1 Performing validation digs before receiving the Final Report is at the discretion of the GTIM Engineer.

11.1.2 Review the deformation and metal loss indications in the Preliminary Report and consider selecting at least two (2) validation examination location candidates.

11.1.2.1 Base determination of the validation digs on anomaly severity, CIS data (if available), feasibility, disruption to landowners, closeness to welds and fittings, and tool velocity.

11.1.2.2 Consider choosing areas of external corrosion with wall loss indications as validation locations.

11.1.3 Document the locations of the validation examinations on GTIM-90441 “Dig Plan Summary”.

Note: The Date of Discovery shall occur no more than 180 days after removing the ILI tool from the pipeline.

12.0 DIG PLAN PREPARATION

12.1 Responsibility: GTIM Engineer or designee

12.1.1 Prepare a dig plan per GTIM-04-026 “Dig Plan Preparation” for validation locations determined in section 11.0, “Determination of Validation Examination Locations”.

12.1.2 Document the need to perform additional testing on GTIM-90440 “Direct Examination Scope of Work”.

13.0 IN-LINE INSPECTION AND DATA ANALYSIS DOCUMENTATION

13.1 Responsibility: GTIM Engineer or designee

13.1.1 After completing the ILI data analysis, complete GTIM-90314.

13.1.2 Confirm the completion of the following forms:

- GTIM-90303 “ILI Tool Above Ground Marker Log”;
- GTIM-90302 “Report of Cleaning Tool Operations”;
- GTIM-91101 “Pipeline Event Evaluation”, when applicable;
- GTIM-90440 “Direct Examination Scope of Work”; and
- GTIM-90441 “Dig Plan Summary” for each location.

13.1.3 Retain the GTIM-90314 and the other ILI documentation in the IM file.

13.1.4 Notify the GTIM Field Supervisor when the dig plan is approved.

13.2 Responsibility: GTIM Field Supervisor or designee

13.2.1 Coordinate the Direct Examination phase work with the excavation and NDE service providers.

<<END>>

GTIM-03-007 ILI Validation Direct Examination

PURPOSE: To establish a standardized method for the Direct Examination of In-Line Inspection (ILI) indications, validating the ILI tools' ability to identify anomalies accurately.

REFERENCES: 49 CFR 192.933; NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:
- Background
- Direct Examination Preparation
- Field Site Verification
- Performing Validation Direct Examinations
- Direct Examination Field Data Documentation
- Examination Data Evaluation
- Addressing Conditions
- Validation Direct Examination Documentation

1.0 BACKGROUND

1.1 The Direct Examination phase determines the pipe condition at the location of the indication(s) identified by the ILI tools.

1.2 The Direct Examination phase also validates the data received from the ILI Service Provider for identifying pipeline anomalies.

2.0 DIRECT EXAMINATION PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Perform direct examinations according to the Dig Plan.

2.1.2 Excavate indications based on the severity and categorization of the indication (i.e., excavate Immediate indications first, etc.). At a minimum, also consider the following:

- Availability of personnel;
- Logistics;
- Availability of additional equipment (e.g., shoring, dump trucks, etc.); and
- Permitting.

2.1.3 Complete the required forms in the Dig Plan and return to the GTIM Engineer.

2.1.4 Prepare each excavation per GTIM-04-027 “Direct Examination Preparation”.

3.0 FIELD SITE VERIFICATION

3.1 Responsibility: GTIM Field Inspector or designee

3.1.1 Before performing any excavation based on ILI data, verify the dig site location using features that include, but not limited to:

- Aboveground markers (AGMs);
- Valves; and
- Casings.

3.2 Responsibility: GTIM Field Inspector or designee

3.2.1 During the direct examination, confirm the exposed joint corresponds to the joint containing the ILI anomaly by comparing with:

- The measured-distance between girth welds;
- The circumferential position of the longitudinal seam weld; or
- The location of the aboveground markers with indications in the ILI log.

3.2.1.1 If the exposed joint does not correspond to the joint indicated in the ILI log, verify the dig location by reviewing the location data.

3.2.1.2 Contact the GTIM Field Supervisor or GTIM Engineer if uncertainties persist.

4.0 PERFORMING VALIDATION DIRECT EXAMINATIONS

4.1 Responsibility: GTIM Field Inspector or designee

4.1.1 Conduct a tailgate safety meeting each morning before beginning any job-site fieldwork.

4.1.2 Evaluate and document findings during the Direct Examination per the requirements of GTIM-04-008 “Data Collection for Direct Examinations”.

4.1.3 Evaluate the anomaly after site excavation per GTIM-04-008.

4.1.3.1 Complete GTIM-90418 “Pipeline Inspection Direct Examination”.

4.1.4 Before repairing or removing the anomaly, record anomaly validation data in the ILI Examination Variance section of GTIM-90315 “In-Line Inspection - Validation Examination”.

4.1.5 Notify the GTIM Field Supervisor or GTIM Engineer of any substantial variances between the ILI reported anomaly detail and the actual anomaly found during examination.

4.1.5.1 Submit GTIM-90315 with the GTIM-90418 attached to the GTIM Engineer.

4.1.6 Take action as required by the applicable O&M section based on the anomaly severity or the presence of unsafe operating conditions.

4.1.6.1 Consult with GTIM Field Supervisor as necessary on findings and repair options.

4.1.7 Provide all field documentation to the GTIM Field Supervisor.

5.0 DIRECT EXAMINATION FIELD DATA DOCUMENTATION

5.1 Responsibility: GTIM Field Supervisor or designee

5.1.1 Review all direct examination field documentation.

5.1.2 Complete applicable sections of GTIM-90315.

5.1.2.1 Retain a copy in the IM file.

5.1.3 Notify the applicable GTIM Engineer(s) when the data is available in the appropriate IM file.

5.1.4 Submit all documentation within 60 days of completing the direct examination field activities, when feasible.

6.0 EXAMINATION DATA EVALUATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Compare the ILI mapping coordinates with anomaly GPS coordinates on GTIM-90418-D.

6.1.1.1 If the coordinates differ by more than the established tolerances, report the variance to the GTIM Manager.

6.1.2 Compare the ILI mapping coordinates with the girth weld coordinates on GTIM-90418-A, when available.

6.1.2.1 If the coordinates differ by more than the established tolerances, report the variance to the GTIM Manager.

6.1.3 Review the Validation Examination section of GTIM-90315 and the GTIM-90418 form for each validation location.

6.1.4 Complete the ILI Examination Variance section of GTIM-90315.

6.1.5 If the result of one (1) of the digs is outside of the Service Provider's stated tool tolerances, perform an additional validation dig.

6.1.6 If the validation digs based on the ILI Report yield results outside the Service Provider's stated tool tolerance, perform additional validation digs.

6.1.6.1 Refer to GTIM-12-001 "In-Line Inspection Data Acceptance" for information on reviewing the validation examinations.

6.1.7 Prepare Unity Graph(s) using the "Unity Graph" template.

6.1.7.1 If the ILI identifies less than five (5) metal loss indications, a Unity Graph is not required.

6.1.7.2 Enter the following information on the data entry sheet of the Unity Graph.

- Nominal outside diameter (OD);
- Nominal wall thickness (wt.);
- ILI detection and sizing capabilities (Probability of Detecting (POD));
- Field measurement depth tolerance;
- Excavation information (e.g., OD, wt., SMYS);
- Anomaly information (i.e., type, external/internal, depth, actual wt., and length); and
- ILI feature information (length and depth).

6.1.7.3 Each anomaly type that has a unique performance tolerance requires an individual Unity Graph plot.

6.1.7.4 Print each plotted Unity Graph to evaluate the accuracy of the tool run.

6.1.7.4.1 A perfect correlation between field and ILI measurements will result in a straight-line pattern on the graph with a slope equal to one (1).

6.1.7.5 Refer to API Std 1163-2013 for more information on run validation.

6.1.8 Communicate ILI validation dig-results to the Service Provider along with any documentation.

6.1.8.1 Discuss these results with the Service Provider and solicit feedback on the results, the quality of the comparison, the necessity of additional validation digs, whether modifications of the analysis algorithm is required, and whether a complete rerun is in order.

6.1.8.2 If the accuracy of the ILI tool(s) falls outside the specified tolerances, consider, on a case-by-case basis, a tool rerun or modification to the analysis algorithm, or aligning with additional tool runs performed as part of the same assessment to determine if tools adequately detected the threats.

6.1.8.3 When making such decisions, document all of the actions taken, and provide a detailed justification for acceptance or rejection of a rerun.

7.0 ADDRESSING CONDITIONS

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 Refer to GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment” for information on ‘Discovery of Condition’ and classifying anomalies.

7.1.1.1 Perform response digs by the deadline dictated by each anomaly per GTIM-05-001.

7.1.1.2 The ‘Discovery of Condition’ date shall not exceed 180 calendar days from the removal date of the last ILI tool from the pipeline.

Note: Set the ‘Discovery of Condition’ date whenever enough information is available to determine the indication condition.

7.1.2 Evaluate and repair the anomalies excavated per O&M 16 “Repairs”, as appropriate.

7.1.2.1 If remediation requires replacement of a section of pipe, engage Gas Transmission Engineering.

7.1.3 Conduct and document a root cause for each anomaly per GTIM-04-012 “Root Cause Analysis”, when applicable.

7.1.4 Follow-up on areas of corrosion per GTIM-08-005 “Evaluating Similar Conditions”.

8.0 VALIDATION DIRECT EXAMINATION DOCUMENTATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Confirm completion of GTIM-90315.

8.1.2 Confirm completion of the following documentation:

- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- Remaining Strength calculations, if applicable;
- GTIM-90421 “Root Cause Analysis”, if applicable;
- GTIM-90315 “In-Line Inspection - Validation Examination”;
- Unity Graph plots and associated data, if applicable;
- Form 1021 “Job Safety Briefing Form”; and
- Form 3020 “Excavation Repair Report”.

8.1.3 Retain documentation in the IM file.

8.1.4 Incorporate the information collected from completed forms into the appropriate database(s) and tracking sheets.

8.1.5 Begin the Post-Assessment phase once the Direct Examination phase is complete.

<<END>>

GTIM-03-008 ILI Post-Assessment

PURPOSE: To establish a standardized method for evaluating the In-Line Inspection (ILI) program effectiveness and establishing reassessment intervals.

REFERENCES: 49 CFR 192.933; NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:

- ILI Final Report Data Integration
- Review of Final Report
- Acceptance of Final Report
- Date of Discovery
- Reassessment Intervals
- Preventive and Mitigative Measures
- Feedback and Continuous Improvement
- Performance Measures
- Changes and Internal Communications
- Post-Assessment Documentation

1.0 ILI FINAL REPORT DATA INTEGRATION

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Create a work order and attach the applicable ILI data for integration into GeoFields.

1.1.1.1 If this is the first ILI assessment on this pipeline, (baseline ILI), utilize the ILI SurveyLoad macro alignment process to load ILI data.

1.1.1.2 If this is not the first ILI assessment performed on this pipeline, verify that past ILI data has been integrated into GeoFields and then utilize the ILI SurveyLoad micro alignment process for data integration.

1.1.2 Confirm incorporation of the ILI assessment data into GeoFields.

1.1.3 Verify integration of all repairs and mitigation activities into GeoFields.

1.1.4 Retain ILI data in GeoFields and the IM file.

1.1.4.1 Utilize ILI data in subsequent ILI runs.

2.0 REVIEW OF FINAL REPORT

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Verify the ILI Service Provider provides, at minimum, one (1) electronic copy of the Final Report within 60 calendar days following the last tool run, whenever possible.

2.1.1.1 Verify receipt of any required viewing software.

2.1.2 Perform a preliminary review of the Final Report.

2.1.3 Verify the Final Report includes the following, at a minimum:

- Project summary;
- ILI tool specification (including accuracies and configuration);
- Pipeline questionnaire(s);

- Inspection summary;
- Metal loss and deformation reports;
- Alignment of deformation, anomaly, and metal loss data;
- Alignment of pipeline features (i.e., longitudinal weld, girth weld, etc.);
- Calculation methods, data usage, and assumptions;
- Pressure based reports; and
- Pipeline listing.

2.1.4 Review the provided information for accuracy and appropriate detail.

2.1.5 Document inaccurate or erroneously omitted data from the Final Report and return to the Service Provider for revision and re-issuance of the Final Report.

2.1.6 If the Final Report results in an adjustment of the analysis algorithm, a new validation dig is required. Perform this validation dig per GTIM-03-007 “ILI Validation Direct Examination”.

3.0 ACCEPTANCE OF FINAL REPORT

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Review any changes made to the Final Report. As appropriate, accept the Final Report.

3.1.1.1 Acceptance of the Final Report requires completion of the following:

3.1.1.1.1 Resolve all identified survey discrepancies with the Service Provider.

3.1.1.1.2 Verify all of the validation digs are within the Service Provider’s specified tool tolerances.

3.1.1.2 Record the receipt and approval dates on GTIM-90316 “In-Line Inspection - Post-Assessment”.

3.2 Responsibility: GTIM Engineer or designee

3.2.1 Review the report for Immediate Repair Conditions per the criteria listed in GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment” immediately following acceptance of the Final Report.

3.3 Responsibility: GTIM Engineer or designee

3.3.1 Classify the remaining anomalies as One-Year, Scheduled, or Monitored according to GTIM-05-001 guidelines within ninety (90) days of accepting the Final Report.

3.3.1.1 Denote the indications selected for examination on the ILI tool run log.

3.3.2 Prepare the GTIM-90501 “Response Schedule” per GTIM-05-001.

3.3.2.1 Document the assessment and required response times for only those indications selected for direct examination and remediation activities.

3.3.2.2 Add significant capital repairs and any future scheduled (1 yr. +) repairs to the IM work schedule for tracking.

3.3.3 Update GTIM-90501 as new excavation and repair information becomes available.

4.0 DATE OF DISCOVERY

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Document the Final Report acceptance date.

4.1.2 The ‘Date of Discovery’ shall occur no more than 180 calendar days after removing the last ILI tool from the pipe.

4.1.2.1 Set the ‘Date of Discovery’ as the date when enough information is available to determine the condition of the anomaly.

5.0 REASSESSMENT INTERVALS

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

5.1.1.1 Document the reassessment interval on GTIM-90316.

5.1.2 Add Reassessments, Confirmatory Direct Assessments, Scheduled Conditions, and other remediation activities on the assessment schedule calendar or other tracking tools.

5.1.3 Create a new GTIM-90209 “Threat Analysis” with the following applicable information:

- Newly identified threats;
- Elimination of threats; and
- Changes to existing threat documentation.

5.1.3.1 Refer to GTIM-02-021 “Threat Identification”.

5.1.3.2 Create a work order to incorporate modified data and attributes.

5.1.3.3 For scheduling purposes, select the next assessment method based on the updated threat assessment results.

6.0 PREVENTIVE AND MITIGATIVE MEASURES

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Review the Preventive and Mitigative (P&M) measures implemented for the applicable covered segment(s).

6.1.1.1 Consider implementing additional P&M measures to address the current threats to the covered segment(s). Refer to GTIM-08-004 “Identify Preventive and Mitigative Measures”.

6.1.1.2 Complete GTIM-90804 “Preventive and Mitigative Measures”.

6.1.2 Compile a list of all regulator stations downstream from the ILI tool runs.

6.1.2.1 Document the number of filters and separators in each regulator station.

6.1.2.2 For each regulator station with zero filters or separators, create a work order for a one-time inspection of the station.

6.1.2.2.1 Schedule the inspection for completion approximately three (3) months after the ILI tool runs.

7.0 FEEDBACK AND CONTINUOUS IMPROVEMENT

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 Request feedback from project participants (i.e., Local Operations, Corrosion Control, etc.). Feedback topics should include, but are not limited to:

- Identification and classification of ILI results;
- Data collected during the direct examinations;
- Remaining strength analysis;
- Root-cause analysis;
- Remediation activities;
- In-process evaluations;
- Validation direct examinations;
- Scheduled and monitoring follow-ups;
- Reassessment intervals; and
- ILI process effectiveness (monitoring criteria).

7.1.2 Solicit “lessons learned” from project participants upon completion of the ILI project.

7.1.2.1 If appropriate, invite the Service Provider(s) to the meeting(s).

7.1.2.2 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- ILI process modification suggestions.

7.1.2.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

7.1.3 Document feedback and continuous improvement activities on GTIM-90316 “In-Line Inspection - Post-Assessment”.

7.2 Responsibility: GTIM Engineer or designee

7.2.1 Review the results of the feedback and determine additional areas of improvement.

7.2.2 If applicable, initiate a change request according to GTIM-11-001 “GTIM Change Management” for each additional P&M recommendation, and any other potential process improvement.

7.2.2.1 Initiate, if applicable, a CNP Management of Change request to publish modifications made to GTIM-Plan procedures.

7.2.3 Complete a GTIM-90424 “Summary Report to Local Operations”, summarizing any repairs made and describing any required or recommended follow-up activities.

7.2.3.1 Send GTIM-90424 to Local Operations and Corrosion Control.

8.0 PERFORMANCE MEASURES

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Document Performance Measures on GTIM-90901 “Performance Measures”.

8.1.1.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

8.1.1.2 Document the total HCA miles or total MCA miles assessed at the top of GTIM-90316.

9.0 CHANGES AND INTERNAL COMMUNICATIONS

9.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

9.1.1 Document any deviations from the documented plan that occurred during the ILI process on GTIM-91101 “Pipeline Event Evaluation”.

9.1.2 Notify the affected parties, if appropriate, according to GTIM-13-002 “Internal Communications”.

9.1.3 Confirm the submission of all change management requests. Document the submission date on GTIM-90316.

9.1.4 Compare and confirm data collected from field activities matches data recorded on the GTIM-90300 “Data Collection Form” during the pre-assessment phase of this assessment.

9.1.4.1 If the field activities data is different from the data on form GTIM-90300, update GTIM-90300.

9.1.4.2 Work with the GTIM Field Inspectors to resolve all inconsistencies to clarify or update the appropriate documents.

9.1.4.2.1 Route any modified field documents to the GTIM Field Supervisor for review and approval.

9.1.4.3 Create a work order to incorporate data into GIS, if needed.

10.0 POST–ASSESSMENT DOCUMENTATION

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Perform a 100% quality check of all requested GIS updates. Document the date completed on GTIM-90316.

10.1.2 Confirm completion of Post-Assessment documentation. Documentation includes, but is not limited to, the following:

- GTIM-90209 “Threat Analysis”;
- GTIM-90302 “Report of Cleaning Tool Operations”;
- GTIM-90303 “ILI Tool Above Ground Marker Log”;
- GTIM-90314 “In-Line Inspection and Data Analysis”;
- GTIM-90315 “In-Line Inspection - Validation Examination”;
- GTIM-90316 “In-Line Inspection - Post-Assessment”;
- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- GTIM-90421 “Root Cause Analysis”, if applicable;
- GTIM-90424 “Summary Report to Local Operations”;
- GTIM-90501 “Response Schedule”;
- GTIM-90804 “Preventive and Mitigative Measures”;
- GTIM-90901 “Performance Measures”;
- GTIM-91101 “Pipeline Event Evaluation”, when applicable;

- GTIM-91102 “Integrity Change Management Record”, if applicable;
- Form 1021 “Job Safety Briefing Form”;
- Remaining Strength calculations, if applicable;
- Unity Graph plots and associated data, if applicable; and
- Any other pertinent data.

10.1.3 Retain copies of communication with the Service Provider, including any discussions or analyses leading to significant decisions and decisions to reanalyze data.

10.1.3.1 Include all forms of communications (i.e., phone conversations, voice messages, etc.) with follow-up documentation such as an email to the other parties confirming your understanding of the communication.

10.1.4 Route pertinent Post-Assessment documentation to Corrosion Control and Local Operations along with a hyperlink to the location of the Post-Assessment documentation file.

10.1.5 Conduct a meeting with the GTIM Manager to review the Post-Assessment documentation and obtain approval.

Note: Upon removal of the final ILI tool of the scheduled series of tools from the pipe, the ILI assessment is considered complete.

Once the Post-Assessment documentation is approved, the ILI process is considered complete.

10.1.6 Confirm all assessment documentation is stored in the IM file within 30 days of completing the Post-Assessment process.

<<END>>

GTIM-03-009 Evaluation of Stations and Equipment

PURPOSE: To provide a standard method for performing a baseline or reassessment on station piping meeting the definition of a transmission line.

REFERENCES: 49 CFR 192.919; ASME/ANSI B31.8S-2004;

SECTIONS:
- General
- Data Gathering
- Assessment Planning
- Performing the Assessment
- Post-Assessment

1.0 GENERAL

1.1 This procedure addresses transmission piping and equipment within a Consequence Area.

1.1.1 Stations and equipment, as defined in this procedure, are facilities including, but not limited to, the following:

- Piping within the transmission system, other than line pipe;
- Meter and regulator stations; and
- Compressor stations.

1.2 In general, Preventive and Mitigative (P&M) measures and routine O&M activities address equipment evaluations.

2.0 DATA GATHERING

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Identify the station for assessment.

2.1.2 Review form GTIM-90300 “Data Collection Form” to determine the types of data to be collected. Collect data from appropriate sources, including but not limited to:

- Subject Matter Experts;
- GIS; and
- Other databases.

2.1.3 Determine if representative as-built drawings, maps, etc., are available for the station.

2.1.3.1 Develop drawings, and alignment sheets depicting the layout of the station line pipe and equipment, if adequate documentation is not available.

2.1.3.2 Update the station map as additional information becomes known during the assessment.

2.1.4 Identify the extents of the transmission piping.

2.1.4.1 If this information is not readily available, additional data research may be required.

2.1.4.2 Confirm MAOPs of station piping.

2.1.4.3 Confirm %SMYS at MAOP for station piping.

2.1.4.4 Document all calculations and assumptions.

2.1.5 Review the extents of any prior assessments.

2.1.5.1 When selecting the extents for the station assessment, ensure there is at least a 50-foot overlap with any prior assessments on adjacent piping to account for spatial errors.

2.1.5.1.1 In some cases, 50 feet may not be practical based upon the location of casings, major roadways, etc. In such cases, document the reason for not overlapping the assessments by 50 feet on GTIM-90308 “Station Pre-Assessment”.

2.1.5.1.2 When performing a 100% direct examination, a 50-foot overlap may not be required. Document the justification on form GTIM-90308.

2.1.5.2 Develop a schematic showing the extents of any prior assessments.

2.2 Responsibility: GTIM Engineer or designee

2.2.1 Perform a site visit if necessary.

2.2.2 Confirm Consequence Areas and Identified Sites.

2.2.2.1 Create a work order if known data attributes need correction in GIS.

2.2.2.2 Refer to GTIM-01-002 “Identification of Consequence Areas” for additional details.

2.2.3 Consider items that may make a particular assessment method impractical. Items to consider include, but are not limited to:

- Amount of buried piping; and
- Accessibility of required equipment.

2.2.4 Complete GTIM-90311 “Stations and Equipment - Evaluation”.

2.2.4.1 Use the form to assess the condition of stations and equipment including but not limited to:

- Failures;
- Overall condition;
- Recommended maintenance; and
- Obsolete equipment.

2.2.4.2 Take photographs as appropriate.

3.0 ASSESSMENT PLANNING

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Review data on GTIM-90300.

3.1.1.1 Document the rationale when utilizing data assumptions.

3.1.2 Complete GTIM-90210 “Threat Analysis - Stations and Equipment” per the requirements of GTIM-02-021 “Threat Identification”.

3.1.3 Identify the assessment method per the requirements of GTIM-03-001 “Assessment Method Selection”.

3.1.4 Develop a schematic showing the extents of the station assessment.

3.1.5 Complete GTIM-90308 “Station Pre-Assessment”.

3.1.5.1 Identify any special considerations for performing the assessment, which may include, but is not limited to:

- Coordination with service providers; and
- Other facility planned work.

3.1.6 Meet with the appropriate Subject Matter Experts (SMEs) to review the identified threats on GTIM-90311 and the planned assessment method. Update the assessment plan as appropriate based upon feedback.

4.0 PERFORMING THE ASSESSMENT

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Proceed with the assessment of the station per the requirements of the applicable assessment method.

4.1.1.1 Coordinate with appropriate CNP and Service Provider personnel.

4.1.2 Complete the required Pre-Assessment documentation.

4.1.3 Consider grouping stations within the same Operating Center or region into a single project when using the External Corrosion Direct Assessment (ECDA) method.

4.1.3.1 ECDA Regions do not need to be contiguous. Therefore, multiple stations can have the same ECDA Regions.

4.1.3.1.1 Refer to GTIM-04-002 “ECDA Pre-Assessment” for guidance on selecting ECDA Regions.

5.0 POST-ASSESSMENT

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Perform the Post-Assessment per the requirements of the specific assessment method.

5.1.2 Confirm the final updates to the station drawings and alignment sheet(s) are complete.

5.1.3 Review GTIM-90311.

5.1.3.1 As appropriate, identify additional or more frequent inspections for the station and equipment. Inspections may include, but are not limited to:

- O&M 13.0 “Odorization” or CNP O&M XIV “Odorization of Gas”;
- O&M 17.0 “Gas Leak Survey and Pipeline Patrols” or CNP O&M XIX “Leak Surveys” and CNP O&M XVII “Patrolling”;
- O&M 24.0 “Regulator Stations” or CNP O&M XXI “Regulator Stations”;
- O&M 25.0 “Regulators, Relief Valves, and Control Valves Minor Inspections” for Minor and Major Inspections or CNP O&M XXII “Valve Maintenance”;
- O&M 26.0 “Valves” or CNP O&M XXII “Valve Maintenance” and CNP O&M XXIV “Compressor Stations”;
- O&M 27.30 “External and Internal Corrosion Inspection and Monitoring” or CNP O&M VIII “External Corrosion Control” and CNP O&M IX “Internal Corrosion Control”;
- O&M 27.31 “Atmospheric Corrosion Control” or CNP O&M X “Atmospheric Corrosion Control”;

- O&M 29.0 “Compressor Stations” or CNP O&M XXIV “Compressor Stations”;
- O&M 31.0 “Vaults” or CNP O&M XXV “Other Maintenance Procedures/D: Vault Maintenance”; and
- O&M 38.0 “Meters” or CNP O&M XXV “Other Maintenance Procedures”.

5.1.4 Document additional and more frequent inspections on GTIM-90311 “Stations and Equipment - Evaluation”, and include:

- Type and frequency of additional inspections;
- The basis for choosing additional inspections; and
- Other documentation as necessary.

5.1.4.1 Work with Local Operations to schedule additional inspections.

5.1.4.2 If no additional inspections are identified for the station or equipment, document on GTIM-90311 “Stations and Equipment - Evaluation”.

5.1.5 Submit all assessment documentation to the GTIM Manager for review.

5.1.6 Retain documentation for the life of the pipeline and station in the IM file.

<<END>>

GTIM-03-010 In-Line Inspection Requests for Proposal

PURPOSE: To establish a standardized method for requesting services from In-Line Inspection (ILI) Service Providers.

REFERENCES: 49 CFR 192 Subpart O; ANSI/ASNT ILI-PQ-2005; ASME/ANSI B31.8S-2004, Section 6; NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:

- Background
- Personnel Qualifications
- Request for Proposal

1.0 BACKGROUND

1.1 In-Line Inspection (ILI) tools are also known as “intelligent” or “smart” pigs.

1.2 ILI tools are highly specialized pieces of equipment requiring skilled technicians for proper operation.

2.0 PERSONNEL QUALIFICATIONS

2.1 Third-party Service Providers must provide personnel meeting or exceeding the qualifications for the applicable activities being implemented or performed.

2.2 Documentation confirming the qualifications of the personnel provided by the Service Provider must be ‘on file’ at CNP or provided to CNP before the ILI tool runs. Documentation includes but is not limited to:

- Verify all crew members meet the required CNP training, testing, and certification processes for the specific activities;
- Prior training and experience testing with similar inspection technology, per ANSI/ASNT ILI-PQ-2005 “In-Line Inspection Personnel Qualification and Certification Standard”;
- Technicians performing the ILI tool testing must have a minimum of Level 2 certification for the inspection technology used; and
- Technicians reviewing the data for the final report must have a minimum of Level 2 certification for the inspection technology used.

Note: Level 1 certified technicians may be allowed with justification and prior written approval from the GTIM Manager.

3.0 REQUEST FOR PROPOSAL

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Include personnel qualification requirements in the Request for Proposal (RFP) specifications.

3.1.2 Itemize all characteristics of the pipeline segment(s) on GTIM-90312 “ILI Pre-Assessment Questionnaire”.

3.1.3 Confirm that the following are defined, at a minimum:

- Scope of the work;
- Liability issues;
- Qualifications of personnel performing ILI tasks (see section 2.0 “Personnel Qualifications”);
- Compliance to regulations;
- Reports and payment schedules;
- Acceptance criteria and tool reruns;
- Scheduling changes;
- Service interruptions; and
- Failure to appear penalties.

3.1.4 In the event of sensor, carrier, or other equipment failures on a tentatively accepted tool run, the Service Provider shall submit a Preliminary Report with the following information:

- A detailed description of the failure;
- A description where the failure occurred during the run;
- Sensor profile for the entire run;
- Tool rotational profile;
- Assessment of the impact on run performance and data accuracy;
- Recommendations for run acceptance or rejection; and
- Justification of the recommendation.

3.1.5 Include ILI data acceptance criteria in the bid package.

3.1.5.1 Refer to GTIM-12-001 “In-Line Inspection Data Acceptance” for criteria details.

3.1.6 Consider the following criteria during the Service Provider selection process:

- The tool’s ability to successfully navigate the pipe segment(s);
- The tool’s ability to gather dependable data;
- The ability to provide qualified personnel;
- Accuracy specifications;
- Tool run success rate;
- Previous experience with the prospective Service Provider, if applicable;
- The Service Provider’s availability schedule; and
- Cost.

3.1.7 In consultation with the GTIM Manager and GTIM Field Supervisor, select a Service Provider to perform the ILI work.

<<END>>

GTIM-03-011 In-Line Inspection Tool Run Preparation

PURPOSE: To establish a standardized method for the preparation of an In-Line Inspection (ILI) tool run.

REFERENCES: 49 CFR 192 Subpart O; ANSI/ASNT ILI-PQ-2005; ASME/ANSI B31.8S-2004, Section 6; NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:

- General
- Inspection Preparation

1.0 GENERAL

1.1 In-Line Inspection (ILI) tools are also known as "intelligent" or "smart" pigs.

1.2 ILI tool runs require detailed communication and contingency planning to ensure a successful inspection.

2.0 INSPECTION PREPARATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Review the Pre-Assessment documentation.

2.1.2 Identify, schedule, and complete all required retrofits before the start of the In-Line Inspection tool runs.

2.1.3 Create a tool run work packet. Include the following items, if applicable:

2.1.3.1 Detail the processes for preparing, launching, and receiving the ILI tools on GTIM-90317 "In-Line Inspection Tool Run Work Instructions".

2.1.3.2 Create a Communication Contact List of internal and external project stakeholders to update stakeholders on the progress of the ILI tool runs.

2.1.3.3 Create an Emergency Contact List of internal and external stakeholders for notifying in the event of an emergency.

2.1.3.4 Complete Form 3185 "System Operations Plan", review with the involved parties, and obtain approvals. Reviewers and approvers include the GTIM Manager and the GTIM Field Supervisor.

2.1.3.4.1 Develop and include Contingency Plan(s) for common unwanted ILI behaviors (at minimum, a stuck tool) within the Systems Operations Plan.

- Identify possible actions to address the potential scenario(s);
- Consider the availability of equipment and material when identifying possible actions; and
- Include communications plan for customers that may be affected.

2.1.3.5 Include (blank) forms to be completed during the tool runs, if not available electronically.

- GTIM-90302 "Report of Cleaning Pig Operations"; and
- GTIM-90314 "In-Line Inspection and Data Review".

2.1.3.6 Provide schematics or maps showing the 'normal operation' system configuration, and the 'during the inspection' system configuration.

2.1.3.7 Provide schematics or maps of the Launcher (include the associated valves and identify each).

2.1.3.8 Provide schematics or maps of the Receiver (include the associated valves and identify each).

2.1.3.9 Provide schematics or maps of the various regulator stations associated with the ILI project.

2.1.3.10 Consider including applicable In-Line Inspection documentation (e.g., white papers, best practices, procedures, etc.) to reference during the tool runs.

2.1.3.11 Include the Communication Contact List and the Emergency Contact list.

2.1.4 Coordinate the pipeline product handling details with Gas Control.

2.1.5 Request development of a custom SCADA screen from Gas Control to show all pressure and flow monitoring locations on one screen.

2.1.6 Select the preliminary Above Ground Marker (AGM) locations to monitor.

2.1.6.1 Locate markers where other structures (e.g., crossover tees, side taps, and valves) are not available as reference points for locating anomalies.

2.1.6.2 Consider valves in place of an AGM when planning AGM spacing.

2.1.6.3 Consider the placement of AGMs at the following locations, if applicable:

- Changes in pipe attributes (i.e., grade, diameter, wall thickness);
- Inaccessible areas (e.g., on each side of a river where the pipeline passes underneath the river);
- Covered segment entry and exit points; and
- At fixed, above-grade reference points.

2.1.6.4 Consider reducing AGM spacing to less than the maximum of one (1) mile, typically, to every 1,000 feet in the following areas:

- Residential area;
- Areas containing multiple points of inflection;
- As required by the ILI service provider;
- When running inertial mapping tools; and
- Hilly areas.

2.1.6.5 Request a list of Land Owners from Land Services or Local Operations to get contact information for all landowners along the pipeline route to select AGM locations.

Note: Avoid locating Above Ground Markers where the pipe has a depth over six (6) feet. Consult with the ILI tool provider for specific tool ranges.

2.2 Responsibility: GTIM Field Supervisor or designee

2.2.1 Schedule the ILI tool runs with the Service Provider.

2.2.2 Receive documentation confirming the qualifications of the personnel provided by the service provider (i.e., the ILI tool operator, ILI data analyst).

2.2.2.1 Verify documentation is 'on file' at CNP or provided to CNP before commencing ILI tool runs. (See GTIM-03-010 section 2.2 for required personnel qualifications.)

2.2.3 Develop a schedule for the ILI tool run(s) fieldwork. Consider the following when creating the schedule.

- Access to the launcher and receiver;
- Access to tool tracking locations;
- Pipeline throughput obligations;
- Estimated tool run times include possible reruns;
- Provision for issues such as maintaining control of tool speed and tool operation;
- Length of tool run and number of monitored AGMs;
- Tool speed and tool battery life;
- Valve operation and monitoring;
- Heavy equipment and resources for loading and unloading inspection tools;
- Pumping equipment, if needed;
- Storage of liquids for propulsion, if needed;
- Temporary tanks for fluid/debris, including filter equipment; and
- A support-personnel hub (e.g., Mobile Command Center, etc.).

2.2.4 Coordinate the placement of permanent AGMs:

2.2.4.1 Verify the ILI Service Provider supplies the marker boxes for placement, as required.

2.2.4.2 Place semi-permanent stakes at all marker locations to assist in locating indications during the evaluation/remediation process.

2.2.4.3 Document GPS coordinates for each AGM.

2.2.5 Confirm that geophones or other suitable pig tracking devices are available to track the location of caliper or ILI pigs during the inspection.

2.2.6 Contact the CNP Environmental Department for proper methods of handling debris and obtaining environmental permits.

2.2.7 Inform the ILI Service Provider if the pipeline potentially contains a hazardous element (e.g., hydrogen sulfide, etc.).

2.2.8 Contact and address the following in advance of the inspection:

- Landowners for access permission; and
- Gas Control for product handling details.

2.2.9 Review the System Operations Plan before commencing the tool runs.

2.2.10 Coordinate the ILI tool run(s) with Gas Control, Local Operations, Gas Transmission Engineering, and other stakeholders as applicable.

2.2.11 Provide a copy of the tool run work packet to the GTIM Field Supervisor.

<<END>>

GTIM-03-015 Non-HCA (MCA) Assessments

PURPOSE: To provide a standardized approach for assessing Moderate Consequence Areas.
REFERENCES: 49 CFR 192.710;
SECTIONS:
- Applicability
- Non-HCA (MCA) Assessments
- Documentation

1.0 APPLICABILITY

1.1 For onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

- A Class 3 or Class 4 location; or
- A moderate consequence area, as defined in §192.3, if the pipeline segment can accommodate inline inspection tools.

Note: This procedure does not apply to pipeline segments located in a high consequence area.

2.0 NON-HCA (MCA) ASSESSMENTS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Select assessment methods capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible. Refer to GTIM-03-001 “Assessment Method Selection”.

2.1.2 Assess the covered segments utilizing the applicable procedures for the assessment method(s) selected.

2.1.2.1 Analyze and account for the data obtained from an assessment performed to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience.

2.1.2.1.1 When identifying and characterizing anomalies, account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, etc.).

2.1.2.1.2 Discovery of a condition occurs when adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline, but no later than 180 days after conducting an integrity assessment.

2.1.2.2 Remediate conditions per GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

2.1.3 In the absence of any condition or the remediation of all confirmed and suspected conditions, calculate the next reassessment compliance date.

2.1.3.1 To the completion date of this assessment, add 126 months (10 years).

2.1.3.1.1 Consider a shorter reassessment interval, if warranted, based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

2.1.3.2 Confirm entry of the reassessment with the lower compliance date on the assessment schedule calendar.

3.0 DOCUMENTATION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Retain all generated documentation for the life of the pipeline in the IM file.

<<END>>

GTIM-04-001 Long-Range Ultrasonic Testing

PURPOSE: To establish a standard method for performing a Long-Range Ultrasonic Testing (LRUT) assessment.

REFERENCES: 49 CFR 192 Subpart O;

SECTIONS:

- General
- Definitions
- Equipment Specifications and Documentation
- Qualifications of the LRUT Service Provider
- Pre-Assessment
- PHMSA Notification
- Assessment Preparation
- Excavation and Direct Examination
- Performing the LRUT Inspection
- Determining the Number of Validation Locations
- Selecting the Validation Examination Locations
- Performing the Validation Examinations
- Data Analysis
- LRUT Service Provider Report
- Remediation
- Reassessment Intervals
- Post-Assessment

1.0 GENERAL

1.1 LRUT may be used on cased, buried, or above grade steel pipe to locate and evaluate areas of corrosion.

1.2 LRUT uses a transducer collar temporarily installed on a section of the pipe. The transducer impresses ultrasonic energy on the pipe and detects ultrasonic energy reflected from piping features such as weld joints, bends, flanges, and metal loss anomalies.

1.3 Ultrasonic energy is transmitted and detected on both sides of the transducer collar, thus testing on both sides of the transducer collar location.

1.4 Typically, for buried pipe, inspection distances range from 40 to 150 feet on either side of the transducer collar. The type of coating, coating thickness, annular fill in a casing, and presence of bends typically affect the range of the LRUT.

1.4.1 If the assessment distance is greater than 80 feet, alternative assessment methods may be required to confirm the assessment of the entire distance.

1.4.1.1 Refer to procedure GTIM-03-001 “Assessment Method Selection”.

1.4.1.2 The “Pre-Assessment” section of this procedure provides additional guidance.

1.5 LRUT cannot distinguish between internal and external corrosion, requiring a direct examination of the pipe at the location of the indication with an ultrasonic pipe thickness tester to identify internal corrosion.

1.6 The Pipeline and Hazardous Materials Safety Administration (PHMSA) published an 18-item Guided Wave UT Target Items for Go-No-Go Procedures paper, which provided the basis for the development of this procedure.

2.0 DEFINITIONS

2.1 **Dead Zone** is an area immediately adjacent to the transducer collar, typically three (3) to six (6) feet on either side, where the LRUT unit is not able to obtain reliable results. If the exact distance of the dead zone is unknown, use a distance of 3 feet either side of the collar.

2.2 **Near Zone** is an area one (1) to two (2) feet beyond the dead zone where results are unreliable or inconclusive, resulting from unfocused beams and reflections.

2.3 **LRUT Group** is a collection of LRUT inspections performed on a pipe with similar pipe features, with the same equipment and analysis techniques.

2.4 **Direct Region** is the region of primary consideration for the LRUT inspection. When inspecting a casing, the Direct Region is the carrier pipe within the casing. For inspections not performed at a casing, the Direct Region is the area intended for evaluation. See Figures 04-001-F1 and 04-001-F2.

2.5 **Secondary Region** is the area of pipe assessed that is coincidental to the LRUT inspection. When inspecting a casing, the Secondary Region is the area of pipe assessed outside of the casing. See Figures 04-001-F1 and 04-001-F2.

Figure 04-001-F1: Direct and Secondary Regions for a Casing Application

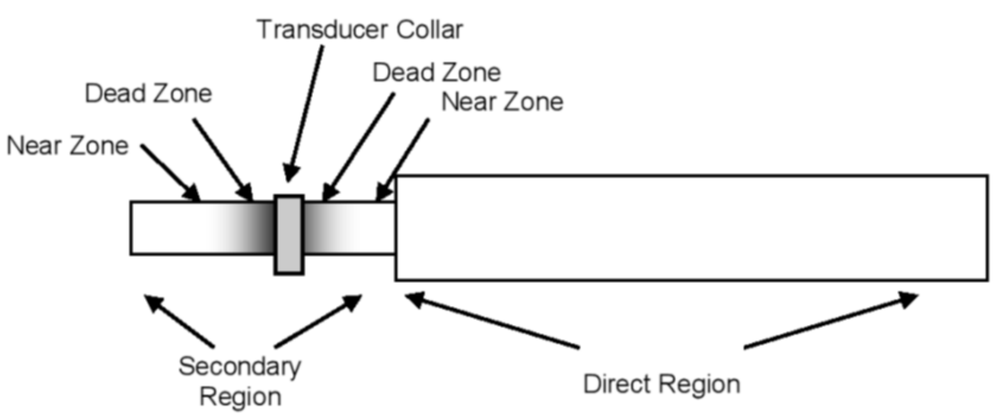
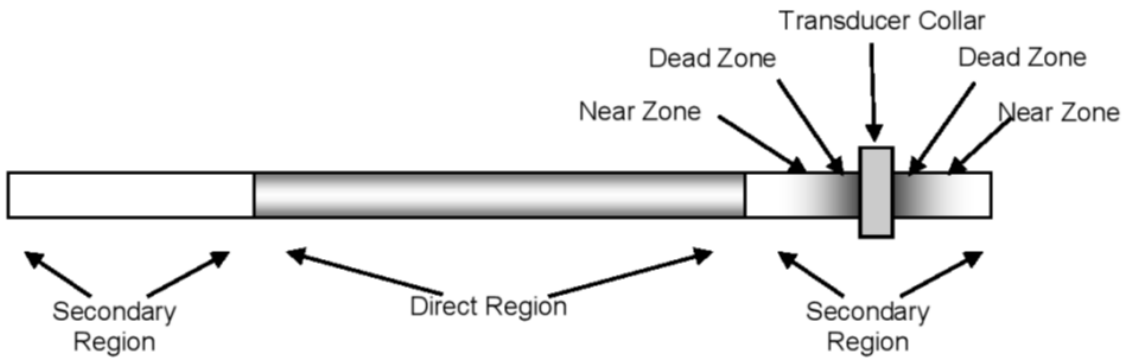


Figure 04-001-F2: Direct and Secondary Regions for a Non-Casing Application



3.0 EQUIPMENT SPECIFICATIONS AND DOCUMENTATION

3.1 Responsibility: LRUT Service Provider

3.1.1 Utilize the following equipment during the assessment:

- GUL Wavemaker G-3, Teletest Rev 3, or equivalent (hardware and software specifically developed to operate the instrument transducer collar);
- A test instrument transducer collar with signal output capabilities suited explicitly for the relevant pipe installation conditions (i.e., cased coal tar coated pipe, direct buried FBE);
- An analysis product that is part of the hardware/software referenced above that will provide preliminary on-site data analysis of each test conducted; and
- If filters are required to remove noise from the reflected waveform, they cannot detract from the tool's accuracy.

3.1.2 At a minimum, utilize equipment with torsional wave signals.

3.1.3 Equipment must be readily traceable back to the manufacturer (i.e., serial numbers, calibration certificate, etc.).

3.1.4 All computer software must be the latest version approved by the manufacturer to work with the tool.

3.2 Responsibility: LRUT Service Provider

3.2.1 Provide proof of calibration for the equipment (i.e., calibration certificate) to the GTIM Field Inspector before commencing the assessment.

3.2.1.1 Documentation must include:

- The last date of calibration;
- The due date of the next calibration; and
- The serial number(s) of the equipment used.

3.2.2 Provide the following documentation in the final report.

3.2.2.1 Document noise elimination filters, if used, and how the filters will not detract from the tool's accuracy.

3.2.2.2 Document the type of sensors (i.e., single or dual) as well as the spacing of the sensors.

4.0 QUALIFICATIONS OF THE LRUT SERVICE PROVIDER

4.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

4.1.1 Confirm the qualifications of the Service Provider performing the LRUT assessments.

4.1.1.1 Request that the potential Service Provider(s) provide all necessary qualifications/requirements during the service provider selection process.

4.1.2 To be qualified, a Service Provider must meet the following qualifications/requirements:

- Provides equipment meeting the specifications of the “Equipment Specifications and Documentation” section within this procedure.
- Provides qualified personnel:
  - Completion of a minimum of one week of classroom training;
  - Successful completion of course work testing;
  - Minimum of one week of documented field training related explicitly to buried steel pipelines and buried cased steel pipelines;
  - Prior experience testing similar pipe;
  - Technician performing testing must have a minimum of Level 2 certification for LRUT or equivalent;
    - A Level 1 technician is sufficient if the technician’s experience is similar to that of a Level 2;
    - Document approval from the GTIM Engineer before using a Level 1 technician;
  - Technician reviewing the data for the final report must possess a minimum of Level 2 Certification for LRUT or equivalent and applicable to the specific testing equipment, and data reviews include data interpretation for filter screening, the conversion of wave signals, and the interpretation of metal loss; and
  - Level 2 Certification training equivalent to ASNT or similar recognized training accreditation society.
- Documented test and data analysis procedures;
- Documented Quality Assurance procedures that include:
  - Training and qualification program(s) for personnel;
  - Safety precautions;
  - Verification that equipment is in good operating condition before beginning work; and
  - Calibration of equipment.

5.0 PRE-ASSESSMENT

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Identify the locations to perform LRUT.

5.1.2 Apply for the appropriate permits.

5.1.2.1 When testing casings, apply for permits on each side of the cased crossing.

Note: Some permits (i.e., streams, rivers, or railroads) may take three (3) to six (6) months to obtain - plan accordingly.

5.1.3 Gather traceable, verifiable, and complete (TVC) material properties and attributes records applicable to the pipeline assessment segments. If TVC records are not available, obtain the undocumented data using GTIM-02-010 "Material Verification" during direct examinations. Pre-Assessment information should include:

- Location and identification information; *****
- Length intended for assessment; *****
- Year of installation;
- Pipe diameter; *****
- Wall thickness; ******
- Pipe grade;
- Joint type;
- Longitudinal seam type;
- Pipe manufacturer;
- Year of pipe manufacture;
- Coating type; ******
- Coating thickness (assumed if no actual data available); ******
- MAOP;
- Operating stress level (%SMYS);
- Date of last ILI;
- Date of last DA;
- Date of last Hydro test;
- Soil type; ******
- Pipe depth; ******
- Locations of valves, fittings (if visible); ******
- Locations of bends;
- Repair history;
- Any adjacent metal objects;
- As-built drawings; and
- Alignment sheets.

* *indicates required information.*

** *Obtain TVC records for undocumented data once the pipe is exposed and document the needed information on GTIM-90414 "LRUT Pre-Assessment Data".*

5.1.4 For applications at cased pipeline locations, also compile the following information:

- Length of the casing;
- Construction practices at casing (i.e., spacers);

- Medium annular space fill material (i.e., water, dirt, wax);
- Casing orientation information (e.g., is one end of the casing lower than the other); and
- Shorted casing information, if applicable.

5.1.5 Document all information on GTIM-90414 “LRUT Pre-Assessment Data”.

5.1.5.1 Add additional locations to the bottom of the form to encompass all of the work to be performed.

5.1.5.2 Document feasibility and the rationale for the assessment method selection on GTIM-90414.

5.1.6 Create a work order to update data attributes in GIS.

5.1.6.1 Example: No casing identified in GIS; however, Pre-Assessment research determined a casing does exist from as-built records or actual observation.

5.1.7 For locations with an intended assessment length greater than 80 feet, reconsider the use of LRUT. Other options may include:

- In-Line Inspection;
- Pressure Testing;
- Pipeline reroutes; and
- Casing removal to directly examine the pipe.

5.1.7.1 If the LRUT tools or method does not meet the required sensitivity thresholds beyond 80-feet, utilization of an additional assessment is mandatory to consider the covered segment assessed.

5.1.8 Provide the appropriate forms and related information to the Service Provider and GTIM Field Supervisor before performing the assessment.

6.0 PHMSA NOTIFICATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Determine if LRUT will be used to evaluate pipe within a High Consequence Area (HCA) or Moderate Consequence Area (MCA) as part of an integrity assessment.

Note: The use of ‘other technology’ methods require the pre-approval of the GTIM Manager and PHMSA.

6.1.1.1 LRUT is considered an “other technology”. Unless LRUT is supplemental to another assessment method, notification to the Pipeline Hazardous Materials and Safety Administration (PHMSA) is mandatory in advance of using the “other technology”.

6.1.1.1.1 Notify PHMSA at least 90 days before conducting the assessment following the requirements of procedure GTIM-13-001 “Required Notifications to Regulatory Agencies”.

6.1.1.1.1.1 Use of the “other technology” may proceed 91 days after submittal of the notification unless a letter from the Associate Administrator for Pipeline Safety is received objecting to the proposed use of the “other technology", or stating that PHMSA requires additional time to conduct its review.

6.1.1.1.2 Notify key personnel of response, include any objections or questions, or if proceeding without a response.

6.1.1.1.2.1 If appropriate and with the approval of the GTIM Manager, address objections and resubmit the notification.

7.0 ASSESSMENT PREPARATION

7.1 Responsibility: GTIM Field Supervisor or designee

7.1.1 Discuss pipe access requirements with the LRUT Service Provider before performing excavations. In general:

7.1.1.1 A buried pipe will require a full-encirclement excavation.

7.1.1.1.1 Create a minimum of six (6) inches of clearance around the circumference of the pipe.

7.1.1.2 For buried pipe in a casing, place the transducer on the carrier pipe, approximately ten (10) feet outside of the casing.

7.1.1.2.1 If the end of the casing is not accessible, place the transducer in a location that allows for multiple collar locations within the excavation, maximizing inspection length and confirming that no area intended for inspection falls within the Dead Zone or Near Zone.

7.1.1.2.2 If bends or other conditions prevent the tool from being placed on the pipe ten (10) feet outside of the casing, place the tool at least four (4) feet outside the casing. Document the conditions and confirm that no part of the assessment area falls within the dead zone or near zone.

7.1.1.3 For buried pipe not inside of a casing, the transducer collar should be placed approximately ten (10) feet outside of the assessment area.

7.1.1.3.1 As an alternative, place the transducer collar in the middle of the pipe segment. Using this approach requires moving the collar to several different locations to avoid missing areas due to the Dead Zones or Near Zones.

7.1.2 Schedule excavating crew for the buried pipe.

7.1.3 Retain the services of a qualified service provider to perform direct examinations of the exposed pipe, if appropriate.

Note: When possible, arrange for the pipe to be exposed and the excavation shored and plated (per CNP's "Excavation and Trenching Policy") at all or a majority of the locations before the arrival of the LRUT Service Provider to significantly decrease project costs.

7.1.4 Coordinate the timing of activities between the Service Providers and CNP personnel.

7.2 Responsibility: Excavation Crew

7.2.1 Apply for appropriate locates of buried facilities before performing the excavations.

7.2.1.1 Notify the applicable state one-call system.

7.2.1.2 Be aware that locates generally require two (2) working days lead-time and expire after two (2) weeks.

Note: Request that Locator Service Providers mark all CNP facilities.

7.2.1.3 Contact other non-participating utilities to locate their facilities near the proposed excavations.

8.0 EXCAVATION AND DIRECT EXAMINATION

8.1 Responsibility: GTIM Field Supervisor or designee

8.1.1 Confirm a qualified Direct Examination crew is on-site to examine the pipe during excavation and preparation for the LRUT inspection.

8.2 Responsibility: GTIM Field Inspector or designee

8.2.1 For the first inspection of an LRUT group, have the Excavation Crew excavate beyond the intended assessment area to locate a weld.

8.2.2 Evaluate the condition of the coating.

8.2.2.1 Document the results on O&M Form 3105 “Pipe Exam”.

8.2.3 Confirm the Excavation Crew removes an approximate three (3) feet full-encirclement area of coating for collar placement approximately ten (10) feet from the end of the casing.

8.2.3.1 Remove an approximate three (3) feet full encirclement area of coating at the exposed weld location for the first inspection of an LRUT group.

8.2.3.1.1 Confirm that this weld location will not be within the tool’s Dead Zone or Near Zone. Confirmation may require removing additional coating so that the tool placement can be adjusted accordingly.

8.2.3.2 It is not necessary to remove the coating on Fusion Bonded Epoxy (FBE) coated pipe.

8.2.3.3 If the pipe is concrete coated, reconsider the use of LRUT. If continuing with LRUT on a concrete coated pipe, special considerations will apply on a case-by-case basis.

Note: Confirm removal of the coating on coal tar coated pipe complies with CNP’s Safety Program “Policy for Handling Coal Tar Wrapped Pipe, Valve Gaskets, and Packing Material-2008”.

8.2.4 Verify the Excavation Crew cleans the pipe to a smooth, bare metal finish.

8.2.5 Once cleaned, confirm the Excavation Crew examines the pipe and performs testing per the requirements of GTIM-04-008 “Data Collection for Direct Examinations”.

8.2.5.1 Document the inspection on GTIM-90418 “Pipeline Inspection Direct Examination”.

8.2.5.2 Gather required data elements listed in the “Pre-Assessment” section of this procedure when the pipe is exposed using GTIM-02-010 "Material Verification".

8.2.6 Upon finding adverse conditions (i.e., mechanical damage or evidence of Stress Corrosion Cracking) during the examination, notify the GTIM Field Supervisor as soon as practical.

8.2.6.1 For each corrosion and crack-like anomaly, notify the GTIM Field Supervisor or GTIM Engineer to complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

8.2.7 For shorted, mechanical or electrolytic, casings, contact Corrosion Control personnel for assistance with identifying and clearing casings.

8.2.7.1 Clear the shorted pipe before performing the LRUT.

8.2.8 When performing LRUT on cased pipe, expose the end of the casing and remove the casing end seals.

8.2.8.1 If water is present inside the casing, drain the water from the casing before performing the LRUT.

8.2.8.2 Visually inspect the first two (2) to five (5) feet of pipe within the casing. Confirm a sufficient light source is available and utilized. Inspect around the entire circumference (360°) of the pipe, documenting any indications discovered during this visual inspection on GTIM-90418.

8.2.8.3 If the end of the casing cannot be exposed, perform LRUT as close to the casing end as possible.

8.2.8.3.1 If the casing end cannot be exposed, document the reason, and retain the documentation in the IM file.

8.2.8.3.2 Estimate the location of the casing end from maps, drawings, work orders, or other sources. Ensure the cased pipe does not fall in a dead-zone or a near-zone by placing the tool at least ten (10) feet from the end of the casing.

8.2.8.3.3 Examples of this situation may include, but are not limited to:

- A highway, widened over a cased crossing, and the casing ends are now beneath the pavement; and
- Casing ends are within a railroad right-of-way, and the railroad denies permission to dig within the right-of-way.

9.0 PERFORMING THE LRUT INSPECTION

9.1 Responsibility: LRUT Service Provider

9.1.1 Perform the LRUT per the requirements of this procedure after the pipe examination.

9.1.2 Perform a diagnostic check and system check on the equipment at the beginning of each workday, and any time the equipment is moved to a different LRUT group.

9.1.2.1 Perform the check per the manufacturer’s specifications.

9.1.2.2 Document the checks and provide the documentation to the GTIM Field Inspector.

9.1.2.3 If diagnostic checks of the equipment show deviations from the acceptable limits established by the manufacturer, do not begin testing until the equipment meets the manufacturer’s specifications.

9.1.3 Before performing the first shot in any LRUT group, perform a test shot to set the Distance Amplitude Curve (DAC).

9.1.3.1 Confirm that the exposed weld is outside of the Dead Zone or Near Zone.

9.1.3.2 Use the exposed weld to confirm that the equipment is correctly sizing and locating them.

9.1.3.3 Perform a test shot to set the DAC for each LRUT group.

9.1.4 Perform a minimum of two (2) shots at each location.

9.1.4.1 Perform the first shot approximately ten (10) feet from the end of the casing or covered segment to be assessed, ensuring both the dead zone and near zone will be outside of the desired assessment area.

9.1.4.1.1 Confirm documentation of the length of the dead zone in the final report.

9.1.4.2 Perform the second shot with the collar moved a distance of at least one (1) foot from the original location.

9.1.4.3 Repeat the shot at the new-collar location to validate the results of the first shot.

9.1.4.4 Review the results of the shots and verify both shots detect the same anomalies/features.

9.1.4.5 If the shots do not indicate the same features/anomalies, identify the reason(s) for the discrepancy.

9.1.4.6 Perform additional shots as necessary to confirm two consecutive shots with the same features/anomalies.

9.1.5 For each LRUT shot, use a minimum of three (3) frequencies.

9.1.5.1 Run a sufficient number of frequencies on each shot to determine the optimum frequency for categorizing the location and o’clock position of any indications.

9.1.5.1.1 Frequency selection should also take into account maximizing the range of the inspection while minimizing the Dead Zone.

9.1.5.2 Use the optimum frequency, one greater than optimum, and one less than optimum.

9.1.5.3 Frequencies used must be within the range as specified by the manufacturer of the equipment.

9.1.5.3.1 These frequencies can range from fifteen (15) to fifty (50) kHz.

9.1.5.3.2 The normal range for frequencies used for LRUT is twenty (20) to forty (40) kHz.

9.1.5.4 Document each of the frequencies run.

9.1.5.5 Document each of the frequencies utilized for the shot.

Note: If any reason exists to suspect the LRUT unit is damaged or not functioning correctly, stop the inspection and verify the proper operation of the tool. Re-calibrate the equipment as required and provide documentation as required in the “Equipment Specifications and Documentation” section of this procedure.

9.1.6 Perform the required shots using torsional waves.

9.1.6.1 Use longitudinal waves to supplement data gathered from torsional waves.

9.1.6.2 Document the wave type(s) utilized.

9.1.7 For LRUT applications at casing locations, perform LRUT shots on each side of the casing.

9.1.7.1 Compare the data from the shots on each side of the casing.

9.1.7.2 Confirm that shots overlap within the casing by at least 20% of the length of the assessment segment.

9.1.7.2.1 Verify shots overlap by at least 20%, or re-perform the shots with the tool placed closer to the end of the casing.

9.1.7.2.2 If the shots still do not overlap by at least 20%, assess casing by another assessment method.

9.1.8 Utilize one or a combination of the options below to assess the entire length of the casing, if needed (i.e., long cased pipeline segments):

- Remove a portion of the casing at the end of the cased location to decrease the required shot length; or
- Remove a portion of the casing near the middle of the cased location.

9.1.8.1 In some cases, an alternate method of assessment or other options may be necessary. Options for verifying the integrity of the segment might include:

- In-Line Inspection;
- Pressure Testing;
- Pipeline reroutes; and
- Casing removal to directly examine the pipe.

9.1.9 Provide preliminary results to the GTIM Field Supervisor and GTIM Field Inspector.

9.1.10 Recommend appropriate locations for validation examinations.

9.1.11 For each validation location, provide the GTIM Field Supervisor and GTIM Field Inspector with the distance of the validation locations referencing the collar location or other stationary features.

9.2 Responsibility: GTIM Field Inspector or designee

9.2.1 Confirm the LRUT Service Provider is performing the inspection(s) per the contract and procedural requirements.

9.2.2 Complete the form, GTIM-90415 “LRUT Field Notes”, during the inspection.

9.2.3 Review initial results provided by the LRUT Service Provider with the GTIM Field Supervisor or GTIM Engineer.

9.2.4 Review recommendations from the LRUT Service Provider with GTIM Field Supervisor or GTIM Engineer regarding the locations of validation examinations.

10.0 DETERMINING THE NUMBER OF VALIDATION LOCATIONS

10.1 Responsibility: GTIM Field Supervisor or GTIM Engineer

10.1.1 To determine the required number of validation examinations, first, categorize the examinations into LRUT Groups.

10.1.2 Base LRUT Groups on past assessments that meet all of the following requirements:

- Used the same equipment with the same serial number;
- Data analyzed by the same Service Provider personnel;
- Conducted within the same timeframe (i.e., same mobilization); and
- On pipes with the same characteristics (i.e., same vintage, construction practices, coating type, diameter, etc.).

10.1.3 Identify the number of validation examinations per the guidelines below:

- One (1) to three (3) LRUT inspection locations in the LRUT Group: Perform a validation examination for each LRUT inspection location; or
- Four plus (4+) LRUT inspection locations in the LRUT Group: Perform validation examinations on a minimum of 25% of the locations or three (3) locations, whichever is more significant in number.

11.0 SELECTING THE VALIDATION EXAMINATION LOCATIONS

11.1 Responsibility: GTIM Field Supervisor or GTIM Engineer or GTIM Field Inspector

11.1.1 For LRUT applications at cased pipeline locations, perform validation examinations in the Secondary Region (refer to Figure 04-001-F1).

11.1.2 For LRUT applications at non-cased pipe locations, perform the validation examination in the Direct Region (refer to Figure 04-001-F2).

11.1.2.1 If the Direct Region lies in a “difficult area”, validation examinations in the Secondary Region may be performed.

11.1.2.2 Examples of a “difficult area” include a streambed or 4+ lane roadway.

11.1.3 Choose validation examination locations per the following order of preference:

(1) Corrosion anomalies;
(2) Known features (i.e., girth welds); and
(3) “No-feature” locations.

11.1.4 Confirm the LRUT Service Provider provides the distance from a physical reference point as well as the sizing (for metal loss anomalies) of the feature to utilize for validation.

11.1.5 It may be possible to extend the length of an existing excavation to use for the validation examination.

11.1.6 When possible, perform the validation examination(s) while the LRUT service provider is still on-site.

11.1.6.1 Results from the validation digs will assist the LRUT service provider in analyzing the data from the inspection.

12.0 PERFORMING THE VALIDATION EXAMINATIONS

12.1 Responsibility: GTIM Field Inspector or designee

12.1.1 Confirm a qualified Direct Examination Service Provider is on-site to perform the validation examination.

12.1.2 Confirm the Direct Examination crew follows the data collection requirements of procedure GTIM-04-008 “Data Collection for Direct Examination”.

12.1.3 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”, including:

- Locate the approximate anomaly location based upon guidance from the LRUT Service Provider or LRUT report references.
- Instruct the excavation crew to remove a full-encirclement area of coating at the area of the anomaly. Remove approximately three (3) feet of coating, more if coating damage is extensive.

- For external corrosion, verify the corrosion anomaly dimension from the reference point as given by the LRUT service provider or LRUT report references.
- Measure the defect pit depth, if applicable.
- Measure the maximum defect length, if applicable.
- Evaluate the pipe remaining strength per RSTRENG, if applicable.

Note: RSTRENG is not valid for wall loss greater than 80%. Wall loss greater than 80% is an Immediate Condition.

- Take ultrasonic thickness measurements around the circumference of the pipe at six (6) inch intervals. Refine the measurement interval as necessary to determine the extent of internal wall loss.
  - Perform a minimum of four (4) readings.
- Compare the results of the ultrasonic thickness measurements with as-built wall thickness to evaluate for internal wall loss.
- Document the results on the GTIM-90418 “Pipeline Inspection Direct Examination”.
- Take photographs documenting the pipe condition.
  - Use a dry erase board in photographic documentation (excluding close-ups) and document on the board the date, casing number, and other relevant information.
- Verify the size of the corrosion anomaly reasonably agrees with the sizing provided by the LRUT Service Provider.

12.1.4 For validation examinations at a known feature (i.e., weld), perform and document the following:

- Verify the feature location dimension from the reference point as given by the LRUT Service Provider or LRUT report references.
- Expose the girth weld or feature. Remove enough coating to identify the existence of the girth weld/feature positively.
- Take photographs of the girth weld or feature.
- As deemed necessary, remove more of the coating to allow additional inspection.
- Document the results of the direct examination on GTIM-90418 “Pipeline Inspection Direct Examination”.
- Take photographs documenting the pipe condition.

12.1.5 For validation examinations at a “no-feature” location, perform and document the following:

- Verify the dimension location from the reference point(s) as indicated by the LRUT Service Provider or LRUT report references.
- Remove an approximate three (3) foot width of coating around the circumference of the pipe, regardless of the coating condition.
- Verify no external corrosion anomalies exist.
- Evaluate the condition of the pipe.
- Perform ultrasonic thickness measurements around the entire circumference of the pipe at six (6) inch intervals.
  - Perform a minimum of four (4) readings.

- Compare the ultrasonic thickness measurements with the as-built wall thickness to evaluate for internal wall loss.
- Document the direct examination on the form GTIM-90418 “Pipeline Inspection Direct Examination”.

12.1.6 Make repairs per O&M 16.0 “Repairs” or CNP O&M XX: “Transmission Pipeline Repair”.

12.2 Responsibility: GTIM Field Supervisor or GTIM Field Inspector or designee

12.2.1 Review the results of each validation examination.

12.2.2 Determine if the results of the examination reasonably agree with information from the LRUT Service Provider or LRUT report.

12.2.2.1 If the results of one (1) or more validation examinations do not agree with the inspection results, perform a validation examination for the remaining locations in the LRUT Group.

12.2.2.2 Re-perform the LRUT assessment at each location where the results of the validation examination do not correlate to the original LRUT results.

12.2.2.2.1 Perform an additional validation examination for each location or use the results from the previous validation examination.

12.2.2.3 If the results of the LRUT assessment still do not agree with the results of the validation examination, determine the appropriate response.

12.2.2.3.1 Potential responses include:

- Re-calibration of the equipment;
- Dismissal of the LRUT Service Provider; or
- Assessment via an alternate technology.

12.2.2.4 Request assistance or feedback from the GTIM Field Supervisor, and the GTIM Engineer as deemed appropriate.

12.2.2.5 Resolve discrepancies with the Service Provider as necessary.

12.3 Responsibility: GTIM Field Inspector or designee

12.3.1 Upon completion of the inspection, confirm the recoating of the pipe per O&M 27.35 “Protective Coatings”.

12.3.2 Using a plastic zip tie, mark the location of the center of the LRUT collar.

12.3.2.1 Place the zip tie over the top of the coating.

12.3.3 As necessary, re-attach or install new test leads per O&M 27.34 “Test Stations”.

12.3.4 As necessary, replace casing end seals.

12.3.5 As necessary, repair or replace casing vents.

12.3.6 Backfill and restore the excavation site.

13.0 DATA ANALYSIS

13.1 Responsibility: LRUT Service Provider

13.1.1 Set the DAC curves to the amplitude of a known feature (i.e., weld).

13.1.2 Compare the DAC curves and the noise level.

13.1.3 Determine the equipment shot distance at sensitivities of 3%, 4%, and 5% of the Cross-Sectional Area (CSA).

13.1.3.1 Record the distances achieved at each of the sensitivities.

13.1.3.2 If using a 3% or 4% sensitivity results in too much background noise or not enough shot overlap, consider a 5% sensitivity shot distance.

13.1.4 Determine and document the CSA of all detectable metal loss features.

13.1.4.1 Metal loss features greater than 5% of the CSA requires remediation. Refer to the “Remediation” section in this procedure.

14.0 LRUT SERVICE PROVIDER REPORT

14.1 Responsibility: LRUT Service Provider

14.1.1 Within 30 days of completing the field inspection, provide two (2) copies of the final inspection report, and one (1) electronic copy of the report in Adobe Acrobat format to the GTIM Engineer. The report should include at a minimum:

- Cover page that includes full customer name, pipeline name, inspected section location, date of inspection and report date;
- Project scope description;
- Color photographs including;
    - Opening from grade, including ditch shoring and support;
    - Exposed pipe;
    - Transducer test collar attached to the pipe and the drive electronics, showing manufacturer and model of the unit;
    - Casing end seal (if applicable);
    - Exposed weld joints (if available);
- Color analysis plot for the entire length of the inspected pipe including marked locations of weld joints, bends, casing seals, casing spacers and anomalies;
- Length of the dead zone for each shot;
- Anomaly data, including;
    - Location dimension from zero reference point;
    - Cross-sectional area (CSA) loss;
- Determination of severity classification (i.e., minor, moderate, severe) of the indication;
    - Based upon vendor experience;
    - Provide a definition or matrix for defining severity classifications;
    - If the LRUT Service Provider believes the indication is severe, contact the GTIM Engineer;
- Overall assessment of pipe inspected including a summary of which inspections completely assessed the desired length and which did not;
    - Achievement of a minimum of 20% overlap between shots for the length of the pipe for a successful assessment;
- Summary of unusual conditions, if found;
- Summary of compliance with Quality Assurance Procedure;

- Summary tutorial of the LRUT test process, with a specific overview of reflected response data analysis methodology;
- Information about the tool tolerances and signal attenuation at each inspection location;
- Equipment specifications as outlined in the " Equipment Specifications and Documentation" section within this procedure, including but not limited to;
  - Manufacturer model number and serial number for the transducer, transducer drive unit, and information on other significant test equipment;
  - Name, version, and version date of analysis software used;
- Equipment documentation as outlined in the "Equipment Specifications and Documentation" section of this procedure, including, but not limited to;
  - Proof of calibration;
  - Noise elimination filters used;
  - Types of (i.e., single or dual) sensors used; and
  - The spacing of sensors.
- Qualifications documentation as outlined in the "Qualifications of the LRUT Service Provider" section of this procedure including, but not limited to:
  - Certification of the technicians performing the test, reviewing the data, and checking the report;
  - Test and analysis procedures; and
  - Quality assurance procedures.
- Documentation on the diagnostic and system check as outlined in the "Performing the LRUT Inspection" section of this procedure;
- Documentation of frequencies run and utilized for each shot as outlined in the "Performing the LRUT Inspection" section of this procedure;
- Distances achieved for each of the sensitivities shot as outlined in the "Data Analysis" section of this procedure;
- Documentation of the wave type(s) used as outlined in the "Performing the LRUT Inspection" section of this procedure;

14.1.2 Submit a copy of the invoice to the GTIM Field Supervisor.

14.1.3 Confirm the report is reviewed and signed by the person analyzing the results.

14.1.3.1 Additionally, a second qualified person designated as having authority by the LRUT Service Provider should review and approve the report.

14.2 Responsibility: GTIM Engineer or designee

14.2.1 Review the LRUT report, including the color analysis plots.

14.2.2 Verify the plots and report includes:

- Each of the required items from section 15.1.1;
- The LRUT shot(s) include the entire length of pipe intended for inspection;
- The feature locations (i.e., weld joints, casing seals, pipe supports) marked on the color plots agree with known information about the pipeline;

14.2.3 Contact the LRUT Service Provider if any required information is missing or to resolve any discrepancies.

14.2.4 Notify the GTIM Field Supervisor when all contract requirements are complete for payment of the Service Provider invoice.

14.3 Responsibility: GTIM Field Supervisor or designee

14.3.1 Pay the invoice once the contract requirements are complete.

Note: Discovery of Condition occurs once the GTIM Engineer has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. Discovery of Condition shall occur no later than 180 days after performing the LRUT assessment.

Discovery of Condition typically occurs upon acceptance of the final LRUT report.

15.0 REMEDIATION

15.1 Responsibility: GTIM Engineer or designee

15.1.1 Review the LRUT report and schedule all indications greater than or equal to five percent (5%) CSA for direct examination or other assessment within 30 days of receiving the report. Other assessments or alternative options may include:

- In-Line Inspection;
- Pressure Testing; or
- Pipeline reroute.

15.1.2 Respond to indications within the timelines provided as follows:

15.1.2.1 For pipelines operating at or below 30% SMYS, schedule a direct examination or other assessment to be performed within 12 months of accepting the final report.

15.1.2.2 For pipelines operating above 30% SMYS, schedule a direct examination or other assessment to be performed within 180 days of accepting the final report.

15.1.3 Reduce pressure and implement additional preventive measures upon review of the report until the pipe is direct examined or replaced.

15.1.3.1 For pipelines operating below 30% SMYS, perform a leak survey monthly at the assessment location(s).

15.1.3.1.1 Perform the leak survey per O&M 17.33 “Transmission Line Leak Survey”.

15.1.3.2 For pipelines operating above 30% SMYS and less than or equal to 50% SMYS, confirm the operating pressure does not exceed the pressure at Discovery of Condition.

15.1.3.2.1 Additionally, perform a leak survey monthly at the assessment location(s) until completion of the direct examinations or performing another assessment.

15.1.3.2.2 Perform the leak survey per O&M 17.33 “Transmission Line Leak Survey”.

15.1.3.3 For pipelines operating above 50% SMYS, reduce operating pressure to 80% of the highest operating pressure achieved from the time of the LRUT inspection until the Discovery of Condition.

15.1.3.4 Notify Local Operations personnel of scheduled direct examinations or other assessments, and if monthly leak surveys are required.

15.1.3.4.1 Notify Local Operations personnel when monthly leak surveys are no longer required once the direct examinations or other assessments are complete.

15.1.4 For anomalies located on pipe within a casing, evaluate the approved remediation options. Options include:

- For repairs near the end of a casing, consider cutting back the end of the casing, repairing the pipe and replacing the cut-back casing as required;
- Re-boring or rerouting the crossing location and abandoning the existing pipe and casing in-place;
- Removing the casing pipe to expose the carrier pipe;
    - Perform a 100% visual inspection of the pipe coating;
    - Measure from the zip tie (tool location) to the anomaly location;
    - Remove a three (3) foot full encirclement area of coating and perform a direct examination;
        - Evaluate the performance of the UT tool to analyze internal corrosion through direct examination;
        - For inaccurate reporting of an anomaly location, remove an additional one (1) foot full encirclement area of coating from each end of the anomaly location and perform a direct examination; and
    - Make repairs as required and recoat the pipe per O&M 27.35 “Protective Coatings”.

15.1.5 For anomalies not located on pipe within a casing, remediate per the requirements of the O&M.

15.1.6 Prepare a dig plan to outline the locations to be examined or further assessed per the requirements of GTIM-04-026 “Dig Plan Preparation”.

15.2 Responsibility: Local Operations

15.2.1 Perform leak surveys per O&M 17.33 “Transmission Line Leak Survey”.

15.2.1.1 Perform leak surveys at the location(s) indicated by the GTIM Engineer.

15.2.1.2 Perform leak surveys at monthly intervals until notified by the GTIM Engineer of completion of the direct examinations or other assessments.

16.0 REASSESSMENT INTERVALS

16.1 Responsibility: GTIM Engineer or designee

16.1.1 The maximum reassessment interval is seven (7) years.

16.1.1.1 Consider a shorter reassessment interval based upon operation and maintenance information, as well as feedback from Subject Matter Experts.

16.1.2 Document the reassessment interval.

16.1.3 Add reassessment dates, Confirmatory Direct Assessment dates, and remediation activities to the assessment schedule calendar.

17.0 POST-ASSESSMENT

17.1 Responsibility: GTIM Engineer or designee

17.1.1 Evaluate the results of the LRUT inspections.

17.1.2 Create a work order.

17.1.2.1 Document pipeline data verified by assessment to be incorporated or updated in GIS. Examples include the following:

- Pipe attributes found during bell hole digs (e.g., OD, Wall Thickness, Grade, etc.);
- Centerline changes; and
- Repairs made.

17.1.3 Determine if there was active corrosion found during the integrity assessments.

17.1.4 Review pipelines, both covered and non-covered segments, for similar conditions per the requirements of GTIM-08-005 “Evaluating Similar Conditions”.

17.1.5 Update GTIM-90209 “Threat Analysis” with the following information, if applicable:

- New identified threats;
- Eliminated threats; and
- Changes to existing threat documentation.

17.1.5.1 Refer to GTIM-02-021 “Threat Identification”.

17.1.5.2 Create a work order to update and modified attributes in GIS and other appropriate databases.

17.1.6 Review the Preventive and Mitigative (P&M) measures implemented for the applicable covered segment(s).

17.1.7 Consider implementing additional P&M measures to address the threat of third-party damage.

17.1.7.1 Document additional P&M measures per the requirements of GTIM-08-004 “Identify Preventive and Mitigative Measures”.

17.1.8 Solicit “lessons learned” from project participants upon completion of the LRUT project.

17.1.8.1 If appropriate, invite the Service Provider(s) to the meeting.

17.1.8.2 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- Modifications to the LRUT process.

17.1.8.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

17.1.9 If applicable, initiate a Change Management request for approval per GTIM-11-001 “GTIM Change Management” for each recommended procedural change, each additional P&M recommendation, and any other potential process improvement.

17.1.10 Document Performance Measures on GTIM-90901 “Performance Measures”.

17.1.10.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

17.1.11 Perform a 100% quality check of all requested GIS updates.

17.1.12 Conduct a meeting with GTIM Manager to review the documentation and obtain approval.

17.1.13 Once the documentation is approved, the LRUT process is considered complete.

17.1.14 Confirm all documentation is stored in the IM file within 30 days of completing the LRUT process.

<<END>>

GTIM-04-002 ECDA Pre-Assessment

PURPOSE: To establish a standardized method for performing the Pre-Assessment phase of an External Corrosion Direct Assessment (ECDA).

REFERENCES: 49 CFR 192.923; 49 CFR 192.925; NACE SP0502-2010;

SECTIONS:

- Background
- Personnel Qualifications
- Consequence Areas and Identified Site Review
- Data Collection
- Feasibility Assessment
- ECDA Region Identification
- Cased Pipelines
- Indirect Inspection Tool Selection
- Applying ECDA to a Pipeline Segment for the First Time - Pre-Assessment Phase
- Applying ECDA to a Pipeline Segment for the First Time - Indirect Inspection Phase
- Pre-Assessment Documentation

1.0 BACKGROUND

1.1 CNP's process and procedures for conducting External Corrosion Direct Assessment (ECDA) comply with 49 CFR 192 Subpart O and NACE SP0502-2010 “Pipeline External Corrosion Direct Assessment Methodology”.

1.2 ECDA may be used to assess the threat of external corrosion and evaluate residual third-party damage threats when integrated with encroachment and foreign pipeline information.

1.3 CNP may elect to use Direct Assessments in conjunction with other assessment methods such as a Pressure Testing or In-Line Inspection depending upon the applicable threats.

1.4 CNP may use ECDA in Consequence Areas or non-Consequence Areas. CNP may consider a single application of ECDA as the assessment method for all covered segments on the line, subject to the ECDA assessment for a pipeline containing multiple Consequence Areas.

1.5 An External Corrosion Direct Assessment (ECDA) consists of four phases:

- Pre-Assessment;
- Indirect Inspection;
- Direct Examination; and
- Post-Assessment.

2.0 PERSONNEL QUALIFICATIONS

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Ensure Service Providers involved with the ECDA process meet or exceed the following qualifications:

- The qualifications listed in the specific procedure being implemented or performed; and
- The qualifications of CNP personnel who would otherwise be performing the activities.

2.1.2 CNP personnel responsible for the ECDA process will meet at least one (1) of the following qualification requirements:

- NACE International CP Technician (CP Level 2), or higher;
- A degreed engineer;
- Technical degree with two (2) years relevant pipeline experience; or
- Five (5) years minimum pipeline relevant experience.

3.0 CONSEQUENCE AREAS AND IDENTIFIED SITE REVIEW

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Perform a site visit to verify Consequence Areas and the locations of Identified Sites if necessary.

3.1.2 Create a work order if known Consequence Areas or structure information requires correction in GIS.

3.1.3 Prepare aerial maps of the covered segment(s) on the pipeline, including assessment extents.

3.1.4 Document the covered segment(s) information for the pipeline on GTIM-90406 “ECDA - Pre-Assessment” and GTIM-90209 “Threat Analysis”.

4.0 DATA COLLECTION

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Identify the assessment boundaries for the pipeline.

4.1.2 Collect and integrate historical data for the assessment segment.

4.1.2.1 Refer to the Feasibility Assessment section of this procedure for a list of mandatory data elements.

4.1.2.1.1 Refer to GTIM-90400 “DA Data Element Table” for a list of non-mandatory data.

4.1.2.2 Sources of information include, but are not limited to:

- IM databases;
- GIS;
- Project files and work orders, including:
  - Facility information;
  - Operating history;
  - Results of prior aboveground indirect inspections and direct examinations;
- Investigative digs, as needed to obtain pipe related information such as:
  - Wall thickness;
  - Grade;
  - Coating type;
  - Seam type; and
- Subject Matter Experts.

4.1.3 Consider assigning a qualified Service Provider to assist with the data collection process.

4.1.3.1 If data is missing and extensive data research is required, refer to GTIM-02-001 "Data Gathering and Research".

4.1.4 Request assistance from corrosion control and operating personnel as required.

4.1.5 Review and update, as needed, the information on GTIM-90400 "DA Data Element Table".

4.1.6 When identifying new information about one of the following data elements, append the new information to the pre-existing data element information.

- Material (e.g., steel, cast iron, plastic);
- Wall thickness;
- Coated pipe (i.e., Y/N);
- Primary coating type (e.g., coal-tar, FBE, etc.);
- Locations of any mechanically-coupled pipe;
- Un-bonded electrical isolation (i.e., flange, monolithic fitting, etc.);
- Parallel external sources, within the same ROW or in proximity, potentially influencing CP currents (i.e., other pipelines, structures, high voltage electric transmission lines, and DC rail systems);
- Evidence of external Microbiologically Influenced Corrosion (MIC);
- Pipe exposed to the atmosphere;
- Underwater section (i.e., Y/N); or
- Casing (i.e., Y/N).

4.1.6.1 Refer to the ECDA Region Identification section of this procedure for further details.

4.1.6.2 Refer to GTIM-06-004 "Continual Data Integration, Management, and Evaluation".

4.1.7 Review the applicable threats to the pipeline.

4.1.7.1 Refer to GTIM-02-021 "Threat Identification".

4.1.8 Review existing Preventive and Mitigative (P&M) measures for the covered segment(s) on the pipeline.

4.1.9 Document and justify any assumptions made with the data in the comments area of GTIM-90400 "DA Data Element Table" or the appropriate database.

4.1.10 Confirm all data and documentation requirements.

4.1.11 Provide Corrosion Control with information regarding the segment to be surveyed. Include information such as survey segment starting and ending points.

4.1.11.1 Request that Corrosion Control completes GTIM-90404 "Rectifier and Critical Bond Locations".

4.2 Responsibility: Corrosion Control

4.2.1 Complete GTIM-90404 "Rectifier and Critical Bond Locations".

4.2.1.1 This form will facilitate the Indirect Inspection survey effort.

4.2.2 Provide a copy of completed GTIM-90404 and the supporting documentation to the GTIM Engineer.

4.3 Responsibility: GTIM Engineer or designee

4.3.1 Complete the data collection section of GTIM-90406 "ECDA - Pre-Assessment".

4.3.2 Confirm completion of the minimum data requirements, listed below in the Feasibility Assessment section.

4.3.3 Attach the completed GTIM-90400 to GTIM-90404.

5.0 FEASIBILITY ASSESSMENT

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Evaluate existing pipe conditions that may preclude the use of ECDA by hindering the application or a technical impracticality.

5.1.2 If not all data is available, make justifiable data assumptions and document on GTIM-90400 in the comments area or the appropriate database or arrange for investigative digs to gather the information.

5.1.2.1 Obtain the pipe wall thickness during direct examinations.

5.1.3 When the data for any required data element is not obtainable and cannot support assumptions, ECDA is an unfeasible assessment method for this pipeline segment.

5.1.4 Table 04-002-1 lists the minimum required data elements.

Table 04-002-1: Minimum Data Requirements for ECDA[1]

Pipe Related	
• Material (i.e., steel, cast iron, plastic)	• Locations of casings
• Diameter	• Locations of foreign-lines in proximity
• Wall thickness	• Locations of underwater sections, river crossings
• Bare or coated pipe	• Year manufactured
• Grade	• Seam types
Construction Related	
• System maps	• Depth of cover (can be approximated)
• Year installed	• Locations of insulating joints
Soils / Environmental	
• Land use (i.e., pasture, residential)	• Topography
• Frozen ground	• Right-of-way (i.e., unpaved, concrete)
Corrosion Control	
• Type of cathodic protection system	• Years without CP applied
• Sources of stray current	• Coating type (pipe and joints)
• Test point locations	• Rectifier and bond locations
• Annual survey data	• Rectifier readings
• CP maintenance history	
Operational Data	
• Repair history	• Operating stress level (%SMYS)
• Leak/rupture history	• MAOP

[1] Derived from NACE SP0502-2010.

5.2 Responsibility: GTIM Engineer or designee

5.2.1 Review GTIM-90400.

5.2.2 Determine whether the conditions along the pipeline segments allow indirect inspection methods by considering the following information:

- Locations where pipe coatings may cause electrical shielding;
- Locations with rock backfill or rock ledges that could cause electrical shielding;
    - ECDA is not feasible if a rock “cap” resides above the pipeline;
    - ECDA is not feasible if the pipeline has been trenched in rock and is lying directly on rock;
- Locations where the ground surface produces a high resistance contact with a reference electrode (i.e., frozen ground, concrete, asphalt);
    - Indirect inspections are not feasible over frozen ground;
    - Indirect inspections are not feasible through undrilled-pavement;
- Locations with buried parallel metallic structures positioned directly over the top of the pipe;
- Locations that are impractical for indirect inspections (e.g., casings, large bodies of water, etc.);
- Restricted locations.

5.2.3 Document the feasibility and the rationale for the selected method on GTIM-90406.

5.3 Responsibility: GTIM Engineer or designee

5.3.1 If ECDA is determined to be unfeasible for a pipeline segment, choose another method of assessment based upon the identified threats. Applicable assessment methods may include:

- Pressure Testing;
- In-Line Inspection; or
- “Other Technology”.

5.3.2 Refer to GTIM-03-001 “Assessment Method Selection” for details on choosing assessment methods.

6.0 ECDA REGION IDENTIFICATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Define ECDA Regions based upon pipeline segments with similar physical characteristics, operating history, expected future corrosion conditions, and that allow the same indirect inspection tools.

6.1.2 Review the ECDA Pre-Assessment data.

6.1.3 Consider conditions that could significantly affect external corrosion and use the following guidelines when identifying ECDA regions:

- Individual ECDA regions do not need to be contiguous; and
- ECDA requires associating all pipeline segments subject to the ECDA assessment, to an ECDA region.

6.1.4 Analyze the populated pipeline data to confirm the individual ECDA regions. Establish a different ECDA region for each of the following data changes:

- Material (e.g., steel, cast iron, plastic);
- Wall Thickness categories;
  - < 0.156";
  - ≥ 0.156" and ≤ 0.250";
  - > 0.250";
- Bare or coated pipe (i.e., Y/N);
- Primary coating type (i.e., coal-tar, FBE, etc.);
  - Define regions based on the type of line pipe coating;
- Locations of any mechanically-coupled pipe;
  - Define regions by the span of a continuously coupled pipe;
  - Regions do not encompass individual couplings;
- Un-bonded electrical isolation (i.e., flange, monolithic fitting, etc.);
  - A region boundary exists at each unbonded isolation point;
  - Regions do not encompass individual fittings;
- Parallel external sources, within the same ROW or in proximity, potentially influencing CP currents (i.e., other pipelines, structures, high voltage electric transmission lines, and DC rail systems);
  - Define a region with the extents of an area where the foreign structure parallels the subject pipeline;
  - Define a region with the extents of a pipeline subject to known interference issues;
- Evidence of external Microbiologically Influenced Corrosion (MIC);
  - If a pipeline has a history of MIC, define the boundaries of a region at the location where the coating age and type changes;
- Pipe exposed to the atmosphere;
  - Define a new region;
  - Perform a 100% Direct Examination in this area;
- Underwater section (i.e., Y/N);
  - Define a new region at the boundaries of a body of water too deep to navigable by walking;
- Casing (i.e., Y/N).

6.1.5 Document a new line of data for each of the above changes to facilitate region identification.

6.1.6 Using the criteria above, open the "ECDA Region" tab of the GTIM-90400 "DA Data Element Table" form, and assign each unique pipe segment a region number.

6.1.6.1 Document the region number in the appropriate column.

6.1.6.2 Confirm assignment of a region number for each pipeline segment.

6.1.6.3 Verify no property or attribute changes exist for the pipeline assessment segment before considering the reuse of prior assessment region numbers.

6.1.6.3.1 Assign new region numbers if pipeline changes warrant an updated ECDA region.

6.1.6.3.2 Document changes to ECDA region numbering per GTIM-11-001 “GTIM Change Management”.

6.1.6.4 Refer to the “Guidance” tab of GTIM-90400 for guidance on completing the form.

6.1.7 Create a work order if known data attributes need correction in GIS.

6.1.7.1 Example: No casing identified in GIS and pre-assessment research determined casing does exist per information gathered from as-built records or actual observation.

7.0 CASED PIPELINES

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Assess cased crossings within covered segments where ECDA is the primary assessment method using technologies accepted by the Pipeline Hazardous Materials Safety Administration (PHMSA).

7.1.1.1 If assessing the cased crossing as part of the ECDA process is not possible, assess the cased crossing using another PHMSA accepted technology or provide notification to appliable regulatory agencies of the intent to use an “other technology” assessment method.

7.1.1.1.1 Refer to GTIM-13-001 “Required Notifications to Regulatory Agencies” for additional details.

7.1.1.2 If removal of the casing is feasible, remove the casing and perform a 100% Direct Examination of the carrier pipe.

7.1.1.2.1 Create a work order to update the data attributes in GIS.

8.0 INDIRECT INSPECTION TOOL SELECTION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Select a minimum of two (2) indirect inspection tools to assess each ECDA region.

8.1.1.1 Use the following criteria when selecting the indirect inspection tools:

- Select tools for their ability to detect corrosion and coating holidays under the specific pipeline conditions as determined during the data collection;
- Select complementary indirect inspection tools. For example, Close Interval Survey (CIS) and Direct Current Voltage Gradient (DCVG) are complementary tools since CIS assesses the level of cathodic protection and DCVG identifies areas of potential coating damage;
- Use the indirect inspection tools over the entire length of an ECDA region;
- Some ECDA regions may require more than two indirect inspection tools;
- Follow the pre-assessment and post-assessment processes when substituting with 100% Direct Examination.

Note: For CDA, only one (1) indirect inspection tool is required. SCCDA requires a minimum of one (1) indirect inspection tool.

8.1.2 Choose from the following indirect inspection methods:

- Close-Interval Survey (CIS);
- Direct Current Voltage Gradient (DCVG);
- Pipeline Current Mapper (AC Attenuation);
- Pipeline Current Mapper with A-Frame (ACVG); and
- Cell-to-Cell Survey.

8.1.2.1 Although NACE SP0502-2010 references other indirect inspection methods, such as C-Scan and Pearson Survey, CNP prefers the methods listed above.

8.1.2.2 If an alternate indirect inspection method is selected, document the method's applicability, the equipment, the method's procedure, the basis for validating the data, and the data utilization on GTIM-90406.

8.1.2.3 The GTIM Manager must approve any alternative tool used and sign the GTIM-90406.

8.1.3 Using Table 04-002-2 as a guide, select the indirect inspection tools.

8.1.3.1 Consider the tool uses and limitations. NACE SP0207-2007[2] and NACE TM0109-2009[3] contain additional information on observing appropriate safety precautions with electrical measurements.

Table 04-002-2: Indirect Inspection Tool Applications and Limitations

Indirect Inspection Method	**Applications**	**Limitations**
Close-Interval Survey (CIS)	• Determines level of cathodic protection on the pipeline; • Can also be used to determine electric shorts and areas of stray current interference;	• Does not detect coating holidays; • Cannot utilize in areas where the coating is causing electrical shielding, over frozen ground, over a cased pipe, or rocky terrain; • Requires drilling holes through paved surfaces; • The survey may be performed over concrete using the "sponge" technique if approved by the GTIM Field Supervisor;
Direct Current Voltage Gradient (DCVG)	• Detects coating holidays with size ranging from small to large; • Can determine if the holiday is anodic or cathodic;	• Does not determine the level of cathodic protection; • Cannot utilize over frozen ground, areas where the coating is causing electrical shielding, over cased pipe or rocky terrain; • Requires drilling holes through paved surfaces; • The survey may be performed over concrete using the "sponge" technique if approved by the GTIM Field Supervisor;

[2] NACE SP0207, NACE Standard Practice 0207, "Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines", 2007, (NACE SP0207);
[3] NACE TM0109, NACE Standard TM0109, "Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition", 2009, (NACE TM0109);

Indirect Inspection Method	Applications	Limitations
Alternating Current Voltage Gradient (ACVG)	• Similar to DCVG survey; • Used to detect coating holidays ranging in size from large to small;	• Does not determine the level of cathodic protection; • Cannot utilize over frozen ground, where the coating is causing electrical shielding, over asphalt roads, over cased pipe or rocky terrain/backfill;
AC Current Attenuation Surveys	• Assess coating quality and detect and compare coating anomalies; • Does not require electrical contact with the soil and performs through concrete;	• Does not determine the level of cathodic protection; • Cannot utilize where the pipeline coating is causing electrical shielding, under high-voltage alternating current overhead electric transmission lines and over cased pipe;
Cell-to-Cell Survey	• Usually performed on bare or poorly coated pipelines and electrically discontinuous pipelines; • Determines areas of current discharge;	• Results of a cell-to-cell survey can be affected by adjacent buried metallic structures and adjacent galvanic anodes; • Cannot utilize where the pipeline coating is causing electrical shielding, over cased-pipe, over paved roads or rocky backfill/terrain; • Requires drilling holes through paved surfaces; • The “sponge” technique may be used over concrete if approved by the GTIM Field Supervisor;

8.1.4 As an additional guide, when selecting indirect inspection tools, use Table 04-002-3, which associates right-of-way conditions with applicable indirect inspection methods.

Table 04-002-3: Tool Application per Right-of-Way Condition

	CIS[1]	DCVG[2]	Current Attenuation (PCM)[2]	ACVG (PCM with A-Frame)[2]	Cell-to-Cell Survey
Blacktop - Limited Access			x		
Blacktop - Wide Span *(if drilled)*	x	x	x	x	x
Blacktop - Narrow Span			x		
Blacktop - Wide Span			x		
Concrete - With Rebar & Holes Drilled	x	x	x	x	x
Concrete - No Rebar	x	x	x		
Concrete - With Rebar			x		
Water Crossing	x	x			
Casing	x[4]	x[3]	x[4]		
Solid Rock			x		
Frozen Ground			x		
Steep Slopes *(walkable)*	x	x	x	x	
Bare Pipe	x				x
Parallel Mains	x	x	x	x	x

	CIS[1]	DCVG[2]	Current Attenuation (PCM)[2]	ACVG (PCM with A-Frame)[2]	Cell-to-Cell Survey
AC Corridor		x		x	x
Soil Cover	x	x	x	x	x

***1** = Tools that show CP protection or direction of current flow*
***2** = Tools used to show coating conditions*
***3** = Coating holidays at a casing edge may indicate the existence of a hard casing short*
***4** = Readings graphed on each side of a casing may indicate loss of current caused by casing short*

8.1.5 Document the tools selected and the rationale for selecting them on GTIM-90406.

8.1.6 Explain on GTIM-90406 why the tools are complementary.

8.1.7 Document any special considerations for the survey. Special considerations may include, but are not limited to:

- Traffic Control;
- Drilling holes through paved surfaces;
- Special permits or required notifications; and
- Watercraft for bodies of water.

8.1.7.1 Typically, indirect inspection techniques are not capable of penetrating paved surfaces; consider an alternate method or arrange for paved surfaces greater than ten (10) feet in length to be drilled per GTIM-04-031 “Drilling or Coring of Improved Surfaces” unless otherwise directed.

8.1.7.2 At the discretion of the GTIM Field Supervisor, perform an “off-set” survey when the centerline of the pipeline is off-set from grassy terrain by a maximum of three (3) feet.

9.0 APPLYING ECDA TO A PIPELINE SEGMENT FOR THE FIRST TIME - PRE-ASSESSMENT PHASE

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Implement “more restrictive criteria” during the Pre-Assessment phase when applying ECDA to a pipeline segment for the first time. Options include, but are not limited to:

- Subdivide the ECDA regions into additional ECDA regions;
- Perform a test excavation to validate and improve the quality of the data found during the data collection step;
- Hold a Pre-Assessment meeting with field personnel and Subject Matter Experts (SMEs) to gather additional information about the pipeline based on their experiences; and
- Pre-mark the pipeline to enhance data integration by placing flags or paint every twenty-five (25) feet along the pipeline.

9.1.2 Document the more restrictive criteria used on GTIM-90406.

10.0 APPLYING ECDA TO A PIPELINE SEGMENT FOR THE FIRST TIME - INDIRECT INSPECTION PHASE

10.1 Responsibility: GTIM Engineer or designee

10.1.1 During preparation for the Indirect Inspection, specify the “more restrictive criteria” to be utilized during that phase.

10.1.2 Use a minimum of one (1) technique from each column in Table 04-002-4 below:

Table 04-002-4: Indirect Inspection Techniques for First Time Application of ECDA

NACE RP0169-2002[4]	PHMSA FAQ 242[5]
• Take duplicate readings at random test stations along the indirect inspection path with a separate survey meter and compare the readings;	• Perform more than two (2) indirect inspection techniques for part or all of the survey area; • Consider taking soil resistivity readings at 1000 foot intervals as an additional indirect inspection technique;
• Repeat an indirect inspection;	• Perform indirect inspection techniques at a shorter spacing than required;
• When performing a close-interval survey, resurvey any areas where the readings are more electro-positive than -0.850 volts;	• For paved areas, obtain direct contact with the soil by boring through the pavement;
• A GTIM Field Inspector, familiar with indirect inspections, reviews the previous day’s survey data and requests a resurvey of any suspect data;	• Obtain soil resistivity readings at DCVG and ACVG indications and use data to help identify excavation locations when necessary;

10.1.3 Document the use of the more restrictive criteria on GTIM-90406.

11.0 PRE-ASSESSMENT DOCUMENTATION

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Perform a 100% quality check of all requested GIS updates.

11.1.2 Confirm completion of the following forms:

- GTIM-90400 “DA Data Element Table”;
- GTIM-90404 “Rectifier and Critical Bond Locations”;
- GTIM-90406 “ECDA - Pre-Assessment”;
- GTIM-90209 “Threat Analysis”; and
- HCA Aerial Maps.

11.1.3 Retain all assessment documentation in the IM file for the life of the system.

11.1.4 Conduct a Pre-Assessment approval meeting.

11.1.5 Notify the GTIM Field Supervisor upon approval of the Pre-Assessment.

[4] NACE RP0169-2002, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems”, 2002;
[5] PHMSA FAQ 242, “Gas Transmission Integrity Management: FAQs”, The Pipeline and Hazardous Materials Safety Administration (PHMSA), phmsa.dot.gov, Web, 31 March 2020;

11.2 Responsibility: GTIM Field Supervisor or designee

11.2.1 Inform the Service Provider that the Indirect Inspection work can begin.

<<END>>

GTIM-04-003 ECDA Indirect Inspection

PURPOSE: To establish a standardized method for performing the Indirect Inspection phase of the External Corrosion Direct Assessment (ECDA) methodology.

REFERENCES: 49 CFR 192.917; 49 CFR 192.925(b)(2); GTI/AGA Research Collaboration; NACE SP0502-2010;

SECTIONS:

- Background
- Indirect Inspection Preparation
- Performing the Indirect Inspections
- Data Alignment and Comparison
- Data Classification
- Data Prioritization
- Integrating Foreign Line and Encroachment Data
- Redefining ECDA Regions
- Direct Examination Selection
- Determining the Region Most Likely for Corrosion
- Validation Examinations
- Applying ECDA to a Pipeline Segment for the First Time
- Dig Plan Preparation
- Indirect Inspection Documentation

1.0 BACKGROUND

1.1 The Indirect Inspection phase identifies areas of potential corrosion activity.

1.2 Two or more complementary indirect inspection tools are used over the pipeline segment to provide detection reliability under the wide variety of conditions.

1.3 The Indirect Inspection phase is not necessary if assessing the pipe segment through 100% Direct Examination.

1.3.1 Refer to GTIM-04-028 “100% Direct Examination for Station Assessments” for more information.

2.0 INDIRECT INSPECTION PREPARATION

2.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

2.1.1 Review the survey route and identify areas where permits may be required. Work with Local Operations to obtain.

2.1.2 Prepare for the indirect inspections per the requirements of GTIM-04-030 “Indirect Inspection Survey Field Preparation” and based on the scope of work.

3.0 PERFORMING THE INDIRECT INSPECTIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Locate and mark the pipeline segment to be surveyed per the requirements of GTIM-04-032 “Locating and Marking a Survey Segment”.

3.1.2 Conduct each indirect inspection according to the applicable procedures:

- GTIM-04-020 “Close-Interval Survey”;
- GTIM-04-021 “Direct Current Voltage Gradient Survey”;
- GTIM-04-022 “Current Attenuation Survey using the Pipeline Current Mapper”; and
- GTIM-04-023 “Alternating Current Voltage Gradient Survey”.

3.1.2.1 Perform indirect inspections over the entire length of each ECDA region, within the covered segments to be assessed.

3.1.3 Notify Corrosion Control of inoperative cathodic protection systems identified during an indirect inspection.

3.1.4 Take soil resistivity measurements per GTIM-04-013 “Soil Resistivity with the Wenner 4-Pin Method”.

3.1.5 Take pipeline depth measurements per GTIM-04-033 “Pipeline Depth Survey” while performing the indirect inspections.

3.1.6 Document in the survey comments, all visible indications of encroachment found while performing the Indirect Inspection.

3.1.6.1 Provide notification to the Encroachment Program Manager per CNP’s encroachment policy.

3.1.6.2 Take photographs of encroachments and the pipeline easement.

3.1.6.2.1 Provide reference points (i.e., regulator stations, location markings, etc.) of CNP’s pipeline and the encroachment.

3.1.6.3 Examples of encroachments include, but are not limited to:

- Evidence of excavation activity near the pipeline;
- Water lines;
- Fence posts;
- Fiber optic cables; and
- Signposts.

3.1.6.4 Document as much information about the encroachment as possible (i.e., company name, type of foreign-line crossing, building description).

3.2 Responsibility: GTIM Field Supervisor or designee

3.2.1 Document any deviations that occurred during the Indirect Inspection phase on GTIM-91101 “Pipeline Event Evaluation”.

3.2.1.1 Deviations may include changes such as skipped distances greater than ten (10) feet.

4.0 DATA ALIGNMENT AND COMPARISON

4.1 Responsibility: GTIM Field Supervisor or designee

4.1.1 Review data plots and the report from the Service Provider. At a minimum, verify:

- The entire length of the survey segment as directed;
- Gaps in survey data are warranted;
- Assessment IDs and names are correct in documentation;

- There are no copy/paste errors in the report; and
- Dates and weather conditions for each survey day documented.

4.1.2 As appropriate, instruct the Service Provider to:

- Resurvey all or portions of the survey segment; and
- Revise and submit report or survey plots

4.1.3 Review the stack charts and determine if the results are consistent.

4.1.3.1 Consider the impact of spatial errors when comparing the data.

4.2 Responsibility: GTIM Engineer or designee

4.2.1 Analyze the data to determine whether aligned indications mark the same physical location along the pipeline and are assigned the same level of severity.

4.2.2 Consider additional surveys or direct examinations if two (2) or more tools indicate significantly different locations where corrosion may exist and when differences are unexplainable.

4.2.2.1 Preliminary direct examinations can be used instead of additional indirect inspections if the direct examination identifies a localized and isolated cause for the discrepancy.

4.2.2.2 As an alternative, use additional indirect inspections to resolve the differences.

4.2.3 After completion of additional inspections, align and compare the data.

4.2.3.1 If the discrepancies remain unresolved, reassess the feasibility of the ECDA process for the ECDA region.

4.2.3.2 Document assessment and retain in the IM file.

4.2.4 Compare the results from the Indirect Inspection phase, the Pre-Assessment results, and prior corrosion history for each ECDA region.

4.2.4.1 If results from the Indirect Inspection phase are not consistent with the Pre-Assessment phase and prior history, reassess the feasibility for the ECDA region as well as the definition of the ECDA region(s).

5.0 DATA CLASSIFICATION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Document all indication locations on GTIM-90411 “Indication Severity Classification & Priority Category”.

5.1.1.1 For DCVG indications, document %IR value when classifying indications, when applicable.

5.1.1.2 Include the Indirect Survey Stationing and GPS reference points, if known, for all CIS indications.

5.1.1.2.1 Note that it is possible to have a CIS indication with no corresponding DCVG indication.

5.1.1.3 Include the ECDA Region with each indication.

5.1.2 Classify each indication found in the Indirect Inspection data based on the severity of the indication. Classifications are defined below.

- Severe - Indications that have the highest likelihood of corrosion activity;

- Moderate - Indications that may have corrosion activity; and
- Minor - Indications that are inactive or have a low probability of corrosion activity.

5.1.3 Use the criteria outlined in the following table to classify the severity of each indication.

Table 04-003-1: Severity of Measurement Amplitude Classification Table[1]

Tool	Measurement Amplitude Change of Indication		
	Minor	**Moderate**	**Severe**
CIS[1] *(impressed current system)*	Small or Medium Dips with "on" and "off" potentials more negative than -0.850V	Medium and Large Dips <u>or</u> "on" potential more negative than -0.850V and "off" potential more positive than -0.850V	"On" and "off" potentials more positive than -0.850V <u>or</u> a dip with "On" readings more positive than -0.900V and "off" readings more positive than -0.850V
CIS[1] *(constant current/sacrificial anodes) on-reads*	Small or Medium Dips with potentials more negative than -0.850V	Medium and Large Dips more negative than -0.850V	Large dips <u>or</u> potentials more positive than -0.850V
DCVG	1% - 35% or Cathodic/Cathodic	36% - 60% or Cathodic/Anodic or Cathodic/Neutral	61% - 100% or Anodic/Anodic
PCM[1] *(EM, AC Current Attenuation)*	1% - 30%	> 30% and ≤ 50%	50% - 100%
PCM A-Frame *(ACVG)*	30 - 50 dBμV	> 50 and ≤70 dBμV	> 70 dBμV *(2 feet intervals around defect)*
4-Pin Resistivity	> 10,000 ohm-cm	1000 - 10,000 ohm-cm	< 1000 ohm-cm

1 *= Level of dips depends on conditions particular to the pipeline region under study.*

5.1.4 Use conservative judgment when determining indication classification. Choose the more severe classification when in doubt or borderline situations.

5.1.5 Document the classification for each indication on GTIM-90411.

5.1.5.1 Score indications as follows:

- 1 = Minor;
- 2 = Moderate; or
- 3 = Severe.

5.1.5.2 When indications are "borderline" (i.e., close to the minor/moderate or moderate/severe threshold), consider the soil resistivity severity when available.

[1] Adapted from Table 4.6.2 "Severity of Measure Amplitude Classification Table", External Corrosion Direct Assessment (ECDA) Implementation Protocol, Gas Technology Institute, 2004 Revision 3;

5.1.5.3 Consider using the more severe classification for indications with a %IR near the threshold and with a soil resistivity less than 1,000 ohm-cm, or pursue them further as a discretionary dig.

5.1.6 If utilizing ECDA on bare pipelines, evaluate the classification criteria, and verify that it is sufficient to locate anodic regions.

5.1.7 Determine the Overall Severity using the following table.

5.1.7.1 The Overall Severity is the aggregate severity based on the results of all indirect inspection techniques.

Table 04-003-2: Developed using NACE SP0502-2010 in conjunction with industry experience.

		Tool 1			
		Severe	**Moderate**	**Minor**	**No Indication**
Tool 2	**Severe**	Severe	Severe	Moderate	Moderate
	Moderate	Severe	Moderate	Minor	Minor
	Minor	Moderate	Minor	Minor	Minor
	No Indication	Moderate	Minor	Minor	No Indication

5.1.8 Document the Overall Severity on GTIM-90411.

- Severe;
- Moderate; or
- Minor.

5.1.9 Total the individual severity scores for each indication in the “Overall Score” column on GTIM-90411.

5.1.10 If pipeline conditions warrant different classification criteria, document the new criteria, and attach to GTIM-90408 “ECDA - Indirect Inspection”.

5.1.10.1 Different classification criteria may be warranted based on the capabilities of the Indirect Inspection tool and unique conditions that may be present in a particular ECDA region.

6.0 DATA PRIORITIZATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Use the following table to prioritize the classified Indirect Inspection indications.

Table 04-003-3: Developed using NACE SP0502-2010 in conjunction with industry experience.

Overall Classification	ECDA Indication Prioritization
Severe	Immediate Action Required
Moderate	Scheduled Action Required
Minor	Suitable for Monitoring
Severe	Immediate Action Required

Note: Although the terms are similar, the ECDA Indication Prioritization terms are different from Immediate Condition, Scheduled Condition, and Monitored Condition as defined in GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

6.1.2 Additionally, consider the following when prioritizing data. Based upon the table below, adjust the prioritization of indications, if indicated.

Table 04-003-4: Derived from NACE SP0502-2010 (Section 5.2 Prioritization)

ECDA Indication Prioritization		
Immediate Action Required	**Scheduled Action Required**	**Suitable for Monitoring**
• Severe indications in proximity; ◦ Consider proximity as less than or equal to ten (10) feet;	• Severe indications that are not in proximity to other severe indications and not placed in the “Immediate Action Required” category;	• All remaining indications;
• Isolated indications that are classified as severe by more than one (1) indirect inspection technique/tool at approximately the same location;	• Based on SME engineering judgment, moderate indications that have significant or moderate prior corrosion likely at or near the indication;	
• For initial ECDA applications, indications with noted unresolved discrepancies;		
• Based on SME engineering judgment, severe and moderate indications, if significant, prior corrosion is suspected at or near the indication;		

6.1.2.1 Pipeline condition, age, and cathodic protection history may warrant different criteria.

6.1.3 Document the ECDA Indication Prioritization Category for each indication on GTIM-90411 “Indication Severity Classification & Priority Category”.

- Immediate Action Required;
- Scheduled Action Required; or
- Suitable for Monitoring.

6.1.4 Document any additional or different criteria used to prioritize the indications on a separate piece of paper and attach to GTIM-90408 “ECDA - Indirect Inspection”.

7.0 INTEGRATING FOREIGN LINE AND ENCROACHMENT DATA

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Review the coating indication and depth of cover data provided by the Service Provider.

7.1.2 Determine if there are any foreign-line crossings not indicated in the survey data.

7.1.2.1 Review records for additional foreign-line crossing data as necessary. Sources of information to evaluate include:

- GIS;
- Alignment Sheets; and
- System Maps.

7.1.3 Manually integrate information regarding foreign line crossings with the survey data as appropriate by marking the encroachment directly on the survey data or integrating directly into GIS.

7.1.4 Document on GTIM-90408 locations where a coating indication corresponds with an encroachment or foreign-line crossing.

7.1.4.1 For field integrated data, document all coating indications within three (3) feet of an encroachment (i.e., detail encroachment directly in survey comments).

7.1.4.2 For manually integrated coating survey data and encroachment data locations, document all coating indications within ten (10) feet of an encroachment.

7.1.4.2.1 The increased distance will help account for any spatial errors.

7.1.5 Determine the locations of potential third-party damage for evaluation.

7.1.5.1 Schedule the following indications for direct examination:

- “Moderate” or “Severe” DCVG indications within three (3) feet of an encroachment; and
- “Moderate” or “Severe” DCVG indications for manually integrated data within ten (10) feet of an encroachment.

7.1.6 Document locations for potential third-party damage on GTIM-90408.

7.1.6.1 Specify in the Comments section of GTIM-90408 details about the encroachment (i.e., company name, type of foreign-line crossing, building description, etc.).

Note: Reconcile and evaluate the locations of residual third-party damage with locations required for the ECDA process, if applicable to both processes, evaluate locations at the same time.

8.0 REDEFINING ECDA REGIONS

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Redefine the ECDA regions as appropriate, based upon information learned during the Indirect Inspection phase.

8.1.1.1 Example: If the tool initially used for the ECDA Indirect Inspection could not be used for the entire length of the region.

8.1.2 When a region change is required based upon results of the Indirect Inspection phase, redefine the regions before developing the Dig Plan.

9.0 DIRECT EXAMINATION SELECTION

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Determine the number of excavations for each ECDA Region using the criteria in the following table.

Table 04-003-5: Derived from NACE SP0502-2010, section 5.3 Guidelines for Determining the Required Number of Direct Examinations;

No Indications Identified	Perform one (1) Direct Examination at a location identified as most likely for external corrosion within the ECDA region.
	When applying ECDA for the first time, perform (2) Direct Examinations at locations identified as most likely for external corrosion within the ECDA region. Refer to section 10.0 “Determining the Region Most Likely for Corrosion” of this procedure.
Immediate Action Required	Perform direct examinations at all ‘Immediate Action Required’ indications.
Scheduled Action Required	If the ECDA Region contains one (1) or more ‘Scheduled Action Required’ indication but did not contain any ‘Immediate Action Required’ indications, perform one (1) Direct Examination on the most severe ‘Scheduled Action Required’ indication in the ECDA Region. • If applying ECDA to the pipeline segment for the first time, perform Direct Examinations at the two (2) most severe ‘Scheduled Action Required’ indications. • If no additional ‘Scheduled Action Required’ indications exist, perform the direct examination(s) at a ‘Suitable for Monitoring’ indication. If no additional ‘Suitable for Monitoring’ indications exist, choose a random “No Indication” location in the ECDA region to excavate.
	If the ECDA Region contains ‘Scheduled Action Required’ indications and contains one (1) or more ‘Immediate Action Required’ indication, perform a direct examination at the most severe ‘Scheduled Action Required’ indication. • If applying ECDA to the pipeline segment for the first time, perform Direct Examinations at two (2) additional (for a total of 3) most severe ‘Scheduled Action Required’ indications. • If no additional ‘Scheduled Action Required’ indications exist, perform the additional excavations at ‘Suitable for Monitoring’ indications. If no additional ‘Suitable for Monitoring’ indications exist, choose a random “No Indication” location in the ECDA region to excavate.
	If the results of a Direct Examination on any ‘Scheduled Action Required’ indication finds corrosion deeper than 20% of the original wall thickness, and deeper or more severe than an ‘Immediate Action Required’ indication in the same ECDA Region, perform a minimum of one (1) additional Direct Examination at a ‘Scheduled Action Required’ indication. • Continue performing direct examinations until corrosion deeper than 20% or more severe than an ‘Immediate Action Required’ indication is no longer found. • If applying ECDA to the pipeline segment for the first time, perform a minimum of two (2) additional Direct Examinations.

Suitable for Monitoring	If the ECDA Region does not contain ‘Immediate Action Required’ or ‘Scheduled Action Required’ indications, perform one (1) Direct Examination at the most severe ‘Suitable for Monitoring’ indication. • If applying ECDA to the pipeline segment for the first time, perform Direct Examinations at the two (2) most severe ‘Suitable for Monitoring’ indications. If no additional ‘Suitable for Monitoring’ indications exist, perform direct examinations at random “No Indication” locations.
	If multiple ECDA Regions contain ‘Suitable for Monitoring’ indications but do not contain any Immediate or Scheduled Action indications, perform one (1) Direct Examination in the ECDA Region (containing ‘Suitable for Monitoring’ indications) most likely to have external corrosion. • If applying the ECDA process to the pipeline segment for the first time, perform two (2) Direct Examinations in the ECDA Region (containing ‘Suitable for Monitoring’ indications) most likely to have external corrosion. If the region most likely for external corrosion only has one (1) indication, proceed to the next most likely region for external corrosion containing indications and perform the excavation within that region.

9.1.1.1 When performing an ECDA integrity assessment, select ECDA indications for direct examinations that are within Consequence Areas.

9.1.1.1.1 As deemed appropriate by the GTIM Engineer, perform direct examinations outside of the Consequence Areas. These direct examinations will be considered discretionary.

9.1.1.2 Refer to the Overall (Average) Score calculated on GTIM-90411 “Indication Severity Classification & Priority Category” when determining the most severe Scheduled Action Required indication. A Scheduled Action Required indication with an Overall (Average) Score of three (3) will take precedence over a Scheduled Action Required indication with an Overall (Average) Score of two (2) when developing the Dig Plan.

9.1.1.3 Refer to the Overall (Average) Score when determining the most severe Suitable for Monitoring indication. A Suitable for Monitoring indication with an Overall (Average) Score of two (2) will take precedence over a Suitable for Monitoring indication with an Overall (Average) Score of one (1) when developing the Dig Plan.

9.1.2 Document each the indications requiring direct examination on GTIM-90411.

9.1.3 Identify any additional “discretionary” direct examination locations on GTIM-90411.

9.1.3.1 Discretionary digs may include locations not required by the documented classification and prioritization criteria, but where deemed appropriate.

9.1.3.2 If applying ECDA to the line segment for the first time, these digs will count toward ‘more restrictive criteria’. Document the more restrictive criteria on GTIM-90411.

9.1.3.3 Indicate “discretionary” in the “Comments” column of GTIM-90411 to track digs to be performed beyond procedure requirements.

9.1.4 Document required dig locations on GTIM-90411.

10.0 DETERMINING THE REGION MOST LIKELY FOR CORROSION

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Per section 9.0 “Direct Examination Selection” above, in some circumstances, a direct examination can be performed in the ECDA region where external corrosion is most likely to occur. These situations include when:

- No indications in any ECDA region; and
- Multiple regions contain ‘Suitable for Monitoring’ indications but no ‘Immediate Action Required’ or ‘Scheduled Action Required’ indications.

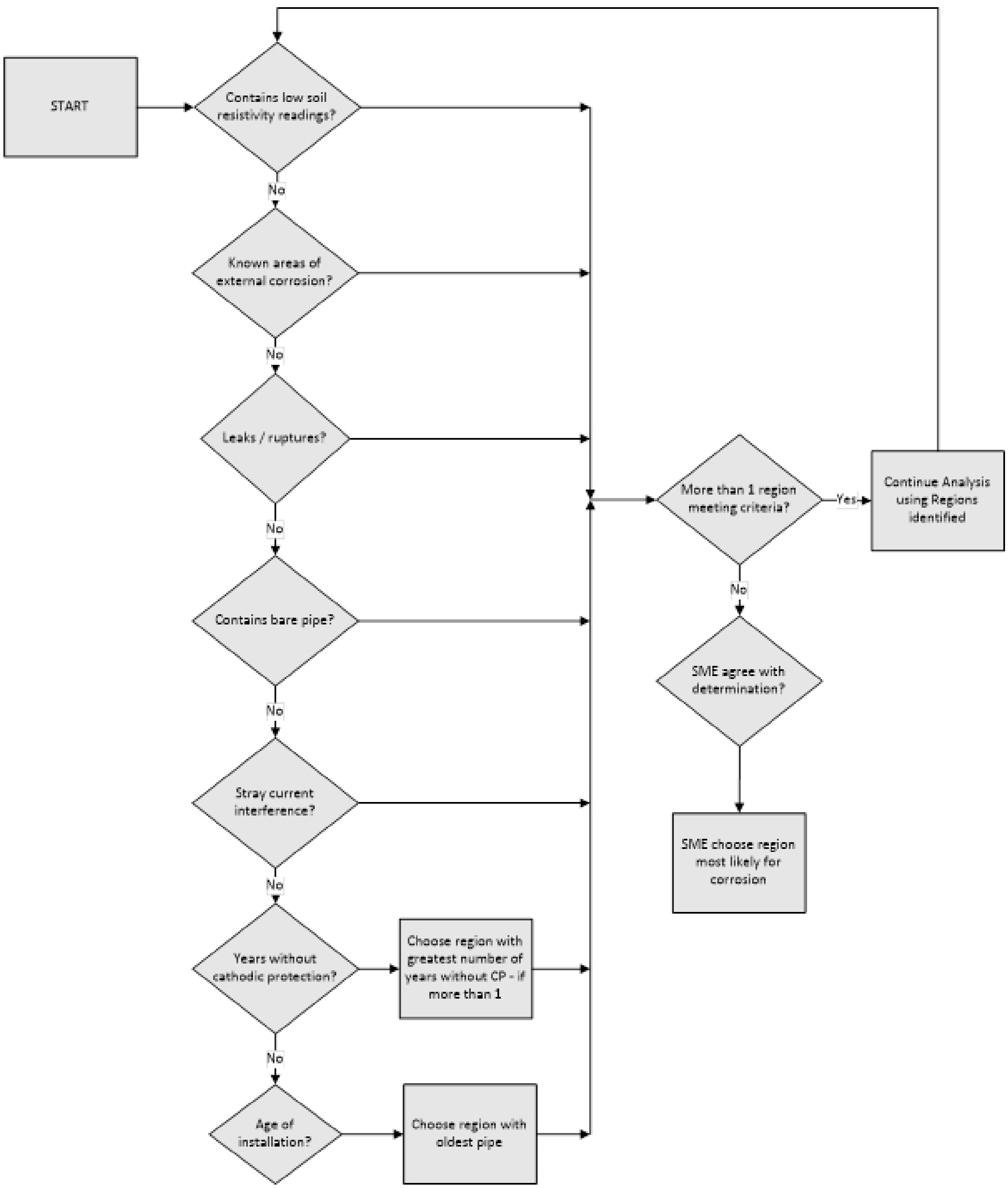
10.1.2 Refer to the Pre-Assessment data contained in the GTIM-90400 “DA Data Element Table” file or appropriate database.

10.1.3 Use the process flow chart, Figure 04-003-F1, on the next page to determine the ECDA region where external corrosion is most likely to occur.

10.1.3.1 Document the determination on GTIM-90411.

10.1.4 When multiple regions contain ‘Suitable for Monitoring’ indications but no ‘Immediate Action Required’ or ‘Scheduled Action Required’ indications, consider only ECDA regions containing ‘Suitable for Monitoring’ indications in the analysis.

Figure 04-003-F1: Determining the Region Most Likely for External Corrosion



11.0 VALIDATION EXAMINATIONS

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Choose locations within an HCA to verify the process for each application of ECDA.

11.1.1.1 Choose one (1) location at a randomly selected ‘Scheduled Action Required’ indication in any ECDA Region.

11.1.1.1.1 If no additional ‘Scheduled Action Required’ indications remain, choose the validation indication at a ‘Suitable for Monitoring’ indication.

11.1.1.2 For first time applications of ECDA, at least two (2) additional direct examinations are required for process validation.

11.1.1.2.1 Choose one (1) location at a randomly selected ‘Scheduled Action Required’ indication in any ECDA Region.

11.1.1.2.1.1 If no additional ‘Scheduled Action Required’ indications remain, choose the validation indication at a ‘Suitable for Monitoring’ indication.

11.1.1.2.2 Choose at least one (1) additional direct examination at a random “No Indication” location.

11.1.2 Document the locations of the validation examinations on GTIM-90411 by indicating “Validation Examination”, or similar, in the comments section.

12.0 APPLYING ECDA TO A PIPELINE SEGMENT FOR THE FIRST TIME

12.1 Responsibility: GTIM Engineer or designee

12.1.1 Implement ‘more restrictive criteria’ during the Direct Examination phase. Utilize each criterion listed in the NACE SP0502-2010 column and one (1) or more criteria listed in the “PHMSA FAQ 242” column in the following table:

Table 04-003-6: Indirect Inspection Techniques for First Time Application of ECDA

NACE SP0502-2010	PHMSA FAQ 242[2]
• Categorize indications where the status of the corrosion (i.e., active, inactive) is undetermined as “Immediate Action Required” or “Scheduled Action Required”;	• Resurvey the ECDA region after repairing “Immediate Action Required” indications to determine if the large indication masked any other indications;
• Do not downgrade any classification or prioritization criteria;	• Provide a larger excavation to confirm the discovery of all nearby indications;
• Do not downgrade any indication that was initially placed in the “Immediate Action Required” or “Scheduled Action Required” priority category to a lower priority category;	• Perform additional testing in the hole (beyond the requirements in GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”). Examples may include magnetic particle testing or other non-destructive testing techniques;
	• Excavate indications beyond those already required by NACE SP0502-2010;

[2] PHMSA FAQ 242, “Gas Transmission Integrity Management: FAQs”, The Pipeline and Hazardous Materials Safety Administration (PHMSA), phmsa.dot.gov, Web, 31 March 2020;

12.1.2 Document on GTIM-90408 “ECDA - Indirect Inspection” the use of the more restrictive criteria, the rationale for choosing the more restrictive criteria, and the reason for considering the criteria more restrictive.

13.0 DIG PLAN PREPARATION

13.1 Responsibility: GTIM Engineer or designee

13.1.1 Prepare Dig Plan Packets per GTIM-04-026 “Dig Plan Preparation”.

13.1.2 Document the need to perform magnetic particle testing at twenty-five percent (25%) of the ECDA Direct Assessment direct examination locations for each ECDA region.

13.1.2.1 Perform magnetic particle testing at a minimum of one (1) direct examination location per ECDA region.

13.1.3 Document the need to perform magnetic particle testing on GTIM-90440 “Direct Examination Scope of Work”.

14.0 INDIRECT INSPECTION DOCUMENTATION

14.1 Responsibility: GTIM Engineer or designee

14.1.1 Confirm completion of GTIM-90408 for the Indirect Inspection phase.

14.1.2 Confirm completion of the following forms:

- GTIM-90404 “Rectifier and Critical Bond Locations”;
- GTIM-90412 “Daily Progress Report Indirect Surveys” for each survey day;
- GTIM-90413 “Soil Resistivity Data Collection”;
- GTIM-91101 “Pipeline Event Evaluation”, when applicable;
- GTIM-90440 “Direct Examination Scope of Work”; and
- GTIM-90441 “Dig Plan Summary” for each location.

14.1.3 Retain all Indirect Inspection phase documentation in the IM file.

14.1.4 Notify the GTIM Field Supervisor when the Direct Examinations can commence.

14.2 Responsibility: GTIM Field Supervisor or designee

14.2.1 Inform the Service Provider the Direct Examination work can begin once the ECDA Indirect Inspection report is complete.

<<END>>

GTIM-04-004 ECDA Direct Examination

PURPOSE: To establish a standardized method for performing the Direct Examination phase of the External Corrosion Direct Assessment (ECDA) methodology.

REFERENCES: 49 CFR 192.925; NACE SP0502-2010; ASME/ANSI B31.8S-2004, Section A3;

SECTIONS:

- Background
- Direct Examination Preparation
- Direct Examination Timeframe
- Excavation and Data Collection
- Validation Examinations
- Investigation for the Presence of SCC
- Remaining Strength Evaluation
- Anomaly Repair
- Direct Examination Field Data Documentation
- Root-Cause Analysis
- In-Process Evaluation, Reclassification, and Reprioritization
- Direct Examination Phase Documentation

1.0 BACKGROUND

1.1 The Direct Examination phase determines the pipe condition at the location of the indications identified during Indirect Inspection.

1.2 Data from the direct examinations is collected to identify and assess the impact of external corrosion and third-party damage on the pipeline.

2.0 DIRECT EXAMINATION PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Perform direct examinations according to the Dig Plan.

2.1.2 Arrange direct examinations according to the categorization and prioritization of the indication (i.e., excavate Immediate indications first). After excavating Immediate indication, consider the following at a minimum:

- Availability of personnel;
- Logistics;
- Availability of additional equipment (e.g., shoring, dump trucks); and
- Permitting.

2.1.3 Complete and return the required forms in the Dig Plan to the GTIM Engineer.

2.1.4 Prepare for the direct examination per the requirements of GTIM-04-027 “Direct Examination Preparation”.

3.0 DIRECT EXAMINATION TIMEFRAME

3.1 Responsibility: GTIM Field Supervisor or GTIM Engineer

3.1.1 Complete all direct examinations within 180 days of receiving the final Indirect Inspection report whenever feasible.

3.1.1.1 If completion of the direct examinations cannot occur within 180 days, review the Indirect Inspection data and, if needed, take actions to confirm the integrity of the pipeline.

3.1.1.1.1 Implement additional preventive and mitigative measures as necessary until completion of the direct examinations.

3.1.1.1.2 Refer to GTIM-08-004 “Identifying P&M Measures” for additional guidance.

3.1.1.2 Perform all direct examinations within 365 days of receiving the final Indirect Inspection report.

4.0 EXCAVATION AND DATA COLLECTION

4.1 Responsibility: GTIM Field Inspector or designee

4.1.1 Conduct a tailgate safety meeting each morning before beginning direct examinations.

4.1.2 Evaluate and document findings during the Direct Examination phase per the requirements of GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

4.1.3 Minimum data to be collected during the direct examination phase includes:

- Pipe-to-soil potentials;
- Soil resistivity;
- Soil testing, when applicable;
- Water sample collection, if applicable;
- Under-film liquid pH, if applicable;
- Photographic documentation;
- Data for other integrity analyses such as MIC, when appropriate;
- Identification of coating type;
- Assessment of coating condition;
- Mapping and measurement of coating defects, when applicable;
- Coating thickness;
- Identification and mapping of corrosion defects, when applicable; and
- Corrosion product collection, if applicable.

4.1.4 Direct the excavation crew to increase the length of the excavation in the appropriate direction if the direct examination indicates severe coating damage or significant corrosion defects that extend beyond one or both ends of the excavation or when not finding the indication.

4.1.4.1 If increasing the length of the excavation still reveals severe coating damage, significant corrosion defects, or when not finding the indication, inform the GTIM Field Supervisor and discuss options.

4.1.5 Document all results of the direct examination and any remedial activities on GTIM-90418 “Pipeline Inspection for Direct Examinations”. Attach additional sheets as necessary.

5.0 VALIDATION EXAMINATIONS

5.1 Responsibility: GTIM Field Inspector or designee

5.1.1 Collect data for Validation Examinations per section 4.0 “Excavation and Data Collection” of this document.

5.1.1.1 Remove a minimum one (1) foot full-encirclement area of coating to verify that no corrosion defects are present. Removing the coating may not be necessary for Fusion Bonded Epoxy (FBE) for validation examinations at no indication.

5.1.2 Notify the GTIM Field Supervisor or GTIM Engineer for further guidance if the results of the validation examination are not as intended. Examples include, but are not limited to:

- Finding coating damage or an anode at a random “no indication” location; or
- DCVG location with no coating damage.

6.0 INVESTIGATION FOR THE PRESENCE OF SCC

6.1 Responsibility: GTIM Field Inspector or designee

6.1.1 Perform magnetic particle testing on a minimum of twenty-five percent (25%) of the ECDA Direct Assessment locations for each ECDA region, at direct examination locations.

6.1.1.1 Perform magnetic particle testing at a minimum of one (1) direct examination location per ECDA region.

6.1.1.2 Perform magnetic particle testing on the pipe body per the process outlined in the Gas Construction Standards, section 5.3.8, “Magnetic Particle Inspection of Welds”.

6.1.2 Inform the GTIM Field Supervisor or GTIM Engineer when finding SCC any location.

6.1.2.1 If SCC is not present, magnetic particle testing requires no future integrity reassessments of the line segment.

7.0 REMAINING STRENGTH EVALUATION

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

7.1.1 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

7.1.2 Calculate the remaining strength of each corrosion defect per procedure GTIM-05-003 “RSTRENG”.

7.1.3 Address confirmed Immediate Conditions per GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

7.1.4 Assume similar defects are present in the ECDA region if a corrosion defect exceeds allowable limits per O&M 16 “Repairs” unless root-cause analysis indicates the corrosion defect is unique and isolated to that location.

7.1.5 Re-evaluate the Indirect Inspection data and indication classifications and prioritizations. Determine if additional direct examinations are needed.

8.0 ANOMALY REPAIR

8.1 Responsibility: GTIM Field Inspector or designee

8.1.1 Notify the GTIM Field Supervisor or GTIM Engineer if finding a defect other than external corrosion.

8.1.1.1 Examples include mechanical damage or stress corrosion cracking.

8.1.2 Address stress corrosion cracking per GTIM-04-065 SCCDA Direct Examination and Post-Assessment”.

8.1.3 Address other conditions found per GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

8.2 Responsibility: GTIM Manager or designee

8.2.1 If a temporary pressure reduction exceeds 365 days, document a technical justification as to why the continued pressure reduction will not jeopardize the integrity of the pipeline and submit it to PHMSA per GTIM-13-001 “Required Notifications to Regulatory Agencies”.

8.3 Responsibility: GTIM Field Supervisor or designee

8.3.1 Repair any anomalies found during the excavation, according to the CNP O&M.

8.3.2 If remediation requires replacement of a large section, engage Gas Transmission Engineering to replace.

9.0 DIRECT EXAMINATION FIELD DATA DOCUMENTATION

9.1 Responsibility: GTIM Field Supervisor or designee

9.1.1 Load all direct examination data to the network. Notify the GTIM Engineer once the data is available on the network.

9.1.2 Complete applicable sections of GTIM-90410 “ECDA - Direct Examination”.

9.1.3 Retain a copy of the form in the IM file.

10.0 ROOT-CAUSE ANALYSIS

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Perform root cause analysis on the following anomalies per procedure GTIM-04-012 “Root Cause Analysis”.

- All Immediate Conditions;
- Corrosion greater than 20% wall thickness on the pipe in a covered segment;
- Third-party damage/excavation damage anywhere on the pipeline;
- A pressure test failure;
- Any anomaly deemed appropriate by the GTIM Engineer.

10.1.1.1 Examples of root-cause for external corrosion include, but not limited to:

- Inadequate cathodic protection;
- Improper coating preparation;
- Improper coating application;

- Stray current interference; and
- Improper coating choice.

10.1.2 Determine if the corrosion anomalies are unique and isolated to that location.

10.1.3 If the defects are not unique and isolated, consider other supplemental methods of assessing the integrity of the ECDA region. Examples include extending the limits of the assessment or performing another indirect survey or both.

10.1.4 For each root cause, identify all indications with similar root causes.

10.1.4.1 Determine if the additional indications require excavation depending on the severity and consequences of the root cause.

10.1.4.2 Document the rationale for excavating or not excavating the indications with similar root causes.

10.1.5 Consider other pipeline segments with similar characteristics per GTIM-08-005 “Evaluating Similar Conditions”.

10.1.6 If a root-cause determines that ECDA is not well suited (i.e., electrical shielding caused by disbonded coating), use alternative assessment methods such as a pressure test or In-Line Inspection to assess the integrity of the ECDA region.

11.0 IN-PROCESS EVALUATION, RECLASSIFICATION, AND REPRIORITIZATION

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Evaluate all ECDA data and assess the criteria used to categorize the need for repair and the criteria used to classify the severity of individual indications.

11.1.1.1 ECDA data should include:

- Indirect Inspection data;
- Direct Examination data;
- Remaining strength evaluation results; and
- Root-cause analysis.

11.1.2 Assess the extent and severity of corrosion activity found based on the assumptions made in establishing the priority categories for repair (Immediate, Scheduled, Monitored). Refer to GTIM-04-003 “ECDA Indirect Inspection”.

11.1.2.1 Optionally, modify the criteria and reprioritize all indications when finding corrosion less severe than initially prioritized.

11.1.2.2 Redefining the criteria and reprioritizing all indications is required if existing corrosion is more severe than initially prioritized.

11.1.2.3 If any indication for which comparable direct examination measurements show a more severe condition than suggested by the Indirect Inspection data, modify the indication to a more severe priority category.

- Do not downgrade Immediate indications lower than Scheduled; and
- For first time applications of ECDA, do not downgrade Immediate or Scheduled indications.

11.1.3 Assess the corrosion activity at each excavation relative to the criteria used to classify the severity of the indications (Severe, Moderate, Minor). Refer to GTIM-04-003 “ECDA Indirect Inspection”.

11.1.3.1 If the corrosion activity is less severe than previously classified, optionally, adjust the criteria used to define the severity of all indications.

- Also, consider adjusting the criteria used to prioritize the need for repair.
- For first time applications of ECDA, do not downgrade any classification or prioritization criteria.

11.1.3.2 Reclassification of all indications is required when results from the direct examination show corrosion activity that is more severe than indicated by the Indirect Inspection data.

- Also, consider the need for additional indirect inspections and adjusting the criteria used to prioritize the need for repair.
- Re-evaluate ECDA feasibility for the pipeline segment if the direct examinations repeatedly indicate corrosion activity that is worse than indicated by the Indirect Inspection data.

11.1.4 Document new criteria, classifications, and prioritizations, on GTIM-90410.

12.0 DIRECT EXAMINATION PHASE DOCUMENTATION

12.1 Responsibility: GTIM Engineer or designee

12.1.1 Confirm completion of GTIM-90410.

12.1.2 Confirm the following documentation is complete:

- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- GTIM-90471 “Magnetic Particle Inspection Report”, if applicable;
- Remaining Strength calculations, if applicable;
- GTIM-90421 “Root Cause Analysis”, if applicable;
- Form 1021 “Job Safety Briefing Form”; and
- Form 3020 “Excavation Repair Report”.

12.1.3 Retain documentation in the IM file.

12.1.4 Integrate information and the data collected from the completed forms into the appropriate database and tracking sheets.

12.1.5 Begin the Post-Assessment phase once the Direct Examination phase is complete.

<<END>>

GTIM-04-005 ECDA Post-Assessment

PURPOSE: To establish a standardized method for performing the Post-Assessment phase of the External Corrosion Direct Assessment (ECDA) methodology.

REFERENCES: 49 CFR 192.925; NACE SP0502-2010, Section 6; ASME/ANSI B31.8S 2004, Appendix B; ASME/ANSI B31G-1991;

SECTIONS:

- Direct Examination Documentation Review
- Discovery of Condition
- Like and Similar Pipe Segments
- ECDA Effectiveness
- Encroachment Information Review
- Redefining ECDA Regions
- Remaining Life Calculations
- Reassessment Interval Determination
- Preventive and Mitigative Actions
- Performance Measures
- Feedback and Continuous Improvement
- Changes and Internal Communications
- Post-Assessment Documentation

1.0 DIRECT EXAMINATION DOCUMENTATION REVIEW

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Review the documentation from the direct examinations.

1.1.2 Determine if information learned during the Direct Examination warrants additional or different validation locations.

1.1.2.1 As necessary, choose additional validation locations.

1.1.3 Determine if magnetic particle testing detected SCC at any of the testing locations.

1.1.3.1 If SCC is not present, magnetic particle testing requires no future integrity reassessments of the line segment.

1.1.3.2 When finding SCC at any of the locations, create a Change Management record per GTIM-11-001 “GTIM Change Management”.

1.1.3.2.1 Provide Notification to PHMSA per the requirements of GTIM-13-001 “Required Notifications to Regulatory Agencies”.

1.1.3.2.2 Schedule for the line to be assessed with an assessment method suitable for SCC (i.e., Pressure Testing, In-Line Inspection, Stress Corrosion Cracking Direct Assessment).

1.1.3.2.3 Update the threat assessment to reflect the new information.

1.1.4 Complete GTIM-90501 “Response Schedule” to document the assessment and required response times for remediation activities.

1.1.4.1 Ensure all indications identified are documented on GTIM-90501, regardless of excavation or not.

1.1.4.2 Continuously update the Response Schedule form as information becomes available for ongoing repairs.

1.1.4.3 Report large capital repairs or future scheduled (1+ year) repairs on the IM Work Schedule for tracking.

2.0 DISCOVERY OF CONDITION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Make Discovery of Condition on the date of the particular direct examination.

2.1.1.1 Consider the ECDA integrity assessment complete once all field activities related to the direct examinations are complete (not including any repair activities).

2.1.2 For indications not evaluated during the Direct Examination phase, make Discovery of Condition the date of completion of the field portion of the Direct Examination phase.

3.0 LIKE AND SIMILAR PIPE SEGMENTS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Identify “like and similar” pipeline segments per GTIM-08-005 “Evaluating Similar Conditions” when identifying active corrosion in a covered pipeline segment.

4.0 ECDA EFFECTIVENESS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Review the results of each root-cause analysis performed per GTIM-04-004 “ECDA Direct Examination”.

4.1.1.1 Determine if the results of any validation dig were more severe than the initial direct examinations.

4.1.1.2 Discuss the findings with the GTIM Field Inspector and re-evaluate the steps of the ECDA process.

4.1.2 Document the discussion and the results in the ECDA Effectiveness section of GTIM-90420 “ECDA - Post-Assessment”.

5.0 ENCROACHMENT INFORMATION REVIEW

5.1 Responsibility: GTIM Engineer or designee

5.1.1 As part of the Post-Assessment process, review direct examination information.

5.1.2 When finding third-party damage during the direct examination(s), consider the use of another assessment method (i.e., Pressure Testing or In-Line Inspection) to assess for mechanical damage.

5.1.3 When finding third-party damage during the direct examination(s), review the P&M measures implemented for the applicable covered segment(s).

5.1.4 Consider implementing additional P&M measures to address the threat of third-party damage.

5.1.4.1 As required, determine additional P&M measures per the requirements of GTIM-08-004 “Identifying Preventive and Mitigative Measures”.

5.1.5 Complete the “Encroachment Review” section of GTIM-90420.

5.1.6 Provide notification to the Encroachment Program Manager per CNP’s Encroachment Policy.

6.0 REDEFINING ECDA REGIONS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Redefine the ECDA regions as appropriate, based on information learned during the Direct Examination phase.

6.1.1.1 Examples for redefining ECDA Regions include:

- The tool initially used for the ECDA Indirect Inspection could not be used for the entire length of the region; and
- During the Direct Examination, the pipe wall thickness range was different than anticipated.

6.1.2 When a region change is required based upon results of the Direct Examination phase, additional direct examinations may be required.

6.1.3 Document region changes on GTIM-90420 “ECDA - Post-Assessment”.

6.1.4 Create a work order if known data attributes need correction in GIS.

7.0 REMAINING LIFE CALCULATIONS

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Determine the applicability of performing the Remaining Life calculation.

7.1.1.1 When finding no corrosion defects, no Remaining Life calculation is needed; the Remaining Life of the pipe is the same as for a new pipeline.

7.1.2 Review the data from the direct examinations for each ECDA Region and perform the calculation as necessary.

7.1.3 Identify the most severe corrosion defect found during the direct examination phase for each ECDA Region.

7.1.3.1 If the results of the root cause analysis determined the cause of the most severe defect was “unique”, use the next most severe corrosion defect.

7.1.4 Estimate the corrosion growth rate (GR) for each defect found using the lowest rate possible from the following four (4) options:

- Option 1: Use the actual corrosion rate for the pipeline segment by directly comparing the measured wall thickness changes over a known time interval.
  - This option requires wall thickness documentation from prior excavations, maintenance records, or In-line Inspection data within the same specific pipe region.
- Option 2: Use 12.16 mpy[1] *(0.01216 inches/year)* when operating records indicate the pipe segment has been under adequate cathodic protection (as determined by regulatory requirements) for at least 90 percent of the time since the installation of the pipe.

[1] Corrosion Growth Rate from NACE SP0502-2010;

- Use 16.0 mpy when unable to demonstrate adequate cathodic protection.
- Option 3: Corrosion rates based on the soil resistivity at the defect[2]:
  - 3 mpy - A soil resistivity greater than 15,000 ohm-cm and no active corrosion
  - 6 mpy - A soil resistivity within 1,000-15,000 ohm-cm
  - 6 mpy - A soil resistivity greater than 1,000 ohm-cm with active corrosion
  - 12 mpy - A soil resistivity less than 1,000 ohm-cm
- Option 4: Use other corrosion rates based on sound engineering analysis.
  - If using other corrosion rates, provide documented justification and approval from the GTIM Field Supervisor.

7.1.5 Perform the Remaining Life calculations for each corrosion defect identified in section 1.0 of this procedure using the following formula:

$$RL = \frac{C \times SM \times t}{GR}$$

where:

RL = Remaining Life *(years)*
C = Calibration factor = 0.85 *(dimensionless)*
SM = Safety Margin = Failure Pressure Ratio – MAOP Ratio *(dimensionless)*
t = Nominal Wall Thickness of the Pipe *(inches)*
GR = Corrosion Growth Rate Estimate *(inches/year)*

7.1.5.1 Calculate the Failure Pressure Ratio and MAOP Ratio using the following:

$$Failure\ Pressure\ Ratio = {P'}/{Yield\ Pressure}\ (dimensionless)$$

$$MAOP\ Ratio = {MAOP}/{Yield\ Pressure}\ (dimensionless)$$

where:

MAOP = Maximum Allowable Operating Pressure established *(i.e., not calculated)* for the pipe segment *(psi)*
P' = Calculated failure pressure from RSTRENG or ASME/ANSI B31G-1991 *(psi)*

7.1.5.2 Calculate the yield pressure required for the above calculation using the following formula:

$$Yield\ Pressure = \frac{2 \times S \times t}{D}$$

where:

t = Nominal wall thickness of the pipe *(inches)*
S = Specified minimum yield strength of pipe *(psi)*
D = Outside diameter of the pipe *(inches)*

[2] Adapted from ASME/ANSI B31.8S-2004 Appendix B;

7.1.6 Calculate the failure pressure (P') using the most severe flaw dimensions found from all excavated ‘Scheduled’ indications.

7.1.6.1 If the root cause analysis indicates that the most severe indication is unique, use the size of the next most severe indication for the calculated failure pressure (P').

7.1.6.2 Document the Remaining Life calculation(s) and associated decisions on GTIM-90417 “Remaining Life and Reassessment Intervals”.

8.0 REASSESSMENT INTERVAL DETERMINATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

8.1.2 Document the Reassessment Interval for each ECDA Region on GTIM-90417 “Remaining Life and Reassessment Intervals”.

8.1.3 Additionally, document the Reassessment Interval for the pipeline segment on GTIM-90420 “ECDA - Post-Assessment”.

8.1.4 Add reassessments, confirmatory-direct assessments, and remediation activities to the assessment schedule calendar.

9.0 PREVENTIVE AND MITIGATIVE ACTIONS

9.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

9.1.1 Update GTIM-90209 “Threat Analysis” with the following information, if applicable:

- New identified threats;
- Eliminated threats; and
- Changes to existing threat documentation.

9.1.1.1 Refer to GTIM-02-021 “Threat Identification”.

9.1.1.2 Create a work order to incorporate modified attributes.

9.1.2 Review the Preventive and Mitigative (P&M) measures implemented for the applicable covered segment(s).

9.1.3 Recommend preventive and mitigative actions to mitigate or preclude future external corrosion from the significant root causes.

9.1.4 Develop a detailed plan and timeline for performing/implementing any appropriate preventive and mitigative measures within 365 days of performing the direct examinations on the region.

10.0 PERFORMANCE MEASURES

10.1 Responsibility: GTIM Engineer or designee

10.1.1 Document Performance Measures on GTIM-90420 and GTIM-90901 “Performance Measures”.

10.1.1.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

10.1.1.2 Document the information on both the ‘Performance Measures’ section of GTIM-90420 and the total HCA miles assessed on the top of the form.

10.1.2 If the performance measures do not show improvement between ECDA applications, re-evaluate the applicability of the ECDA process with the GTIM Manager, and evaluate alternative methods of assessing the integrity of the pipeline.

11.0 FEEDBACK AND CONTINUOUS IMPROVEMENT

11.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

11.1.1 Gather feedback from participating personnel (i.e., GTIM Field Supervisor, GTIM Field Inspector, Local Operations, Corrosion Control, etc.). Areas where feedback may be incorporated include, but are not limited to:

- Identification and classification of indirect inspection results;
- Data collected during the direct examinations;
- Remaining strength analysis;
- Root-cause analysis;
- Remediation activities;
- In-process evaluations;
- Validation direct examinations;
- Criteria for monitoring the ECDA effectiveness; and
- Scheduled, monitoring, and reassessment intervals.

11.1.2 Solicit “lessons learned” from project participants upon completion of the ECDA project.

11.1.2.1 If appropriate, invite the Service Provider(s) to the meeting.

11.1.2.2 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- ECDA process modification suggestions.

11.1.2.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

11.1.3 Consider if additional Preventive and Mitigative measures are needed.

11.1.3.1 Refer to GTIM-08-004 “Identify Preventive and Mitigative Measures”.

11.1.4 Document cathodic protection systems identified during the ECDA that are inoperative, ineffective, or needing repair on GTIM-90420.

11.2 Responsibility: GTIM Engineer or designee

11.2.1 Review the results of the feedback and determine additional areas of improvement.

11.2.2 Document feedback and continuous improvement activities on GTIM-90420.

11.2.3 If applicable, initiate a Change Management entry according to GTIM-11-001 “GTIM Change Management” for each recommended procedural change, each additional P&M recommendation, and any other potential process improvements.

11.2.4 Complete a GTIM-90424 “Summary Report to Local Operations”, summarizing any repairs made and describing any required or recommended follow-up activities.

11.2.4.1 Send to Local Operations and the Corrosion Control.

12.0 CHANGES AND INTERNAL COMMUNICATIONS

12.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

12.1.1 Document any deviations from the documented procedures that occurred during the ECDA process on GTIM-91101 “Pipeline Event Evaluation”. Deviations may include but are not limited to, changes that:

- Affect the severity classification;
- Change the priority of direct examination;
- Change the time frame for examining indications; and
- Skipped survey distances greater than ten (10) feet.

12.1.2 Notify the affected parties per GTIM-11-001 “GTIM Change Management” and GTIM-13-002 “Internal Communications”.

12.2 Responsibility: GTIM Engineer or designee

12.2.1 Confirm entry of all Change Management items. Document the date confirmed on GTIM-90420.

12.2.2 Review GTIM-90411 “Indication Severity Classification and Priority Category” and confirm the scheduling of any follow-up items.

12.2.3 Compare and confirm data collected from field activities matches data recorded on the GTIM-90300 “Data Collection” and GTIM-90400 “DA Data Element Table” during the Pre-Assessment phase of this assessment.

12.2.3.1 Resolve all inconsistencies working with the GTIM Field Inspectors to clarify or update the appropriate documents.

12.2.3.1.1 Route any modified field documents to the GTIM Field Supervisor for review and approval.

12.2.3.2 Create a work order to incorporate corrections to the data in GIS, if needed.

13.0 POST-ASSESSMENT DOCUMENTATION

13.1 Responsibility: GTIM Engineer or designee

13.1.1 Perform a 100% quality check of all requested GIS updates.

13.1.2 Confirm completion of Post-Assessment documentation. Documentation includes, but is not limited to:

- GTIM-90209 “Threat Analysis”;
- GTIM-90417 “Remaining Life and Reassessment Intervals”;
- GTIM-90420 “ECDA - Post-Assessment”;
- GTIM-90424 “Summary Report to Local Operations”;
- GTIM-90501 “Response Schedule”, if applicable;
- GTIM-90804 “Preventive and Mitigative Measures”;

- GTIM-91101 “Pipeline Event Evaluation”, if applicable; and
- GTIM-91102 “Integrity Change Management Record”, if applicable.

13.1.3 Retain copies of communications with the Service Provider, including any discussions or analyses leading to significant decisions or decisions to reanalyze data.

13.1.3.1 Include all forms of communications (i.e., phone conversations, voice messages, etc.), documenting with an email to the other parties confirming your understanding of the discussion items.

13.1.4 Route pertinent Post-Assessment documentation to Corrosion Control and Local Operations along with the location of the Post-Assessment documentation file.

13.1.5 Conduct a meeting with the GTIM Manager to review the Post-Assessment documentation and obtain approval.

13.1.6 Once the Post-Assessment is approved, the ECDA process is considered complete.

13.1.7 Confirm all assessment documentation is stored in the IM file within thirty (30) days of completing the ECDA process.

<<END>>

GTIM-04-006 Pipeline Elevation Profile

PURPOSE: To provide a standard method of measuring and determining the pipeline elevation profile.
REFERENCES: 49 CFR 192.927;
SECTIONS:

- Survey Preparation
- Safety Considerations
- Measuring the Pipeline Terrain Elevation Profile
- Measuring Pipeline Depth of Cover
- Determining Pipeline Elevation Profile
- Documentation

1.0 SURVEY PREPARATION

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Arrange for the surveying of the appropriate pipeline segment(s).

1.1.2 Secure a Pipeline Surveyor Service Provider, or provide qualified personnel to perform the survey.

1.1.2.1 Confirm the Pipeline Surveyor has prior experience obtaining GPS coordinates.

1.1.2.2 Confirm the Pipeline Surveyor has a documented Quality Assurance process. Verify the process includes:

- Equipment calibration; and
- Training of personnel.

1.1.2.3 Confirm personnel associated with the inspection are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual. Applicable covered tasks include:

- Abnormal operating conditions; and
- Pipeline locating.

1.1.3 Before beginning the survey, provide the Pipeline Surveyor with maps of the segment(s) to be surveyed.

1.1.4 Confirm the Pipeline Surveyor uses equipment capable of taking x, y, and z coordinates to a minimum of sub-centimeter accuracy.

1.1.4.1 The accuracy of the coordinates requires tying into established survey landmarks.

1.1.5 Refer to procedure GTIM-04-043 “GPS Coordinates” for additional details on quality control.

2.0 SAFETY CONSIDERATIONS

2.1 Responsibility: Pipeline Surveyor or designee

2.1.1 While performing GTIM-04-033 “Pipe Depth Survey”, take appropriate safety precautions when working on and around the pipeline right-of-way.

2.1.2 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline.

2.1.3 Use caution when working around roads and railroads.

2.1.3.1 Use barricades, signboards, and traffic control flag personnel, when appropriate.

2.1.3.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, “Reflective Safety Vests”.

2.1.4 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

3.0 MEASURING THE PIPELINE TERRAIN ELEVATION PROFILE

3.1 **Responsibility:** Pipeline Surveyor or designee

3.1.1 Locate the pipeline using a radio detection Pipeline Current Mapper (PCM) or approved equivalent that is capable of locating pipeline and obtaining accurate depth readings.

3.1.2 Use the following minimum guidelines to obtain elevation measurements. Obtain GPS coordinates (x, y, and z) at:

- 100-foot intervals on flat and gently sloping terrain;
- 25-foot intervals on hilly terrain;
- 5-foot intervals on very hilly terrain;
- 10-foot intervals upstream and downstream of features where directional boring may have occurred (i.e., roads, railroads, streams, rivers, lakes, foreign pipelines, etc.);
    - Record the crossing type in the survey comments;
    - Continue taking readings until the pipeline depth readings become consistent and reaching gently sloping or flat terrain;
- Vertical bends;
- Points of horizontal inflection (start, center, end);
- Pipeline inlets and outlets;
- Main Line valves;
- Locations where the pipe is above-grade;
- All physical features over the pipeline. Physical features may include, but are not limited to:
    - Test stations;
    - Aerial markers;
    - Foreign line crossings;
    - Roads;
    - Railroads;
    - Streams;
    - Ditches;
    - Sidewalks;
    - Parking lots;

- Fences; and
- Signposts.

3.1.3 Whenever pipeline depth changes are noticed or anticipated, decrease the reading interval accordingly.

4.0 MEASURING PIPELINE DEPTH OF COVER

4.1 Responsibility: Pipeline Surveyor or designee

4.1.1 Locate the pipeline and measure the pipeline depth with a Pipeline Current Mapper (PCM) or equivalent per GTIM-04-033 “Pipe Depth Survey”.

4.1.1.1 For areas where the depth of the pipeline does not allow accurate depth measurements, indicate in the survey comments that the boundaries where depth readings are unattainable and the reason.

4.1.2 Measure the pipeline depth simultaneously with the taking GPS coordinates.

4.1.3 Measure the pipeline depth at each recorded GPS coordinate location per section 3.0 “Measuring Pipeline Terrain Elevation Profile”.

5.0 DETERMINING PIPELINE ELEVATION PROFILE

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Convert each “pipeline depth” measurement to a “true depth of cover” measurement.

5.1.1.1 Subtract the radius of the pipe from the pipeline depth.

5.1.2 Determine the elevation of the pipeline.

5.1.2.1 Subtract the “true depth of cover” measurement from the surface elevation of the terrain.

5.1.3 Document each of the x, y, and z coordinates.

6.0 DOCUMENTATION

6.1 Responsibility: Pipeline Surveyor or designee

6.1.1 Provide the GTIM Engineer with all survey data.

6.1.2 Provide the data in an Excel spreadsheet with each of the following in a separate column:

- Northing in US survey feet with a minimum of three (3) decimal places;
- Easting in US survey feet with a minimum of three (3) decimal places;
- Latitude with eight (8) decimal places, when possible;
- Longitude eight (8) decimal places, when possible;
- Elevation;
- Pipeline depth; and
- Comments.

6.1.2.1 Refer to GTIM-04-043 “GPS Coordinates” for additional information.

6.1.3 Provide pipeline elevation drawings electronically.

6.1.4 Provide a copy of all field notes.

6.1.5 Provide documentation discussing the type of equipment used to perform the survey, the most recent equipment calibration date, and the equipment serial number(s) if possible.

6.2 Responsibility: GTIM Engineer or designee

6.2.1 Create a work order to update data in GIS, if needed.

6.2.2 Retain all provided survey data in the IM file.

<<END>>

GTIM-04-008 Data Collection for Integrity Management Direct Examination

PURPOSE: To provide a standard method of collecting and recording data during a Direct Examination used for integrity management purposes.

REFERENCES: NACE SP0204-2015; NACE SP0502-2010, Section 5;

SECTIONS:

- General
- Pre-excavation Meeting
- Safety Considerations
- Photographs
- Data Collection Prior To and During Excavation
- Soil Testing
- Groundwater Sampling
- Data Collection Prior To Coating Removal
- Data Collection During and After Coating Removal
- Documentation

1.0 GENERAL

1.1 Proper data collection is a required element for assessing pipeline integrity.

1.2 "Direct Examination Crew", as used in this document, encompasses all personnel related to the direct examination, including the Non-Destructive Examination (NDE) Service Provider.

1.3 Prepare for the examination per GTIM-04-027 "Direct Examination Preparation".

2.0 PRE-EXCAVATION MEETING

2.1 Responsibility: GTIM Field Inspector or designee

2.1.1 Provide a copy of the Dig Plan Packet to the Excavation Crew and the Direct Examination Crew before they arrive on site.

2.1.2 Conduct a Tail-Gate Safety Meeting with the crews at the beginning of each workday and review the following:

- Safety precautions;
- Personal Protective Equipment (PPE);
- Scope of work;
- Work site-specific requirements;
- Landowner and permit requirements; and
- Order of direct examinations;
  - For applications of Direct Examinations, perform direct examinations in the order dictated by the indication severity (i.e., most severe indications first).
  - Modify the order of the excavations based upon considerations such as the availability of additional equipment (i.e., shoring, dump trucks, etc.), permitting, and logistical issues as appropriate.

2.1.3 Document the meeting on Form 1021 "Job Safety Briefing Form".

3.0 SAFETY CONSIDERATIONS

3.1 **Responsibility:** Excavation Crew and Direct Examination Crew

3.1.1 Take appropriate safety precautions when performing direct examinations.

3.1.1.1 Refer to the Corporate Safety Manual, “Excavation and Trenching Policy”.

3.1.2 Wear a hard hat in and around the construction site per the Corporate Safety Manual.

3.1.3 Use caution when using long lengths of test wire near high voltage alternating current (HVAC) power lines.

3.1.3.1 HVAC lines can induce hazardous voltage levels on the test wire.

3.1.4 Discontinue the work when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline segment.

3.1.5 Use caution when working around roads and railroads.

3.1.5.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.5.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, “Reflective Safety Vests”.

3.1.6 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 PHOTOGRAPHS

4.1 **Responsibility:** Direct Examination Crew or GTIM Field Inspector

4.1.1 Collect photographic documentation of the excavation site before, during, and after the excavation.

4.1.1.1 Include in photographic documentation (excluding close-ups).

4.1.1.1.1 Document the date and Indication Number.

4.1.1.1.2 Indicate the orientation of the pipe (i.e., “E” with an arrow).

4.1.1.1.3 Confirm close-ups have a ruler in the picture for scale.

4.1.1.1.4 Optionally, mark the Indication Number and orientation on the pipe. Confirm marking is visible in the picture.

4.1.1.2 Take the following minimum photographs:

- Site before excavation;
- Site during excavation;
- Stand-off and close-up photographs of any coating defect or corrosion features;
- Any color changes of the coating or corrosion products after exposure to air;
- Backfill material directly in contact with the pipe;
- Pipe when recoating completed; and
- The dig site, once the bell hole backfill is complete.

5.0 DATA COLLECTION PRIOR TO AND DURING EXCAVATION

Note: Per O&M policies, Form 3105 “Pipe Exam” must be completed each time a pipeline is exposed – this is in addition to any forms referenced in this procedure.

5.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

5.1.1 Collect the following data before beginning the excavation. Document all information on GTIM-90418-A “Pipeline Inspection Direct Examination”.

5.1.1.1 GPS coordinates (sub-meter) of the excavation site. (Sub-centimeter GPS coordinates are preferred.)

5.1.1.1.1 If moving an excavation site to a new location, document the GPS coordinates for the center of the new excavation location.

5.1.1.2 When exposing anomalies and girth welds for ILI excavations, the use of sub-centimeter GPS coordinates is preferred.

5.1.1.3 Take pipe-to-soil readings at grade, if a test station is available.

5.1.1.4 Take casing-to-soil readings, if applicable.

5.1.2 Verify pipe characteristics match the pipe characteristics specified on the GTIM-90440 “Direct Examination Scope of Work” (i.e., diameter, coating type).

5.1.2.1 If the pipe characteristics do not match, notify the GTIM Engineer or GTIM Field Supervisor for further guidance.

5.1.3 Review the type of indication and excavation location on GTIM-90440 “Direct Examination Scope of Work”.

5.1.3.1 Determine if the type of indication and location matches the description on GTIM-90440; if findings do not match descriptions, notify the GTIM Engineer or GTIM Field Supervisor for further guidance. Examples include, but are not limited to:

- The pipe inclination should be sloping north to south but instead is sloping south to north;
- Finding coating damage at a random “no indication” validation location; or
- Excavating a DCVG indication and finding no coating damage.

5.1.4 Confirm excavation of the intended pipe when exposing non-transmission or foreign piping.

5.1.4.1 If damaged, photograph, and document damage.

5.1.4.2 Contact the GTIM Engineer or GTIM Field Supervisor with questions.

6.0 SOIL TESTING

6.1 Responsibility: Direct Examination Crew

6.1.1 Take soil pH in the field using the Palintest® 7100 Photometer, or equivalent. Use distilled water when making the soil slurry.

6.1.2 As directed, collect a soil sample for lab analysis. Refer to GTIM-04-009 “Laboratory Testing for Soil Samples”.

6.1.3 When external corrosion is suspected or is found, test soil. When possible, test soil immediately adjacent to the anomaly.

6.1.3.1 Test soil using a Dixie Testing and Products Soil and Liquid Chemistry Test Kit or similar.

6.1.3.1.1 Follow manufacturer instructions for testing.

6.1.3.2 Document results on GTIM-90418 “Pipeline Inspection Direct Examination”.

7.0 GROUNDWATER SAMPLING

7.1 Responsibility: Direct Examination Crew

7.1.1 If present, sample the groundwater for the following:

- pH;
- Chlorides;
- Sulfates; and
- Nitrates.

7.1.2 Collect a groundwater sample from the open excavation as soon as practical.

7.1.2.1 Fill a plastic eight (8) ounce jar with the groundwater sample, enough to displace air.

7.1.2.1.1 Avoid touching the sample with bare hands or tools to prevent contamination.

7.1.3 Use the Palintest® 7100 Photometer, or equivalent to analyze the groundwater.

7.1.4 Document the results on GTIM-90418 “Pipeline Inspection Direct Examination”.

8.0 DATA COLLECTION PRIOR TO COATING REMOVAL

8.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

8.1.1 On GTIM-90418-A, document the length, width, and depth of the excavation area.

8.1.2 Take soil resistivity readings in the hole at pipe depth using the Collins Rod per GTIM-04-014 “Soil Resistivity with the Single Probe Method”.

8.1.3 Verify the accuracy of the excavation location when excavating for an ECDA indication and finding no anomaly.

8.1.3.1 If the location is confirmed, extend the length of the bell hole to verify no anomaly exists.

8.1.3.2 Contact the GTIM Engineer or GTIM Field Supervisor as necessary for further guidance.

8.1.4 Test liquid for MIC if any liquid is present under the coating per GTIM-04-011 “Field Testing for Microbiologically Influenced Corrosion Bacteria”.

8.1.4.1 When enough liquid is present, test liquid trapped under bubble FBE coating.

8.1.5 Measure the under-film liquid pH if any liquid is present.

8.1.5.1 Extract a sample using a clean hypodermic and measure pH with litmus paper or pH probe.

Note: When used, dispose of hypodermics properly. Destroy needles before throwing away by cutting the tip off the needle or by bending back the needle tip or deposit needle and syringe in a Sharps Container. Destroy syringes by breaking or shattering the barrel.

8.1.5.1.1 Alternatively, slice the coating, and slip the litmus paper behind the coating; press the coating to the paper for a few seconds to confirm good contact.

8.1.5.1.1.1 Clean the area with alcohol to confirm the sample is not contaminated when slicing the coating.

8.1.5.1.1.2 Use a tool cleaned with alcohol to slice the coating to confirm the sample is not contaminated.

8.1.5.1.2 Avoid touching the sample with hands or tools other than those cleaned with alcohol to prevent contamination.

8.1.5.2 Note and record the pH using the chart provided with the litmus paper.

8.1.6 Record the coating thickness, if the coating is bonded to the pipe, in the 12, 3, 6, and 9 o'clock positions by using a magnetic or electronic coating thickness gauge.

8.1.7 Map out coating defect(s) and sketch on GTIM-90418-C "Pipeline Inspection Direct Examination".

8.1.7.1 See GTIM-04-024 "Documentation of Corrosion and Coating Defects" for information.

8.1.7.2 Photograph the coating defects, include a ruler in the picture for reference.

9.0 DATA COLLECTION DURING AND AFTER COATING REMOVAL

Note: Be mindful that some activities listed below require observation and inspection <u>during</u> the coating removal.

9.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

9.1.1 Record whether the pipe is bare or coated.

9.1.1.1 If coated, note the type of coating found on the pipe, as well as any girth welds, repairs, and fittings if applicable.

9.1.2 If coating damage is present, remove the section of coating to encompass the damaged area(s) of the coating.

9.1.2.1 If the pipe is coal tar coated, remove the coating per the Corporate Safety Manual, section 4.1.1, "Policy for Handling Coal Tar Wrapped Pipe, Valve Gaskets".

9.1.3 Obtain pipe-to-soil readings with the connection to the pipe at the location of the removed coating.

9.1.3.1 At each end of the bell-hole, take a pipe-to-soil reading at the 12-, 3-, 6-, and 9-o'clock positions. Keep the reference-electrode close to the pipe.

9.1.3.2 At grade, above the removed coating location, and with a connection to the pipe, take a pipe-to-soil reading.

9.1.4 Evaluate and document any coating conditions such as delamination, cracks, areas of erosion, mechanical damage, tenting, coating blisters (whether filled with liquid or not), or any other observations on GTIM-90418.

9.1.4.1 Using calipers, measure the thickness of any disbonded coating, when applicable.

9.1.4.2 Determine and document the condition of the coating using the following guidelines[1]:

- Excellent:
  - Less than 1% disbondment with occasional coating holidays;
  - No electrolyte beneath the coating;
  - Minor to nonexistent tenting (on Double Submerged Arc Weld (DSAW) and girth welds) or wrinkling of tape coating; and
  - The thickness of the asphalt and coal tar coatings is uniform, with no evidence of wrinkling.
- Good:
  - Adhesion with 1% to 10% disbondment and scattered holidays;
  - Isolated locations with electrolyte beneath the disbonded coating;
  - Minor intermittent tenting (on DSAW and girth welds) or wrinkling of tape coating; and
  - Evidence exists of isolated, poor adhesion, wrinkling, or other damage associated with soil stress on the asphalt and coal tar coatings.
- Fair:
  - Fair adhesion with 10% to 50% disbondment and scattered to numerous holidays;
  - Intermittent locations with electrolyte beneath the disbonded coating;
  - Intermittent tenting (on DSAW and girth welds) or wrinkling of tape coating;
  - Random areas of poor adhesion, wrinkling or other damage associated with soil stress on asphalt and coal tar coatings; and
  - Asphalt and coal tar coatings are brittle.
- Poor:
  - Poor adhesion with 50% to 80% disbondment and numerous coating holidays;
  - Corrosion deposits at holidays and beneath disbonded coating;
  - Numerous locations with electrolyte beneath the disbonded coating;
  - Continuous tenting (on DSAW and girth welds) or wrinkling of tape coating;
  - Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings; and
  - Asphalt and coal tar coatings are very brittle.
- Very Poor:
  - Very poor adhesion with greater than 80% disbondment and numerous coating holidays;
  - Corrosion deposits at holidays and beneath disbonded coating;
  - Numerous locations with electrolyte beneath the disbonded coating;
  - Continuous tenting (on DSAW and girth welds) or wrinkling of tape coating;

[1] Coating condition characteristics adapted from NACE RP0204-2004 “Stress Corrosion Cracking (SCC) Direct Assessment Methodology”

  - Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings; and
  - Asphalt and coal tar coatings are very brittle.

9.1.5 Measure and record the pipe temperature after removing the coating by making contact at the 6 o'clock position in the shade.

9.1.6 Observe corrosion defects. Microbiologically Influenced Corrosion (MIC) may be present if the pit has the following features:

- Large crater up to 2-3 inches or more in diameter;
- Cup-type hemispherical pits on the pipe surface or in the craters;
- Striations or contour lines in the pits or craters running parallel to longitudinal pipe axis (around the pipe); and
- Tunnels, sometimes at the end of the craters, running parallel to the longitudinal pipe axis (around the pipe).

Note: Do not pick or scrape at the crumbling metal or corrosion product as a leak could occur. The corrosion may have jeopardized the integrity of the pipe wall.

9.1.6.1 If MIC is suspected or when requested by IM Personnel, perform testing per GTIM-04-011 "Field Testing for Microbiologically Influenced Corrosion Bacteria".

9.1.7 Identify, measure, and chart all corrosion defects on GTIM-90418-C.

9.1.7.1 See GTIM-04-024 "Documentation of Coating and Corrosion Defects" for additional information.

9.1.8 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 "Predictive Failure Pressure".

9.1.9 Contact the GTIM Field Supervisor or GTIM Engineer to determine the remaining strength of the pipe per GTIM-05-003 "RSTRENG".

9.1.10 Perform ultrasonic thickness measurements around the entire circumference of the pipe at six (6) inch increments, maximum.

9.1.10.1 Perform a minimum of four (4) readings.

9.1.10.2 If a girth weld is exposed, perform ultrasonic thickness measurements on each side of each weld.

9.1.10.3 Refer to the Gas Construction Standards (GCS), section 5.3.6, "Welding - Process Piping/Procedures/Ultrasonic Inspection of Welds".

9.1.10.4 Apply tool tolerances provided in the manufacturer's manual for the specific instrument used.

9.1.11 Photograph any pipe defect(s), include a ruler in the picture for reference.

9.1.12 When finding evidence of mechanical defects resulting from third-party damage are found, complete forms 3112 "Gas Damage Report" and "Facilities Damage Transmission Supplemental" form.

9.1.12.1 Send the completed form to the GTIM Field Supervisor.

9.2 Responsibility: Direct Examination Crew or NDE Service Provider or GTIM Field Inspector

9.2.1 Perform non-destructive testing as directed by the GTIM Field Supervisor or GTIM Field Inspector or GTIM Engineer.

9.2.2 Perform repair or remediation as required in O&M 16.0 “Repairs” or CNP O&M XX “Transmission Pipeline Repair”, and GCS 13.0 “Repairs”.

9.2.3 Upon completion of the inspection, and repair if required, confirm the recoating is complete per O&M 27.35 “Corrosion Control/Protective Coatings” or CNP O&M VIII “External Corrosion Control/Protective Coatings”.

9.2.3.1 Once the recoating of the pipe is complete, take photographs.

9.2.4 As necessary, reattach or install new test leads per O&M 27.34 “Corrosion Control/Test Stations”.

9.2.5 Backfill and restore the excavation site.

9.2.5.1 The excavation site may be left open in the event of a pending replacement only when specified by the GTIM Field Supervisor.

9.2.6 Complete restoration paperwork, Form 3020 “Excavation Repair Report”.

9.2.7 Complete Form 3195 “Gas Facility Field Detail Sketch”, indicating a pipe replacement with new pipe, or pipeline modifications (i.e., repair sleeves, tees, taps, fittings, casing removed, etc.).

10.0 DOCUMENTATION

10.1 Responsibility: GTIM Field Inspector or designee

10.1.1 Complete a daily report on GTIM-90416 “Daily Progress Report Direct Examinations”. Include on the report the following:

- Record any problems encountered that day;
- Record the progress completed that day; and
- Record the total progress made towards the completion of the project.

10.1.2 Submit GTIM-90416 within thirty (30) days of completing the Dig Packet to the GTIM Field Supervisor.

10.2 Responsibility: Direct Examination Crew and GTIM Field Inspector

10.2.1 Upon completion of a direct examination, the Direct Examination Crew and the GTIM Field Inspector shall sign the GTIM-90418.

10.2.2 Scan or copy the GTIM-90418 to allow both the Direct Examination Crew and the GTIM Field Inspector to have a copy.

10.2.3 Submit a GTIM-90418 for each location within thirty (30) days of completing the Dig Packet to the GTIM Field Supervisor.

10.2.3.1 Include all other relevant field documentation, including but not limited to:

- Form 3020 “Excavation Repair Report”;
- Form 3105 “Pipe Exam”; and
- Form 3195 “Gas Facility Field Detail Sketch”.

10.3 Responsibility: Direct Examination Crew

10.3.1 Submit applicable soil, groundwater, and MIC data to the GTIM Field Supervisor, or GTIM Engineer within thirty (30) days of completing the direct examination.

10.4 Responsibility: GTIM Field Supervisor or designee

10.4.1 Submit Form 3112 “Gas Damage Report” and the “Facilities Damage Transmission Supplemental” forms to the appropriate CNP department(s), when applicable.

10.4.2 Review GTIM-90416 and GTIM-90418.

10.4.3 Forward copies of Form 3020 “Excavation Repair Report” and Form 3195 “Gas Facility Field Detail Sketch” to Local Operations for their records.

10.4.4 Retain all forms and any generated attachments in the IM file.

10.4.5 Notify the GTIM Engineer once the data is available.

10.5 Responsibility: GTIM Engineer or designee

10.5.1 Create a work order to incorporate the following data in GIS:

- All data collected during bell hole digs and direct examinations (i.e., GTIM-90418, etc.);
- Any pipeline modifications made; and
- Any pipe attributes collected or observed during the direct examinations that are not correct in GIS.

10.5.2 When direct examinations are associated with an Integrity Assessment, perform a 100% quality check of all requested GIS edits during the Post-Assessment phase.

10.5.2.1 Document the date of the quality check performed on the appropriate form.

<<END>>

GTIM-04-009 Laboratory Testing for Soil Samples

PURPOSE: To provide a standard method of testing soil samples collected during an Integrity Management Direct Examination.

REFERENCES: NACE SP0502-2010;

SECTIONS:
- Sample Collection
- Sample Testing
- Soil Samples
- Documentation
- Result Concern Levels

1.0 SAMPLE COLLECTION

1.1 Responsibility: GTIM Field Inspector or NDE Service Provider

1.1.1 Obtain two (2), eight (8) ounce samples of undisturbed soil immediately adjacent to the pipe at each bell hole.

1.1.2 Collect the soil with a clean instrument and place it in an eight (8) ounce plastic jar with a plastic lid. Pack the sample jar full of soil to displace air.

1.1.2.1 Alternatively, collect the sample using clean rubber gloves.

1.1.2.2 Alternatively, collect the sample in a clean double-bagged Ziploc-type bag and compress the bags to displace the air when sealing.

1.1.2.3 Avoid touching the sample with bare hands or tools, other than those in the test kit to prevent contamination.

1.1.2.4 Tightly close the jar (or alternately seal the plastic bags), seal with plastic tape, and using a permanent marker, label the jar or bag with the following information:

- Date of the collection;
- Pipeline ID and name;
- Assessment ID;
- Indication number; and
- If CNP personnel, the collector’s Initials, or if a Service Provider, the collector’s name and company.

1.1.2.5 Send the soil sample to a qualified laboratory and have the soil sample tested per the requirements in this procedure.

1.1.2.5.1 Keep samples in a cooler to maintain the temperature as close to the original temperature as possible.

1.1.2.5.2 Take and send samples to the lab at the end of each week.

1.1.2.5.2.1 In cases where the ambient temperature is extreme and maintaining the original temperature is difficult, take and send the sample to the lab the same day.

2.0 SAMPLE TESTING

2.1 Responsibility: NDE Service Provider or designee

2.1.1 Use a qualified laboratory for analyzing soil samples.

2.1.1.1 Confirm the laboratory has documented testing procedures for soil testing, including those listed in section 3.0 “Soil Samples”.

2.1.1.2 Send lab qualifications to the GTIM Field Supervisor.

2.1.2 Verify each soil sample label contains the following information before sending to the lab for analysis:

- Date of the collection;
- Pipeline ID and name;
- Assessment ID;
- Indication number; and
- If CNP personnel, the collector’s Initials, or if a Service Provider, the collector’s name and company.

2.1.3 Send or deliver the sample(s) to the approved laboratory.

3.0 SOIL SAMPLES

3.1 Responsibility: Testing Laboratory

3.1.1 Analyze the soil sample for the following constituents per the following standards:

- Moisture content (a modified version of AASHTO Method T 265[1]);
- Sulfide ion concentration (EPA 376.1[2]);
- Conductivity (ASTM D 1125[3]);
- pH (ASTM D 4972[4]);
- Chloride Ion concentration (ASTM D 512[5]); and
- Sulfate ion concentration (ASTM D 516[6]).

3.1.1.1 If the previous test methods are not utilized, provide a documented procedure for the substituted method used and justification as to why the substituted test method is comparable to the GTIM Manager for approval before instituting the new test method.

3.1.2 Visually determine the soil classification per the Unified Soil Classification System (USCS).

3.1.2.1 If requested, test the soil per ASTM D2487[7].

[1] AASHTO Method T 265 (latest revision), “Standard Method of Test for Laboratory Determination of Moisture Content of Soils” (Washington, DC: AASHTO);
[2] EPA 376.1 (latest revision), “Standard Operating Procedure for the Analysis of Sulfide in Water (Titrimetric)” (Washington, DC: EPA);
[3] ASTM D 1125 (latest revision), “Standard Test Methods for Electrical Conductivity and Resistivity of Water” (West Conshohocken, PA: ASTM);
[4] ASTM D 4972 (latest revision), “Standard Test Method for pH of Soils” (West Conshohocken, PA: ASTM);
[5] ASTM D 512 (latest revision), “Standard Test Methods for Chloride Ion in Water” (West Conshohocken, PA: ASTM);
[6] ASTM D 516 (latest revision), “Standard Test Method for Sulfate Ions in Water” (West Conshohocken, PA: ASTM);
[7] ASTM D 2487 (latest revision), “Standard Classification of Soils for Engineering Purposes (Unified Soil Classification System” (West Conshohocken, PA: ASTM);

4.0 DOCUMENTATION

4.1 Responsibility: Testing Laboratory

4.1.1 Provide a documented report for each sample and label each report with the following information.

- Date of the soil collection;
- Pipeline ID and name;
- Assessment ID;
- Indication number;
- Initials (or name and company) of the person who obtained the sample;
- Date sample analyzed; and
- Name of person performing the lab analysis.

4.1.2 Send the report to the GTIM Field Inspector.

4.2 Responsibility: GTIM Field Inspector or designee

4.2.1 Submit the report to the GTIM Field Supervisor.

4.3 Responsibility: GTIM Field Supervisor or designee

4.3.1 Confirm documentation is complete.

4.3.2 Place the report in the appropriate IM file.

5.0 RESULT CONCERN LEVELS

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Review the laboratory results to determine if levels are of concern.

5.1.1.1 Concerning Soil Levels:

- Sulfide ion concentration (0.25% or greater);
- pH (less than 5.5 or greater than 10); or
- Sulfate ion concentration (150 or greater).

5.1.1.1.1 The following constituents are considered soil diagnostic parameters and are informational.

- Moisture content; and
- Conductivity.

5.1.2 For results that are of concern, notify the Corrosion Control Supervisor for the appropriate area.

5.2 Responsibility: Corrosion Control Supervisor

5.2.1 Determine the appropriate course of action, if any.

5.2.2 Document any required action items, including any mitigative actions.

5.2.3 Maintain the documentation in the IM file.

<<END>>

GTIM-04-011 Field Testing for Microbiologically Influenced Corrosion Bacteria

PURPOSE: To provide a standardized method for testing the bacterial population and corrosive products of liquids found beneath the pipe wrap coating in the determination of Microbiologically Influenced Corrosion.

REFERENCES: NACE SP0502-2010;

SECTIONS:

- General
- Determination of Sampling Locations
- Sampling Procedures
- Interpretation of Results
- Documentation

1.0 GENERAL

1.1 Microbiologically Influenced Corrosion (MIC) is corrosion associated with the presence and activities of microorganisms such as acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB).

1.1.1 The presence of APBs and SRBs can result in corrosion affecting a pipeline's integrity.

1.2 MIC test kits allow testing for MIC in the field. Appropriate MIC kits include:

- Dixie Test Kit #4 by Dixie Testing and Products, Inc.;
- MICkit®5 by BTI Products, LLC; and
- Other kits, as approved by the GTIM Manager.

1.3 The MIC test kit typically contains:

- Media Vials;
- Syringes;
- Sterile tongue depressor for sampling solids;
- Sterile cotton swab for swabbing surfaces; and
- Alcohol swab.

1.4 The MIC test kits have an expiration date. Do not use the kit if the incubation period exceeds the expiration date.

1.5 Do not expose the MIC test kits to high temperatures (greater than 90˚F).

1.5.1 High temperatures accelerate the growth of contamination.

1.5.2 Scrutinize exposure to temperatures over 90˚F of all bottles before using the kit.

1.5.2.1 If all the bottles appear the same, new and unbroken, continue with using the bottles.

1.5.2.1.1 Corrupted bottles may appear cloudy, have black deposits, or an observable color change.

1.5.2.2 If corruption is present in any bottle, discard the entire kit and use a new one.

1.6 Examine test kits exposed to low temperatures (less than 32˚F).

1.6.1 If the bottles all appear the same, new and unbroken, the kit is acceptable.

2.0 DETERMINATION OF SAMPLING LOCATIONS

2.1 Responsibility: GTIM Field Inspector or NDE Service Provider or Direct Examination Crew

2.1.1 Test for bacteria wherever liquid is present under the coating when possible. In some cases, there may not be enough liquid available for testing.

2.1.2 Test for bacteria whenever MIC is suspected.

2.1.2.1 Microbiologically Influenced Corrosion (MIC) may be present if the pit has any of the following characteristics:

- Large crater up to 2-3 inches or more in diameter;
- Cup-type hemispherical pits on the pipe surface or in the craters;
- Craters or pit sometimes surrounded by un-corroded metal;
- Striations or contour lines in the pits or craters running parallel to longitudinal pipe axis (around the pipe); or
- Tunnels, sometimes at the end of the craters, running parallel to the longitudinal pipe axis (around the pipe).

3.0 SAMPLING PROCEDURES

3.1 Responsibility: GTIM Field Inspector or NDE Service Provider or Direct Examination Crew

3.1.1 Obtain samples of solids, scale, biofilm, and liquids.

Note: Do not pick or scrape at the crumbling metal or corrosion product as a leak could occur. The corrosion may have jeopardized the integrity of the pipe wall.

3.1.1.1 Test sample per the instructions included with the test kit.

3.1.2 Obtain samples and inoculate media while the bell hole is open to confirm enough sample material was acquired.

3.1.2.1 Follow the test kit instructions for placing the culture into the media vials.

Note: When used, dispose of hypodermics properly. Destroy needles before throwing away by cutting the tip off the needle or by bending back the needle tip or deposit needle and syringe in a Sharps Container. Destroy syringes by breaking or shattering the barrel.

3.1.3 Incubate all bottles of media at pipe surface temperature.

3.1.4 Check the bottles at the end of each incubation period, as specified in the test kit instructions.

3.1.5 Document the findings each day checked on GTIM-90419 “MIC Testing” by indicating the number of vials with color change on the form.

3.1.5.1 Confirm utilization of the appropriate version of form GTIM-90419.

- GTIM-90419-A is specific to Dixie Test Kit #4 by Dixie Testing and Products, Inc.
- GTIM-90419-B is specific to MICkit®5 by BTI Products, LLC.
- GTIM-90419-C is a general form for use with another approved test kit.

4.0 INTERPRETATION OF RESULTS

4.1 Responsibility: NDE Service Provider or Direct Examination Crew

4.1.1 Review the results of the data and provide results or report to the GTIM Field Inspector.

4.1.2 Refer to the test kit instruction for analysis of the media vials.

4.1.3 If MIC present, notify GTIM Field Supervisor.

4.2 Responsibility: GTIM Engineer or designee

4.2.1 Review the results of the data.

4.2.2 Consult with subject matter experts to develop a plan of action when MIC is present.

5.0 DOCUMENTATION

5.1 Responsibility: GTIM Field Inspector or NDE Service Provider or Direct Examination Crew

5.1.1 Provide GTIM-90419 “MIC Testing” to the GTIM Field Supervisor, after required inoculation time.

5.2 Responsibility: GTIM Field Supervisor or designee

5.2.1 Review GTIM-90419.

5.2.2 Place GTIM-90419 in the appropriate IM file.

5.2.3 Notify GTIM Engineer when the file is available.

<<END>>

GTIM-04-012 Root Cause Analysis

PURPOSE: To establish a standardized method for performing a Root Cause Analysis for pipeline events as they relate to the Integrity Management Program.

REFERENCES: 49 CFR 192.925; 49 CFR 192.933; 49 CFR 192.935;

SECTIONS:

- General
- Pipe Information and Location Description
- Data Gathering for Immediate Conditions
- Data Gathering for Corrosion
- Data Gathering for Third-party Damage
- Determination of Root Cause
- Post-Assessment of Root Cause

1.0 GENERAL

1.1 Root Cause Analysis is a process of gathering and analyzing data to determine the causal factors that contributed to an event.

1.2 Examples of events requiring Root Cause Analysis for the Gas Transmission Integrity Management Program include, but are not limited to:

- Immediate Conditions;
- Corrosion Found on pipe within a Consequence Area;
- Third-party damage or excavation damage anywhere on a pipeline;
- Severe corrosion or damages found on a transmission line;
- Transmission MAOP exceedances; and
- A pressure test failure.

1.3 The GTIM Engineer has the discretion to perform a Root-Cause Analysis on any transmission event, condition.

1.4 Refer to the Emergency Response Plan 7.00, “Accident and Failure Investigation”, when investigating pipeline accidents and failures.

2.0 PIPE INFORMATION AND LOCATION DESCRIPTION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Document location and pipe information on GTIM-90421 “Root Cause Analysis”.

2.1.2 Excavate and in situ examine the pipeline if warranted.

2.1.2.1 Attach GTIM-90418 “Pipeline Inspection Direct Examination” and additional site-specific documentation, such as:

- Photographs;
- Measurements collected;
- Inspection and repair documentation; and
- Reports.

3.0 DATA GATHERING FOR IMMEDIATE CONDITIONS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Perform a Root Cause Analysis on all Immediate Conditions as defined in GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”.

3.1.1.1 If a corrosion anomaly is present, or if the possibility of corrosion exists as a root cause, continue analysis using section 4.0, “Data Gathering for Corrosion”.

3.1.1.2 If the segment area contains dents, deformations, or gouges, refer to section 5.0, “Data Gathering for Third-Party Damage”.

3.1.2 Gather and document as much information about the Immediate Condition as possible.

3.1.2.1 Document all applicable information on GTIM-90420 “ECDA - Post Assessment”.

3.1.3 Complete GTIM-90421, “Section 4 Determination of Root Cause (Immediate)”.

3.1.3.1 Attach all applicable supporting documentation to GTIM-90421.

3.1.4 Skip to section 7.0, “Post-Assessment of Root Cause”, to complete documentation.

4.0 DATA GATHERING FOR CORROSION

4.1 Responsibility: GTIM Field Supervisor or designee

4.1.1 Perform data collection per GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

4.1.1.1 Measure for induced Atmospheric Corrosion (AC) at the anomaly.

4.1.1.1.1 Take appropriate actions if induced AC is present.

4.1.1.2 Test for the presence of Microbiologically Influenced Corrosion (MIC), if there is liquid under the coating or if MIC is suspected.

4.1.1.2.1 Refer to procedure GTIM-04-011 “Field Testing for Microbiologically Influenced Corrosion Bacteria”.

4.1.1.3 When deemed appropriate, perform magnetic particle testing per the Gas Construction Standards, section 5.3.8, “Magnetic Particle Inspection of Welds”.

4.1.1.4 If the possibility of internal corrosion exists as a potential root cause, perform the following:

4.1.1.4.1 Take Ultrasonic Thickness (UT) measurements per the Gas Construction Standards, section 5.3.6, “Ultrasonic Inspection of Welds”.

4.1.1.4.1.1 Apply tool tolerances provided in the manufacturer’s manual for the specific instrument used.

4.1.1.4.2 Take a representative gas sample from the nearest upstream sampling location.

4.1.1.4.2.1 Evaluate the gas sample for potentially damaging constituents such as hydrogen sulfide, water, and bacteria.

4.1.2 Document all applicable information on GTIM-90418 “Pipe Inspection Direct Examination”.

4.1.2.1 Include photographs if applicable.

4.1.3 Perform a Root Cause Analysis for external corrosion anomalies greater than 20% wall loss found on pipe within a Consequence Area. As part of the analysis, consider the following:

4.1.3.1 Perform a Close Interval Survey (CIS) a minimum of 100 feet in both directions of the anomaly location per GTIM-04-020 “Close Interval Survey”.

4.1.3.1.1 If the corrosion was discovered as part of the ECDA process, performing another Close-Interval Survey is not required.

4.1.3.2 Determine if foreign-line crossings or impressed current rectifiers contributed to stray current interference.

4.1.4 A detailed analysis may not be required if the root cause is apparent; consult with the GTIM Manager.

4.1.5 Complete GTIM-90421, “Section 2 Determination of Root Cause (Corrosion)”.

4.1.5.1 Attach GTIM-90418 “Pipe Inspection Direct Examination”.

4.1.6 Skip to section 7.0, “Post-Assessment of Root Cause” to complete documentation.

5.0 DATA GATHERING FOR THIRD-PARTY DAMAGE

5.1 Responsibility: GTIM Field Supervisor or Local Operations

5.1.1 Perform a Root Cause Analysis for all third-party damage.

5.1.1.1 Third-party damage includes, but is not limited to:

- Dents;
- Gouges;
- Scratches; and
- Damaged coating.

5.1.2 Observe the aboveground features. Look for physical characteristics that may help indicate the root cause:

- Foreign-line crossings (e.g., flags, markers, paint);
- Disturbed earth;

5.1.3 Document the condition of the pipe on applicable sections of GTIM-90418 “Pipe Inspection Direct Examination”. Information should include, but is not limited to:

- Measurements of dents/gouges (i.e., length, depth);
- Assessment of coating condition; and
- Photographs when applicable.

5.1.4 Complete Form 3112 “Gas Damage Report”.

5.1.4.1 Refer to GTIM-08-006 “Collecting Information on Excavation Damage”.

5.1.5 Review continuing surveillance records and confirm the frequency of required patrols.

5.1.5.1 Refer to O&M 8.0 “Continuing Surveillance” or CNP O&M XVI (B) “Other Operating Procedures/Continuing Surveillance.

5.1.6 Complete GTIM-90421, “Section 3 Determination of Root Cause (Third-Party / Excavation Damage)”.

5.1.6.1 Attach Form 3112 “Gas Damage Report”.

5.1.7 Skip to section 7.0, “Post-Assessment of Root Cause” to complete documentation.

6.0 DETERMINATION OF ROOT CAUSE

6.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

6.1.1 Review documentation and findings from GTIM-90421 “Root Cause Analysis”.

6.1.2 As necessary, gather additional pertinent information from applicable databases and document on GTIM-90421. Information may include:

- Age of pipe;
- Type of cathodic protection system;
- Leak history; and
- Previous maintenance history.

6.1.3 Evaluate the data to identify the Root Cause(s).

6.1.3.1 Request the input of Subject Matter Experts as appropriate.

6.1.4 Document the conclusions (Root Cause) on GTIM-90421, “Section 5 Determination of Root Cause (Other)”.

6.1.5 Attach all applicable supporting documentation to GTIM-90421. Supporting documentation may include, but is not limited to:

- Photographs;
- Laboratory reports;
- Test reports; and
- Any interviews conducted (i.e., with Local Operations and other participants).

7.0 POST-ASSESSMENT OF ROOT CAUSE

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 Based upon the established Root Cause, determine if additional Preventive and Mitigative (P&M) measures are appropriate.

7.1.1.1 P&M measures may include, but are not limited to:

- Additional leak patrols;
- Temporary pressure reduction;
- Pipeline re-routes; and
- Ground bed installations or upgrades.

7.1.1.2 See GTIM-08-004 “Identify Additional Preventive and Mitigative Measures” for further details.

7.1.2 Document the implemented P&M measures, as well as the recommended P&M measures, on GTIM-90421, “Section 6”.

7.1.3 When the root cause is excavation damage or third-party damage, document the root cause per GTIM-08-006 “Collection Information on Excavation Damage”.

7.1.4 If the root cause is determined to be corrosion, refer to GTIM-08-005 “Evaluating Similar Conditions”.

7.1.5 Retain GTIM-90421 “Root Cause Analysis” and all associated documentation in the IM file.

<<END>>

GTIM-04-013 Soil Resistivity with the Wenner 4-Pin Method

PURPOSE: To establish a standardized approach for taking soil resistivity readings using the Wenner Four-Pin method.

REFERENCES: NACE SP0502-2010, Appendix B;

SECTIONS:
- General
- Equipment
- Equipment Set-Up
- Obtaining Soil Resistivity Readings
- Documentation
- Soil Resistance Formula
- Soil Resistivity Values
- Illustrations of Meter Equipment

1.0 GENERAL

1.1 Use a four-pin meter to measure the average soil resistivity of an area of electrolyte (earth or water).

1.2 Soil resistivity directly affects the output of anodes (galvanic or impressed) and the corrosion rate of metallic structures.

1.3 The soil resistivity value is required when designing cathodic protection systems.

1.4 The soil resistivity readings correlate to the corrosiveness or conductivity of the soil.

1.5 The Wenner 4-Pin method is the preferred method of taking soil resistivity readings during the indirect inspection phase of External Corrosion Direct Assessment (ECDA).

1.5.1 This method takes soil resistivity readings at approximate 1,000-foot intervals and at each approximate DCVG or ACVG indication location, when feasible.

2.0 EQUIPMENT

- Nilsson Model 400 Four-Pin Soil Resistivity Meter, or equivalent;
- Four (4) pin harness (with fixed or adjustable pin spacing);
- Four (4) metallic pins; and
- A portable 12-volt battery.

3.0 EQUIPMENT SET-UP

3.1 Responsibility: Indirect Inspection Crew or Corrosion Control

3.1.1 Drive the four (4) pins in a straight line into the earth at equal spacing.

3.1.1.1 Run pins perpendicular to the pipeline or in an open area away from any metallic structure.

3.1.1.1.1 Spacing is typically equal to the depth of the pipe.

3.1.1.1.2 The distance between the pins determines the average depth of resistivity measured.

3.1.1.1.3 Readings taken perpendicular to a metallic structure should have the first pin placed at a distance of at least ½ the pin spacing from the metallic structure.

3.1.2 Connect the outer two (2) pins to the C (current) 1 and 2 terminals of the instrument. Connect the two (2) center pins to the P (potential) 1 and 2 terminals of the instrument.

3.1.2.1 Connect the pins in the proper sequence.

3.1.2.2 From the meter, the first pin will be C1, the next pin will be P1, the next pin will be P2, and the last pin will be C2.

3.1.3 Insert the pins into the electrolyte beyond the top (dry) layer of dirt. Driving pins further into the ground is not necessary.

3.1.3.1 Typically, driving the pins down two (2) to three (3) inches is sufficient.

3.1.3.2 DO NOT insert pins to a depth greater than 10% of pin spacing.

3.1.3.3 DO NOT position the pins directly over a metallic structure or parallel to a metallic structure.

4.0 OBTAINING SOIL RESISTIVITY READINGS

4.1 Responsibility: Indirect Inspection Crew or Corrosion Control

4.1.1 Verify the battery status of the instrument.

4.1.2 Energize the instrument using the “LOW” or “COARSE” setting with the RANGE selector set to its minimum value.

4.1.2.1 If the meter needle “pegs” the right, turn the RANGE selector up one (1) or more values so that the meter needle falls to the center of the display.

4.1.3 Null the meter indicator with the “FINE” or “HIGH” SENSITIVITY setting.

5.0 DOCUMENTATION

5.1 Responsibility: Indirect Inspection Crew or Corrosion Control

5.1.1 Record the following measurements for each reading location on GTIM-90413 “Soil Resistivity Data Collection” once the meter is “nulled”:

- PS = Pin Spacing *(feet)*;
- MR = Meter Range *(decimal)*; and
- NO = The number on the dial when balanced or “nulled”.

5.1.2 Record the following information on GTIM-90413:

- Name of the Service Provider and the person taking the readings;
- Date of the survey;
- Description of location (i.e., approximate Indirect Survey Stationing, nearby landmarks, etc.);
- GPS coordinates for each reading location;
- ECDA Region, if applicable or known; and
- Current weather conditions (i.e., temperature, wet soil, dry soil, etc.).

5.1.3 Alternatively, collect all of the information listed above electronically in the data logger or document the reading on GTIM-90418 “Pipeline Inspection Direct Examination”.

6.0 SOIL RESISTANCE FORMULA

6.1 Responsibility: Indirect Inspection Crew or Corrosion Control

6.1.1 Using the data collected in section 5.0 “Documentation” above, use the following formula to calculate the average soil resistivity:

$$Soil\ Resistivity\ (SR) = 191.5\ \times PS\ \times MR\ \times NO$$

where:

SR = Soil Resistivity *(Ω-cm)*
PS = Pin Spacing *(feet)*
MR = Meter Range *(decimal)*
NO = The number on the dial when balanced or “nulled”.

6.1.2 Record the Soil Resistivity reading(s) on GTIM-90413.

7.0 SOIL RESISTIVITY VALUES

7.1 Responsibility: Indirect Inspection Crew or Corrosion Control

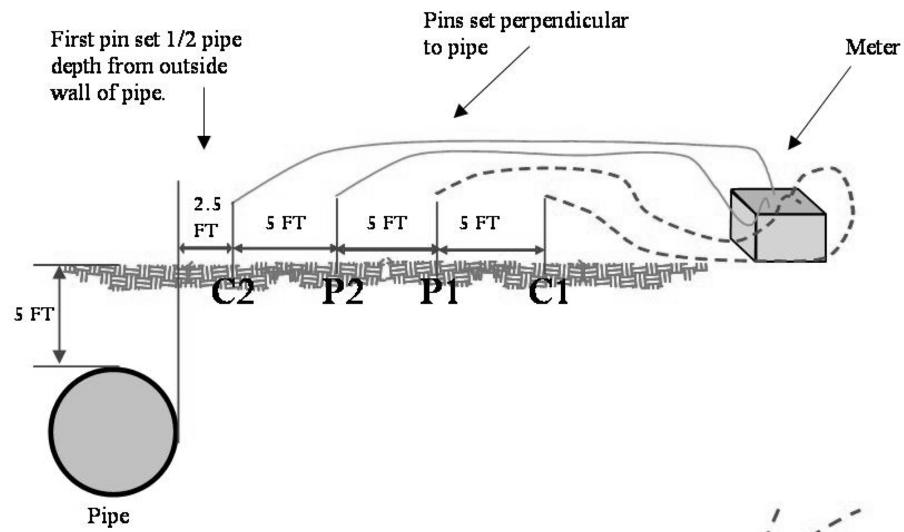
7.1.1 Review the soil resistivity readings. As desired, determine general corrosiveness of the soil per the following table:

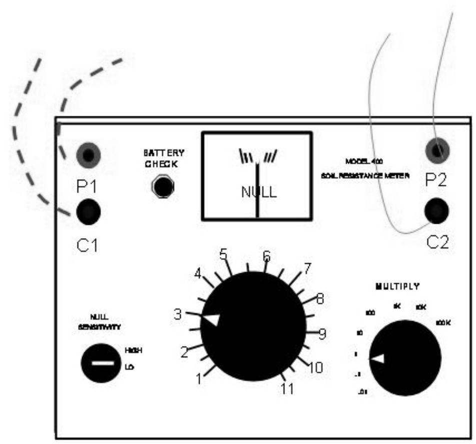
Table 04-013-1: Soil Resistivity Categorization

Soil Resistivity *(Ω-cm)*	**Soil Corrosiveness**
5 – 500	Very Corrosive
500 – 1,000	Corrosive
1,000 – 2,000	Moderately Corrosive
2,000 – 10,000	Mildly Corrosive
Above 10,000	Negligible

8.0 ILLUSTRATIONS OF METER EQUIPMENT

Figure 04-013-F1: Illustrations of Meter Equipment





Top of Meter

<<END>>

GTIM-04-014 Soil Resistivity with the Single Probe Method

PURPOSE: To establish a standardized approach for taking soil resistivity readings using the Single-Probe Method (Collins Rod).

REFERENCES: NACE SP0502-2010, Appendix B;

SECTIONS:

- General
- Equipment
- Survey Preparation
- Obtaining Soil Resistivity Readings
- Documentation
- Soil Resistivity Values
- Illustrations of Meter Equipment

1.0 GENERAL

1.1 The Collins Rod is used to measure the average soil resistivity of an area of electrolyte (earth or water).

1.2 The soil resistivity directly affects the output of anodes (galvanic or impressed) and the corrosion rate of metallic structures.

1.3 Soil resistivity is a value required when designing cathodic protection systems.

1.4 The soil resistivity readings correlate to the corrosiveness or conductivity of the soil.

1.5 Use the Single-Probe Method when the Wenner 4-Pin method is impractical due to confined spaces or the proximity of other buried metallic structures.

1.6 The Collins Rod meter uses one (1) probe that consists of two (2) isolated sections to measure soil resistivity.

1.6.1 The rod tip measures the resistivity of the earth or water, then transmits the readings through the body of the rod.

Note: The Wenner 4-Pin method is the preferred method of taking soil resistivity reading during the indirect inspection phase of External Corrosion Direct Assessment (ECDA).

2.0 EQUIPMENT

- Collins Rod Model 54-A, a hexagonal steel rod with handles and insulated tip; and
- AC resistivity audio bridge instrument with earphones.

3.0 SURVEY PREPARATION

3.1 **Responsibility:** Indirect Inspection Crew or Corrosion Control

3.1.1 Test the unit for proper operation.

3.1.1.1 Turn the power switch to “on” before connecting the test leads to the soil rod.

3.1.1.2 Connect the earpiece and place over-ear.

3.1.1.3 Push and hold the “test” switch up.

3.1.1.3.1 Hold the test switch up, turn the dial pointer until the tone “nulls” in the earpiece.

3.1.1.3.1.1 Achieve a “null” at the center where there is no tone heard through the earpiece.

3.1.1.3.2 The reading on the dial should match the test position value.

3.1.1.3.3 If the reading on the dial does not match the test position value, reset the dial.

3.1.1.4 Push and hold the “test” switch down.

3.1.1.4.1 While holding the test switch down, turn the dial pointer until the tone “nulls” in the earpiece.

3.1.1.4.2 The reading on the dial should match the test position value.

3.1.1.4.3 If the reading on the dial does not match the test position value, reset the dial.

3.1.2 Connect the wire leads between the terminals on the meter and the probe bar.

3.1.3 Push the bar into the earth using your body weight.

3.1.3.1 DO NOT insert the bar directly into hard ground or rock that might damage the insulating washer located between the probe tip and the rod.

3.1.3.2 If the earth is frozen, rocky, or otherwise challenging to drive, use a “drive bar” to provide an initial hole in which to insert the probe.

3.1.3.3 DO NOT damage the probe tip or insulating washer.

4.0 OBTAINING SOIL RESISTIVITY READINGS

4.1 Responsibility: Indirect Inspection Crew or Corrosion Control

4.1.1 Turn the power switch “on” and “null” the dial.

4.1.2 Take five (5) readings in the “X” pattern to determine the average.

5.0 DOCUMENTATION

5.1 Responsibility: Indirect Inspection Crew or Corrosion Control

5.1.1 Once the meter is “nulled”, record all of the following information for each reading location on GTIM-90413 “Soil Resistivity Data Collection”.

- Name of the company and person taking the reading;
- Date of the survey;
- Description of the location (i.e., approximate Indirect Survey Stationing, nearby landmarks);
- GPS coordinates of the reading location;
- Soil Resistivity reading;
- ECDA Region (if applicable); and
- Weather conditions (i.e., temperature, wet soil, dry soil).

5.1.2 Alternatively, collect all of the information listed above electronically in the data logger or document the reading on GTIM-90418 “Pipeline Inspection Direct Examination”.

6.0 SOIL RESISTIVITY VALUES

6.1 Responsibility: Indirect Inspection Crew or Corrosion Control

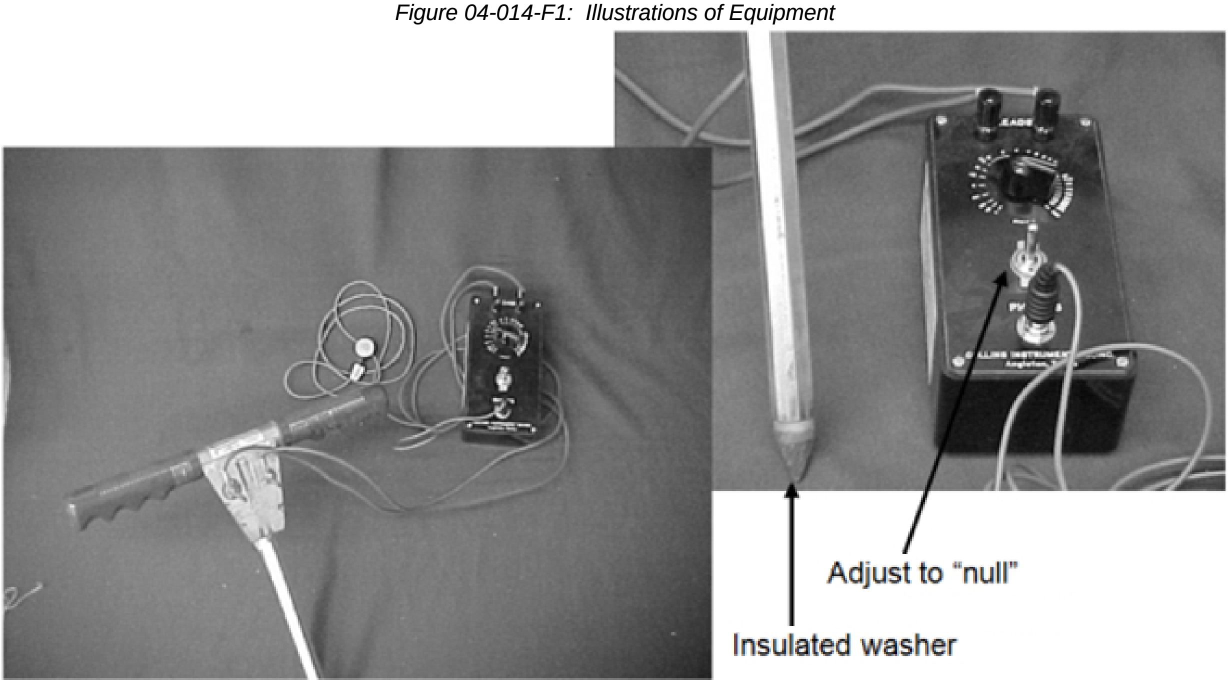
6.1.1 Review the soil resistivity readings. As desired, determine general corrosiveness of the soil per the following table:

Table 04-014-1: Soil Resistivity Categorization

Soil Resistivity *(Ω-cm)*	**Soil Corrosiveness**
5 – 500	Very Corrosive
500 – 1,000	Corrosive
1,000 – 2,000	Moderately Corrosive
2,000 – 10,000	Mildly Corrosive
Above 10,000	Negligible

7.0 ILLUSTRATIONS OF METER EQUIPMENT

Figure 04-014-F1: Illustrations of Equipment



<<END>>

GTIM-04-020 Close Interval Survey

PURPOSE: To establish a standardized method for performing a Close-Interval Survey (CIS).

REFERENCES: NACE SP0502-2010, Section 4;

SECTIONS:

- General
- Survey Preparation
- Safety Considerations
- Equipment
- Performing the Survey
- Data Quality
- Data Presentation

1.0 GENERAL

1.1 Close-Interval Survey (CIS) applies to buried pipelines with an electrolytic cover.

1.1.1 CIS may not be applicable in areas with frozen ground, or locations of “shielding” caused by disbonded coating, or cased pipeline locations, or paved surfaces.

1.1.2 CIS may be used for paved surfaces with additional measures, such as drilling and coring holes, to achieve electrolyte access.

1.2 CIS measures the potential difference between the structure (pipe) and the electrolyte (soil).

1.2.1 For cathodically protected pipelines, CIS is used to assess the effectiveness of the CP system.

1.2.2 CIS can also be used to detect stray current interference and metallic shorts.

2.0 SURVEY PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Prepare for the CIS by performing the requirements of procedure GTIM-04-030 “Indirect Inspection Survey Field Preparation”.

2.1.1.1 Typically, preparations need to begin three (3) to six (6) months in advance of the survey.

2.1.2 Confirm personnel associated with the inspection are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual.

2.1.2.1 Applicable covered tasks include:

- Abnormal operating conditions;
- Measuring pipe-to-soil readings;
- Rectifier readings;
- Rectifier maintenance;
- Inspect and test bonds; and
- Pipeline locating.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Take appropriate safety precautions when performing indirect inspections.

3.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

3.1.3 Use caution when using long lengths of test wire near high voltage alternating current (HVAC) power lines.

3.1.3.1 HVAC lines can induce hazardous voltage levels on the test wire.

3.1.4 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

3.1.5 Use caution when working around roads and railroads.

3.1.5.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.5.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, “Reflective Safety Vests”.

3.1.6 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 EQUIPMENT

4.1 Responsibility: Indirect Inspection Crew

4.1.1 Use a data collection unit that meets the following specifications:

- High input impedance voltage meter (10MΩ or greater) with one (1) mV accuracy in the range of -10V to + 10V DC; and
- A meter with AC rejection to minimize the effect of AC potentials on DC measurements.

4.1.2 Use current interrupters that have the following capabilities:

- GPS synchronized;
    - When using only one interrupter, the interrupter does not have to be GPS synchronized;
- “On” and “off” cycle such that the “off” readings are easily distinguishable from the “on” readings;
- “On” and “off” cycle that does not allow significant depolarization;
- A standard interruption cycle is 3 seconds “on” and 1 second “off”; and
- Programmable such that the rectifier remains “on” at night.

4.1.3 Use copper or copper-sulfate reference electrodes.

4.1.4 At a minimum, use a sub-meter GPS unit.

4.2 Responsibility: Indirect Inspection Crew

4.2.1 Interrupt all known sources of current along the pipeline.

4.2.1.1 Sources of current include rectifiers, galvanic anode banks, foreign-rectifiers, and bonds.

4.2.1.1.1 Galvanic anodes attached directly to the pipeline cannot be interrupted.

4.2.1.2 Interrupt all foreign-rectifiers and bonds, unless otherwise directed.

4.2.1.2.1 If it is not possible to interrupt all foreign-rectifiers, interrupt the bond.

4.2.1.3 Record the tap settings and output (current and voltage) at each rectifier before setting up the current interrupter.

4.2.1.3.1 Document readings on GTIM-90404 “Rectifier and Critical Bond Locations”.

4.2.1.4 When performing DCVG before the CIS, confirm the rectifier output was not adjusted, no installation of temporary ground beds, and the use of the same interruption cycle for the CIS survey.

4.2.1.4.1 Performing DCVG and CIS simultaneously requires achieving the minimum DCVG signal strength without adding additional current. Refer to procedure GTIM-04-021 “Direct Current Voltage Gradient Survey” for more information.

4.2.1.5 If incurring additional sources of current during the survey, document current sources on GTIM-90404.

4.2.2 At the start of each survey day, balance the reference electrodes to a value less than or equal to five (5) mV.

4.2.2.1 Rebuild or discard any reference electrodes that do not balance.

4.2.2.2 Note proof of calibration in the field notebook, field survey records, or survey comments.

4.2.2.3 Balance a third electrode for verification purposes.

4.2.3 Before commencing the survey, check the meter for accuracy by comparing the readings to an independent high input impedance voltage meter (10MΩ or greater).

4.2.3.1 Document occurrence of this check on GTIM-90412 “Daily Progress Report Indirect Inspection Surveys”.

4.2.4 During the survey, carefully repair any unintentional wire breaks that may occur.

4.2.4.1 Thoroughly clean the coating off both ends of the copper wire with sandpaper.

4.2.4.2 Twist the clean ends of the survey wire together to achieve electrical continuity.

4.2.4.3 Place a piece of electrical tape over the twist.

4.2.4.4 Place a knot in the survey-wire a few inches downstream of the repair.

4.2.4.4.1 The knot places the wire tension at the knot and not the repair.

5.0 PERFORMING THE SURVEY

5.1 Responsibility: Indirect Inspection Crew

5.1.1 Complete a new GTIM-90412 daily.

5.1.1.1 Record the date, weather conditions, and temperature on GTIM-90412.

5.1.2 Confirm completion of pipeline locating and marking per GTIM-04-032 “Locating and Marking a Survey Segment” before commencing the CIS.

5.1.3 Generate a wave print daily to verify interruption synchronization.

5.1.3.1 Do not perform the survey until achieving adequate synchronization.

5.1.4 Connect the test wire to an above-grade contact point (i.e., test station).

5.1.4.1 Confirm all survey connections are mechanically sound and have low resistance.

5.1.4.2 Reconnect at all above-grade contact points.

5.1.4.2.1 Reconnection to another point less than 1,000 feet away is not required.

5.1.4.2.2 Do not make connections at rectifier negatives, galvanic anode leads, bonds, or other current-carrying wires.

5.1.4.3 Note the type of connection (i.e., test station, MLV, etc.) in the survey remarks.

5.1.5 Take “on” and “off” pipe-to-soil potentials and capture the data electronically.

5.1.5.1 “Off” readings do not apply to a non-interruptible sacrificial system.

Note: References made to “off” readings throughout this procedure, do not apply to sacrificial cathodic protection systems.

5.1.6 Take pipe-to-soil potentials at approximate three (3) foot spacing, unless approved by the GTIM Field Supervisor.

5.1.6.1 Take pipe-to-soil readings directly over the pipeline centerline.

5.1.6.2 Pipe-to-soil readings are not necessary over cased pipeline crossings.

5.1.6.2.1 Take pipe-to-soil and casing-to-soil readings at the end of each casing.

5.1.7 Consider the appropriateness of skipping paved surfaces less than ten (10) feet in length.

5.1.8 For areas of pavement greater than ten (10) feet in length, drill holes in the pavement per procedure GTIM-04-031 “Drilling and Coring of Improved Surfaces” to achieve electrolyte access.

5.1.8.1 Obtain approval from the GTIM Field Supervisor to “skip” areas larger than ten (10) feet.

5.1.9 Conditions on the pipeline right-of-way may not allow measurements to be taken directly over the pipeline, in select circumstances. In some of these circumstances, consider taking offset surveys.

5.1.9.1 DO NOT perform an offset survey more than three (3) feet from the centerline of the pipeline, unless otherwise approved by the GTIM Field Supervisor.

5.1.9.2 Indicate the beginning of the offset location in the survey comments. Document the obstruction and note the distance from the pipeline’s centerline.

5.1.9.3 Return to the centerline of the pipeline as soon as practical.

5.1.9.3.1 Note the location in the comments where readings resume over the centerline.

5.1.10 When performing surveys across lakes, rivers, and other bodies of water:

5.1.10.1 Perform surveys on foot across shallow, narrow bodies of water, such as creeks and streams.

5.1.10.2 If the Survey Crew Leader or the GTIM Field Supervisor deems it unsafe to walk across the body of water, use alternative methods of obtaining pipe-to-soil readings.

5.1.10.3 Personal Protective Equipment (PPE) such as flotation vests may be required. Refer to the Corporate Safety Manual, section 4.37, “Working In/On or Near Water”.

5.1.10.4 Discuss options for surveying bodies of water that prohibit surveying on foot with the GTIM Field Supervisor.

5.1.10.4.1 Additional equipment may be necessary to perform the survey, such as watercraft.

5.1.11 Congested or impassable right-of-way conditions do not warrant an offset survey.

5.1.11.1 When an area is impassable due to poor rights-of-way, or other conditions, notify the GTIM Field Supervisor as soon as practical.

5.1.11.1.1 Discuss and approve options for completing the survey in this area with the GTIM Field Supervisor.

5.1.12 Notify the GTIM Field Supervisor of any circumstances that prevent completion of the survey.

5.1.13 Enter all physical references into the data logger as comments.

5.1.13.1 Physical reference points include, but are not limited to:

- Test stations;
- Mainline valves;
- Aerial markers;
- Roads;
- Railroads;
- Streams;
- Ditches;
- Sidewalks; and
- Driveways.

5.1.13.2 At concrete and asphalt surfaces such as driveways and roads, add references to both edges of the pavement.

5.1.14 Enter all encroachments, and suspected encroachments, into the data logger as comments.

5.1.14.1 Encroachments may include, but are not limited to:

- Fence posts;
- Signposts;
- Buildings;
- Pools; and
- Foreign-pipelines.

5.1.14.2 Enter as much information about each encroachment into the survey comments as possible.

5.1.14.2.1 For foreign-pipelines, this includes the type of crossing and the name of the owner company, when known.

5.1.14.3 Provide notification to the Encroachment Program Manager per CNP's Encroachment Policy.

5.1.15 Record a GPS coordinate at each physical reference point and encroachment. Refer to procedure GTIM-04-043 “GPS Coordinates”.

5.1.15.1 This GPS coordinate requires the use of an external GPS unit in conjunction with the survey voltmeter in most cases.

5.1.16 Record GPS coordinates every 100 feet along the pipeline.

5.1.17 Record a GPS reference at all “abnormal conditions”, including exposed pipe spans and sinkholes. Include a description of the exposure in the survey comments.

5.1.17.1 Notify the GTIM Field Supervisor of any “abnormal conditions” on GTIM-90412.

5.1.17.2 Notify the GTIM Field Supervisor, as soon as practicable of any conditions that might pose a safety or environmental threat.

5.1.18 Measure and record the metallic IR drop by taking “on”/“off” Near-Ground and “on”/“off” Far-Ground readings at each test station.

5.1.18.1 With the survey wire still connected to the Far-Ground test station, record the “on”/“off” reading.

5.1.18.2 With the reference electrode in the same location, disconnect the test wire from the Far-Ground test station and connect the test wire to the Near-Ground test station.

5.1.18.2.1 Record the “on” / “off” reading.

5.1.18.3 With the positive terminal connected to the survey wire (connected at the Far-Ground test station) and the negative terminal connected to the Near-Ground test station, record the “on” / “off” reading.

5.1.18.3.1 This reading measures the metallic IR drop.

5.1.19 During a survey, the survey wire can occasionally break due to outside forces. In some instances, it is not practical to find the break and repair it.

5.1.19.1 In these cases, mark the location of the break and survey back to that point.

5.1.19.2 Indicate the location of the wire break in the survey comments.

5.1.19.3 In such a case, an “on” / “off” far ground reading may not be possible.

5.1.20 At the end of each survey day, clear the right-of-way of debris, including, but is not limited to:

- Survey wire;
- Road leads; and
- Duct tape.

5.1.21 At the end of the field survey, remove all current interrupters, and restore all bonds.

5.1.21.1 Upon removing each current interrupter, document the tap settings and output (voltage, current) at each rectifier.

5.1.21.2 Document information on GTIM-90404.

5.1.22 Remove all marking material after job completion, unless it is desirable to leave the marking material intact for relocating indications.

5.1.22.1 If performing additional surveys after the CIS (i.e., DCVG), keep the marking material in-place until the completion of the additional survey(s).

6.0 DATA QUALITY

6.1 Responsibility: Indirect Inspection Crew

6.1.1 Review the raw data/plots before the next survey day.

6.1.2 Determine if the data indicates discrepancies or suspect data.

6.1.2.1 Discrepancies may include, but are not limited to:

- Areas with poor reference electrode contact; and
- Rectifiers being out of synchronization.

6.1.2.2 As appropriate, resurvey the segment with suspect data.

6.1.2.2.1 If a resurvey is required, start the resurvey at the test station downstream from the suspect data and end at the test station upstream of the suspect data or a physical reference point.

6.1.3 If the data indicates that not all sources of current have been interrupted, identify the additional sources of current that require interruption.

6.1.3.1 Interrupt additional sources as applicable.

6.1.3.2 Resurvey the entire line segment.

6.1.3.3 Notify the GTIM Field Supervisor of any unidentifiable sources of current.

6.1.4 Compare the pipe-to-soil potentials.

6.1.4.1 At the end of the survey day, record the “on” / “off” pipe-to-soil readings at a test point within the survey segment using the survey equipment.

6.1.4.2 Before starting the survey the next day, verify and record the on/off readings at the same test point, with the reference electrode in the same location as in the above paragraph.

6.1.4.3 Calculate the IR drop difference (“on” vs. “off”) for the readings on each day and compare.

6.1.4.4 If the pipe-to-soil potential difference between the two (2) days is more than 20mV, investigate, and document sources of current change.

6.2 Responsibility: Indirect Survey Crew Leader or Subject Matter Expert (SME)

6.2.1 For each test station, when applicable, evaluate the measured metal IR to verify adequate interruption of Direct Current (DC). In general, a difference of 2% or less between the Near-Ground off and Far-Ground off readings is acceptable. Evaluate items such as:

- Proximity to rectifiers;
- Polarity;
- The resistance of pipeline between Far-Ground and Near-Ground points;
- The ratio of “on” and “off” values;
- Actual values of “on” and “off”; and
- Foreign lines.

6.2.2 If measured metal IR is not adequate, identify and address the cause, as applicable.

6.2.2.1 After addressing the issue, determine if a resurvey is required.

6.2.2.1.1 Perform another survey, if required.

6.2.2.2 If correcting the condition is not possible, discuss other options with the GTIM Field Supervisor.

7.0 DATA PRESENTATION

7.1 Responsibility: Indirect Inspection Crew

7.1.1 Present the final data in graphical format.

7.1.1.1 Confirm the x-axis of the plot has a maximum scale of 1" = 100'.

7.1.1.2 Confirm the y-axis of the plot has a maximum scale of 3/8" = 100mV.

7.1.1.3 Confirm consistency of the scale for the x- and y-axis throughout the survey project.

7.1.1.4 Develop data plots in color with a separate color used for the "on" and the "off" readings, when applicable.

7.1.1.5 Include the -850 mV criteria line on the plots.

7.1.1.6 Include comments on the plots in their approximate Indirect Survey Stationing location. Comments include, but are not limited to locations of:

- Skips;
- Encroachments;
- Foreign crossings; and
- Survey offsets.

7.1.1.7 Present the data in a downstream, increasing Indirect Survey Stationing format.

7.1.1.8 Indicate the direction of the survey on the plots.

7.1.2 Compile the raw data into a spreadsheet format such as Excel.

7.1.2.1 Correlate all data strings and represent each in an individual column with the appropriate heading.

7.1.2.2 Include the following data:

- Cumulative footage or Indirect Survey Stationing;
- "On" reading;
- "Off" reading;
- Remarks; and
- GPS coordinates.

7.1.2.3 Compile all data into a single spreadsheet.

7.1.2.4 Proofread all comments.

7.1.2.4.1 Clarify in the final data any abbreviations used in the field that may not be understood by others.

7.1.2.4.2 Provide a legend of abbreviations used in the survey comments.

7.1.3 Provide two (2) paper copies and one (1) electronic copy with all information to the GTIM Field Supervisor within 30 days of completing the survey or a previously agreed upon time frame. Information includes, but is not limited to:

- Data plots;
- Raw data in electronic format;
- Survey notes (if separate from other data sources);

- GTIM-90412 “Daily Progress Report Indirect Inspection Surveys”, for each day of the survey; and
- GTIM-90404 “Rectifier and Critical Bond Locations”.

7.2 Responsibility: GTIM Field Supervisor or designee

7.2.1 Confirm receipt of all survey data.

7.2.1.1 Complete the applicable portions of GTIM-90408 “ECDA - Indirect Inspection”.

7.2.1.2 Save to the appropriate IM file.

7.2.2 Approve final payment once all data is complete (per terms of the contract).

7.2.3 Provide data to responsible GTIM Engineer.

Note: When performing multiple surveys on the same line segment (i.e., CIS and DCVG), provide one (1) CD with the raw data for all surveys. Additionally, provide “stack” charts with all Indirect Survey data aligned. Refer to procedure GTIM-04-003 “ECDA Indirect Inspection” for more details.

7.3 Responsibility: GTIM Engineer or designee

7.3.1 Review the data per procedure GTIM-04-003 “ECDA Indirect Inspection”.

7.3.2 Retain the data, report(s), field notes, and other pertinent survey information in the IM file.

<<END>>

GTIM-04-021 Direct Current Voltage Gradient Survey (DCVG)

PURPOSE: To establish a standardized method for performing a Direct Current Voltage Gradient (DCVG) survey.

REFERENCES: NACE SP0502-2010, Section 4;

SECTIONS:

- General
- Survey Preparation
- Safety Considerations
- Equipment
- Equipment Set-up and Maintenance
- Performing the Survey
- Indication Sizing
- Data Presentation

1.0 GENERAL

1.1 DCVG applies to buried pipelines with an electrolytic cover.

1.1.1 DCVG may not be applicable for the following:

- Areas of frozen ground;
- Areas with “shielding”;
- Cased pipeline locations;
- Paved surfaces; or
- Areas with excessive cover.

1.1.2 DCVG may be used for paved surfaces with additional measures, such as drilling and coring holes, to achieve electrolyte access. Refer to procedure GTIM-04-031 “Drilling and Coring of Improved Surfaces”.

1.2 DCVG surveys evaluate coating conditions on buried pipelines.

1.2.1 DCVG works by measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

1.2.2 Voltage gradients arise as a result of electrical current pick-up and discharge at coating holiday locations.

1.2.3 A typical DCVG system consists of a current interrupter, an analog strap-on voltmeter, connection cables, and two probes with electrodes filled with water or a saturated copper sulfate solution.

1.2.3.1 A current interrupter interrupts current on an existing rectifier unit or a temporary CP system.

1.2.3.1.1 The cycling occurs at a rapid rate with the “on” period less than the “off” period. For example, such as 1/3 second on and 2/3 second off. This short cycle allows for a quick deflection measurement by the voltmeter.

1.2.3.2 Use a voltmeter to adjust the high input impedance, deflection measurement, and to display the data.

1.2.3.2.1 The instrument's needle deflects in both the positive and negative directions from the zero point; this assists in determining the direction the current is flowing in the soil.

2.0 SURVEY PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Prepare for the DCVG survey by performing the requirements of procedure GTIM-04-030 "Indirect Inspection Preparation".

2.1.1.1 Typically, preparations for the survey need to begin three (3) to six (6) months in advance.

2.1.2 Confirm personnel associated with the inspection are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual. Applicable covered tasks include:

- •Abnormal operating conditions;
- •Measuring pipe-to-soil readings;
- •Rectifier readings;
- •Rectifier maintenance; and
- •Pipeline locating.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Take appropriate safety precautions when performing indirect inspections.

3.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

3.1.3 Test for induced A/C at all test stations, rectifiers, and bonds before making connections.

3.1.4 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

3.1.5 Use caution when working around roads and railroads.

3.1.5.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.5.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, "Reflective Safety Vests".

3.1.6 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 EQUIPMENT

4.1 Responsibility: Indirect Inspection Crew

4.1.1 Use a voltmeter with the following specifications:

- High input impedance voltmeter (10MΩ or greater);

- The ability to deflect, in both the negative and positive direction, from the zero-point; and
  - An analog meter is preferred.
  - The use of a digital meter requires approval by the GTIM Field Supervisor.
- Deflections of less than 1mV are distinguishable.

4.1.2 Use current interrupters that have the following capabilities:

- GPS synchronized; and
- Programmable such that the rectifier remains “on” at night.

4.1.3 Use electrodes as recommended by the equipment manufacturer.

4.1.4 Use a sub-meter GPS unit.

5.0 EQUIPMENT SET-UP AND MAINTENANCE

5.1 Responsibility: Indirect Inspection Crew

5.1.1 Place a DCVG signal on the pipeline using an existing impressed current rectifier or a temporarily installed ground bed.

5.1.1.1 It may be necessary to increase the output of the rectifier to achieve the appropriate signal strength if using an existing rectifier.

Note: CIS should be performed before the DCVG survey if the DCVG survey requires changing the normal operating conditions of the Cathodic Protection (CP) system (i.e., increasing current at the rectifier).

5.1.1.1.1 Performing DCVG and CIS simultaneously requires achieving the minimum DCVG achieved signal strength without adding additional current. Refer to procedure GTIM-04-020 “Close-Interval Survey” for further information.

5.1.1.1.2 Record the tap settings and output (current and voltage) of the rectifier before installing the current interrupter and increasing the output.

5.1.1.1.3 Record readings on GTIM-90404 “Rectifier and Critical Bond Locations”.

5.1.2 Place the current interrupter in series with the current source.

5.1.2.1 Interrupt enough current to achieve minimum signal strength of 100 mV and maximum signal strength of 1500 mV at both test points.

5.1.2.1.1 If a 100mV shift is not achievable, contact the GTIM Field Supervisor for further actions. Further actions may include allowing the survey results or choosing a different survey tool.

5.1.2.1.2 It is not necessary to interrupt all sources of current.

5.1.3 Multiple rectifiers, temporary ground beds, or a combination of both may be required.

5.1.3.1 Document the use of temporarily installed ground beds on GTIM-90404. Information should include:

- Location;
- Type of current source; and

- Type of ground bed.

5.1.3.2 Sacrificial anode systems require a temporary ground bed.

5.1.3.2.1 Record the source (i.e., fence, culvert), GPS location, and current output of the temporary ground bed.

5.1.3.3 When utilizing multiple current sources, GPS-synchronize the current interrupters.

5.1.4 Set the interrupter(s) to a rapid cycle time.

5.1.4.1 A typical DCVG interruption cycle is 0.3 seconds “on” and 0.7 seconds “off”.

5.1.4.1.1 Other interruption cycles are acceptable, provided they are within acceptable ranges and parameters as specified by the equipment manufacturer or other industry practices.

5.1.4.2 Program the current interrupters such that the rectifiers are “on” during the night.

6.0 PERFORMING THE SURVEY

6.1 Responsibility: Indirect Inspection Crew

6.1.1 Complete GTIM-90412 “Daily Progress Report Indirect Inspection Surveys” daily.

6.1.1.1 Record the date, weather conditions, and temperature on the form.

6.1.2 Confirm completion of pipeline locating and marking per procedure GTIM-04-032 “Locating and Marking a Survey Segment” before commencing the DCVG.

6.1.3 When performing DCVG before the CIS, confirm no adjustments to the rectifier output, no installation of temporary ground beds, and use of the same interruption cycle as used for the CIS survey.

6.1.4 Before commencing the survey, check the DCVG signal strength at test points at both ends of the survey segment.

6.1.4.1 Document the DCVG signal strength (“on” minus the “off” pipe-to-soil reading) in the GPS data logger.

6.1.4.2 The signal strength should be at least 100 mV at both test points.

6.1.4.2.1 If a 100mV shift is not achievable, contact the GTIM Field Supervisor for further actions, such as allowing the survey results or choosing a different survey tool.

6.1.4.3 If shorted casings or anodes connected directly to the pipeline prevent obtaining adequate signal strength, discuss options for completing the survey with the GTIM Field Supervisor.

6.1.5 There are two (2) techniques for performing the survey, the Perpendicular technique, and the In-Line technique.

6.1.5.1 The perpendicular technique includes:

6.1.5.1.1 Place the left-hand cane over the centerline of the pipeline.

6.1.5.1.2 Place the right-hand cane perpendicular to the pipeline, at a distance of 4 to 5 feet from the left-hand cane.

6.1.5.1.3 Walk the length of the pipeline.

6.1.5.1.4 Maintain firm contact with the ground with both electrodes while observing the readings.

6.1.5.1.4.1 Outside of the voltage gradient field of a coating holiday, the voltage difference between the two electrodes should be close to zero.

6.1.5.1.4.2 The voltage difference between the two reference electrodes will increase in magnitude when approaching a coating holiday.

6.1.5.1.4.3 The voltage difference between the two electrodes will decrease in magnitude when passing the coating defect.

6.1.5.1.5 Locate the epicenter of the coating holiday, as described in section 6.1.6.

6.1.5.2 The In-Line technique includes:

6.1.5.2.1 Over the centerline of the pipe, place one electrode. Place a second electrode over the centerline of the pipe, about 3 to 6 feet in front of the first.

6.1.5.2.2 Observe the magnitude and polarity of the reading on the meter.

6.1.5.2.3 Maintain firm contact with the ground with both electrodes when observing the readings.

6.1.5.2.3.1 The magnitude of the readings will increase when approaching a coating holiday.

6.1.5.2.3.2 The readings will shift in polarity once past the holiday.

6.1.5.2.3.3 A zero deflection on the meter indicates the reference electrodes are straddling the defect (i.e., lie on the equipotential line of the gradient field for the defect).

6.1.6 Precisely locate the epicenter of the coating holiday.

6.1.6.1 Locate the defect as described above (i.e., the location of the maximum voltage reading).

6.1.6.2 Using a plastic marking disk, wooden stake, or other approved marking device, mark the epicenter of the coating holiday and document the GPS coordinates.

6.1.6.2.1 Make an effort to root the stake well into the ground such that it can be found several weeks after the end of the survey.

6.1.6.2.2 The plastic marking disk is the preferred method.

6.1.6.3 Record and save the GPS coordinates at the center of the coating holiday.

6.1.6.4 Record measurements to the coating holiday from at least two (2) fixed, visible, physical reference points to provide future site identification.

6.1.6.4.1 Three (3) measurements are preferred.

6.1.6.5 Once locating the center of the coating holiday, take a series of perpendicular readings towards remote earth, typically in the direction of the largest voltage measurement.

6.1.6.5.1 Field obstructions or other buried facilities may prevent movement in the direction of the largest voltage measurement.

6.1.6.6 There are two acceptable methods for determining OLRE (Over Line Remote Earth):

6.1.6.6.1 *Method 1*: Begin moving perpendicular to the pipe at 3- to 6-foot increments until the readings go to zero.

6.1.6.6.1.1 The line-to-remote-earth voltage is the sum of these perpendicular readings.

6.1.6.6.1.2 Document these readings.

6.1.6.6.2 *Method 2*: Place one electrode over the center of the pipeline.

6.1.6.6.2.1 Place the other electrode at the line-to-remote-earth.

6.1.6.6.2.2 Document this reading.

6.1.7 Record the voltage measurement obtained in Method 1 or Method 2 above in the equipment.

6.1.7.1 Using a permanent marker, write the voltage measurement and a unique identifier on the stake or marking device (i.e., Indirect Survey Stationing).

6.1.7.2 Indicate the unique identifier in the survey comments.

6.1.8 Until repaired, a large coating indication may mask smaller coating indications.

6.1.9 Record the pipe depth at each DCVG indication.

6.1.10 Record the soil resistivity per procedure GTIM-04-013 “Soil Resistivity with the Wenner 4-Pin Method” at each indication.

6.1.10.1 Readings at each indication may not be necessary when several DCVG indications are within proximity to each other.

6.1.10.2 Document readings on GTIM-90413 “Soil Resistivity Data Collection”.

6.1.11 Record the signal strength at each test point location.

6.1.11.1 Record the Indirect Survey Stationing, as indicated on the alignment sheets, for each test point location.

6.1.12 Paved areas less than 10 feet may be “skipped” and not surveyed across using the reference electrodes.

6.1.12.1 Drill additional holes, as needed, when the DCVG signal indicates a location within the skipped area. Refer to procedure GTIM-04-031.

6.1.13 For areas of pavement greater than ten (10) feet in length, drill holes in the pavement per procedure GTIM-04-031 to achieve electrolyte access.

6.1.13.1 Drill additional holes perpendicular to the line for a DCVG indication to obtain remote earth.

6.1.14 Conditions on the pipeline right-of-way may not allow measurements to be taken directly over the pipeline, in select circumstances. “Off-set” surveys may be performed for some of these circumstances.

6.1.14.1 DO NOT perform an off-set survey more than three (3) feet from the centerline of the pipeline, unless approved by the GTIM Field Supervisor.

6.1.14.2 Indicate the location of the beginning of the off-set and the type of obstruction in the survey comments.

6.1.14.2.1 Return to the centerline of the pipeline as soon as practical.

6.1.14.2.2 Note the location in the comments where readings resume over the centerline.

6.1.15 Continue surveying across shallow lakes, rivers, and other bodies of water.

6.1.15.1 If the Survey Crew Leader or GTIM Field Supervisor deems it unsafe to walk across the body of water, use an alternative survey technique.

6.1.15.2 Personal Protective Equipment (PPE) such as flotation vests may be required. Refer to the Corporate Safety Manual, section 4.37, “Working In/On or Near Water”.

6.1.15.3 Discuss options for surveying bodies of water that prohibit surveying on foot with the GTIM Field Supervisor.

6.1.15.3.1 Additional equipment may be necessary to perform the survey, such as watercraft.

6.1.16 Congested or impassable right-of-way conditions or other conditions, notify the GTIM Field Supervisor as soon as practical.

6.1.16.1.1 Discuss and approve options for completing the survey in this area with the GTIM Field Supervisor.

6.1.17 DCVG is not applicable in locations where the pipeline is extremely deep.

6.1.17.1 Discuss and approve options for completing the survey in this area with the GTIM Field Supervisor.

6.1.17.1.1 Options could include increasing current on the pipeline during the survey of this area.

6.1.18 At the end of the survey, restore all wires in the test station(s) to the original condition and place the test station cover/top back on the test station(s).

6.1.19 At the end of the field survey, remove all current interrupters and temporary ground beds.

6.1.19.1 Upon removing a current interrupter from an existing rectifier, return the rectifier to its original setting (if applicable), document the tap settings, and output (voltage, current) as left.

6.1.19.2 Document readings on GTIM-90404.

6.1.20 Upon completion of the survey, remove all marking material, unless it is desirable to leave the marking material intact for relocating indications.

6.1.20.1 If performing additional surveys after the DCVG (i.e., ACVG), keep the marking material in-place until the completion of the additional survey(s).

7.0 INDICATION SIZING

7.1 Responsibility: Indirect Inspection Crew

7.1.1 Calculate the location-specific signal strength for locations other than test stations (where the signal strength can be directly measured) with the following equation:

$$Signal\ Strength_{(x)} = A - \left({ABS(A-B)}/{D} \right) \times \left(footage_{(xA)} \right)$$

or

$$Signal\ Strength_{(x)} = B + \left({ABS(A-B)}/{D} \right) \times \left(footage_{(xB)} \right)$$

where:

x = Location of coating indication
A = The signal strength of test point 1 (upstream from indication)
B = The signal strength of test point 2 (downstream from indication)
D = Distance between test point 1 and test point 2
$footage_{(xA)}$ = Distance from test point 1
$footage_{(xB)}$ = Distance from test point 2
ABS = Absolute Value

7.1.2 Verify the signal strength calculation.

7.1.2.1 If the calculated signal strength is greater than the highest signal strength of test point 1 or 2, or lower than the lowest signal strength of test point 1 or 2, the calculation was incorrect.

7.1.3 Estimate the size and severity of each coating holiday by determining the potential voltage lost from the epicenter of the holiday to remote earth upon completion of the survey.

$$\%IR = {}^{Line\ To\ Remote\ Earth\ voltage}\!\Big/_{Signal\ Strength(x)} \times 100$$

Note: These calculations may be performed by the survey software, depending upon the type of survey meter and survey software used.

7.1.3.1 The %IR is the potential voltage lost from the holiday epicenter to remote earth divided by the total potential shift on the pipeline.

8.0 DATA PRESENTATION

8.1 Responsibility: Indirect Inspection Crew

8.1.1 If not calculated by survey software, determine the corrosion state of the coating indication by comparing the polarity of current flow with the rectifier on and with the rectifier off as indicated below:

- Cathodic/Cathodic: Denotes holidays that are protected while the CP system is on and remain polarized when the CP is interrupted or off;
  - Polarity in readings indicates the current flowing to the pipe with the cathodic protection system both on and off.
- Cathodic/Neutral: Holidays appear to be protected when the CP system is on, but return to a negative state while the CP is interrupted;
  - Polarity in readings indicates the current flowing to the pipe with the cathodic protection system on; no current flow with the cathodic protection system off.
- Cathodic/Anodic: Denotes holidays that appear to be protected while the CP system is on and appear anodic when the CP is interrupted; and
  - Polarity in readings indicates the current flowing to the pipe with the cathodic protection system on; current flowing away from the pipe with the cathodic protection system off.
- Anodic/Anodic: Holidays receive no protection regardless of whether the CP system is on or off;
  - Polarity in readings indicates the current flowing away from a cathodically protected pipe both on and off.

8.1.1.1 Document the classification for each indication.

8.1.2 Provide the final data in spreadsheet format.

8.1.2.1 Correlate all data strings and represent each in an individual column with the appropriate heading.

8.1.2.2 Provide data for each coating indication, including GPS coordinates, Indirect Survey Stationing, %IR, corrosion state, Signal Strength, and any comments.

8.1.3 If performed with other indirect inspections, provide “stack charts” with the results from all indirect inspection surveys aligned.

8.1.4 Provide two (2) paper copies and one (1) electronic copy with all information to the GTIM Field Supervisor within 30 days of completing the survey or a previously agreed upon time frame. Information includes, but is not limited to:

- Data Plots;
- Raw data in electronic format;
- GTIM-90412 “Daily Progress Report Indirect Inspection Surveys”, for each day;
- GTIM-90404 “Rectifier and Critical Bond Locations”; and
- GTIM-90413 “Soil Resistivity Data Collection”.

8.2 Responsibility: GTIM Field Supervisor or designee

8.2.1 Review data to confirm receipt of all data.

8.2.1.1 Complete the applicable portions of GTIM-90408 “ECDA - Indirect Inspection”.

8.2.1.2 Save to appropriate IM file.

8.2.2 Approve final payment once all data is complete per the terms of the contract.

8.2.3 Provide data to responsible GTIM Engineer.

8.3 Responsibility: GTIM Engineer or designee

8.3.1 Review data per procedure GTIM-04-003 “ECDA - Indirect Inspection”.

8.3.2 Retain the data, report, field notes, and other pertinent survey information in the IM file.

<<END>>

GTIM-04-022 Current Attenuation Survey

PURPOSE: To establish a standardized method for performing a Current Attenuation Survey using the Pipeline Current Mapper (PCM).

REFERENCES: NACE SP0502-2010, Section 4;

SECTIONS:
- General
- Survey Preparation
- Safety Considerations
- Equipment
- Process for Current Mapper Magnetometer Foot
- Obtaining Depth Measurements
- Obtaining Current Measurements
- Data Presentation

1.0 GENERAL

1.1 Current Mapping Theory - A flowing electrical current on a buried conductive structure produces a magnetic field directly proportional to the magnitude of the applied current.

1.1.1 The PCM transmitter applies a current to the pipeline.

1.1.2 The current reduces in strength as the distance from the transmitter increases.

1.1.3 The rate of reduction depends on the condition of the pipe coating, ground resistivity, and the electrical resistance of the pipe.

1.1.4 The Pipeline Current Mapper can obtain readings over concrete and asphalt, unlike other indirect inspection methods.

2.0 SURVEY PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Prepare for the Current Attenuation Survey utilizing GTIM-04-030 “Indirect Inspection Survey Field Preparation”.

2.1.1.1 Typically, preparations need to begin three (3) to six (6) months in advance of the survey.

2.1.2 Confirm personnel associated with the inspection are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual.

2.1.2.1 Applicable covered tasks include:

- Abnormal operating conditions;
- Rectifier readings;
- Rectifier maintenance; and
- Pipeline locating.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Take appropriate safety precautions when performing indirect inspections.

3.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

3.1.3 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

3.1.4 Use caution when working around roads and railroads.

3.1.4.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.4.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6 “Reflective Safety Vests”.

3.1.5 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 EQUIPMENT

4.1 Responsibility: Indirect Inspection Crew

4.1.1 Use the following equipment to perform the survey:

- PCM Transmitter;
- PCM Receiver; and
- PCM Magnetometer Foot (mag-foot).

5.0 PROCESS FOR CURRENT MAPPER MAGNETOMETER FOOT

Note: Refer to the “Pipeline Current Mapper (PCM+) User Guide” by Radiodetection® for specific details on how to use the PCM+ equipment.

5.1 Responsibility: Indirect Inspection Crew

5.1.1 Complete a GTIM-90412 “Daily Progress Report Indirect Inspection Surveys” each day.

5.1.2 The PCM transmitter requires an AC power source, a ground, and a pipe connection.

5.1.3 Set-up the PCM Transmitter as follows:

5.1.3.1 Connect the transmitter to an appropriate ground location, as indicated in manufacturer literature.

5.1.3.2 Connect the transmitter two (2) output leads:

5.1.3.2.1 Connect the white lead to the pipe test lead.

5.1.3.2.2 Connect the green lead to the ground.

5.1.3.3 Turn off the device, set the output level to the lowest setting (100mA), and set the frequency to ELF Locate Frequency with Current Direction.

5.1.3.4 Turn on the transmitter.

5.1.3.5 Adjust the output level until achieving the maximum output.

5.1.4 Pipeline depth measurements are possible in all of the location frequencies except the 50/60Hz power frequency.

5.1.5 Current measurements are possible in the ELF, LF, and 8 kHz frequencies.

5.1.6 When the PCM magnetometer foot (mag-foot) is attached to the PCM, confirm that the PCM mag-foot arrow is pointing along the direction of the pipeline centerline.

5.1.7 Confirm the mag-foot is parallel to the pipeline.

5.1.7.1 Keep the receiver at a 90° angle to avoid incorrect depth measurements.

5.1.7.2 The attachment allows a certain degree of adjustment to help maintain this position on a slope.

5.1.8 Avoid taking PCM measurements over "T" junctions, bends, and pipeline depth changes. These locations tend to distort the readings.

5.1.9 Peak Mode is the preferred mode for locating.

6.0 OBTAINING DEPTH MEASUREMENTS

6.1 Responsibility: Indirect Inspection Crew

6.1.1 Confirm the mag-foot is attached to the receiver.

6.1.2 Position the PCM receiver directly above the pipeline.

6.1.2.1 Place the receiver blade vertical to the pipeline.

6.1.3 Take depth readings per the manufacturer's literature.

6.1.3.1 The PCM displays the distance, in inches, between the bottom of the unit and the centerline of the pipe.

6.1.4 Capture data into the memory of the PCM unit.

6.1.4.1 Record the readings in a field notebook or as a comment in GPS location data.

7.0 OBTAINING CURRENT MEASUREMENTS

7.1 Responsibility: Indirect Inspection Crew

7.1.1 Take and record current measurements as specified in the project scope.

7.1.2 Confirm the mag-foot is attached to the receiver.

7.1.3 Position the unit directly over the pipeline.

7.1.3.1 Position the receiver blade vertical to the pipeline.

7.1.4 Take readings according to the manufacturer's literature.

7.1.5 Retake any readings that appear to be erroneous.

7.1.5.1 Receiver movement or nearby vehicles can cause erroneous readings.

7.1.6 Capture data into the memory of the PCM unit.

7.1.6.1 Record the readings in a field notebook or similar.

7.1.7 Record a GPS coordinate to correspond with each current measurement.

7.1.7.1 Record GPS coordinates at all significant physical features such as test stations, roads, streams, and railroads.

7.1.7.2 Obtain sub-meter accuracy for all GPS coordinates.

8.0 DATA PRESENTATION

8.1 Responsibility: Indirect Inspection Crew

8.1.1 Plot the data in graphical format upon completion of the survey.

8.1.2 Review the areas of significant current loss on the plots.

8.1.3 Calculate the percentage (%) of current loss (dBmA) per unit length at these locations.

8.1.4 Compile the data into an Excel spreadsheet.

8.1.4.1 Correlate all data strings and represent each in an individual column.

8.1.4.2 Include GPS coordinates, indirect survey stationing, current, defect classification, and comments in the spreadsheet.

8.1.5 Provide two (2) paper copies and one (1) electronic copy with all information to the GTIM Field Supervisor within 30 days of completing the survey or a previously agreed upon time frame. Information includes, but is not limited to:

- Data plots;
- Raw data in electronic format; and
- GTIM-90412 “Daily Progress Report Indirect Inspection Surveys”.

Note: When performing multiple methods of inspections (i.e., CIS and Current Attenuation) on a line segment, provide one (1) CD with the raw data for all surveys and “stack” charts with all indirect inspection surveys aligned. Refer to GTIM-04-003 “ECDA Indirect Inspection” for further details.

8.2 Responsibility: GTIM Field Supervisor or designee

8.2.1 Confirm receipt of all data and review.

8.2.1.1 Upon data confirmation, approve the final payment to the Service Provider(s) per the terms of the contract(s).

8.2.2 Complete the applicable portions of GTIM-90408 “ECDA - Indirect Inspection”.

8.2.2.1 Save to the appropriate IM file.

8.2.3 Provide data to responsible GTIM Engineer.

8.3 Responsibility: GTIM Engineer or designee

8.3.1 Review data per procedure GTIM-04-003 “ECDA Indirect Inspection”.

8.3.2 Retain the data, report, field notes, and other pertinent survey information in the IM file.

<<END>>

GTIM-04-023 Alternating Current Voltage Gradient Survey

PURPOSE: To establish a standardized method for performing an Alternating Current Voltage Gradient (ACVG) Survey using the Pipeline Current Mapper (PCM) with the A-Frame accessory.

REFERENCES: NACE SP0502-2010, Section 4;

SECTIONS:

- General
- Survey Preparation
- Safety Considerations
- Equipment
- Process for ACVG
- Data Presentation

1.0 GENERAL

1.1 ACVG applies to buried pipelines with an electrolytic cover.

1.1.1 ACVG is not applicable for the following:

- Areas of frozen ground;
- Areas with “shielding”;
- Cased pipeline locations; or
- Paved surfaces.

1.2 ACVG surveys evaluate the coating conditions on a buried pipeline.

2.0 SURVEY PREPARATION

2.1 **Responsibility:** GTIM Field Supervisor or designee

2.1.1 Prepare for the ACVG Survey utilizing GTIM-04-030 “Indirect Inspection Survey Field Preparation”.

2.1.1.1 Typically, preparations for the survey need to begin three (3) to six (6) months in advance.

2.1.2 Confirm personnel associated with the inspection are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual. Applicable covered tasks include

- Abnormal operating conditions;
- Rectifier readings;
- Rectifier maintenance; and
- Pipeline locating.

2.1.3 Disconnect galvanic anodes from the pipeline to prevent current loss and boost the current flow down the pipeline, when possible.

2.1.3.1 Confirm reconnection of the galvanic anodes upon survey(s) completion.

2.1.4 Disconnect any bonds with foreign-pipelines.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Take appropriate safety precautions when performing indirect inspections.

3.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

3.1.3 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

3.1.4 Use caution when working around roads and railroads.

3.1.4.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.4.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6 “Reflective Safety Vests”.

3.1.5 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 EQUIPMENT

4.1 Responsibility: Indirect Inspection Crew

4.1.1 Use the following equipment to perform the survey:

- PCM Transmitter;
- PCM Receiver;
- PCM A-Frame accessory; and
- PCM Mag-foot (optional).

5.0 PROCESS FOR ACVG

Note: Refer to the “Pipeline Current Mapper (PCM+) User Guide” by Radiodetection® for specific details on how to use the PCM+ equipment.

5.1 Responsibility: Indirect Inspection Crew

5.1.1 Complete GTIM-90412 “Daily Progress Report Indirect Inspection Surveys” daily.

5.1.2 Connect the Pipeline Current Mapper (PCM) transmitter to an appropriate ground as recommended in manufacturer literature.

5.1.2.1 Follow manufacturer literature for setting up the unit.

5.1.3 PCM indication readings do not require a connection to the PCM mag-foot (boot) receiver.

5.1.4 When taking readings for the ACVG survey, a connection to the A-Frame accessory is required.

5.1.5 If the A-Frame probes maintain constant ground contact, taking readings in various soil conditions is allowed.

Note: Make sure there is good ground contact between the probes and the ground. When surveying over concrete, pour water on the road or use wet sponges to improve the results. Do not perform the survey over asphalt without first drilling or coring holes in the pavement to provide access to the native soil beneath.

5.1.6 Locate the pipeline, position the A-Frame above, and parallel to the pipeline.

5.1.6.1 The A-Frame does not need to be directly over the pipeline but within three (3) feet of the pipeline centerline.

5.1.6.2 Push the A-Frame spikes into the ground to take a reading.

5.1.6.2.1 Keep the spike marked green away from the transmitter connection point.

5.1.6.2.2 Verify the spike marked red points towards the transmitter.

5.1.6.2.3 Confirm the A-Frame spikes have good contact with the ground.

5.1.6.2.3.1 Damp conductive earth provides better results. Dampen the earth with water if needed to obtain a good contact.

5.1.6.3 Locate indications per the manufacturer’s literature.

5.1.7 Move farther along the pipeline at three (3) to five (5) foot intervals and continue to make ground contact with the A-Frame spikes.

5.1.7.1 If a new position gives forward indicating arrows and the next position yields backward indicating arrows, then the operator has walked over an indication.

5.1.7.2 Retest the areas by making small movements forward and backward until narrowing in on the position with the lowest dB reading and where the arrows change in direction.

5.1.7.2.1 Positions with the lowest dB readings confirm a coating indication is under the center of the A-Frame.

5.1.7.2.2 Mark this point with a stake or other marking device or paint and record a GPS reference.

5.1.7.3 Continue with locating all coating indications.

5.1.7.3.1 Until repaired, a large coating indication may mask smaller coating indications.

5.1.8 Determine the severity of each indication.

5.1.8.1 Place the A-Frame at 90 degrees to the pipeline, place one of the spikes directly over the pipeline, and the other spike away from the pipeline to take readings.

5.1.8.1.1 Start approximately three (3) feet from the coating indication location.

5.1.8.2 Continue moving the A-Frame toward the coating indication at ten (10) inch or smaller intervals.

5.1.8.3 Save the highest dBµV reading obtained into the memory of the PCM unit.

5.1.8.3.1 Use this value to determine the severity of the indication.

5.1.9 Capture data into the memory of the PCM unit and display in the information using the PCM upload software.

5.1.9.1 Record a GPS coordinate to correspond with each indication.

5.1.9.2 Record a depth of pipe measurement at each indication.

5.1.10 Record a soil resistivity reading at each indication.

5.1.10.1 Document the reading on GTIM-90413 “Soil Resistivity Data Collection”.

5.1.11 Record GPS coordinates at all significant physical features such as test stations, roads, streams, and railroads.

5.1.11.1 Obtain sub-meter accuracy for all GPS coordinates.

6.0 DATA PRESENTATION

6.1 Responsibility: Indirect Inspection Crew

6.1.1 Provide final data in a spreadsheet format. Also, provide an electronic copy of the raw data.

6.1.1.1 Correlate all data strings. Represent each in an individual column with the appropriate heading.

6.1.1.2 Include GPS coordinates of coating indications, dBμV readings for each coating indication, and comments on the spreadsheet.

6.1.1.3 Provide two (2) paper copies and one (1) CD with all information to the GTIM Field Supervisor. Information includes, but is not limited to:

- Data plots;
- Raw data in electronic format;
- GTIM-90412 “Daily Progress Report Indirect Inspection Surveys”; and
- GTIM-90413 “Soil Resistivity Data Collection”.

Note: When performing multiple methods of inspections (i.e., CIS and DCVG) on a line segment, provide one (1) CD with the raw data for all surveys and “stack” charts with all indirect inspection surveys aligned. Refer to GTIM-04-003 “ECDA Indirect Inspection” for further details.

6.2 Responsibility: GTIM Field Supervisor or designee

6.2.1 Confirm receipt of data.

6.2.1.1 Upon data confirmation, approve the final payment to the Service Provider(s) per the terms of the contract(s).

6.2.2 Complete the applicable portions of GTIM-90408 “ECDA - Indirect Inspection”.

6.2.2.1 Save GTIM-90408 to the appropriate IM file.

6.2.3 Provide data to responsible GTIM Engineer.

6.3 Responsibility: GTIM Engineer or designee

6.3.1 Review data per procedure GTIM-04-003 “ECDA Indirect Inspection”.

6.3.2 Retain the data, report, field notes, and other pertinent survey information in the IM file.

<<END>>

GTIM-04-024 Documentation of Coating and Corrosion Defects

PURPOSE: To establish a standardized method for documenting coating and corrosion defects.
REFERENCES: NACE SP0502-2010, Section 5;
SECTIONS:
- Pipe Preparation
- Measuring and Mapping Defects

1.0 PIPE PREPARATION

1.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

1.1.1 Upon discovery of coating defects, map the coating defects as described in section 2.0, "Measuring and Mapping Defects" before preparing the pipe surface.

Note: Do not pick or scrape at the crumbling metal or corrosion product as a leak could occur. The corrosion may have jeopardized the integrity of the pipe wall.

1.1.2 Clean away any corrosion material present with a clean, dry, stiff brush, such as a nylon-bristle brush.

1.1.2.1 If any of the deposit remains, use a brass bristle brush in the longitudinal direction only.

1.1.3 When possible, dry the area with an air blast or an alcohol swab (or similar).

1.1.3.1 A shiny, metallic surface under the deposit and around the pit suggests the possibility of active corrosion.

2.0 MEASURING AND MAPPING DEFECTS

2.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

2.1.1 Indicate the overall location of defects on GTIM-90418-C "Pipeline Inspection Direct Examination".

2.1.1.1 Indicate all defects and their approximate location on the pipe diagram.

2.1.1.1.1 Explicitly differentiate coating, corrosion, and mechanical defects.

2.1.1.1.2 Attach additional pages if necessary.

2.1.1.1.3 If using digital photos, insert the photo into the document and include detailed labels.

2.1.2 Provide a detailed mapping of coating defects and corrosion pitting on the grid provided on GTIM-90418-D.

2.1.2.1 Consider mapping the coating defects on a separate grid from corrosion defects.

2.1.2.1.1 Attach additional pages if necessary.

2.1.2.1.2 If using digital photos, insert the photo into the document and include detailed labels.

2.1.3 Map out defect(s) noting circumferential and axial orientation.

2.1.3.1 Take measurements parallel to the long seam and girth weld if possible.

2.1.4 Using a grid system, document the defect(s) on GTIM-90418-D.

2.1.4.1 Use a grid system with a minimum spacing of 1/4 inch and maximum spacing of one (1) inch.

2.1.4.2 Take ultrasonic thickness measurements in each grid square where applicable.

2.1.4.3 Measure the defect(s) axially from a known station point.

2.1.4.4 On the grid, the y-axis is the o'clock position, and the x-axis is the axial length going downstream in feet.

2.1.4.5 Indicate the direction of North.

2.1.4.6 Use additional diagrams as needed.

2.1.5 As an alternative, use other tools capable of determining the wall thickness. Examples may include laser profile mapping or UT mapping.

2.1.5.1 Obtain the approval of the GTIM Field Supervisor before use.

2.1.6 Take depth, length, and width measurements of corrosion pitting using a Pit Gauge. A digital or analog pit gauge is preferred.

2.1.6.1 Take depth measurements per manufacturer's specifications.

2.1.6.2 Provide as much detail as possible concerning length, width, shape, and depth if applicable.

2.1.6.2.1 Measure and record the deepest pit in each square with metal loss.

2.1.6.3 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 "Predictive Failure Pressure".

2.1.6.4 Take a sufficient number of depth measurements to facilitate performing RSTRENG. Refer to GTIM-05-003 "RSTRENG" for further details.

2.1.6.5 When multiple pits are present, measure and record both the longitudinal and axial distance between pits.

2.1.6.5.1 Provide as much detail as possible concerning length, width, shape, and depth.

2.1.6.6 Document each reading and map the defect on GTIM-90418-D.

2.1.6.6.1 Sketch the shape of the defect(s) as close a replica to the actual defect as possible.

2.1.6.6.2 As an alternative, provide an etching of the corrosion defect(s). Provide appropriate labels.

2.1.6.7 Photograph the defect(s) with the Pit Gauge or a ruler in the picture for reference.

<<END>>

GTIM-04-026 Dig Plan Preparation

PURPOSE: To establish a standardized method for developing Direct Examination dig plans.
REFERENCES: (no specific references)
SECTIONS:
- General
- Dig Plan Cover Sheet
- Excavation Scope of Work
- Location Maps
- Environmental Compliance
- Other Permits
- Dig Plan Packet

1.0 GENERAL

1.1 Prepare a Dig Plan packet for each line segment.

1.2 The Dig Plan packet should include all direct exams being performed on the line segment, regardless of the assessment method (i.e., ECDA, ICDA, casings, and ILI).

2.0 DIG PLAN COVER SHEET

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Prepare GTIM-90441 “Dig Plan Summary” for each line segment at direct examination locations.

2.1.1.1 Provide the name and contact information for the GTIM Engineer, as well as a backup GTIM Engineer.

2.1.1.2 Provide a summary of all required digs for the line segment.

2.1.1.3 Work with Gas Control to determine the nearest isolation point (i.e., valve) upstream and downstream for each dig location.

3.0 EXCAVATION SCOPE OF WORK

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Review the following:

- GTIM-90440 “Direct Examination Scope of Work”;
- GTIM-90458 “ICDA - Direct Examination”;
- Other appropriate documentation to determine required dig locations, as applicable;

3.1.2 Include in the Dig Plan packet, a separate GTIM-90440 form for each direct examination location.

3.1.3 For the Dig Plan, digs should be numbered consecutively along the pipe segment, in the same direction as the ILI tool run or indirect survey.

3.1.3.1 Assign each anomaly or indication a unique integer only identifier (i.e., 1; 2; 3; etc.).

3.1.3.2 As applicable, translate each dig location to "Overall Dig Plan ID #" on GTIM-90440 or GTIM-90458.

3.1.4 Complete a GTIM-90440 "Direct Examination Scope of Work" for each direct examination location.

3.1.5 Document the purpose for each dig (i.e., ECDA, ICDA, casings, unknown pipe, ILI) on GTIM-90440.

3.1.5.1 More than one assessment method may apply.

3.1.6 Document any additional testing. Additional testing may include, but is not limited to:

- Magnetic particle testing; and
- OES testing.

4.0 LOCATION MAPS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Prepare a one (1) page, overall-map showing all dig locations for the line segment.

4.1.1.1 Include text box with a leader to each location indicating the Overall Dig ID #.

4.1.1.2 Provide an 8.5" x11" color map or an 11"x17" color map if additional detail is required.

4.1.2 Prepare an individual map showing the location of each examination location.

4.1.2.1 Use GIS or equivalent to prepare the maps. Include the following:

- Aerial photograph background;
- Aerial vintage;
- North indicator;
- Preparer's name; and
- Date prepared.

4.1.2.2 Include one (1) location per map.

4.1.2.2.1 Do not put multiple digs on the same map unless they are close. If multiple digs are on the same map, confirm there is sufficient detail to show the dig location.

4.1.2.3 Include the following information on the map:

- Distribution piping (within the immediate area of dig location);
- Inspection beginning and ending points, including descriptions;
- ECDA region beginning and ending points, including descriptions, if in the vicinity;
- Waterways and water boundaries;
- Names of streets;
- Valves;
- Three (3) to four (4) joint lengths around dig site; and
- Adjacent features and assets to the dig site.

4.1.2.4 For ICDA-excavation locations include a map showing the pipeline elevation.

4.1.2.5 Provide 8.5" x 11" or 11" x 17" color maps, if additional detail is required.

5.0 ENVIRONMENTAL COMPLIANCE

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Provide the list of dig locations to Environmental Affairs.

5.1.2 Reference the CNP Environmental Affairs - Road Cut Soil Disposal Protocol when preparing the Dig Plan.

5.1.3 If necessary, complete GTIM-90427 “Acreage Calculation” and GTIM-90427 “Bell Hole Estimator” to determine if an acreage permit is required.

5.1.3.1 Alternatively, an approved third-party service provider may supply this information.

5.1.3.2 If the total acreage is more than one (1) acre, a permit may be required depending on the jurisdictional governmental agency.

5.2 Responsibility: Environmental Affairs

5.2.1 Review the dig locations for, but not limited to, the following:

- Erosion control;
- Wetlands; and
- Sensitive areas.

5.2.2 Complete and return the environmental assessment to the GTIM Engineer.

5.2.3 Obtain any required environmental-related permits or plans.

5.2.4 Provide required environmental-related permits or plans to the GTIM Engineer. Information may include, but is not limited to:

- Stormwater Pollution Prevention Plan (SWPPP);
- Floodway permits; and
- Wetland and stream permits.

6.0 OTHER PERMITS

6.1 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

6.1.1 Work with appropriate governmental agencies to obtain the required permits.

6.1.2 Provide appropriate governmental agencies with pertinent excavation information. Information includes:

- Location description;
- GIS or equivalent map indicating the proposed location;
- Standardized excavation sketch or description; and
- Bond or Certificate of Insurance, if required.

Note: Some permits (e.g., Corps of Engineers, stream crossings, river crossings, and railroads) may take three (3) to six (6) months or longer to obtain – plan accordingly.

6.2 Responsibility: GTIM Engineer or designee

6.2.1 Include copies of the required permits in the Dig Plan packet.

6.2.1.1 For permits received after issuing the Dig Plan packet, provide copies to the GTIM Field Supervisor as soon as practical.

7.0 DIG PLAN PACKET

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Obtain the list of current landowners as provided by the Land Department.

7.1.1.1 For In-Line Inspection projects, landowner identification occurs during the AGM location determination.

7.1.2 Review overall dig plan with GTIM Field Supervisor.

7.1.3 Prepare the Dig Plan packet. Confirm the packet contains the following information:

- GTIM-90441 “Dig Plan Summary”;
- GTIM-90440 “Direct Examination Scope of Work” for each direct examination location;
- Overall map;
- Site-specific map for each location;
- List of current landowners;
- GTIM-90427 “Acreage Calculation” and GTIM-90427 “Bell Hole Estimator”, if applicable;
- Permits;
- Erosion Control Plan/Analysis, if required;
- Wetlands analysis, if applicable;
- GTIM-90458 “ICDA - Direct Examination”, if applicable;
- Indirect inspection data for and adjacent to each examination location, if applicable; and
- ILI data for and adjacent to each examination location, if applicable.

7.1.4 Provide the completed Dig Plan packet to the GTIM Manager.

7.1.5 Conduct Dig Plan approval meeting with GTIM Manager to obtain approval.

7.1.5.1 Include the GTIM Field Supervisor in the meeting.

7.2 Responsibility: GTIM Manager or designee

7.2.1 Review the Dig Plan packet.

7.2.2 Request clarification as necessary.

7.2.3 Sign the GTIM-90441 and the Dig Plan report.

7.3 Responsibility: GTIM Engineer or designee

7.3.1 Retain the original, approved Dig Plan packet in the IM file.

7.3.2 Provide copies of the approved and signed Dig Plan packet to the GTIM Field Supervisor once completed.

7.3.2.1 Consult with the GTIM Field Supervisor to determine the number of copies required.

7.3.3 Provide the Overall Dig Plan ID # and other pertinent information to the GTIM Field Supervisor.

7.3.4 Additional digs may be required based upon results found in the field.

<<END>>

GTIM-04-027 Direct Examination Preparation

PURPOSE: To provide a standard method for preparing for direct examinations.
REFERENCES: (no specific references)
SECTIONS:
- General
- Excavation Preparation

1.0 GENERAL

1.1 Under the original Transmission Integrity Management regulations published in 2002, excavation and in-situ examinations typically occurred at the most severe indications identified during the indirect inspection phase of an assessment.

1.2 With the implementation of the new 49 CFR Part 192 regulations in 2020, the number of Direct Examinations will likely increase based on the requirements of §192.607 "Verification of Pipeline Material Properties and Attributes", §192.624 "Maximum Allowable Operating Pressure Reconfirmation", and §192.712 "Analysis of Predicted Failure Pressure".

2.0 EXCAVATION PREPARATION

2.1 **Responsibility:** GTIM Field Supervisor or designee

2.1.1 Review the locations specified for direct examination in the Dig Plan Packet.

2.1.2 Identify restricted access areas that may require site-specific training or requirements.

2.1.3 Schedule any field-related activities around seasonal conditions, as applicable.

2.1.4 Confirm arrangements for each direct examination, including, but is not limited to:

- Applying for and obtaining permits;
  - Railroads;
  - Corps of Engineers;
  - City;
  - County;
  - State;
  - Department of Natural Resources; and
  - Highways and roads.
- Providing notification to landowners and making any necessary arrangements;
- Work with the Land Services department to assist with any ROW issues;
- Making arrangements for traffic control and safety equipment; and
- Engage excavation and inspection service providers.

Note: Be mindful that some permitting agencies may require several months to obtain permits.

2.1.5 Provide notification to landowners as far in advance as possible. Consider one of the following options for notification:

- Send a letter to the landowner.
- Have a representative visit the site to discuss excavation work with the property owner.
- Notify the landowner by phone.

2.1.6 Refer to the GTIM-90440 “Direct Examination Scope of Work” for additional testing that may be required, such as magnetic particle testing or shear wave testing.

2.1.7 Confirm completion of locating and marking before commencing work.

2.1.8 Review the Corporate Safety Manual to confirm excavations meet the requirements of OSHA and CNP.

2.2 Responsibility: Direct Examination Service Provider

2.2.1 Provide qualifications of personnel performing Direct Examinations to the GTIM Field Supervisor before commencing work.

2.3 Responsibility: GTIM Field Supervisor or designee

2.3.1 Notify the Local Operations of pending work.

2.3.1.1 Discussion items may include:

- Schedule for digs;
- Names of Service Provider personnel performing excavations;
- Discussion of Dig Plan;
- Local knowledge of dig location;
  - Inactive and active services;
  - Local fill material (i.e., rock, sand);
  - Local waste disposal sites;
  - Utilities not participating in One-Call;
  - Special considerations (i.e., specific contact person, approved disposal sites);
  - Previous work and repairs in the dig area;
  - Special equipment requirements;
- Contact information
  - Single point of contact for Local Operations;
  - Integrity Management personnel (i.e., GTIM Engineer, GTIM Field Supervisor);
- Availability of anticipated repair material;
  - Landscaping service providers;
  - Pavement restoration Service Providers;
- Landowners;
  - Easement and landowner agreements;
  - Notifications; and
- Excavation safety.

2.4 Responsibility: GTIM Field Inspector or designee

2.4.1 Mark the excavation location as per O&M 9.31 “Damage Prevention/Locating Procedures” or CNP O&M XV “Damage Prevention”.

2.4.2 Confirm that the Excavation Service Provider has notified One-Call and non-participating utilities.

2.4.3 Confirm completion of all required arrangements for the appropriate road closures and traffic control.

2.5 Responsibility: GTIM Field Supervisor or designee

2.5.1 Review Service Provider’s personnel qualifications and confirm the Direct Examination Crew is qualified to perform the direct examination.

2.5.1.1 Review the specific GTIM procedure for the type of direct examination to verify the qualification requirements.

2.5.1.1.1 Postpone the examination or arrange for other resources when the Direct Examination Crew is not qualified.

2.5.1.2 Dismiss the Direct Examination Crew if necessary.

2.5.2 Enter the names and titles of the Direct Examination personnel provided in the “Quality Assurance” section of GTIM-90441 “Dig Plan Summary”.

<<END>>

GTIM-04-028 100% Direct Examination for Station Assessments

PURPOSE: To provide a standard method for station assessments when performing a 100% direct examination in conjunction with the ECDA process.

REFERENCES: 49 CFR 192.919; NACE SP0502-2010;

SECTIONS:
- General
- Performing the Assessment
- Documentation

1.0 GENERAL

1.1 When performing an External Corrosion Direct Assessment, utilize a 100% direct examination for ECDA regions containing above-grade pipe.

1.1.1 Typically, regions are defined so that the entirety of the region consists of above-grade pipe.

1.1.2 Completion of the Pre-Assessment and Post-Assessment phases of the ECDA process is required.

1.1.2.1 Refer to GTIM-04-002 “ECDA Pre-Assessment” and GTIM-04-005 “ECDA Post-Assessment”.

2.0 PERFORMING THE ASSESSMENT

2.1 **Responsibility:** GTIM Field Inspector or Direct Examination Crew

2.1.1 Refer to procedure GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

2.1.2 Perform an atmospheric inspection on above-grade pipe per the requirements of O&M 27.31 “Atmospheric Corrosion Control” or CNP O&M X “Atmospheric Corrosion Control”, which includes the evaluation of the soil-to-air interface.

2.1.3 Obtain ultrasonic thickness measurements at the 12:00, 3:00, 6:00, and 9:00 positions.

2.1.3.1 Obtain readings at a minimum of four (4) locations on the above-grade pipe.

2.1.3.2 Obtain readings on each pipe diameter.

2.1.3.3 Obtain readings at each air-to-soil interface.

2.1.3.4 When using a tool, apply the specific instrument’s tool tolerances provided in the manufacturer’s manual.

2.1.4 Based on SME input, perform additional work as appropriate, such as:

2.1.4.1 Removing pipe supports for inspection of the pipe.

2.1.4.2 Utilize a short-range guided-wave on pipe traversing through walls.

2.1.5 Complete form GTIM-90418 “Pipeline Inspection Direct Examination” to document the assessment.

2.1.5.1 As appropriate, use multiple forms to document the assessment.

3.0 DOCUMENTATION

3.1 Responsibility: GTIM Field Inspector or Direct Examination Crew

3.1.1 Complete all documentation as required by GTIM-04-008.

3.1.2 Provide documentation to GTIM Field Supervisor for review and submission to the GTIM Engineer.

3.1.3 Retain all documentation in the IM file.

<<END>>

GTIM-04-030 Indirect Inspection Survey Field Preparation

PURPOSE: To establish a standardized method for preparing a pipeline for an indirect inspection survey.

REFERENCES: NACE SP0502-2010;

SECTIONS:

- General
- Identifying the Survey Segment
- Survey Scheduling
- Survey Preparation
- Crew Preparation
- Documentation

1.0 GENERAL

1.1 Indirect surveys require access to the surveyed pipeline segment(s).

Note: Some survey preparation activities may take three (3) to six (6) months - plan accordingly.

2.0 IDENTIFYING THE SURVEY SEGMENT

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Identify the segment(s) for assessment.

2.1.1.1 Identify the start of the covered segment and the end of the covered segment using GIS or other data sources.

2.1.1.2 Using one of the following, identify a reference-point, at each end, at least 100 feet outside the boundaries of the covered segment. These reference points are the starting and ending locations of the indirect inspection survey.

- A known physical reference point;
- A location referenced from a physical reference point; and
- Known GPS coordinates.

2.1.1.2.1 Extending the boundaries ensures the inclusion of the entire covered segment.

2.1.1.3 Develop a map showing the starting and ending location points for the indirect inspection surveys.

2.1.1.4 Consider consolidating multiple covered segments on a single pipeline into one indirect inspection when the compliance assessment dates are in the same year.

3.0 SURVEY SCHEDULING

3.1 **Responsibility:** GTIM Field Supervisor or designee

3.1.1 Consider land use when scheduling indirect inspection surveys. For example, perform surveys through farm fields in early spring or late fall, while there are no crops in the field.

3.1.1.1 Mow or remove crop stubble to allow ease of survey, if needed.

3.1.2 When repeating or conducting multiple types of indirect inspections, schedule the surveys as close in time as reasonably possible, with a maximum spread of 60 days.

3.1.2.1 For surveys completed greater than 60 days apart, verify that changes that may affect the integrity of the survey data or ability to align the survey data have not occurred. Changes to be considered include, but are not limited to:

- Installation or abandonment of rectifiers;
- Installation or abandonment of interference bonds;
- Rectifiers or interference bonds becoming inoperable;
- Increase or decrease of rectifier output; and
- Significant weather changes (i.e., extremely dry soil to extremely wet soil; ground goes from unfrozen to frozen).

3.1.2.1.1 Evaluate the need to perform another indirect inspection survey on all or a portion of the pipeline.

3.1.2.1.2 Document the review.

3.1.2.1.3 Retain the review in the IM file.

3.1.3 Communicate survey scheduling and survey requirements with Local Operations.

4.0 SURVEY PREPARATION

4.1 Responsibility: GTIM Field Supervisor or designee

4.1.1 Perform a visual evaluation of the condition of the right-of-way.

4.1.2 Schedule clearing of trees, brush, or debris from the right-of-way before commencing the survey, if needed.

4.1.2.1 Request the assistance of the Land and Field Services (L&FS) department as necessary.

4.1.2.2 Confirm landowners are notified of right-of-way clearing activities before they occur.

4.1.3 Review test station locations and confirm the installation of additional test stations as needed.

4.1.3.1 Confirm test stations or other pipeline attachments are available at 1-mile intervals when possible.

4.1.3.2 Test station installation should be near major roads and on the downstream side of the road when possible.

4.1.4 Confirm functionality of all cathodic protection rectifiers and interference bonds affecting the survey segment.

4.1.4.1 If necessary, repair rectifiers and interference bonds before commencing the survey.

4.1.5 Verify the isolation of the survey segments.

4.1.6 If necessary, notify the landowner(s) and tenants along the right-of-way. Notifications should include:

- Survey(s) scheduled dates;
- The name of the company performing the survey(s);
- A brief description of the purpose of the survey(s);

- CNP company contact information; and
- Access requirements.

4.1.7 Identify restricted access areas that may require site-specific training or requirements.

4.1.8 Assist in obtaining appropriate permits as applicable.

4.1.8.1 Permits may include:

- Traffic control;
- Lane closures;
- Drilling holes;
- Restricted areas; and
- Railroad crossings;
    - A flagger may need to be present while crossing the tracks.

4.1.8.2 Provide copies of permits to the inspection crew as necessary.

4.1.9 As required, arrange for the drilling of holes in pavement per GTIM-04-031 “Drilling or Coring of Improved Surfaces”.

4.1.10 Provide GTIM-90404 “Rectifier and Critical Bond Locations”, completed pre-assessment documentation, and all applicable pipeline information to the Indirect Inspection Crew before beginning the survey.

4.1.10.1 Provide alignment drawings with test stations prominently indicated.

4.1.10.2 Provide a list of all sources of current, such as:

- CNP rectifiers within the survey section
- All sources of current, or a minimum of three (3) CNP rectifiers downstream of the survey section and three (3) CNP rectifiers upstream of the survey section
    - Additional rectifiers may need to be interrupted as appropriate
- All bonds with foreign pipeline companies
- All foreign pipeline rectifiers that may influence the survey

4.1.10.3 Provide the starting and ending points of each survey segment along the pipeline to be assessed.

4.1.11 Provide GTIM-90406 “ECDA - Pre-Assessment” to the Indirect Inspection crew before beginning the survey.

4.1.12 Coordinate the use of traffic control elements as required.

4.1.12.1 Arrange for barricades and signs for any lane closures.

4.1.13 Coordinate interruption of any foreign-rectifiers with the rectifier’s owners as necessary.

4.1.14 Coordinate with other service providers as necessary.

5.0 CREW PREPARATION

5.1 Responsibility: Indirect Inspection Crew

5.1.1 Provide qualifications of personnel performing Indirect Inspections to the GTIM Field Supervisor before commencing work.

5.2 Responsibility: GTIM Field Supervisor or designee

5.2.1 Review service provider qualifications and confirm the Indirect Inspection crew is qualified to perform the survey.

5.2.1.1 When a crewmember is not qualified, request the Service Provider (if applicable) to provide a qualified replacement.

5.2.1.1.1 Postpone the survey as necessary.

5.2.1.2 Dismiss the survey crew if necessary.

5.2.2 Hold a pre-survey meeting with the Indirect Inspection crew leader; agenda items include, but are not limited to:

- Landowner or property access issues.
- Protocol if landowners question field crew personnel.
- Visually verify the boundaries of the Indirect Inspection Survey.
  - Review ECDA region changes.
  - Verify survey tools to be used.
- Review and confirm all appropriate station numbers.
- Verify survey boundaries starting and ending 100 feet outside the covered segment area.
- Communicate locations and operation of all test stations, bonds, rectifiers, and other pertinent equipment.
- Method for surveying paved areas.
- Discuss additional tests and plans for any known special circumstances.
- Discuss allowable ingress and egress for the field crew to each survey area.
- Pertinent company and service provider contact information, daily work schedule, service provider’s execution plan, etc.
- Recognition of potential safety hazards.
- Review of safe work practices.
  - Review listing of general hazards and what to do in case of injury.
  - Review listing of emergency phone numbers, company and service provider phone numbers, location of hospitals, and other care facilities.

5.2.3 Review the required survey equipment specified for each applicable indirect inspection technique.

5.3 Responsibility: Indirect Inspection Crew

5.3.1 Notify tenants before entering the property, if possible.

6.0 DOCUMENTATION

6.1 Responsibility: GTIM Field Supervisor or designee

6.1.1 Retain qualifications for each person performing the Indirect Inspection survey(s) in the IM file.

<<END>>

GTIM-04-031 Drilling and Coring of Improved Surfaces

PURPOSE: To provide a standardized approach for the drilling or coring of improved surfaces (concrete or asphalt), as well as techniques for pavement restoration.

REFERENCES: (no specific references)

SECTIONS:

- General
- Safety Considerations
- Survey Preparation
- Surface Repairs - Asphalt
- Surface Repairs - Concrete

1.0 GENERAL

1.1 Before an External Corrosion Direct Assessment (ECDA) Indirect Inspection, the pipeline segment(s) crossing under pavement should have holes drilled or cored to provide access to the native soil to obtain readings properly.

1.2 Additional holes perpendicular to the pipe for pinpointing specific indication locations may be required while performing the survey.

2.0 SAFETY CONSIDERATIONS

2.1 **Responsibility:** Indirect Inspection Crew or Survey Crew

2.1.1 Take appropriate safety precautions when working on and around the pipeline right-of-way.

2.1.2 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

2.1.3 Use caution when working around roads and railroads.

2.1.3.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

2.1.3.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.3.6, “Reflective Safety Vests”.

2.1.4 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

3.0 SURVEY PREPARATION

3.1 **Responsibility:** Indirect Inspection Crew or Survey Crew

3.1.1 Notify One-Call a minimum of 48 hours in advance.

3.1.1.1 Complete Locate Daily Crew Report daily and send it to the GTIM Field Supervisor.

3.1.1.1.1 When possible, submit Locate Daily Crew Report the night before.

3.1.1.1.2 At the latest, submit the Locate Daily Crew Report by 9:00 AM Central.

3.1.1.2 Adjust the location of the hole to prevent damage to underground facilities.

3.1.1.3 When working at gas service stations or other locations where a vent, product piping, or electrical conduit may be installed, use caution when drilling or coring.

3.1.2 Verify pipe depth before drilling.

3.1.3 Drill all holes through asphalt or concrete, including the roadbed, until reaching native soil.

3.1.4 Paved surfaces of ten (10) feet or less in width, do not require drilling.

3.1.5 Drill holes with a diameter of 1 ¼”.

3.1.5.1 Drilling holes of other diameters requires approval from the GTIM Field Supervisor before for prior approval to utilize other diameters.

3.1.6 The spacing of the holes is typically three (3) to four (4) feet.

3.1.6.1 Adjust spacing to minimize drilling in decorative concrete or through handicap ramps, which are excessively thick pavement.

3.1.6.2 Avoid drilling directly on or within two (2) inches of any designed expansion joint.

3.1.7 When encountering metallic rebar, stop drilling, fill the hole immediately per section 5.0 of this procedure, and move the hole to an adjacent location.

3.1.8 Fill the drilled hole with appropriate sand type and tamp to compact.

4.0 SURFACE REPAIRS - ASPHALT

4.1 Responsibility: Indirect Inspection Crew or Survey Crew

4.1.1 Repair holes according to the local jurisdiction for the roadway using the appropriate pavement repair material described below unless otherwise specified by the GTIM Field Supervisor or pavement owner.

4.1.1.1 Use Asphalt Plug Material relative to the size of the hole and according to the manufacturer’s instructions.

4.1.1.2 Use Epoxy Fill Material according to the manufacturer’s instructions.

4.1.1.3 Use Pavement sealer according to the manufacturer’s instructions.

5.0 SURFACE REPAIRS - CONCRETE

5.1 Responsibility: Indirect Inspection Crew or Survey Crew

5.1.1 Make repairs of improved-roadway surfaces according to the local jurisdiction for the roadway using the appropriate concrete repair options described below unless otherwise specified by the GTIM Field Supervisor or pavement owner:

5.1.1.1 Use Elastic Cement according to the manufacturer’s instructions.

5.1.1.2 Use Anchoring Cement according to the manufacturer’s instructions.

<<END>>

GTIM-04-032 Locating and Marking a Survey Segment

PURPOSE: To establish a standardized method for locating and marking a pipeline before an Indirect Inspection.

REFERENCES: NACE SP0502-2010; NACE TM0497-2018;

SECTIONS:
- General
- Survey Preparation
- Safety Considerations
- Pipeline Locating

1.0 GENERAL

1.1 Before an External Corrosion Direct Assessment (ECDA) Indirect Inspection or preventive and mitigative (P&M) indirect survey, the survey segment should be flagged and marked at approximately 100-foot intervals.

1.1.1 Flagging and marking aids in data alignment and helps reduce spatial errors.

2.0 SURVEY PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Refer to procedure GTIM-04-030 “Indirect Inspection Survey Field Preparation”.

2.1.2 Confirm personnel associated with the line locating and marking are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual. Applicable covered tasks include:

- Abnormal operating conditions; and
- Line locating.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew

3.1.1 Take appropriate safety precautions when working on and around the pipeline right-of-way.

3.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

3.1.3 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline segment.

3.1.4 Use caution when working around roads and railroads.

3.1.4.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.4.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, “Reflective Safety Vests”.

3.1.5 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

4.0 PIPELINE LOCATING

4.1 Responsibility: Indirect Inspection Crew

4.1.1 Perform pipeline locating in conjunction with the procedure, GTIM-04-033 “Pipeline Depth Survey”.

4.1.2 Accurately locate the pipeline centerline with a radio frequency pipe locator.

4.1.2.1 A direct connection of the transmitter to the pipeline is the preferred setup method (conductive).

4.1.2.1.1 Other locating tools are acceptable where a conductive approach is not feasible.

4.1.2.2 Casing vents and pipeline markers are not acceptable means of pipeline locating.

4.1.3 Starting at either end of the survey segment, measure approximate 100-foot intervals along the pipeline using GPS, a slack chain, or equivalent.

4.1.3.1 Locations typically begin at an above-grade physical reference point, such as a test station.

4.1.3.2 When utilizing GPS to measure, refer to procedure GTIM-04-043 “GPS Coordinates”.

4.1.3.3 DO NOT use a measuring wheel unless over a flat, paved surface.

4.1.3.4 Measurements used with a cloth tape instead of a slack chain are acceptable.

4.1.3.4.1 Stretch the cloth tape taut for the accuracy of the measurement.

4.1.4 Mark the 100-foot intervals to easily distinguish.

4.1.4.1 Mark each increment with a flag or paint in dirt or grass-covered areas using the same style and color of flags for the entire segment.

4.1.4.2 Mark each increment with paint on hard-surfaced areas (e.g., pavement, gravel, etc.).

4.1.5 Place 100-foot markings directly over the centerline of the pipeline.

4.1.6 Continue locating the pipeline, measuring, and marking the 100-foot intervals until the entire survey segment is complete.

4.1.7 As needed, locate and mark the pipe centerline more frequently than every 100 feet such that the marking material remains in the line-of-site at all times.

4.1.7.1 Mark all location points of inflection (PI).

4.1.7.1.1 Mark the inflection starting, center, and endpoints, where applicable.

4.1.7.1.2 Confirm that the point of inflection is easily distinguishable from other points using additional markings or symbols.

4.1.8 Confirm the 100-foot interval markings are easily distinguishable from other pipeline locate markings.

4.1.8.1 Interval markings are essential for the Indirect Inspection crew so they can enter the location into the data stream when performing the Indirect Inspection.

4.1.9 Remove any flags after completion of the survey(s).

<<END>>

GTIM-04-033 Pipe Depth Survey

PURPOSE: To provide a standardized procedure for determining and documenting a pipeline depth of cover as it relates to the Integrity Management Program.

REFERENCES: (no specific references)

SECTIONS:

- Survey Preparation
- Safety Considerations
- Equipment
- Measuring Pipeline Depth
- Documentation
- Project File

1.0 SURVEY PREPARATION

1.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

1.1.1 Arrange for the depth of cover survey in conjunction with GTIM-04-032 “Locating and Marking a Survey Segment” or GTIM-04-006 “Pipeline Elevation Profile”.

1.1.2 Secure qualified personnel or Service Provider to perform the survey.

1.1.3 Confirm personnel associated with the line locating and marking are Operator Qualified for the appropriate covered tasks or directly supervised by an Operator Qualified individual. Applicable covered tasks include:

- Abnormal operating conditions; and
- Line locating.

1.1.4 Before beginning the survey, provide the Indirect Inspection crew with maps for the segment(s) to be surveyed.

2.0 SAFETY CONSIDERATIONS

2.1 Responsibility: Indirect Inspection Crew or Survey Crew

2.1.1 Take appropriate safety precautions when performing indirect inspections.

2.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

2.1.3 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline segment.

2.1.4 Use caution when working around roads and railroads.

2.1.4.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

2.1.4.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.3.6, “Reflective Safety Vests”.

2.1.5 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

3.0 EQUIPMENT

3.1 Responsibility: Indirect Inspection Crew or Survey Crew

3.1.1 Use a Pipeline Current Mapper (PCM), RD4000, or equivalent to perform the survey. (The PCM is the preferred tool.)

3.1.1.1 Obtain the approval of the GTIM Field Supervisor before using other locator tools.

3.1.2 Preferred equipment will have the following characteristics:

- A locator with transmitter and receiver;
- Minimum of three (3) antennas in the receiver;
- Capable of conductive locating;
- Equipped with filters to minimize interference; and
- Provide measurements in inches.

4.0 MEASURING PIPELINE DEPTH

4.1 Responsibility: Indirect Inspection Crew or Survey Crew

4.1.1 Complete a GTIM-90412 “Daily Progress Report Indirect Surveys” each survey day.

4.1.2 Perform the Depth of Cover Survey while marking the pipeline per GTIM-04-032 “Locating and Marking a Survey Segment” or GTIM-04-006 “Pipeline Elevation Profile”.

4.1.3 Verify survey accuracy at the beginning and ending of each day of survey per one of the following methods:

- Take additional readings with the receiver lifted off the ground six (6) inches and compare readings.
- Probe the pipeline.

4.1.3.1 Document the occurrence of the verification on GTIM-90412.

4.1.3.2 Record the verification readings in the survey comments.

4.1.4 Obtain depth measurements at 100-foot intervals.

4.1.4.1 Obtain depth readings at a different interval if directed by the GTIM Field Supervisor.

4.1.5 Obtain GPS coordinates at each depth reading location.

4.1.5.1 Refer to procedure GTIM-04-043 “GPS Coordinates” for further details.

4.1.6 For depth readings less than 24-inches, increase the frequency of readings.

4.1.6.1 Take readings at approximate ten (10) foot intervals until readings exceed 24-inches in both directions.

4.1.6.2 Document the extents of the shallow area with GPS coordinates.

4.1.6.3 Verify all pipeline depth readings less than 24-inches by one of the methods listed in section 4.1.3.

4.1.7 Additionally, obtain GPS coordinates at the beginning and end of any exposed pipe discovered during the survey. Note the exposure type in the survey data.

4.1.7.1 Short exposures only require one GPS coordinate.

5.0 DOCUMENTATION

5.1 Responsibility: Indirect Inspection Crew or Survey Crew

5.1.1 Provide the GTIM Field Supervisor with all survey data.

5.1.2 Provide all of the survey data to the GTIM Field Supervisor in an Excel spreadsheet with separate columns for each of the following items:

- Latitude;
- Longitude;
- Pipeline depth at the pipe centerline, unless otherwise noted; and
- Comments;

5.1.3 Provide documentation discussing the type of equipment used to perform the survey.

5.1.4 Provide GTIM-90412.

5.2 Responsibility: GTIM Field Supervisor

5.2.1 Confirm receipt of all data.

5.2.1.1 Complete the applicable portions of GTIM-90408 “ECDA - Indirect Inspection”.

5.2.1.2 Retain documents in the appropriate IM file.

6.0 PROJECT FILE

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Compile all assessment information in a project file.

6.1.2 Review the data for locations with a depth of cover less than 24-inches.

6.1.2.1 Notify Local Operations if locations exist.

6.1.3 Review any exposure data.

6.1.3.1 Send exposure information to the Local Operations group for further evaluation and remediation.

6.1.4 Report any defects or inaccuracies in the data to the GTIM Field Supervisor to determine if additional indirect inspections or surveys are necessary.

Note: Line markers must be placed and maintained at locations along each section of an aboveground transmission pipe that crosses or lies close to publicly accessible areas and where the potential for future exposure, excavation, or damage is likely.

6.1.5 Retain the data, field notes, and other pertinent survey information for the useful life of the pipeline.

6.1.5.1 Retain the documentation in the IM file.

<<END>>

GTIM-04-043 GPS Coordinates

PURPOSE: To provide a standardized method for obtaining Global Positioning System Coordinates.
REFERENCES: (no specific references)
SECTIONS:

- General
- Survey Preparation
- Safety Considerations
- Equipment
- Survey Specifications
- Data

1.0 GENERAL

1.1 Global Positioning System (GPS) provides precise and reproducible positional location information.

1.1.1 GPS data provides a means for aligning and referring data.

1.1.2 GPS coordinates allow confidence in returning to the same site, and recording results in the integrity management data repositories.

2.0 SURVEY PREPARATION

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Refer to procedure GTIM-04-030 “Indirect Inspection Preparation” for survey preparation details.

2.1.2 Confirm personnel associated with the inspection are Operator Qualified for the appropriate Covered Tasks or directly supervised by an Operator Qualified individual. Applicable Covered Tasks include:

- Abnormal operating conditions; and
- Pipeline locating.

3.0 SAFETY CONSIDERATIONS

3.1 Responsibility: Indirect Inspection Crew or Survey Crew

3.1.1 Take appropriate safety precautions when obtaining GPS coordinates.

3.1.2 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline segment.

3.1.3 Use caution when working around roads and railroads.

3.1.3.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

3.1.3.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.3.6, “Reflective Safety Vests”.

3.1.4 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and

- Unsafe or abnormal pipeline conditions.

4.0 EQUIPMENT

4.1 **Responsibility:** Indirect Inspection Crew or Survey Crew

4.1.1 Use mapping-grade GPS equipment with sub-centimeter (preferred) or sub-meter accuracy with the following minimum specifications:

- Capable of operating in temperatures and other climate conditions found in the survey area(s);
- Able to accept communication from SBAS (Satellite Based Augmentation System), WAAS (Wide Area Augmentation System), or Beacon;
- Ability to track a fee-based satellite service, if required (e.g., OminSTAR®);
- Capable of differentially correcting or post-processing all data collected;
- Possess Position Dilution of Precision (PDOP) display or the capability to set a maximum level for data collection;
- Five (5) Horizontal Root Mean Squared accuracy;
  - Data collection from a minimum of four (4) satellites is preferred while maintaining accuracy; and
- Capable of logging multiple positions at a single location.

4.1.2 Sub-centimeter accuracy is preferred.

4.1.2.1 Sub-centimeter accuracy may require land surveyor-grade equipment.

Note: Sub-meter and sub-foot equipment are only accurate in the x-y planes. For coordinates in the z-plane, in addition to the x-y planes, sub-centimeter equipment must be used.

5.0 SURVEY SPECIFICATIONS

5.1 **Responsibility:** Unit Operator

5.1.1 Confirm the PDOP value is four (4) or less while performing the survey.

5.1.1.1 Lower PDOP values represent, the more accurate the GPS coordinates.

5.1.2 Confirm the horizontal dilution of precision (HDOP) is four (4) or less.

5.1.3 Confirm the satellite elevation mask is greater than or equal to 15-degrees.

5.1.4 Obtain data from a minimum of four (4) satellites.

5.1.4.1 Enter a feature description for each data point collected.

5.1.5 Obtain data at a maximum of every 100 feet and any change in pipeline direction.

5.1.5.1 Project requirements may specify additional data collection points.

5.1.6 Compare GPS readings each survey day.

5.1.6.1 Record a GPS reading at a specific location before beginning the survey.

5.1.6.2 Go back to the same location at the start of each survey day and record another GPS reading.

5.1.6.2.1 If GPS readings differ from the previous day, investigate and document findings, and correct if appropriate.

5.1.7 Verify equipment calibration against a known landmark or monument with known coordinates before beginning the survey.

5.1.8 Take GPS coordinates at above grade appurtenances, terrain changes, and all physical reference points. Physical reference points include, but are not limited to:

- Test stations;
- Mainline valves;
- Aerial markers;
- Foreign line crossings;
- Roads;
- Railroads;
- Streams;
- Ditches;
- Sidewalks; and
- Fences.

5.1.9 Take GPS coordinates at all known and suspected encroachments.

5.1.9.1 Encroachments may include, but are not limited to:

- Fence posts;
- Signposts;
- Buildings;
- Pools; and
- Foreign-pipelines.

5.1.9.2 Enter as much information about each encroachment into the survey comments as possible.

5.1.9.2.1 For foreign-pipelines, this includes the type of crossing and the name of the owner company, when known.

5.1.9.3 Provide notification to the Encroachment Program Manager per CNP's Encroachment Policy.

6.0 DATA

6.1 Responsibility: Unit Operator

6.1.1 Provide the data in latitude and longitude format.

6.1.1.1 Use a datum of WGS 1984 or UTM (proper zone) using a datum NAD 1983 (CONUS[1] unless otherwise required).

[1] CONUS is an acronym for Contiguous United States used by the U.S. Military, which is specifically defined as the 48 contiguous states but is silent on the District of Columbia.

6.1.1.2 Supply elevations in “Height Above Ellipsoid” (HAE) using US Survey feet units.

6.1.1.3 Provide coordinates in decimal degrees.

6.1.1.3.1 When GPS accuracy allows, provide data to eight (8) decimal places.

6.1.2 Provide the data in the northing and easting format when performing a Pipeline Elevation Profile.

6.1.2.1 Use either the UTM or SPC83 as the coordinate system with the horizontal datum NAD 1983 (CONUS1 unless otherwise required) using US Survey feet units.

6.1.2.1.1 Provide a minimum of three (3) decimal places in the northing and easting measurements.

6.1.3 Provide one (1) CD, or other electronic data saving and transfer device format, with all information to the GTIM Field Supervisor. Information includes, but is not limited to:

- Raw data in an Excel spreadsheet; and
- Survey notes or a copy of the field notebook.

6.1.4 Provide the data in an Excel spreadsheet with each of the following in a separate column:

- Latitude;
- Longitude; and
- Comments.

6.1.5 Provide documentation discussing the type of equipment used to perform the survey.

6.1.5.1 Include equipment calibration information, and serial number.

6.2 Responsibility: GTIM Field Supervisor or designee

6.2.1 Review and confirm receipt of all data.

6.2.2 Approve final payment once all terms of the contract are complete.

6.2.3 Provide data to the responsible GTIM Engineer.

6.2.4 Create a work order to incorporate the data into GIS or other appropriate integrity management data repositories.

6.2.5 Retain all documentation in the appropriate IM file.

<<END>>

GTIM-04-051 ICDA Pre-Assessment

PURPOSE: To establish a standardized method for performing the Pre-Assessment phase of an Internal Corrosion Direct Assessment (ICDA).

REFERENCES: 49 CFR 192.927; NACE SP0106-2006; NACE SP0206-2006;

SECTIONS:

- Background
- Personnel Qualifications
- Consequence Areas and Identified Site Review
- Identifying the Pipeline Segments
- First Time Application More Restrictive Criteria
- ICDA Feasibility Assessment
- Flow Modeling
- ICDA Region Determination
- Pre-Assessment Documentation

1.0 BACKGROUND

1.1 Dry Gas - Internal Corrosion Direct Assessment (DG-ICDA) applies to natural gas pipelines that usually carry dry gas, but may suffer from infrequent, short-term upsets of liquid water or other electrolytes.

Note: CNP utilizes the ICDA methodology only when evidence of the threat of internal corrosion that exists in the pipeline segment.

1.2 ICDA methodology predicts locations along a pipeline where water is most likely to accumulate. The examination of these locations determines the status of the remaining length of the pipe.

1.3 Use flow modeling to determine the critical angle and then compare to the pipeline inclination angle plot to select locations where water may accumulate for direct examination.

1.3.1 Prediction of a critical angle occurs through multiphase flow calculations.

1.3.2 Direct examinations include internal metal loss measurements.

1.4 An Internal Corrosion Direct Assessment (ICDA) consists of four (4) phases:

- Pre-Assessment;
- Indirect Inspection;
- Direct Examination; and
- Post-Assessment.

2.0 PERSONNEL QUALIFICATIONS

2.1 **Responsibility:** GTIM Engineer or GTIM Field Supervisor

2.1.1 Ensure Service Providers involved with the ICDA process meet or exceed the following qualifications::

- The qualifications listed in the specific procedure being implemented or performed; and
- The qualifications of CNP personnel who would otherwise be performing the activities.

2.1.2 CNP personnel responsible for the ICDA process will meet at least one (1) of the following qualification requirements:

- NACE Internal Corrosion Technologist or equivalent;
- A degreed engineer;
- Technical degree with two (2) years relevant pipeline experience; or
- Five (5) years minimum pipeline relevant pipeline experience.

3.0 CONSEQUENCE AREAS AND IDENTIFIED SITE REVIEW

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Perform a site visit to verify Consequence Areas and the locations of Identified Sites if necessary.

3.1.2 Create a work order if known Consequence Areas or structure information requiring correction in GIS.

3.1.3 Prepare aerial maps of the covered segment(s) on the pipeline, including assessment extents.

3.1.4 Document the covered segment(s) information for the pipeline on GTIM-90456 “ICDA - Pre-Assessment” and GTIM-90209 “Threat Analysis”.

4.0 IDENTIFYING THE PIPELINE SEGMENTS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Identify the assessment boundaries for the pipeline.

4.1.1.1 If several non-contiguous covered segments exist on the same pipeline, consider assessing them all during one (1) application of ICDA.

4.1.2 Collect and integrate historical data for the entire pipeline on which covered segments are present.

4.1.2.1 The line segment begins at the first station or takeoff downstream of the covered segment(s) and ends at the last station or takeoff upstream of the covered segment(s).

4.1.3 Request assistance from corrosion control and operating personnel as required.

4.1.4 Review and update, as needed, the information on GTIM-90400 “DA Data Element Table” for the pipeline to be assessed.

4.1.5 Table 04-051-1 lists the minimum data required to perform ICDA.

Table 04-051-1: Minimum Data Requirements for ICDA[1]

Pipe Related	
• Material *(i.e., steel, cast iron, plastic)*	• Wall thickness
• Diameter	• Internally coated pipe or bare

[1] Derived from NACE RP0206-2006, “Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)”;

Pipe Related	
Construction Related	
• Elevation profile	• Year installed
• Locations of inputs and withdrawals	• Location of drips
Monitoring Data	
• Liquid analyses, bacteria testing, and water vapor content *(when available)*	• Gas analyses *(when available)*
• Presence of solids, and testing	• Corrosion monitoring
Internal Corrosion Control	
• Use of chemicals or corrosion inhibitor	
Operational Data	
• Operating flow rates *(avg., max.)*	• Type of dehydration
• Operating pressures *(avg., max.)*	• Operating stress level *(%SMYS)*
• Operating temperatures *(avg.)*	• Periods of flow and no flow
• Flow direction	• MAOP
Historical Data	
• Service history *(i.e., conversion)*	• Cleaning pig usage
• Pipe Exam reports of observed internal corrosion	• Hydrostatic test
• Leak and rupture history related to internal corrosion	• Presence of solids or liquids *(upsets)*
	• Repair history records

4.1.6 Sources of information include, but are not limited to:

- Operating and maintenance histories;
- Design and construction records;
- Gas and liquid analyses reports;
- Pipeline inspection reports;
- Corrosion survey records;
- System maps; and
- Leak reports.

4.1.6.1 Refer to GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

4.1.7 Review existing Preventive and Mitigative (P&M) measures for the pipeline segment.

4.1.8 If data is missing and extensive data research is required, refer to GTIM 02 001 “Data Gathering and Research” as necessary.

4.1.9 Document and justify any data assumptions made with the data in the comments area of GTIM-90400 “DA Data Element Table” or the appropriate database.

4.1.9.1 As an alternative, arrange for and perform investigative digs to gather the information.

4.1.10 Confirm all data and documentation requirements.

4.1.11 When the data for any required data element is not obtainable and cannot support assumptions, ICDA is an unfeasible assessment method for this pipeline segment.

4.1.11.1 Refer to section 6.0, “ICDA Feasibility Assessment”, for additional information.

4.1.12 Create a work order if known data attributes need correction in GIS.

4.1.12.1 Example: No casing identified in GIS and pre-assessment research determined casing does exist per information gathered from as-built records or actual observation.

5.0 FIRST TIME APPLICATION MORE RESTRICTIVE CRITERIA

5.1 Responsibility: GTIM Engineer or designee

5.1.1 When applying ICDA to a pipeline segment for the first time, implement ‘more restrictive criteria’ during the Pre-Assessment phase. Options for more restrictive criteria include, but are not limited to:

- Collect and analyze a larger set of data than required;
- Divide ICDA regions into smaller, more defined pipe sections with more specific limiting characteristics;
- Identify ICDA regions for “average” flow conditions in addition to “maximum” flow conditions; and
- Meet with Subject Matter Experts (SMEs) to gather additional information about the operating characteristics of the line segment.

5.1.2 Document the use of more restrictive criteria on GTIM-90456 “ICDA - Pre-Assessment”.

6.0 ICDA FEASIBILITY ASSESSMENT

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Determine whether the following conditions exist along the pipeline segment:

- Wet gas (greater than 7 lbs./MMCF of water vapor[2]);
  - Temporary upsets do not affect the feasibility;
- The pipeline has been converted to a natural gas service from crude oil or other liquid products unless it can be demonstrated internal corrosion did not occur or all previous damage addressed;
- Historical records indicating that internal corrosion has occurred on the top sector of the pipeline;
- The pipeline has been, or currently is, pigged annually or on a more frequent basis with liquids removed;
- Accumulations of solids, sludge, or scale are present in the pipeline unless demonstrating that such accumulations do not significantly influence the validity of the DG-ICDA. Conder the following conditions when determining a significant influence:
  - Prior internal inspections showed evidence of scale build-up, under-deposit corrosion, or biofilm/biomass on the internal surface of the pipe;
  - Prior internal inspections showed evidence of solids or sludge accumulation at low points in the pipeline;
  - Bacteria, biofilm, or scale on internal corrosion coupons or cutouts;
  - Pipeline filter cleaning frequency is more often than recommended by the vendor; and

[2] NACE SP0106-2006 “Control of Internal Corrosion in Steel Pipelines and Piping Systems”, Appendix A;

    - Total accumulated volume (i.e., black powder, silt, etc.) removed from the pipeline at one time is greater than one barrel (55-gallon drum).
- Use of corrosion inhibitor within the pipeline since effectiveness may not be uniform along the entire pipeline segment.

6.1.2 If any of the above is true, ICDA is not feasible for the line segment.

6.1.3 Document the feasibility of using the ICDA method on the GTIM-90456 “ICDA - Pre-Assessment” by evaluating the data collected.

6.1.3.1 If the ICDA method unfeasible, document the rationale.

6.1.4 If ICDA is determined to be unfeasible for a pipeline segment, choose another method of assessment based upon the identified threats. Applicable assessment methods may include:

- Pressure Testing;
- In-Line Inspection; and
- “Other Technology”.

6.1.5 Refer to GTIM-03-001 “Assessment Method Selection” for details on choosing assessment methods.

7.0 FLOW MODELING

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Prepare the top portion of GTIM-90480 “Flow Modeling for ICDA”.

7.1.2 Submit GTIM-90480 to Gas Transmission Design personnel.

7.2 Responsibility: Gas Transmission Design

7.2.1 Complete GTIM-90480 “Flow Modeling for ICDA” to document the flow modeling requirements.

7.2.1.1 If the flow is bi-directional, complete a separate form for each flow direction. Consider both current and historical flow directions.

7.2.2 Use the SynerGEE® modeling program, or equivalent, to calculate the gas velocities and pressures on the line segment.

7.2.2.1 The SynerGEE® model considers the following information:

- Gas velocity;
- Gas pressure;
- Gas input and withdrawal points; and
- Pipe diameter.

7.2.3 Identify all locations where the gas velocity or gas pressure changes by greater than or equal to 10%.

7.2.3.1 This 10% change is determined based upon the change at one (1) location, not a cumulative change.

7.2.3.2 These locations may be at one of the following:

- Change in diameter;
- Gas input;

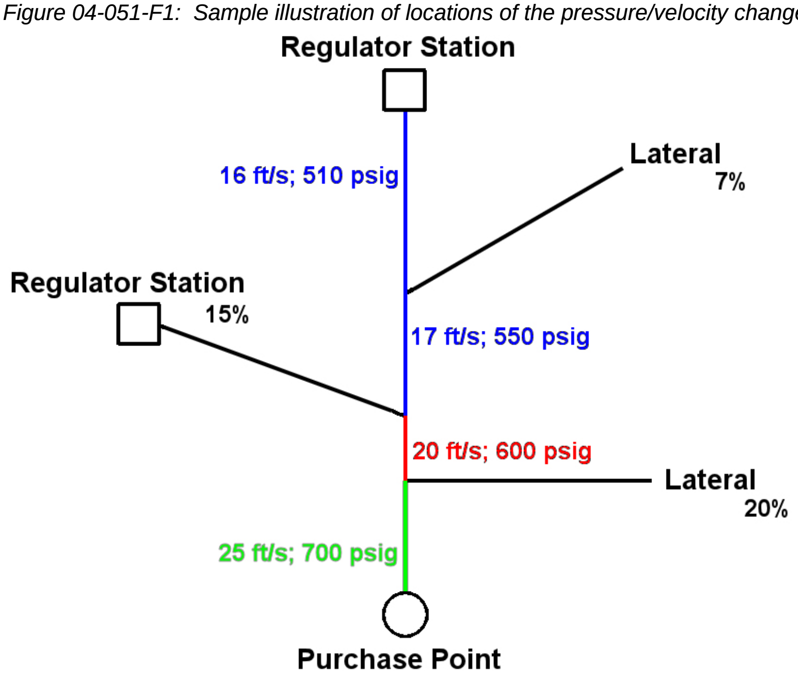
- Gas withdrawal point; or
- Meter/regulator station.

Note: CNP contends that a change in flow or velocity at farm taps is not significant enough to warrant a new ICDA Region. The use of a 10% threshold helps to eliminate farm taps from consideration in the ICDA region determination while still allowing significant changes to be addressed. CNP will re-evaluate the 10% threshold upon the discovery of significant internal corrosion.

7.2.4 For each location with a pressure or velocity change greater than or equal to 10%, document the following information on GTIM-90480:

- Description of location (i.e., regulator station);
- Operating pressure (average, maximum);
- Gas temperature (average);
- Gas velocity (average, maximum);
- Gas flow rate (average, maximum);
- Diagram illustrating the locations of the pressure/velocity changes;
  - Refer to Figure 04-051-F1 for an example diagram; and
  - Attach an additional sheet to GTIM-90480.

Figure 04-051-F1: Sample illustration of locations of the pressure/velocity changes



Note: A change in color and line size indicates a different ICDA region

7.2.5 Return the completed GTIM-90480 to the GTIM Engineer.

8.0 ICDA REGION DETERMINATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Review the information provided by Gas System Design Engineer.

8.1.2 Using GIS or other software, overlay the location information provided by the Gas System Design Engineer with covered segment locations and the pipeline segments for ICDA.

8.1.3 Identify an ICDA Region boundary at each location where:

- The gas velocity and or pressure changes by 10% or more as identified by the Gas System Design Engineer; and
- Gas inputs may introduce liquids into the line.

8.1.4 Identify a separate ICDA region for each location with a bi-directional flow (current or historical).

8.1.4.1 Assign a number to each ICDA region. Do not reuse the same region number. For example, a segment with a bi-directional flow would be named Region 1 for one direction and Region 2 for the opposite direction of flow (not 1 (N-S) and 1 (S-N)).

8.1.5 Identify a separate ICDA region for each flow condition (i.e., average flow and maximum flow conditions). Do not reuse the same number.

Note: When feasible, CNP identifies ICDA regions for "average" flow conditions as part of "more restrictive" criteria for the first-time application of ICDA. During subsequent applications of ICDA, CNP may choose not to identify separate regions for "average" flow conditions.

8.1.6 Apply ICDA regions to each Consequence Area subject to the assessment.

8.1.7 Document each ICDA region on GTIM-90456.

9.0 PRE-ASSESSMENT DOCUMENTATION

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Perform a 100% quality check of all requested GIS updates.

9.1.2 Finalize and complete GTIM-90456 "ICDA - Pre-Assessment". The report serves as a checklist and approval sheet for the associated Pre-Assessment documentation.

9.1.3 Confirm completion of the following forms:

- Aerial maps of all applicable Consequence Areas;
- GTIM-90400 "DA Data Element Table";
- GTIM-90480 "Flow Modeling for ICDA";
- GTIM-90209 "Threat Analysis"; and
- GTIM-90456 "ICDA - Pre-Assessment".

9.1.4 Conduct the Pre-Assessment approval meeting.

9.1.5 Retain all assessment documentation in the IM file.

<<END>>

GTIM-04-054 ICDA Indirect Inspection

PURPOSE: To establish a standardized method for performing the Indirect Inspection phase of the Dry Gas – Internal Corrosion Direct Assessment methodology.

REFERENCES: 49 CFR 192.927; NACE SP0206–2006; GRI-02/0057-2002;

SECTIONS:

- General
- Critical Angle Determination
- Pipeline Inclination Angles
- First Time Application of ICDA to a Pipeline Segment
- Direct Examination Locations
- Validation Examination Locations
- Indirect Inspection Documentation

1.0 GENERAL

1.1 The purpose of the Indirect Inspection phase is to identify the locations within each covered segment, with the highest likelihood for internal corrosion.

1.2 Locations with the highest likelihood for internal corrosion will occur in areas where the inclination angle exceeds the critical angle or at some other water-trapping feature such as low point, drip, sag, or bend.

2.0 CRITICAL ANGLE DETERMINATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Calculate the critical angle for each identified ICDA region.

2.1.1.1 Calculate the critical angle using the “maximum” current flow rate and associated operational gas velocity and pressure.

2.1.2 For the first time application of ICDA, determine the need for critical angle calculations at both the “average” flow and “maximum” flow conditions.

2.1.2.1 Calculate critical angles for both “maximum” and “average” flow conditions as appropriate.

2.1.2.2 Refer to section “First Time Application of ICDA to a Pipeline Segment” of this document for details on applying “more restrictive criteria” during the first time application of ICDA.

2.1.3 Use the following equation to calculate the **compressibility factor for gas (Z)**.

$$Z = \frac{PV}{nRT}$$

where:

Z = Compressibility Factor *(unitless variable)*
P = Pressure *(Pa)*
V = Volume *(m^3)*
n = Moles *(mol)*
R = the Gas Constant *($8.31451\ Pa \cdot m^3 \cdot mol^{-1} \cdot K^{-1}$)*
T = Absolute Temperature *(K)*

2.1.3.1 Use a value of Z = 0.83 *(unitless)* for typical ICDA applications.

2.1.3.2 Refer to referenced texts in NACE SP0206-2006 for values of Z in various conditions and the guidance on non-ideal gas equations.

2.1.4 Use the following equation to calculate the **gas density (ρ_δ)**:

$$\rho_\delta = \frac{P \times MW}{R \times T \times Z}$$

where:

ρ_δ = gas density *(g/cm³)*
P = operating pressure *(absolute MPa)*
T = average temperature *(288.7° K)*
MW = molecular-weight of natural gas *(16 g/g-mol)*
R = ideal universal gas constant *(8.31451 Pa • m^3• mol^{-1} • K^{-1})*

2.1.5 When only the flow rate at the standard temperature and pressure (STP Flow Rate, STP_{FR}) is known, calculate the **operating pressure flow rate (OP Flow Rate)** as follows:

$$OP\ Flow\ Rate = \frac{STP_{FR} \times T \times Z \times P_{STP}}{P \times T_{STP}}$$

where:

OP Flow Rate = operating pressure flow rate *(m^3/hr)*
STP_{FR} = standard temperature and pressure flow rate *(m^3/hr)*
T = average temperature *(288.7° K)*
Z = compressibility factor (see Section 1.1.3)
P_{STP} = standard pressure *(0.101325 MPa)*
T_{STP} standard temperature *(273°K)*
P operating pressure *(absolute MPa)*

2.1.6 Calculate the **superficial velocity**.

$$V_\delta = OP\ Flow\ Rate/Area$$

where:

V_δ = superficial velocity *(m/hr)*
Area = area of the inside of the pipe (m^2)

2.1.6.1 Convert V_δ to *m/s* by dividing by 3,600.

2.1.7 **Flow Modeling Fitted Equation** Approach for Determining the Critical Angle.

Note: For pressures less than 500 psig, CNP has opted to utilize the "Flow Modeling" included in NACE SP0206-2006.

2.1.7.1 This method applies to pipelines with pressure below 500 psig.

2.1.7.2 Calculate the critical angle using the following equation:

$$\theta = arcsin\left[0.675\ \frac{\rho_\delta}{\rho_\iota - \rho_\delta} \times \frac{V_\delta^2}{\delta \times d_{id}}\right]^{1.091}$$

where:

θ = critical-angle *(degrees)*
ρ_ι = liquid density *(1.00 g/cm^3)*
ρ_δ = gas density *(g/cm^3)*
δ = acceleration due to gravity *(9.81 m/s^2)*
d_{id} = internal diameter *(m)*
V_δ = maximum gas velocity *(m/s)*

2.1.8 **GRI Flow Modeling Iterative Equation** Approach for Determining the Critical Angle.

Note: The "GRI Flow Modeling" equation is only valid for pressures above 500 psig.

2.1.8.1 This approach is valid for:

- Nominal pipe diameter between four (4) inches and four-eight (48) inches;
- Pressure between 500 psi and 1100 psi; and
- Velocity 25 ft/s *(7.62 m/s)* or less.

2.1.8.2 As applicable, use the equation below.

$$\theta = arcsin\left[\frac{\rho_\delta}{\rho_\iota - \rho_\delta} \times \frac{V_\delta^2}{\delta \times d_{id}} \times F\right]$$

where:

θ = critical-angle *(degrees)*
ρ_ι = liquid density *(1.00 g/cm^3)*
ρ_δ = gas density *(g/cm^3)*
δ = acceleration due to gravity *(9.81 m/s^2)*
d_{id} = internal diameter *(m)*
V_δ = maximum gas velocity *(m/s)*
= gas flow rate at operating conditions (OP Flow Rate) divided by the area of the inside of the pipe
F = dimensionless number; contingent upon degree of angle per the following guidelines:
= 0.35 at θ < 0.5 degrees
= 0.56 at θ < 2 degrees
= [0.29 + (0.13 x θ)] for 2 > θ < 0.5 degrees

2.1.9 Confirm the units of gas and liquid density are the same.

2.1.10 Confirm the units for velocity, gravitational constant, and diameter are consistent.

2.1.11 For each ICDA region, identify the critical angle using the "maximum" flow conditions.

2.1.11.1 The locations where the critical angle exceeds a given gas velocity, where stagnant water traps are likely to form, if water enters the pipeline, or condenses.

2.1.11.2 If there are no locations where the critical angle exceeds a given gas velocity, water is not likely to form detrimental corrosion traps, and the potential for internal corrosion to occur is considered unlikely.

2.1.11.3 Perform the same calculations if the “average” flow conditions are being used “as more restrictive criteria” per section 2.1.7 or section 2.1.8 as applicable.

2.1.12 Document the critical angles and operating parameters used for each ICDA region in GTIM-90457 “ICDA - Indirect Inspection”.

3.0 PIPELINE INCLINATION ANGLES

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Using the pipeline elevation data for the applicable pipeline segments, determine the inclination angle between each data point.

3.1.1.1 Refer to GTIM-04-006 “Pipeline Elevation Profile” for details on obtaining the pipeline elevation profile.

3.1.2 Using the GPS coordinates, calculate the distance between each data point using the following equation:

$$D = \sqrt{(X_2 - X_1)^2 + (Y_2 - Y_1)^2}$$

where:

D = distance between points
X_2 = Northing of the first point
X_1 = Northing of the second point
Y_2 = Easting of the first point
Y_1 = Easting of the second point

Note: The above equation is only valid for determining the distance between points on UTM or State Plane coordinates.

3.1.3 Calculate the pipeline elevation for each distance increment by taking the elevation of the terrain minus the depth of pipe cover.

3.1.4 Calculate the inclination angle (θ) between two data points by taking the arctangent of the change in pipeline elevation (rise) divided by the change in each distance increment (run) as shown below:

$$\theta_I = arctan\left(\frac{\Delta\, rise}{\Delta\, run}\right)$$

Note: This equation assumes the change in elevation (Δ rise), is calculated as the height of one (1) location subtracted from the height at the next location. The change in the pipe, (Δ run), is the actual footage (distance) of pipe installed, sometimes referred to as stationing or mileposts. When using a GPS device to collect coordinate data over the centerline of the pipe, the (Δ run) variable becomes the horizontal distance *(e.g., no slope, between the two (2) points)*.

3.1.5 Document the critical angle on GTIM-90457.

3.1.6 Create an inclination profile by charting the inclination angles of each dataset increment.

3.1.7 Compare the inclination profile to the critical angle profile of each ICDA region. Determine the locations most likely for internal corrosion to exist.

3.1.8 Document the locations most likely for internal corrosion to exist on GTIM-90457.

4.0 FIRST TIME APPLICATION OF ICDA TO A PIPELINE SEGMENT

4.1 Responsibility: GTIM Engineer or designee

4.1.1 When applying ICDA to a pipeline segment for the first time, collect data utilizing "more restrictive criteria" to ensure high quality and consistency. Options for more restrictive criteria include, but are not limited to:

- Gather pipeline elevation data for the entire line segment;
- Gather additional field data to better refine the pipeline inclination angle profile, especially around critical angles;
- Use different models, compare results and use the more conservative critical angle; and
- Calculate the critical angle for "average" gas velocity and pressure in addition to the "maximum" gas velocity and pressure conditions.

4.1.2 Document the use of more restrictive criteria on GTIM-90457.

5.0 DIRECT EXAMINATION LOCATIONS

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Identify locations for direct examination based on reviewing the pipeline elevation profile data.

5.1.2 For bi-directional flow, consider inclinations for the opposite direction as a separate ICDA region and handle each direction separately.

5.1.3 Using the "maximum" flow characteristics, identify a minimum of two (2) locations within each ICDA region within a covered segment.

5.1.3.1 Locations should be in areas where internal corrosion is most likely to occur.

5.1.3.1.1 If the area where internal corrosion is most likely to occur lies outside of a covered segment, schedule a validation or discretionary dig at this location.

5.1.3.2 Selection priority as follows:

- The first low point (i.e., sag bend, drip, valve, manifold, dead leg, trap) within the covered segment that is nearest the beginning of the ICDA region.
- The second location must be further downstream, within a covered segment, near the end of the ICDA Region.
    - This location should be where the angle meets or exceeds the calculated critical angle or at the maximum inclination angle within the region (next largest inclination if the first low point contained maximum inclination).

5.1.4 If choosing digs based on "average" flow conditions for "more restrictive" criteria, the selection priority is:

- The first location that meets or exceeds the "average flow" critical angle, or the angle of greatest inclination in the covered segment if no critical angle exists; then

- The second location shall meet or exceed the “average flow” critical angle, or the angle of greatest inclination further downstream if a critical angle does not exist.

Note: In cases of bi-directional flow, determine if utilizing the same direct examination location for each direction is possible.

5.1.5 Document direct examination locations on GTIM-90457.

6.0 VALIDATION EXAMINATION LOCATIONS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Choose a minimum of one (1) location for validation examination for the ICDA assessment. If the flow is bi-directional, choose one (1) location for each direction of flow.

6.1.1.1 Note: In some cases, it may be possible for one (1) dig location to validate both flow directions. This criterion requires only one (1) validation location for the assessment.

6.1.2 Use the following as guidelines for choosing validation examination locations:

- A location where the angle meets or exceeds the “maximum flow” critical angle or angle of greatest inclination, downstream of other angle digs, considering the feasibility of excavation; or
- A relatively low point.

6.1.3 Document validation examination locations on GTIM-90457. Indicate the type of dig is a validation location.

7.0 INDIRECT INSPECTION DOCUMENTATION

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Finalize and complete GTIM-90457.

7.1.2 Conduct a meeting with the GTIM Manager to review the completed GTIM-90457 and obtain approval to proceed with the remaining ICDA steps.

7.1.3 Retain the ICDA documentation for the useful life of the pipeline.

<<END>>

GTIM-04-055 ICDA Direct Examination

PURPOSE: To establish a standardized method for performing the Direct Examination phase of the Dry Gas - Internal Corrosion Direct Assessment (ICDA) methodology.

REFERENCES: 49 CFR 192.927; ASME/ANSI B31G-1991; NACE SP0206-2016;

SECTIONS:
- More Restrictive Criteria
- Direct Examination
- Date of Discovery
- Addressing Internal Corrosion
- Documentation

1.0 MORE RESTRICTIVE CRITERIA

1.1 Responsibility: GTIM Engineer or designee

1.1.1 When applying ICDA for the first time, implement one (1) or more restrictive criteria during the Direct Examination phase.

1.1.1.1 The more restrictive criteria include, but are not limited to, the following:

- Examine locations based on “average” flow conditions (in addition to “maximum” flow conditions);
- Use a smaller grid for UT measurements;
- Measure wall thickness around the entire circumference of the pipe;
- When using LRUT or x-ray, use a more conservative “call level”; and
- Use a larger bell-hole to assess a larger area of the pipe.

1.1.1.2 Document the use of more restrictive criteria on GTIM-90458 “ICDA - Direct Examination”.

1.1.2 Notify the GTIM Field Supervisor and GTIM Field Inspector of the use of more restrictive criteria during the examinations.

1.1.3 Prepare Dig Plan packets per the requirements of GTIM-04-026 “Dig Plan Preparation”.

1.2 Responsibility: GTIM Field Supervisor or designee

1.2.1 Prepare for the direct examination per the requirements of GTIM-04-027 “Direct Examination Preparation”.

2.0 DIRECT EXAMINATION

2.1 Responsibility: GTIM Field Inspector or designee

2.1.1 Follow the requirements of GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

2.1.2 Verify the exposure of the intended feature at the dig site.

2.1.2.1 If the feature is a “low point” on the pipe, expose a sufficient length of pipe within the consequence area to confirm that the exposure of the lowest area of the pipe for direct examination.

2.1.2.2 If the feature is a critical angle, confirm that the actual pipeline inclination angle is greater than or equal to the calculated critical angle.

2.1.2.2.1 If the pipeline inclination angle is less than the calculated critical angle, contact the GTIM Field Supervisor or GTIM Engineer for assistance. A new direct examination site may need to be selected.

2.1.3 Document the inclination angle found on GTIM-90418 “Pipeline Inspection Direct Examination”.

2.1.4 Take photographs that clearly show the pipeline inclination angle.

2.1.4.1 Indicate the direction of the pipe inclination (i.e., “E” with an arrow pointing to the east).

2.2 Responsibility: Direct Examination Crew

2.2.1 Perform the inspection activities.

2.2.2 Document each examination on a separate GTIM-90418.

2.2.2.1 Refer to GTIM-04-008 “Data Collection for Integrity Management Direct Examinations” for details.

2.2.3 In addition to collecting ICDA data, collect data as required for any concurrent ECDA efforts, which will help to minimize the number of excavations.

2.2.3.1 Refer to GTIM-04-008 “Data Collection for Integrity Management Direct Examinations”.

2.3 Responsibility: Direct Examination Crew

2.3.1 Remove coating if required for Non-Destructive Examination (NDE).

2.3.1.1 If it is possible to conduct the NDE through the coating (i.e., FBE coating), it may not be necessary to remove the coating.

2.4 Responsibility: Direct Examination Crew

2.4.1 Perform the NDE.

2.4.1.1 Evaluate the location identified for direct examination by using one of the following NDE techniques listed below:

- Long Range Ultrasonic Thickness Testing (LRUT):
  - Refer to GTIM-04-001 “Long Range Ultrasonic Testing” for details.
- Ultrasonic Thickness Measurement (UT):
  - UT measures the actual wall thickness at the point of sensor placement.
  - Refer to the Gas Construction Standards, section 5.3.6, “Ultrasonic Inspection of Welds”.
  - Perform enough UT measurements to confirm the pipe is adequately evaluated. Focus measurements on the bottom half of the pipe.
  - Apply tool tolerances provided in the manufacturer’s manual for each specific instrument.
- Guided Wave Ultrasonic Testing (GWUT).

2.4.1.2 Use other tools, if necessary, capable of determining the wall thickness. Examples may include UT mapping or radiography.

2.4.1.2.1 Obtain the approval of the GTIM Field Supervisor before use.

2.4.1.3 At the intended feature (e.g., low point or critical angle), perform an NDE for a minimum of three (3) feet in each direction from the center of the feature.

2.4.1.3.1 Expanding the NDE area will help confirm that any internal corrosion, if present, is detected.

2.4.1.3.2 If detecting internal corrosion during the NDE, continue the examination until INTERNAL CORROSION IS NO LONGER DETECTED.

Note: If NDE detects a metal loss greater than 12.5% of the nominal wall thickness, NACE SP0206-2016 considers internal corrosion present unless an engineering analysis can provide technical justification explaining that the wall loss was something besides corrosion (i.e., manufacturing defects, etc.).

2.4.2 Consult with GTIM Field Supervisor or GTIM Engineer to calculate the remaining strength per ASME B31G-1991 for each internal corrosion defect.

Note: Because mapping internal corrosion defects are more challenging than mapping external corrosion defects, CNP requires using ASME B31G-1991 for remaining strength calculations of internal corrosion defects, which is more conservative than RSTRENG calculations.

It is acceptable to use the RSTRENG software by Technical Toolboxes to perform remaining life calculations by using the ASME B31G-1991 remaining strength calculations.

2.4.3 Perform any required pipeline repairs of anomalies found during the excavations per CNP’s O&M.

2.5 Responsibility: GTIM Field Inspector or designee

2.5.1 Complete Form 3020 “Excavation Repair Report”.

2.5.1.1 Submit to the GTIM Field Supervisor and Local Operations.

2.6 Responsibility: GTIM Field Supervisor or designee

2.6.1 Load all direct examination data to the network and notify the GTIM Engineer once the data is available on the network.

2.6.2 Complete applicable sections of GTIM-90458. Place a copy of the form in the IM file.

3.0 DATE OF DISCOVERY

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Declare Discovery of Condition on the date of the particular direct examination.

4.0 ADDRESSING INTERNAL CORROSION

4.1 Responsibility: GTIM Field Supervisor or GTIM Engineer or designee

4.1.1 When finding internal corrosion at either of the primary examination locations in an ICDA region, perform steps as follows:

- Respond to defects and remediate per GTIM-05-001 “Addressing Conditions Found During an Integrity Assessment”;
- Perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method per GTIM-03-001 “Assessment Method Selection”; and
- Evaluate the potential for internal corrosion in all pipeline segments (covered and non-covered) with guidance from GTIM-08-005 “Evaluating Similar Conditions”.

4.1.1.1 If remediation requires replacement of a large section of pipe, engage Gas Transmission Engineering.

4.1.2 Perform additional direct examinations.

4.1.2.1 When finding internal corrosion defects, perform at least one (1) additional direct examination of the pipe in each covered segment that is within the ICDA region.

4.1.2.1.1 Determine the location of the additional direct examination where the likelihood of internal corrosion is high (i.e., pipeline inclination less than but close to the critical angle, water trapping feature) per the flow modeling and previous analysis.

4.1.2.1.2 Perform the additional excavation(s) as a part of the current assessment cycle.

4.1.2.1.3 Schedule the excavation as soon as possible consistent with permit requirements, availability of excavation crews, and other considerations.

4.1.2.2 Perform additional excavations until INTERNAL CORROSION IS NO LONGER DETECTED.

4.1.2.2.1 Consider alternate assessment methods (i.e., In-Line Inspection, Pressure Testing) if multiple additional examinations are required.

4.1.3 Perform a root cause analysis to determine and document the root cause of any significant corrosion activity.

4.1.3.1 Refer to GTIM-04-012 “Root Cause Analysis” for guidance.

4.1.4 Evaluate non-covered segments in similar ICDA regions.

4.1.4.1 When finding internal corrosion within a covered pipeline segment, review similar pipeline segments for internal corrosion.

4.1.4.2 Refer to GTIM-08-005 “Evaluating Similar Conditions”.

4.1.4.3 As appropriate, remediate the conditions found per GTIM-05-001 “Addressing Conditions Found During Integrity Assessment”.

4.1.4.4 Each pipeline may be sufficiently unique that findings in one region do not necessarily apply to other regions.

4.1.4.4.1 The basis for this determination is that each pipeline segment that may be part of an ICDA region may have different producers supplying it.

4.1.4.4.2 Product quality and volumes supplied from each producer are not comparable to other producers.

5.0 DOCUMENTATION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Create a work order

5.1.1.1 A work order is required to incorporate the following into GIS:

- All data collected during excavations and direct examinations (i.e., GTIM-90418, etc.);
- Any pipeline modifications made; and
- Any known pipe attributes collected or observed during assessments that are not correct in GIS.

5.1.2 Confirm the following documentation is complete:

- GTIM-90458 “ICDA - Direct Examination”;
- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- GTIM-90440 “Direct Examination Scope of Work” for each location;
- GTIM-90441 “Dig Plan Summary”;
- Form 1021 “Job Safety Briefing Form”;
- Reports from specialty testing (i.e., magnetic particle, OES);
- GTIM-90501 “Response Schedule”, if applicable; and
- Form 3020 “Excavation Repair Report”.

5.1.3 Conduct a meeting with the GTIM Manager to review the ICDA Direct Examination documents.

5.1.4 Retain the ICDA documentation for the useful life of the pipeline.

<<END>>

GTIM-04-056 ICDA Post-Assessment

PURPOSE: To establish a standardized method for performing the Post-Assessment phase of the Dry Gas - Internal Corrosion Direct Assessment (ICDA) methodology.

REFERENCES: 49 CFR 192.927; NACE SP0206-2006;

SECTIONS:

- More Restrictive Criteria
- Reassessment Intervals
- ICDA Effectiveness
- Monitoring
- Performance Measures
- Feedback and Continuous Improvement
- Changes and Internal Communications
- Post-Assessment Documentation

1.0 MORE RESTRICTIVE CRITERIA

1.1 Responsibility: GTIM Engineer or designee

1.1.1 For a first time ICDA on a pipeline segment, implement ‘more restrictive criteria’ during the Post-Assessment phase. Options include, but are not limited to:

- Use a shorter interval than determined for the first reassessment;
- When more than one ICDA region covers the evaluated pipeline segment, use the lowest reassessment interval of all the ICDA regions as the first reassessment interval for all segments;
- Implement additional mitigative measures;
- Track additional performance measures;
- Assign more frequent monitoring of installed internal corrosion monitoring devices; and
- Assign more frequent analysis of liquids recovered from the pipeline.

1.1.2 Document the use of more restrictive criteria on GTIM-90459.

2.0 REASSESSMENT INTERVALS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Update GTIM-90501 “Response Schedule” to document the assessment and required response times for remediation activities.

2.1.1.1 Ensure documentation of all indications identified on GTIM-90501, regardless if excavated or not.

2.1.1.2 Continuously update the Response Schedule form as information becomes available for ongoing repairs.

2.1.2 If growth rate data is available, document the Remaining Life Calculations on GTIM 90417 “Remaining Life and Reassessment Intervals”.

Note: At this time, there is not an industry-accepted default growth rate for internal corrosion. As a result, CNP will use the approach documented in GTIM-06-001 'Determining Reassessment Intervals" for determining reassessment intervals for ICDA instead of estimating the reassessment interval to be half the time required for the largest defect to grow to a critical size.

In the event CNP does have measured growth rate data available, applicable to the assessed segment, CNP will calculate the remaining life based on the Remaining Life equation in GTIM-04-005 "ECDA Post-Assessment". CNP will determine the reassessment interval based upon ½ the Remaining Life, or the table in GTIM-06-001, whichever is less.

2.1.3 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 "Predictive Failure Pressure".

2.1.4 Determine the reassessment interval per GTIM-06-001 "Determining Reassessment Intervals".

2.1.5 Document the reassessment interval on GTIM-90459 "ICDA - Post-Assessment".

2.1.6 Add reassessments, confirmatory-direct assessments, and remediation activities to the assessment schedule calendar.

3.0 ICDA EFFECTIVENESS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Assess the effectiveness of the ICDA process using the validation digs on the "ICDA Effectiveness" section of GTIM-90459.

3.1.1.1 Determine effectiveness by correlating internal corrosion detected versus the predicted water hold up locations.

3.1.2 Document the correlation between actual internal corrosion found and the location predicted for each examination site on GTIM-90459.

3.1.3 If corrosion was not as expected or predicted, re-evaluate the ICDA process.

3.1.3.1 Re-evaluation may include:

- Recalculation of the critical angle;
- Selection of additional, new locations for direct examination; and
- Assess the line segment with an alternate integrity assessment method.

3.1.4 Document the need for re-evaluation of the ICDA process on GTIM-90459, including the re-evaluation method chosen.

4.0 MONITORING

4.1 Responsibility: GTIM Engineer or designee

4.1.1 When finding internal corrosion, prepare a detailed Internal Corrosion Monitoring Plan for each covered segment.

4.1.2 Ensure the Internal Corrosion Monitoring Plan includes one (1) or more of the following continuous monitoring techniques:

- Coupon installations to determine ongoing internal corrosion and provide corrosion rate measurement;
- Installation of UT sensors or electronic probes to monitor wall thickness change over time;
- Establish a periodic liquid removal program at covered segment low points. The program should include liquid analysis for the presence of corrosion products.
- Use of continuous monitoring technology or programs that test for the presence of precursors or the actual occurrence of internal corrosion.

4.1.2.1 Refer to GTIM-06-003 “Internal Corrosion Control Program”.

4.1.2.2 Develop the monitoring plan within one (1) year of completing the ICDA assessment.

4.1.3 Determine the frequency of monitoring and liquid analysis using risk factors specific to the covered segment.

4.1.3.1 Base frequencies on integrated data from all previous integrity assessments. Considerations may include one or more of the following factors:

- The relative severity of the internal corrosion detected;
- Potential for continued water input to the pipeline segment;
- NACE recommended (or best industry practice) monitoring or measuring interval for the type of device installed;
- Projected liquid volumes; and
- Continuous or sporadic liquid input.

4.1.4 Perform one (1) of the following if monitoring indicates evidence of internal corrosion activity:

- Conduct a direct examination at locations downstream from where electrolyte may have entered the pipeline.
- Perform an integrity assessment of the affected covered segment with an in-line inspection or pressure test.

4.1.5 Initiate the Change Management process if applicable.

4.1.5.1 Refer to GTIM-11-001 “GTIM Change Management”.

5.0 PERFORMANCE MEASURES

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Document Performance Measures on GTIM-90459 and GTIM-90901 “Performance Measures”.

5.1.1.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

5.1.1.2 Document the information on both the ‘Performance Measures’ section of GTIM 90459 and the total HCA miles or MCA miles assessed on the top of the form.

5.1.2 If the performance measures do not show improvement between ICDA applications, re-evaluate the ICDA process per section 2.0 “ICDA Effectiveness”, and evaluate alternative methods of assessing the integrity of the pipeline.

6.0 FEEDBACK AND CONTINUOUS IMPROVEMENT

6.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

6.1.1 Gather feedback from participating personnel (e.g., GTIM Field Supervisor, GTIM Field Inspections, Local Operations, Corrosion Control, etc.). Areas where feedback may be incorporated include, but are not limited to:

- Accuracy of flow model prediction of potential internal corrosion locations;
- Data collected during direct examinations;
- In-process evaluations;
- Validation direct examinations;
- Criteria for monitoring ICDA effectiveness;
- Scheduled monitoring and re-assessment intervals; and
- Root cause analysis.

6.1.2 Solicit “lessons learned” from project participants upon completion of the ICDA project.

6.1.2.1 If appropriate, invite the Service Provider(s) to the meeting.

6.1.2.2 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- Modifications to the ICDA process.

6.1.2.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

6.2 Responsibility: GTIM Engineer

6.2.1 Review the results of the feedback and determine additional areas of improvement.

6.2.2 Document feedback and continuous improvement activities on GTIM-90459.

6.2.3 If applicable, initiate a Change Management per GTIM-11-001 “GTIM Change Management” for each recommended procedural change, each additional P&M recommendation, and any other potential process improvement.

6.2.4 Summarize all repairs and any required or recommended follow-up activities on GTIM-90424 “Summary Report to Local Operations”.

6.2.4.1 Send to Local Operations and Corrosion Control.

7.0 CHANGES AND INTERNAL COMMUNICATIONS

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 Document any deviations from the documented procedures that occurred during the ICDA from the documented plan on GTIM-91101 “Pipeline Event Evaluation”.

7.1.2 Notify the affected parties per GTIM-11-001 “GTIM Change Management” and GTIM-13-002 “Internal Communications”.

7.2 Responsibility: GTIM Engineer or designee

7.2.1 Confirm the creation of all Change Management entries. Document the date confirmed on GTIM-90459.

7.2.2 Compare and confirm data collected from field activities matches data recorded on the GTIM-90300 “Data Collection” and GTIM-90400 “DA Data Element Table” during the Pre-Assessment phase of this assessment.

7.2.2.1 Resolve all inconsistencies working with the GTIM Field Inspectors to clarify and update the appropriate documents.

7.2.2.1.1 Route any modified field documents to the GTIM Field Supervisor for review and approval.

7.2.2.2 Create a work order to incorporate the data corrections in GIS, if needed.

8.0 POST-ASSESSMENT DOCUMENTATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Perform a 100% quality check of all requested GIS updates. Document the date completed on GTIM-90459.

8.1.2 Confirm completion of Post-Assessment documentation. Documentation includes, but is not limited to, the following:

- Reports from specialty testing (i.e., magnetic particle, OES);
- GTIM-90209 “Threat Analysis”;
- GTIM-90417 “Remaining Life and Reassessment Intervals”, if applicable;
- GTIM-90418 “Pipeline Inspection Direct Examination” for each dig location;
- GTIM-90424 “Summary Report to Local Operations”;
- GTIM-90459 “ICDA - Post-Assessment”;
- GTIM-90480 “Flow Modeling for ICDA”;
- GTIM-90501 “Response Schedule”, if applicable;
- GTIM-90804 “Preventive and Mitigative Measures”;
- TIMP-91102 “Integrity Management Change Record”, if applicable; and
- Form 1021 “Job Safety Briefing Form”.

8.1.3 Retain copies of communication with the Service Provider, including any discussions or analyses leading to significant decisions or decisions to reanalyze data.

8.1.3.1 Include all forms of communications (i.e., phone conversations, voice messages, etc.), documenting with an email to the other parties confirming your understanding of the discussion items.

8.1.4 Route pertinent Post-Assessment documentation to Corrosion Control and Local Operations along with the location of the Post-Assessment documentation file.

8.1.5 Conduct a meeting with the GTIM Manager to review the Post-Assessment documentation and obtain approval.

8.1.6 Once the Post-Assessment is approved, the ICDA process is considered complete.

8.1.7 Confirm all assessment documentation is stored in the IM file within thirty (30) days of completing the ICDA process.

<<END>>

GTIM-04-063 SCCDA Pre-Assessment and Indirect Inspection

PURPOSE: To establish a standardized method for performing the Pre-Assessment and Indirect Inspection phases of a Stress Corrosion Cracking Direct Assessment (SCCDA) method.

REFERENCES: 49 CFR 192.929; ASME/ANSI B31.8S-2004, Appendix A; NACE SP0204-2015, Section 3;

SECTIONS:

- Background
- Personnel Qualifications
- Pre-Assessment Data Collection
- Tool Selection for Supplemental Data
- Pre-Assessment Documentation
- Indirect Inspection Using ECDA Methodology
- Indirect Inspection Using In-Line Inspection
- Indirect Inspection Documentation
- Determination of Examination Sites
- Subsequent Applications of SCCDA
- Preparation of the Dig Plan

1.0 BACKGROUND

1.1 Stress Corrosion Cracking Direct Assessment (SCCDA) should identify and address locations where Stress Corrosion Cracking (SCC) has occurred, is occurring, or might occur.

1.2 Depending upon the applicable threats, SCCDA may be used as a sole assessment method or in conjunction with other assessment methods such as a Pressure Testing or In-Line Inspection.

1.3 Segments identified as susceptible to Near-Neutral SCC due to an unknown pipe grade resulting in a SMYS greater than 60% will be assessed for SCC until the pipe grade is determined.

Note: CNP applies the SCCDA procedures when identifying SCC as a threat to a pipeline segment.

1.4 Currently, PHMSA considers near-neutral SCCDA an “other technology” requiring approval from PHMSA at least 90 days in advance of using this method following the requirements of GTIM-13-001 “Required Notifications to Regulatory Agencies”.

1.4.1 PHMSA does not consider high pH SCCDA an “other technology” assessment method.

1.5 SCCDA consists of four (4) phases:

- Pre-Assessment;
- Indirect Inspection;
- Direct Examination; and
- Post-Assessment.

2.0 PERSONNEL QUALIFICATIONS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Confirm any third-party service provider performing any part of the SCCDA process meets the following qualifications:

- Meets or exceeds the qualifications listed in the specific procedure being implemented or performed; and
- Meets or exceeds the qualifications of CNP personnel who would otherwise be performing the task.

2.1.2 CNP personnel responsible for the SCCDA process will meet one (1) of the following qualification requirements:

- A minimum of five (5) years of relevant pipeline experience;
- Technical degree with two (2) years relevant pipeline experience;
- NACE International CP Technician (CP Level 2), or higher; or
- A degreed engineer.

3.0 PRE-ASSESSMENT DATA COLLECTION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Collect and integrate data for the proposed assessment segment.

3.1.1.1 Sources of information include, but are not limited to:

- Operating and maintenance data;
- Design and construction records;
- Pipeline inspection reports;
- Corrosion control survey records; and
- System maps.

3.1.1.2 Refer to GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

3.1.2 Collect information relative to the covered segments.

3.1.2.1 Include information from direct examinations performed during routine O&M activities.

3.1.3 Document information on GTIM-90400 “DA Data Element Table” or in the appropriate database.

3.1.4 Listed below in Table 04-063-1, are the minimum data requirements for performing SCCDA on a pipeline segment.

3.1.4.1 Refer to NACE SP0204-2015, Table 1: “Factors to Consider in Prioritization of Susceptible Segments and in-Site Selection for SCCDA” for guidance on conservative assumptions.

Table 04-063-1: Mandatory Data

Pipe Related	
• Pipe material *(i.e., steel, cast iron, etc.)*	• Diameter
• Wall thickness	• Bare pipe
• Shop coating type(s)	• Pipe Manufacturer • Hard spots

Construction – Related	
• Year installed	• Location of dents • Location of casings
• Alignment sheets, route maps, and aerial photos	• Construction practices
• Location of weights and anchors	• Field coating type
Soils and Environmental	
• Land use, past and current *(e.g., pasture, residential)*	• Topography
• Soil characteristics (i.e., moisture, CO_2, etc.)	• Drainage
• Continuous standing groundwater *(e.g., ponds, lakes)*	• Transitional environmental conditions • Location of river crossings
Corrosion Control	
• Type of cathodic protection system and condition (anodes, rectifiers, and locations)	• Years without CP applied
Operational Data	
• Evidence of SCC - for both covered and non-covered segments	• Leak and rupture history (SCC) - for both covered and non-covered segments
• Specific types of pressure fluctuations • Operating stress level *(%SMYS)* and fluctuations	• Direct inspection and repair history
• Product type • Pipe operating pressure	• Pipe operating temperature

3.1.5 Listed below in Table 04-013-2 are the non-mandatory data requirements.

3.1.5.1 Refer to NACE SP0204-2015, Table 1: “Factors to Consider in Prioritization of Susceptible Segments and in-Site Selection for SCCDA” for guidance on conservative assumptions.

3.1.5.2 Clearly indicate any data assumptions on the GTIM-90400 “DA Data Element Table”.

Table 04-013-2: Non-Mandatory Data

Pipe Related	
• Pipe Grade	• Year manufactured
• Seam type	• Surface preparation
Construction – Related	
• Locations of valves, mechanical coupling, and cast-iron components	• Location of bends *(e.g., wrinkle bends, miter bends)*
• Construction practices (DUPLICATE)	• Route changes
Corrosion Control	
• CP evaluation criteria	• CP maintenance history
• Coating system and condition • Coating fault survey information	• CIS and test station information • CP shielding
Operational Data	
• Hydrostatic retest history	• ILI data from crack-detecting pig
• ILI data from metal-loss pig	• Pipe operating pressure (DUPLICATE)

3.1.6 Utilize one of the following options if one or more of the minimum data elements is unknown or not available:

- Make reasonable, logical, data assumptions; and
- Perform investigative digs.

3.1.7 Review existing Preventive and Mitigative (P&M) measures for the pipeline segment.

3.1.8 If the above options are not appropriate or not performable, SCCDA is not feasible for the line segment.

3.1.8.1 Determine an alternative method of integrity assessment. Refer to GTIM-03-001 “Assessment Method Selection”.

3.1.9 Prepare aerial maps of the HCAs and MCAs for the pipeline segments, including extents.

3.1.10 Document the HCA and MCA segment information for the pipeline segments on GTIM-90470 “SCCDA Pre-Assessment and Indirect Inspection” and GTIM-90209 “Threat Analysis”.

3.1.11 Create a work order if known HCA or MCA or structure information needs correction in GIS.

4.0 TOOL SELECTION FOR SUPPLEMENTAL DATA

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Collect additional data to supplement the data collected during the Pre-Assessment phase. Methods of data collection to consider include:

- Indirect Inspection techniques; and
- In-Line Inspection.

Note: In most instances, perform SCCDA in conjunction with an External Corrosion Direct Assessment (ECDA). In such a case, apply the indirect inspection data from the ECDA process - no additional indirect inspections are necessary.

4.1.2 Select indirect inspection tools for the pipeline segment per the “Indirect Inspection Tool Determination” section of GTIM-04-002 “ECDA Pre-Assessment”.

4.1.2.1 Refer to GTIM-03-005 “In-Line Inspection Pre-Assessment” for ILI tool selection, if appropriate.

4.1.3 A minimum of one (1) technique is required.

4.1.3.1 When utilizing indirect inspection techniques, only one (1) tool is required.

4.1.4 Document on GTIM-90470 why additional data collection is not required, if appropriate.

5.0 PRE-ASSESSMENT DOCUMENTATION

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Confirm the following documentation is complete:

- GTIM-90470 “SCCDA Pre-Assessment and Indirect Inspection”;
- GTIM-90400 “DA Data Element Table”;

- GTIM-90209 “Threat Analysis”;
- GTIM-90313 “In-Line Inspection Pre-Assessment”, if applicable; and
- Aerial Maps.

5.1.2 Create a work order to incorporate or update data attributes.

5.1.3 Maintain the Pre-Assessment documentation for the useful life of the pipeline segment.

6.0 INDIRECT INSPECTION USING ECDA METHODOLOGY

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Prepare for indirect inspections per the requirements of GTIM-04-030 “Indirect Inspection Survey Field Preparation”.

6.2 Responsibility: Indirect Inspection Crew

6.2.1 Conduct indirect inspection(s) according to the applicable procedures:

- GTIM-04-020 “Close-Interval Survey”;
- GTIM-04-021 “Direct Current Voltage Gradient Survey”;
- GTIM-04-022 “Current Attenuation Survey using the Pipeline Current Mapper”; or
- GTIM-04-023 “Alternating Current Voltage Gradient Survey”.

6.2.2 Classify the data per the requirements of the specific procedure. Refer to GTIM-04-003 “ECDA Indirect Inspection”.

7.0 INDIRECT INSPECTION USING IN-LINE INSPECTION

7.1 Responsibility: GTIM Engineer or designee

7.1.1 As applicable, prepare for indirect inspections per the requirements of GTIM-03-005 “In-Line Inspection Pre-Assessment”.

7.1.2 Analyze data per the requirements of GTIM-03-006 “In-Line Inspection and Data Analysis”.

7.1.2.1 Items to consider during the data analysis include:

- Locations of dents and bends;
- Areas of coating disbondment; and
- Areas of known corrosion.

8.0 INDIRECT INSPECTION DOCUMENTATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Maintain the following information in the IM file for the life of the pipeline segment:

- Indirect Inspection data, if applicable;
- GTIM-90411 “Indication Severity Classification & Priority Category”, if applicable;
- In-Line Inspection data, if applicable;
- GTIM-90314 “ILI Inspection and Data Analysis”, if applicable; and
- GTIM-90470 “SCCDA Pre-Assessment and Indirect Inspection”.

9.0 DETERMINATION OF EXAMINATION SITES

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Consider the following information when choosing the locations of direct examinations[1]:

9.1.1.1 In Electric-Resistance Welded (ERW) pipe manufactured by Youngstown Sheet and Tube in the 1950s, other pipeline operators found near-neutral SCC.

9.1.1.2 Other pipeline operators found near-neutral SCC along Double Submerged Arc Welds (DSAW) and some electric-resistance welds.

9.1.1.3 Other pipeline operators found high-pH SCC under coal tar, asphalt, and tape coatings.

9.1.1.4 Other pipeline operators found near-neutral SCC under tape and asphalt coatings.

9.1.1.5 Other pipeline operators found near-neutral SCC under buoyancy-control weights (i.e., river weights).

9.1.2 Using information from GTIM-90400 “DA Data Element Table” or appropriate database and the data from supplemental inspections (i.e., indirect inspections, in-line inspection), determine direct examination locations.

9.1.2.1 Determine if the line segment has a history of identified SCC.

9.1.2.1.1 If yes, determine if there were characteristics of the pipe or environment that were unique and may have attributed to the SCC. Unique characteristics may include, but are not limited to:

- Areas of mechanical damage;
- Geophysical features such as soil moisture and drainage;
- Steep slopes with soil subsidence; and
- Coating anomalies.

9.1.2.1.1.1 If unique characteristics were present in the past, document the unique characteristics on form GTIM-90470.

9.1.2.1.1.2 Choose a minimum of four (4) locations within the consequence area with similar characteristics for direct examination.

9.1.2.1.2 If the line segment does not have a history of identified SCC and has a previous indirect inspection such as a Close Interval Survey or a Direct Current Voltage Gradient Survey, review the data for coating indications and areas of possible coating disbondment.

9.1.2.1.2.1 Pipe-to-soil readings more positive than -850 mV may indicate areas of coating disbondment. A DCVG indication may or may not correspond with this location.

9.1.2.1.2.2 Select a minimum of four (4) locations with coating indications of possible coating disbondment for direct examination, within the consequence area.

9.1.2.1.2.3 Also, consider the guidance in section 9.1.1 when choosing locations for direct examination.

9.1.2.1.2.4 If there are not four (4) coating indications, select the remaining locations per the requirements of section 9.1.2.

[1] Refer to NACE SP0204-2015, “Stress Corrosion Cracking (SCC) Direct Assessment Methodology”;

9.1.2.1.3 If applicable, identify areas from the In-Line Inspection that have:

- Dents with a coating system that may shield the pipe;
- Corrosion with a coating system that may shield the pipe; and
- Hard spots.

9.1.2.1.3.1 Select a minimum of four (4) locations, within the consequence area, with the above characteristics.

9.1.2.1.3.2 Also, consider the guidance in section 9.1.1 when choosing locations for direct examination.

9.1.2.1.3.3 When identifying several types of anomalies, perform that at least one (1) of the four (4) direct examinations at each type of anomaly.

9.1.2.1.3.4 If there are not four (4) anomalies, select the remaining locations per the requirements of section 9.1.2.

9.1.3 If none of the above indicators apply, review the Pre-Assessment data and select locations with relatively high:

- Stresses;
- Pressure fluctuations; or
- Temperatures fluctuations.

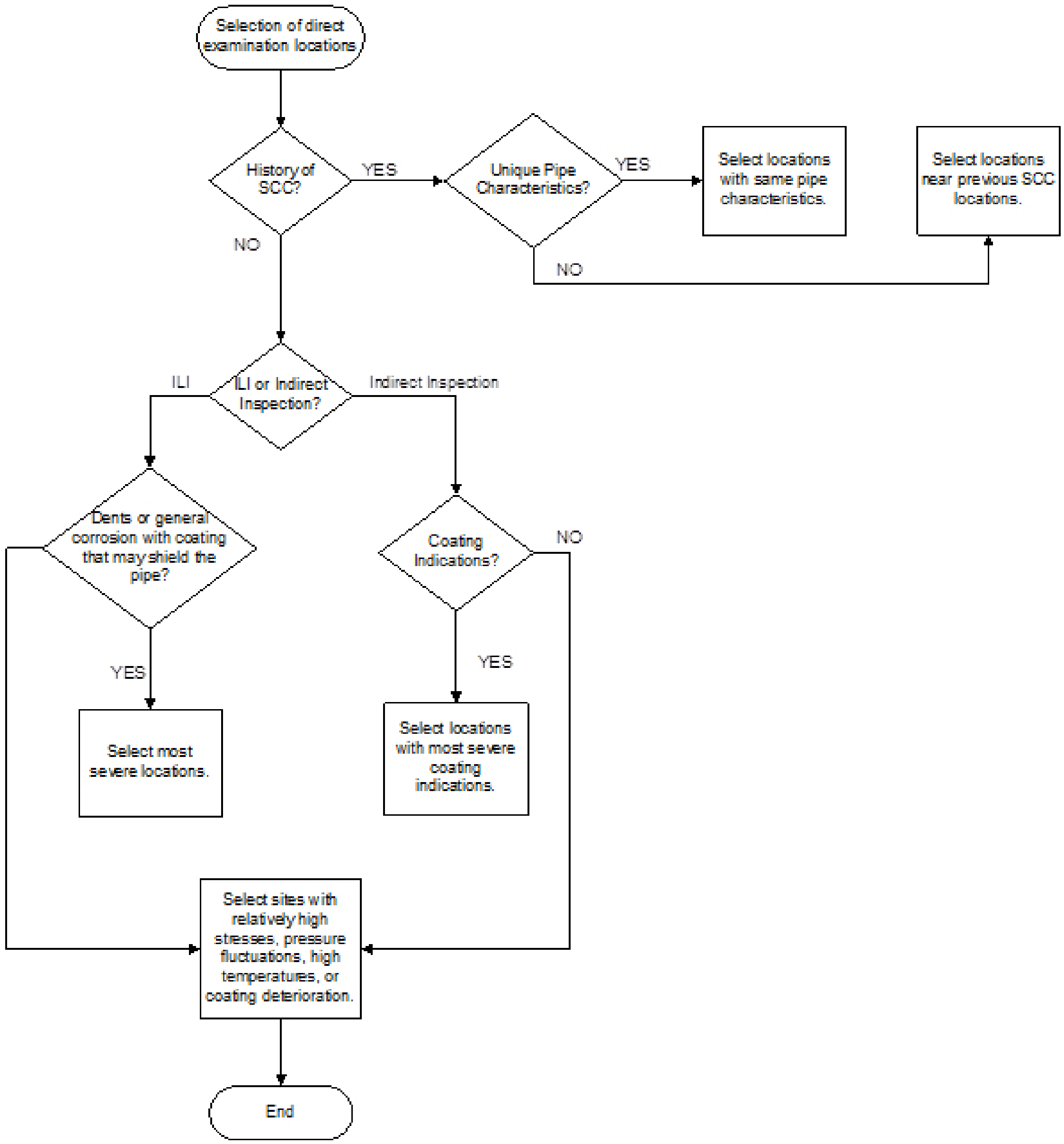
9.1.4 Document the direct examination locations on GTIM-90470.

9.1.4.1 Document the reason(s) for choosing each direct examination location. Examples may include, but are not limited to:

- Location of hard spots;
- Coating indication on ERW pipe manufactured by Youngstown; and
- Location of known soil subsidence.

9.1.5 Refer to the following flow chart for additional guidance.

Figure 04-063-F1: Choosing Direct Assessment Guidance



10.0 SUBSEQUENT APPLICATIONS OF SCCDA

10.1 Responsibility: GTIM Engineer or designee

10.1.1 For subsequent applications of SCCDA in the same area, determine if a previous application(s) identified SCC.

10.1.2 Document any unique features (i.e., steep slopes with subsidence, mechanical damage, etc.) at locations of identified SCC.

10.1.3 Select direct examination locations that have features similar to any previously identified unique features revealed by examination.

10.1.4 If previous examinations did not reveal any unique features, select direct examination areas with stresses, pressure fluctuations, or relatively high temperatures.

10.1.5 Document the direct examination locations on GTIM-90440 “Direct Examination Scope of Work”.

10.1.6 Retain the documentation in the IM file.

11.0 PREPARATION OF THE DIG PLAN

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Refer GTIM-04-026 “Dig Plan Preparation”.

<<END>>

GTIM-04-064 SCCDA Direct Examination and Post-Assessment

PURPOSE: To establish a standardized method for performing the Direct Examination and Post-Assessment phases of a Stress Corrosion Cracking Direct Assessment (SCCDA) method.

REFERENCES: 49 CFR 192 Subpart O; NACE SP0204-2015; ASME/ANSI B31.8S-2004, Appendix A3.4.2;

SECTIONS:

- Direct Examination Preparation
- Direct Examination Data Collection
- Direct Examination Magnetic Particle Inspection
- Direct Examination Documentation
- Post-Assessment
- Feedback and Continuous Improvement
- Changes and Internal Communications
- Post-Assessment Documentation

1.0 DIRECT EXAMINATION PREPARATION

1.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

1.1.1 Prepare for direct examination per the requirements of GTIM-04-027 "Direct Examination Preparation".

1.1.2 Consider opportunistically performing other data collection activities such as GTIM-02-010 "Material Verification".

1.1.3 Complete all direct examinations within 180 days of receiving the final Indirect Inspection report whenever feasible.

1.2 Responsibility: Direct Examination Crew or GTIM Field Supervisor or GTIM Field Inspector

1.2.1 Verify aboveground parameters for the dig site.

1.2.2 Utilize one of the following techniques for location selection of the areas of corrosion activity or coating indications:

- Measure the location from a known reference point identified during the indirect inspection;
- Repeat the indirect inspection in the area of the planned direct examination; or
- GPS coordinates for the indicated location.

1.2.3 Verify the following location of features with In-Line Inspection data, if used:

- Aboveground markers;
- Valves; and
- Casings.

1.2.3.1 Confirm that the exposed joint corresponds to the joint containing the ILI indication by comparing:

- The measured distance between girth welds;
- Circumferential position of the longitudinal seam weld; and
- Location of aboveground markers.

2.0 DIRECT EXAMINATION DATA COLLECTION

2.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

2.1.1 Select a reference point for each excavation and document on GTIM-90418 "Pipeline Inspection Direct Examination".

2.1.2 Perform data collection per the requirements of GTIM-04-008 "Data Collection for Integrity Management Direct Examination".

2.1.3 The table below lists the required data collection at a dig site:

Table 04-064-1: Data Collected at a Dig Site in an SCCDA Program

Data Element	When Collected	Use and Interpretation of Results
Coating system *(type and condition)*	Before coating removal	• Verification of Pre-Assessment data; • Predictive model development;
Corrosion defects assessment	After coating removal	• Helps establish the type of SCC, if present;
Weld seam type identification	After coating removal	• Field site verification;
Magnetic particle inspection	After coating removal	• Establishes if SCC is present;
Location and size of each cluster	After coating removal	• Helps establish the correlation of location with other measured parameters;
Crack length and depth measurements	After coating removal	• Helps establish the significance of cracking and determines whether there is an immediate integrity concern;
Photograph clusters	After coating removal	• Confirms crack measurements;
Wall thickness measurements	After coating removal	• Field site verification;
Pipe diameter measurement	After coating removal	• Field site verification;

2.2 Responsibility: GTIM Engineer or designee

2.2.1 Create a work order to maintain direct examination data in GIS.

2.2.1.1 Verify the incorporation of pipeline assessment data into GIS. Examples include the following:

- Pipe attributes found during bell hole examination (e.g., OD, Wall Thickness, Grade, etc.);
- Centerline changes; and
- Repairs made.

3.0 DIRECT EXAMINATION MAGNETIC PARTICLE INSPECTION

3.1 Responsibility: Direct Examination Crew

3.1.1 Perform a magnetic particle inspection on the pipe body per CNP's Gas Construction Standards, section 5.3.8, "Magnetic Particle Inspection of Welds".

3.1.2 Document the results on GTIM-90471 "Magnetic Particle Inspection Report".

3.1.2.1 Documentation includes:

- Cluster-ID;
- Axial length, circumferential length, maximum length, and width of the colony;
- Presence of interlinking;
- Presence of interacting;
- Maximum crack length;
- Presence of “significant cracking”;
- The maximum crack depth and method of determination;
- Average circumferential separation of adjacent cracks;
- Results of “In situ” metallographic, if applicable;
- Ultrasonic measurements of wall thickness at cluster location; and
- Photographs of the crack cluster.

3.1.2.2 Complete a separate form for each cluster of cracks.

3.2 Responsibility: GTIM Field Inspector or designee

3.2.1 Inform the GTIM Field Supervisor and GTIM Engineer of verified SCC at any location.

3.3 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

3.3.1 Determine if the cracks are interlinking.

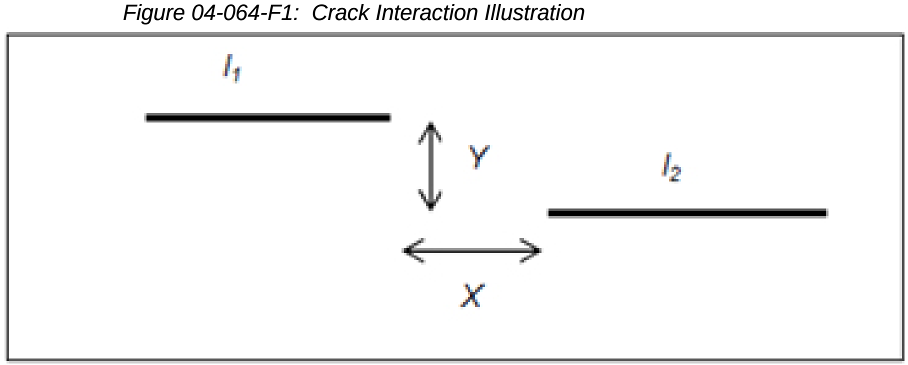
3.3.1.1 Cracks are interlinked if they have physically joined (coalesced) to form a single larger crack.

3.3.2 Determine if the cracks are interacting.

3.3.2.1 Crack interaction is dependent on the circumferential and axial separation between individual (or interlinked) cracks.

3.3.2.2 Two neighboring cracks, as illustrated below, are defined as interacting if the circumferential spacing equation for *Y* is true, and the axial spacing equation for *X* is true:

Figure 04-064-F1: Crack Interaction Illustration



$$Y \leq 0.14 \frac{(l_1 + l_2)}{2}$$

$$X < 0.25 \frac{(l_1 + l_2)}{2}$$

where:

l_1 and l_2 are the individual crack lengths

3.3.3 Determine the maximum crack length, defined as the length of the longest interacting and interlinking crack.

3.3.4 Determine the presence of “significant” cracking.

3.3.4.1 Determine if the deepest crack is greater than 10% of the wall thickness.

3.3.4.2 Determine if the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.

3.3.4.3 Significant cracks could fail in a hydrostatic test.

3.3.5 Determine the maximum crack depth.

3.3.5.1 A method commonly used to determine the maximum depth of the longest interlinked crack at a dig site is by grinding or buffing, in conjunction with a Magnetic Particle Inspection.

3.3.5.1.1 Before grinding or buffing on a pressurized line, determine if a reduction of line pressure is warranted.

3.3.5.1.2 Determine the initial wall thickness by an Ultrasonic Test (UT) per the Gas Construction Standards, section 5.3.6, “Ultrasonic Inspection of Welds”.

3.3.5.1.2.1 Apply tool tolerances provided in the manufacturer’s manual when utilizing specific instruments.

3.3.5.1.3 Refer to specific guidelines found in the PRCI Pipeline Repair Manual[1].

3.3.5.2 Assume all other cracks are less deep.

3.3.6 Determine the average circumferential separation of adjacent cracks.

3.3.7 Use in situ metallography to examine the microstructure of the pipe and the path of the stress corrosion cracks, if appropriate.

3.3.7.1 Establish the type of Stress Corrosion Cracking (SCC).

3.3.7.2 Use qualified personnel for metallographic preparation and the analysis of the microstructures.

3.3.8 Determine the wall thickness at cluster location using Ultrasonic measurement per the Gas Construction Standards, section 5.3.6, “Ultrasonic Inspection of Welds”.

3.3.8.1 Apply tool tolerances as provided in the manufacturer’s manual when utilizing specific instruments.

3.3.8.2 Estimate the failure pressure of the pipe segment containing the SCC per GTIM-05-005 “Predictive Failure Pressure”.

3.3.9 Photograph crack cluster.

3.3.10 Document all information on GTIM-90471 “Magnetic Particle Inspection”.

3.3.11 Whenever feasible, submit all documentation within 60 days of completing the field activities.

[1] Pipeline Research Council International (PRCI), “Pipeline Repair Manual”, 2006;

3.4 Responsibility: GTIM Engineer or designee

3.4.1 Determine the cause of cracking.

3.4.1.1 Near-neutral-pH SCC is frequently associated with light surface corrosion of the pipe.

3.4.1.2 High-pH SCC is usually not associated with apparent external corrosion.

3.4.1.3 Other causes may include mechanical damage or non-injurious mill imperfections.

3.4.2 Confirm the type of SCC. In-situ metallography might be required.

3.4.2.1 High-pH SCC is intergranular and typically branched with little evidence of corrosion of the pipe outside surface and crack walls.

3.4.2.2 Near-neutral-pH SCC is transgranular and typically is unbranched, usually with evidence of corrosion of the pipe outside surface and crack walls.

3.4.2.3 Near-neutral-pH SCC tends to be wider than high-pH SCC.

3.4.3 For guidance on the identification or evaluation of cracking, refer to the CEPA "Stress Corrosion Cracking, Recommended Practices"[2].

3.4.4 Document results on GTIM-90471 "Magnetic Particle Inspection Report".

4.0 DIRECT EXAMINATION DOCUMENTATION

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Confirm the following documentation is complete:

- GTIM-90418 "Pipeline Inspection Direct Examination" for each location;
- GTIM-90440 "Direct Examination Scope of Work" for each location;
- GTIM-90441 "Dig Plan Summary";
- GTIM-90471 "Magnetic Particle Inspection", if applicable;
- GTIM-90315 "In-Line Inspection - Validation Examination", if applicable;
- Form 3020 "Excavation Repair Report"; and
- Form 1021 "Job Safety Briefing Form".

4.1.2 Create a work order for known data attributes that need correction in GIS.

4.1.3 Maintain documentation in the IM file.

5.0 POST-ASSESSMENT

5.1 Responsibility: GTIM Field Supervisor or GTIM Engineer

5.1.1 Recommended actions to mitigate or preclude future stress cracking corrosion includes:

- Repair or removal of the affected pipe length;
- Pressure testing;
- Engineering critical assessment to evaluate the risk and identify further mitigation methods;

[2] Canadian Energy Pipeline Association (CEPA), "Stress Corrosion Cracking, Recommended Practices", 2nd Edition, 2007;

- Document the risk evaluation of SCC and provide a technically sound plan demonstrating pipe integrity. Consider the defect growth mechanism of the SCC process.

5.1.1.1 If remediation requires replacement of a large portion of the pipe, engage Gas Transmission Engineering to perform the replacement.

5.1.2 Document the recommended mitigative actions in the “Mitigative Action” section of GTIM-90475 “SCCDA Direct Examination and Post-Assessment”. Include the following in the documentation:

- Mitigation recommendation;
- Justification for mitigative measure; and
- Timeline for mitigation.

5.1.3 Submit the mitigation recommendations to the GTIM Manager for approval and budgeting purposes.

5.2 Responsibility: GTIM Engineer or designee

5.2.1 Develop and document a pressure re-test program if an in-service leak or rupture occurs that is attributable to SCC.

5.2.1.1 Perform the pressure test according to ASME/ANSI B31.8S-2004, Appendix A3.4.2.

5.2.1.2 Refer to GTIM-03-003 “Pressure Testing” for additional information.

5.2.2 Perform the pressure test within twelve (12) months of the failure.

5.2.2.1 Alternatively, replace the pipe within twelve (12) months.

5.2.3 For verified SCC occurrences, review interactive threats for the pipeline.

5.2.3.1 Refer to GTIM-02-021 “Threat Identification”.

5.2.3.2 Update threats for the line if needed.

5.3 Responsibility: GTIM Engineer or designee

5.3.1 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

5.3.2 Determine the reassessment interval, per GTIM-06-001 “Determining Reassessment Intervals”.

5.3.3 Document the reassessment interval in the “Reassessment Interval” section of GTIM-90475.

5.3.4 Update GTIM-90501 “Response Schedule” to document the assessment and required response times for remediation activities.

5.3.4.1 Ensure all indications identified are documented on GTIM-90501, regardless of excavation or remediation.

5.3.4.2 Update the Response Schedule form with ongoing repair information.

5.3.5 Add reassessment and confirmatory direct assessment dates, including remediation activities, to the assessment schedule calendar.

5.3.6 Assess the effectiveness of the SCCDA process using the “SCCDA Effectiveness” section of GTIM-90475.

5.3.6.1 Additional methods of assessing the effectiveness of the assessment include:

- Comparison of results for selected direct examination locations with results from validation digs;
- Comparison of results of SCCDA for pipeline segments with results from ILI cracking tools;
- Statistical analysis of data from SCCDA direct examinations to identify statistically significant factors associated with the occurrence or severity of cracking; and
- SCC predictive models to determine the reliability of predicting locations and SCC severity.

5.3.6.1.1 CNP does not utilize the methods listed above. However, if the GTIM Engineer determines that additional analysis is needed, this would be appropriate.

5.3.7 Document Performance Measures on GTIM-90901 “Performance Measures”.

5.3.7.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

5.3.7.2 Communicate the Performance Measures to the GTIM Manager.

5.3.8 Document the total HCA or MCA miles assessed on form GTIM-90475.

5.3.9 Create a work order to update data in GIS.

6.0 FEEDBACK AND CONTINUOUS IMPROVEMENT

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Gather feedback from key personnel (e.g., Local Operations, Excavation Crew, Corrosion Control, etc.). Areas where feedback may be incorporated include, but are not limited to:

- Data collected during direct examinations;
- Root cause analysis;
- In-process evaluations;
- Validation direct examinations;
- Criteria for monitoring SCCDA effectiveness;
- Scheduled monitoring; and
- Reassessment intervals.

6.1.2 Solicit “lessons learned” from project participants upon completion of the SCCDA project.

6.1.2.1 If appropriate, invite the Service Provider(s) to the meeting.

6.1.3 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- Modifications to the SCCDA procedures.

6.1.3.1 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

6.2 Responsibility: GTIM Engineer or designee

6.2.1 Create a work order to update data in GIS.

6.2.2 Review the results of the feedback and determine additional areas of improvement.

6.2.3 Document feedback and continuous improvement activities on GTIM-90475 “SCCDA Direct Exam and Post-Assessment”.

6.2.4 Document each recommended procedural change suggestion, each P&M recommendation, additional or modified, and any other potential process improvements.

6.2.4.1 Document on TIMP-91102 “GTIM Change Management Record”.

6.2.5 Summarize all repairs on GTIM-90424 “Summary Report to Local Operations”, and describe any required or recommended follow-up activities.

6.2.5.1 Send to Local Operations and Corrosion Control.

7.0 CHANGES AND INTERNAL COMMUNICATIONS

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 Document any deviations that occurred during the inspection from the documented plan on GTIM-91101 “Pipeline Event Evaluation”.

7.1.2 Notify the affected parties of any changes per GTIM-11-001 “GTIM Change Management” and GTIM-13-002 “Internal Communications”.

7.2 Responsibility: GTIM Engineer or designee

7.2.1 Confirm receipt of all GTIM Change Management requests. Document the date confirmed on GTIM-90475.

7.2.2 Compare and confirm data collected from field activities matches the data recorded on the GTIM-90400 “DA Data Element Table” during the Pre-Assessment phase of this assessment.

7.2.2.1 Resolve all inconsistencies working with the GTIM Field Inspectors to clarify and update the appropriate documents.

7.2.2.1.1 Route any modified field documents to the GTIM Field Supervisor for review and approval.

7.2.2.2 Create a work order to update data in GIS, if needed.

8.0 POST-ASSESSMENT DOCUMENTATION

8.1 Responsibility: GTIM Engineer or designee

8.1.1 Perform a 100% quality check of all requested GIS updates. Document the date confirmed on GTIM-90475.

8.1.2 Confirm completion of Post-Assessment documentation. Documentation includes, but is not limited to, the following:

- GTIM-90313 “In-Line Inspection Pre-Assessment”, if applicable;
- GTIM-90314 “In-Line Inspection and Data Analysis”, if applicable;
- GTIM-90315 “In-Line Inspection - Validation Examination”, if applicable;
- GTIM-90411 “Indication Severity Classification & Priority Category”, if applicable;
- GTIM-90418 “Pipeline Inspection Direct Examination” for each location;
- GTIM-90424 “Summary Report to Local Operations”;
- GTIM-90471 “Magnetic Particle Inspection”, if applicable;
- GTIM-90475 “SCCDA Direct Examination and Post-Assessment”; and

- Aerial Maps.

8.1.3 Conduct a meeting with the GTIM Manager to review the Post-Assessment documentation and obtain approval.

8.1.3.1 Once the Post-Assessment is approved, the SCCDA process is considered complete.

8.1.4 Confirm all assessment documentation is stored in the IM file within 30 days of completing the Post-Assessment process.

<<END>>

GTIM-04-072 Guided Wave Ultrasonic Testing (GWUT)

PURPOSE: To establish a process for implementing Guided Wave Ultrasonic Testing as an integrity assessment method.

REFERENCES: 49 CFR Part 192, Appendix F;

SECTIONS:

- General
- Qualified GWUT Service Providers
- Pre-Assessment
- Safety Considerations
- Performing the Inspection
- Selecting Validation Examination Locations
- Performing Validation Examinations
- GWUT Service Provider Report
- Remediation
- Reassessment Intervals
- Post-Assessment

1.0 GENERAL

1.1 Guided Wave Ultrasonic Testing (GWUT) is a specific type of Long-Range Ultrasonic Testing.

1.2 GWUT is best suited for use on unpiggable pipelines, pipes resting on supports, cased, and elevated or other difficult to access locations allowing assess to several hundreds of feet of pipeline from a single test location.

1.3 Any application of GWUT that does not conform to the criteria described in 49 CFR Part 192, Appendix F, is considered an "other technology". Unless GWUT is supplemental to another assessment method, notification to the Pipeline Hazardous Materials and Safety Administration (PHMSA) is mandatory in advance of using the "other technology".

1.3.1 Provide notification to PHMSA and applicable State Regulatory Agencies per GTIM-13-001 "Required Notifications to Regulatory Agencies".

1.4 All indications of wall loss anomalies above the testing threshold (a maximum of 5% of cross-sectional area (CSA) sensitivity) require direct examination, in-line tool inspected, pressure tested, or replaced before completing the integrity assessment.

1.5 *Dead Zone* is the area adjacent to the collar, typically three (3) to six (6) feet on either side, in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. If the exact distance of the dead zone is unknown, use a distance of three (3) feet either side of the collar.

1.6 *Near Field Zone* is the region beyond the dead zone, typically one (1) to two (2) feet beyond the dead zone, where the receiving amplifiers are increasing in power before the proper establishment of the wave.

2.0 QUALIFIED GWUT SERVICE PROVIDERS

2.1 Guided wave service providers must be able to provide individuals trained and experienced with GWUT equipment operation, field data collection, and GWUT data interpretation on cased-pipe and buried pipe.

2.1.1 Only individuals who have been qualified by the specific equipment manufacturer, or by an equivalent process, similar to ISO 9712 (sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification) that is endorsed by the specific equipment manufacturer, including testing procedures and frequency determinations, may operate the equipment.

2.1.1.1 A senior-level GWUT equipment operator must comply with all appropriate quality control processes, provide on-site oversight of the inspection, and approve the final reports.

2.2 Guided wave service providers must be able to provide documentation on all GWUT equipment (e.g., collars, cables, etc.) tracing the equipment from the manufacturer through to the service provider. Documentation includes the serial numbers, calibration dates, and the version of any GWUT equipment-specific software, if applicable.

2.2.1 The GWUT Service Provider must provide documentation demonstrating appropriate reviews of the GWUT equipment's computer software, at least annually, with intervals not exceeding 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

2.3 GWUT service providers must have operations and maintenance procedures, meeting the requirements of §192.605 to address the effect of shorted casings on a GWUT signal.

3.0 PRE-ASSESSMENT

3.1 **Responsibility:** GTIM Engineer or designee

3.1.1 Identify the pipeline extents of the inspection.

3.1.2 Apply for any needed permits.

3.1.2.1 When testing casings, apply for permits on each side of the cased crossing.

Note: Some permits (i.e., streams, rivers, or railroads) may take three (3) to six (6) months to obtain - plan accordingly.

3.1.3 Gather traceable, verifiable, and complete (TVC) material properties and attributes records applicable to the pipeline assessment segments. If TVC records are not available, obtain the undocumented data using GTIM-02-010 "Material Verification" during direct examinations. Pre-Assessment information should include:

- Pipe manufacturer;
- Year of pipe manufacture;
- Pipe grade;
- Wall thickness; **
- Year of installation;
- Joint type;

- MAOP;
- Soil type; **
- Location and identification information; *
- Intended assessment length; *
- Pipe diameter; *
- Longitudinal seam type;
- Type of coating; **
- Coating thickness (assumed, if no actual data available); **
- Operating stress level (%SMYS);
- Date of last In-Line Inspection, if applicable;
- Date of last Direct Assessment, if applicable;
- Date of last Hydrostatic Pressure Test, if applicable;
- Pipe depth; **
- Locations of bends, valves, and fittings, if visible; **
- Repair history;
- Any adjacent metal objects; and
- Any as-built drawings; and
- Alignment sheets.

* *indicates required information.*

** *Obtain TVC records for undocumented data once the pipe is exposed and document the needed information on GTIM-90414 "LRUT Pre-Assessment Data".*

3.1.4 For applications at cased pipeline locations, also gather:

- Length of the casing;
- Construction practices at casing (i.e., spacers);
- Medium annular space fill material (i.e., water, dirt, wax);
- Casing orientation information (e.g., is one end of the casing lower than the other); and
- Shorted casing information, if applicable.

Note: For shorted, mechanical or electrolytic, casings, contact Corrosion Control personnel for assistance with identifying and clearing casings.

3.1.5 Document feasibility and the rationale for the assessment method selection on GTIM-90414.

3.1.6 Create a work order to update data attributes in GIS, if applicable.

3.1.6.1 For example, if Pre-Assessment research determined a casing's existence at a specific location according to as-built records or actual observation and GIS does not.

3.2 Responsibility: GTIM Engineer or GTIM Field Supervisor

3.2.1 Consider GWUT Service Providers that meet or exceed the following criteria.

- The ability to provide GWUT equipment with a minimum of three (3) frequencies, both torsional and longitudinal wave signals; and B-scan ultrasonic equipment;
    - The equipment must reliably gather data with a maximum sensitivity threshold not greater than five percent (5%) of the cross-sectional area (CSA);
    - Equipment calibrated for performance per the manufacturer's requirements and specifications, including the frequency of calibrations;
- The ability to perform a diagnostic check and system check on-site at each equipment relocation to a different casing or pipeline segment;
    - If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until restoring the equipment to the manufacturer's specifications;
- The ability to provide qualified personnel per the qualifications identified in section 2.0 of this procedure;
- The ability to provide the following documentation:
    - Evidence of updates to and reviews of the inspection equipment's computer software, occurring on an annual basis, or intervals not exceeding 15 months;
    - Evidence tracing the inspection equipment from the vendor to the GWUT Service Provider including the version of the GWUT software used and the serial numbers of the equipment such as collars, cables, etc.;
    - Calibration certificate;
    - The last date of calibration; and
    - The next calibration's date.

3.2.2 Secure a GWUT Service Provider meeting the requirements of section 2.0 above.

3.2.3 Obtain the relevant personnel qualifications, equipment, and software documentation from the service provider.

3.2.3.1 Retain the provided documentation in the IM file.

4.0 SAFETY CONSIDERATIONS

4.1 Responsibility: GWUT Equipment Operator and Excavation Crew

4.1.1 Take appropriate safety precautions when performing inspection activities.

4.1.2 Use insulated test clips and terminals to avoid contact with high voltages that may be present.

4.1.3 Use caution when using long lengths of test wire near high voltage alternating current (HVAC) power lines.

4.1.3.1 HVAC lines can induce hazardous voltage levels on the test wire.

4.1.4 Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the test pipeline.

4.1.5 Use caution when working around roads and railroads.

4.1.5.1 Use barricades, signboards, and traffic control flag personnel when appropriate.

4.1.5.2 Always wear reflective vests when working in such environments. Refer to the Corporate Safety Manual, section 4.30.6, "Reflective Safety Vests".

4.1.6 Notify the GTIM Field Inspector or other appropriate personnel immediately of any safety-related conditions. Conditions may include, but are not limited to:

- Problematic landowners; and
- Unsafe or abnormal pipeline conditions.

5.0 PERFORMING THE INSPECTION

5.1 Responsibility: GTIM Field Supervisor or designee

5.1.1 Discuss pipe access requirements with the GWUT Service Provider to determine the most appropriate locations for placement of the transducer collar before preparing the site. Consider the following:

5.1.1.1 Calculate the number of and placement of the transducer collar based on the length of the assessment extents and keeping the maximum threshold sensitivity at five percent (5%) Cross-Sectional Area (CSA).

5.1.1.1.1 It is the signal to noise (S/N) ratio that determines the range of the inspection the sensitivity. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (i.e., T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

5.1.1.2 Each range of the test requires an inspection from each end to achieve a full assessment.

5.1.1.2.1 Overlaying the two inspections will show the minimum 2 to 1 S/N ratio is met in the middle.

5.1.1.2.2 If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

5.1.2 Retain the services of a qualified Excavation Crew to expose the pipe for inspection, and the subsequent direct examinations.

5.1.2.1 Schedule the excavating crew.

5.1.3 Coordinate the timing of activities between the Service Providers and CNP personnel.

Note: When possible, arrange for the pipe to be exposed and the excavation shored and plated (per CNP's "Excavation and Trenching Policy") at all or a majority of the locations before the arrival of the GWUT Service Provider to significantly decrease project costs.

5.2 Responsibility: Excavation Service Provider

5.2.1 Apply for appropriate locates of the buried facilities before performing the excavations from the applicable state One-Call system.

5.2.1.1 Request that Locator Crews mark all CNP facilities.

5.2.1.2 Contact other non-participating utilities to locate their facilities near the proposed excavations, if applicable.

Note: Be aware that locates generally require two (2) working days lead-time and expire after two (2) weeks.

5.3 Responsibility: GTIM Field Supervisor or GTIM Field Inspector

5.3.1 Conduct a tailgate safety meeting each morning before beginning any job-site fieldwork.

5.3.2 Verify the credentials of all crew members before beginning any job-site fieldwork.

5.4 Responsibility: GTIM Field Inspector or designee

5.4.1 At excavation locations requiring TVC records, ensure enough exposure of the pipe to obtain the necessary information.

5.4.1.1 Gather required data elements listed in the “Pre-Assessment” section of this procedure when the pipe is exposed using GTIM-02-010 "Material Verification".

5.4.2 Examine the pipe and perform testing per the requirements of GTIM-04-008 “Data Collection for Direct Examinations”.

5.4.3 Document the inspection on GTIM-90418 “Pipeline Inspection Direct Examination”.

5.4.4 Upon finding adverse conditions (i.e., mechanical damage or evidence of Stress Corrosion Cracking) during the examination, notify the GTIM Field Supervisor or GTIM Engineer as soon as practical.

5.4.4.1 For each corrosion and crack-like anomaly, provide information to the GTIM Field Supervisor or GTIM Engineer to complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

5.4.5 Provide all field documentation to the GTIM Field Supervisor.

5.5 Responsibility: GTIM Field Inspector or designee

5.5.1 At the first inspection location of the assessment, have the Excavation Crew excavate beyond the intended assessment area to locate a weld and remove an approximate three (3) feet full encirclement area of coating at the exposed weld location.

5.5.1.1 Evaluate the condition of the coating documenting the results on the O&M Form 3105 “Pipe Exam”.

5.5.1.2 Confirm that this weld location will not fall within the tool’s Dead Zone or Near Field Zone. Confirmation may require removing additional coating so that the tool placement can be adjusted accordingly.

5.5.1.3 It is not necessary to remove the coating on Fusion Bonded Epoxy (FBE) coated pipe.

Note: Confirm removal of the coating on coal tar coated pipe complies with CNP’s Safety Program “Policy for Handling Coal Tar Wrapped Pipe, Valve Gaskets, and Packing Material-2008”.

5.5.2 If assessing a cased pipe, confirm the Excavation Crew removes an approximate three (3) feet full-encirclement area of coating for collar placement approximately ten (10) feet from the end of the casing.

5.5.2.1 If the pipe is concrete coated, reconsider the use of GWUT. If continuing with GWUT on a concrete coated pipe, special considerations will apply on a case-by-case basis.

5.5.3 Provide all field documentation to the GTIM Field Supervisor.

5.5.4 Verify the Excavation Crew cleans the pipe at the location for transducer collar to a smooth, bare metal finish.

5.6 Responsibility: GWUT Equipment Operator

5.6.1 Perform a diagnostic check and system check of the equipment on-site at the beginning of each workday and before each relocation of the GWUT equipment to a different casing or pipeline segment.

5.6.1.1 If the on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the restoration of the equipment to the manufacturer's specifications is complete.

5.6.1.2 Document the dates and times of each diagnostic and system check on GTIM-90415 “LRUT Field Notes”.

5.6.2 Before beginning the inspection, at each transducer collar location, perform a test shot to set the Distance Amplitude Correction (DAC) curve.

5.6.2.1 A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

5.6.3 At the first inspection location of the assessment, confirm that the exposed weld is outside of the Dead Zone and Near Field Zone.

5.6.3.1 No other welds may exist between the transducer collar and the calibration weld.

5.6.3.2 A conservative estimate of the predicted amplitude for the weld is 25% CSA.

5.6.3.3 Use the exposed weld to confirm that the equipment is correctly sizing and locating welds, setting the DAC curve.

5.6.3.3.1 Consider using the same DAC calibration for inaccessible welds on the pipe with similar properties such as wall thickness and coating type.

5.6.3.3.2 If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate, and adjustments to the DAC curve may be required.

5.6.3.3.3 Justify the use of an alternative means of calibration, if used, by documenting with engineering analysis and evaluation.

5.6.4 Clear any evidence of interference, other than some slight dampening of the GWUT signal from a shorted casing found while conducting GWUT inspections according to the service provider’s standard operating procedures.

5.6.5 Perform the GWUT inspection per the requirements of this procedure using a minimum of two (2) shots at each location and inspecting from both ends of the assessment segment.

5.6.5.1 Ensure that at least a 2 to 1 signal to noise ratio across the entire pipeline segment for the inspection.

5.6.5.1.1 Overlaying the two (bi-directional) inspections must show the minimum 2 to 1 S/N ratio is met in the middle

5.6.5.2 Use a minimum of three frequencies at each collar location to determine the best frequency for characterizing indications by location and o'clock position.

5.6.5.2.1 Verify the frequencies fall within the range specified by the manufacturer of the equipment.

5.6.5.2.2 Frequency selection should also take into account maximizing the range of the inspection while minimizing the Dead Zone.

5.6.5.2.3 Document each of the frequencies for each shot used for the inspections.

5.6.5.2.4 If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

5.6.5.3 Perform the first shot approximately ten (10) feet from the end of the casing or covered segment to be assessed, ensuring both the dead zone and near field zone will be outside of the desired assessment area.

5.6.5.3.1 Confirm documentation of the length of the dead zone in the final report.

5.6.5.4 Perform a second shot with the collar moved a distance of at least one (1) foot from the original location to validate the results of the first shot.

5.6.5.5 Verify the results of both shots detect the same anomalies and features.

5.6.5.5.1 Perform additional shots if necessary, to validate findings.

5.6.5.5.2 If the shots do not result in the same findings, document the reason(s) for the discrepancy.

Note: If any reason exists at any time to suspect the GWUT equipment is damaged or not functioning correctly, stop the inspection and verify the proper operation of the tools. Re-calibrate the equipment as required and provide documentation as required in this procedure.

5.6.5.6 A completed tool inspection must meet the required sensitivity for the entire length of the pipe, or utilize an alternative method of assessment (i.e., hydrostatic pressure tests or In-Line Inspection).

5.6.6 Recommend appropriate locations for validation examinations.

5.6.6.1 For each validation location, provide the GTIM Field Inspector with the distance of the validation locations referencing the collar location or other stationary features.

5.7 Responsibility: GTIM Field Inspector or designee

5.7.1 Confirm the GWUT equipment operator is performing the inspection(s) per the contract and procedural requirements.

5.7.1.1 Complete the form, GTIM-90415 “LRUT Field Notes”, during the inspection.

5.7.1.2 Review initial results provided by the GWUT Service Provider.

6.0 SELECTING VALIDATION EXAMINATION LOCATIONS

6.1 Responsibility: GTIM Field Supervisor and GTIM Engineer or designee

6.1.1 Review recommendations from the GWUT Service Provider regarding the locations of validation examinations.

6.1.2 Choose validation examination locations per the following order of preference:

(1) Corrosion anomalies;
(2) Known features (i.e., girth welds); and
(3) “No-feature” locations.

6.1.3 Confirm the GWUT service provider provides the distance from a physical reference point as well as the sizing (for metal loss anomalies) of the feature to utilize for validation.

6.1.3.1 It may be possible to extend the length of an existing excavation to use for the validation examination.

6.1.3.2 When possible, perform the validation examination(s) while the GWUT service provider is still on-site.

6.1.3.2.1 Results from the validation digs will assist the GWUT service provider in analyzing the data from the inspection.

7.0 PERFORMING VALIDATION EXAMINATIONS

7.1 Responsibility: GTIM Field Inspector or designee

7.1.1 Confirm a qualified Direct Examination Service Provider is on-site to perform the validation examination.

7.1.2 Confirm the Direct Examination crew follows the data collection requirements of procedure GTIM-04-008 “Data Collection for Direct Examination”.

7.1.3 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”, including:

- Locate the approximate anomaly location based upon guidance from the GWUT Service Provider or GWUT report references;
- Instruct the excavation crew to remove a full-encirclement of coating, approximately three (3) feet in length at the area of the anomaly, more if coating damage is extensive;
- For external corrosion, verify the corrosion anomaly dimension from the reference point as given by the GWUT service provider or GWUT report references;
- Measure the defect pit depth, if applicable;
- Measure the maximum defect length, if applicable;
- Evaluate the pipe remaining strength (i.e., RSTRENG), if applicable;

Note: RSTRENG is not valid for wall loss greater than 80%. Wall loss greater than 80% is an Immediate Condition.

- Take ultrasonic thickness measurements around the circumference of the pipe at six (6) inch intervals, then refine the measurement interval as necessary to determine the extent of internal wall loss;
  - Perform a minimum of four (4) readings;
- Compare the results of the ultrasonic thickness measurements with as-built wall thickness to evaluate for internal wall loss;
- Document the results on the GTIM-90418 “Pipeline Inspection Direct Examination”;
- Take photographs documenting the pipe condition;
  - Use a dry erase board in photographic documentation (excluding close-ups) and document on the board the date, casing number, and other relevant information; and
- Verify the size of the corrosion anomaly reasonably agrees with the sizing provided by the GWUT Service Provider.

7.1.4 For validation examinations at a known feature (i.e., weld), perform and document the following:

- Verify the feature location dimension from the reference point as given by the GWUT Service Provider or GWUT report references;
- Expose the girth weld or feature by removing enough coating to identify the existence of the girth weld or feature positively;
- Take photographs of the girth weld or feature;
- As deemed necessary, remove more of the coating to allow additional inspection;
- Document the results of the direct examination on GTIM-90418 “Pipeline Inspection Direct Examination”; and
- Take photographs documenting the pipe condition.

7.1.5 For validation examinations at a “no-feature” location, perform and document the following:

- Verify the dimension location from the reference point(s) as indicated by the GWUT Service Provider or GWUT report references;
- Remove an approximate three (3) foot width of coating around the circumference of the pipe, regardless of the coating condition;
- Verify no external corrosion anomalies exist;
- Evaluate the condition of the pipe;
- Perform ultrasonic thickness measurements around the entire circumference of the pipe at six (6) inch intervals;
  - Perform a minimum of four (4) readings;
- Compare the ultrasonic thickness measurements with the as-built wall thickness to evaluate for internal wall loss; and
- Document the direct examination on the form GTIM-90418 “Pipeline Inspection Direct Examination”.

7.1.6 Make repairs per O&M 16.0 “Repairs” or CNP O&M XX: “Transmission Pipeline Repair”.

7.2 Responsibility: GTIM Field Inspector or designee

7.2.1 Review the results of each validation examination.

7.2.2 Determine if the results of the examination reasonably agree with information from the GWUT Service Provider or GWUT report.

7.2.2.1 If the results of one (1) or more validation examinations do not agree with the inspection results, perform additional validation examinations at similar locations.

7.2.2.2 Re-perform the GWUT inspection at each location where the results of a validation examination do not correlate to the original GWUT results.

7.2.2.3 If the results of the GWUT assessment still do not agree with the results of the validation examination, consult with the GTIM Field Supervisor to determine the appropriate response.

7.2.2.3.1 Inform the GTIM Manager and the GTIM Engineer.

7.2.2.3.2 Potential responses include:

- Re-calibration of the equipment;
- Dismissal of the GWUT Service Provider; or
- Assessment via an alternate technology.

7.2.2.4 Work with the service provider to resolve discrepancies, as necessary.

7.3 Responsibility: GTIM Field Inspector or designee

7.3.1 Upon completion of the exam, confirm the recoating of the pipe per O&M 27.35 “Protective Coatings” or CNP O&M VIII\C “Protective Coatings”.

7.3.2 Using a plastic zip tie, mark the location of the center of the GWUT collar.

7.3.2.1 Place the zip tie over the top of the coating.

7.3.3 As necessary, re-attach or install new test leads per O&M 27.34 “Test Stations”.

7.3.4 As necessary, replace casing end seals.

7.3.5 As necessary, repair or replace casing vents.

7.3.6 Backfill and restore the excavation site.

8.0 GWUT SERVICE PROVIDER REPORT

8.1 Responsibility: GWUT Service Provider

8.1.1 Within 30 days of completing the field inspection, provide two (2) copies of the final inspection report, and one (1) electronic copy of the report in Adobe Acrobat format to the GTIM Engineer. The report should include at a minimum:

- Cover page that includes full customer name, pipeline name, inspected section location, date of inspection and report date;
- Project scope description;
- Color photographs including;
    - Opening from grade, including ditch shoring and support;
    - Exposed pipe;
    - Transducer test collar attached to the pipe and the drive electronics, showing manufacturer and model of the unit;

  - Casing end seal, if applicable;
  - Exposed weld joints, if available;
- Color analysis plot for the entire length of the inspected pipe including marked locations of weld joints, bends, casing seals, casing spacers and anomalies;
- Length of the dead zone for each shot;
- Anomaly data, including;
  - Location dimension from zero reference point;
  - Cross-sectional area (CSA) loss;
- Determination of severity classification (i.e., minor, moderate, severe) of the indication;
  - Based upon vendor experience;
  - Provide a definition or matrix for defining severity classifications;
  - If the GWUT Service Provider believes the indication is severe, contact the GTIM Engineer;
- Overall assessment of pipe inspected including a summary of which inspections completely assessed the desired length and which did not;
  - Achievement of a minimum of 20% overlap between shots for the length of the pipe for a successful assessment;
- Summary of unusual conditions, if found;
- Summary of compliance with Quality assurance procedures;
- Summary tutorial of the GWUT test process, with a specific overview of reflected response data analysis methodology;
- Information about the tool tolerances and signal attenuation at each inspection location;
- Equipment specifications including but not limited to:
  - Manufacturer model number and serial number for the transducer, transducer drive unit, and information on other significant test equipment; and
  - Name, version, and version date of analysis software used;
- Equipment documentation including, but not limited to:
  - Proof of calibration;
  - Noise elimination filters used;
  - Types of (i.e., single or dual) sensors used; and
  - The spacing of sensors.
- Qualifications documentation including, but not limited to:
  - Certification of the technicians performing the test, reviewing the data, and checking the report;
  - Test and analysis procedures; and
  - Quality assurance procedures.
- Documentation on the diagnostic and system check;
- Documentation of frequencies run and utilized for each shot;
- Distances achieved for each of the sensitivities shot; and

- Documentation of the wave type(s) used.

8.1.2 Submit a copy of the invoice to the GTIM Field Supervisor.

8.1.3 Confirm the report is reviewed and signed by the person analyzing the results.

8.1.3.1 Additionally, a second qualified person designated as having authority by the GWUT Service Provider should review and approve the report.

8.2 Responsibility: GTIM Engineer or designee

8.2.1 Review the GWUT report, including the color analysis plots.

8.2.2 Verify the plots and report includes:

- The GWUT shot(s) include the entire length of pipe intended for inspection;
- The feature locations (i.e., weld joints, casing seals, pipe supports) marked on the color plots agree with known information about the pipeline;

8.2.3 Contact the GWUT Service Provider if any required information is missing or to resolve any discrepancies.

8.2.4 Notify the GTIM Field Supervisor when all contract requirements are complete for payment of the Service Provider invoice.

8.3 Responsibility: GTIM Field Supervisor or designee

8.3.1 Pay the invoice once the contract requirements are complete.

Note: Discovery of Condition occurs once the GTIM Engineer has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. Discovery of Condition shall occur no later than 180 days after performing the GWUT inspection.

Discovery of Condition typically occurs upon acceptance of the final GWUT report.

9.0 REMEDIATION

9.1 Responsibility: GTIM Engineer or designee

9.1.1 Review the GWUT report and schedule all indications greater than or equal to five percent (5%) CSA for direct examination or alternative options within 30 days of receiving the report. Other assessment methods or alternative options may include:

- In-Line Inspection;
- Pressure Testing; or
- Pipeline replacement.

9.1.2 Prepare a dig plan to outline the locations to be examined or further assessed per the requirements of GTIM-04-026 “Dig Plan Preparation”.

9.1.3 Respond to indications within the timelines provided as follows:

9.1.3.1 For pipelines operating at or below 30% SMYS, replace the pipe or directly examine the indication(s) within 12 months.

9.1.3.1.1 Until completion of the direct examinations or pipe replacement, reduce the operating pressure and conduct instrumented leak surveys once every 30 calendar days per O&M 17.33 “Transmission Line Leak Survey” or CNP O&M XIX “Leak Surveys”.

9.1.3.2 For pipelines operating above 30% SMYS and less than or equal to 50% SMYS, replace the pipe or directly examine the indication(s) within six (6) months.

9.1.3.2.1 Until completion of the direct examinations or pipe replacement, maintain MAOP below the operating pressure at the time of discovery and conduct instrumented leak surveys once every 30 calendar days per O&M 17.33 “Transmission Line Leak Survey” or CNP O&M XIX “Leak Surveys”.

9.1.3.3 For pipelines operating above 50% SMYS, replace the pipe or directly examine the indication(s) within six (6) months.

9.1.3.3.1 Until completion of the direct examinations or pipe replacement, reduce MAOP to 80% of the operating pressure at the time of discovery and conduct instrumented leak surveys once every 30 calendar days per O&M 17.33 “Transmission Line Leak Survey” or CNP O&M XIX “Leak Surveys”.

9.1.3.4 Notify Local Operations personnel of scheduled direct examinations or alternative options, and if monthly leak surveys are required.

9.1.3.4.1 Notify Local Operations personnel when monthly leak surveys are no longer required.

9.1.4 For anomalies located on pipe within a casing, evaluate the approved remediation options, including:

- For repairs near the end of a casing, consider cutting back the end of the casing, repairing the pipe and replacing the cut-back casing as required;
- Re-boring or rerouting the crossing location and abandoning the existing pipe and casing in-place;
- Removing the casing pipe to expose the carrier pipe;
    - Perform a 100% visual inspection of the pipe coating;
    - Measure from the zip tie (tool location) to the anomaly location;
    - Remove a three (3) foot full encirclement area of coating and perform a direct examination;
        - Evaluate the performance of the UT tool to analyze internal corrosion through direct examination;
        - For inaccurate reporting of an anomaly location, remove an additional one (1) foot full encirclement area of coating from each end of the anomaly location and perform a direct examination; and
    - Make repairs as required and recoat the pipe per O&M 27.35 “Protective Coatings” or CNP O&M VIII\C “Protective Coatings”.

9.2 Responsibility: Local Operations

9.2.1 Perform leak surveys per O&M 17.33 “Transmission Line Leak Survey” or CNP O&M XIX “Leak Surveys”.

9.2.1.1 Perform leak surveys at the location(s) and at the time interval specified by the GTIM Engineer.

9.3 Responsibility: GTIM Field Inspector or designee

9.3.1 At excavation locations requiring TVC records, ensure enough exposure of the pipe to obtain the necessary information.

9.3.1.1 Gather required data elements listed in the “Pre-Assessment” section of this procedure when the pipe is exposed using GTIM-02-010 "Material Verification".

9.3.2 Examine the pipe and perform testing per the requirements of GTIM-04-008 “Data Collection for Direct Examinations”.

9.3.3 Document the inspection on GTIM-90418 “Pipeline Inspection Direct Examination”.

9.3.4 Upon finding adverse conditions (i.e., mechanical damage or evidence of Stress Corrosion Cracking) during the examination, notify the GTIM Field Supervisor as soon as practical.

9.3.4.1 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

9.3.5 Provide all field documentation to the GTIM Field Supervisor.

10.0 REASSESSMENT INTERVALS

10.1 Responsibility: GTIM Engineer or designee

10.1.1 The maximum reassessment interval is seven (7) years.

10.1.1.1 Consider a shorter reassessment interval based upon operation and maintenance information, as well as feedback from Subject Matter Experts.

10.1.2 Document the reassessment interval.

10.1.3 Add reassessment dates, Confirmatory Direct Assessment dates, and remediation activities to the assessment schedule calendar.

11.0 POST-ASSESSMENT

11.1 Responsibility: GTIM Engineer or designee

11.1.1 Evaluate the results of the GWUT inspections.

11.1.2 Review current P&M measures and propose additional P&M measures, if applicable.

11.1.2.1 Document additional P&M measures per the requirements of GTIM-08-004 “Identify Preventive and Mitigative Measures”.

11.1.3 Create a work order to incorporate information into GIS.

11.1.3.1 Document pipeline data verified by assessment to be incorporated or updated in GIS. Examples include the following:

- Pipe attributes found during bell hole digs (e.g., OD, Wall Thickness, Grade, etc.);
- Centerline changes; and
- Repairs made.

11.1.4 Determine if there was active corrosion found during the integrity assessments.

11.1.5 Review pipelines, both covered and non-covered segments, for similar conditions per the requirements of GTIM-08-005 “Evaluating Similar Conditions”.

11.1.6 Update GTIM-90209 “Threat Analysis” with the following information, if applicable:

- New identified threats;
- Eliminated threats; and
- Changes to existing threat documentation.

11.1.6.1 Refer to GTIM-02-021 “Threat Identification”.

11.1.6.2 Create a work order to update and modified attributes in GIS and other appropriate databases.

11.1.7 Solicit “lessons learned” from project participants upon completion of the GWUT project.

11.1.7.1 If appropriate, invite the Service Provider(s) to the meeting.

11.1.7.2 Consider addressing the following in the “lessons learned” communications:

- Things that went well during the process;
- Areas for improvement; and
- Modifications to the GWUT process.

11.1.7.3 Communications may be in the form of face-to-face meetings, phone calls, emails, or other correspondence.

11.1.8 If applicable, initiate a Change Management request for approval per GTIM-11-001 “GTIM Change Management” for each recommended procedural change, each additional P&M recommendation, and any other potential process improvements.

11.1.9 Document Performance Measures on GTIM-90901 “Performance Measures”.

11.1.9.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

11.1.10 Perform a 100% quality check of all requested GIS updates.

11.1.11 Conduct a meeting with GTIM Manager to review the documentation and obtain approval.

11.1.12 Once the documentation is approved, the GWUT process is considered complete.

11.1.13 Confirm all documentation is stored in the IM file within 30 days of completing the GWUT process.

<<END>>

GTIM-05-001 Addressing Conditions Found During an Integrity Assessment

PURPOSE: To establish a standardized method of addressing anomalous conditions discovered through an Integrity Assessment.

REFERENCES: 49 CFR 192.933; ASME/ANSI B31G-1991; ASME/ANSI B31.8S-2004;

SECTIONS:

- General
- Discovery of Condition
- Classifying Conditions
- Scheduled Conditions
- Response to Immediate Conditions
- Response to One-Year and Scheduled Conditions
- Response to Monitored Conditions
- Failure to Meet Response Requirements

1.0 GENERAL

1.1 Anomalous conditions require evaluation and remediation according to a prioritization schedule.

1.2 Conditions are classified to determine the remediation schedule once sufficient information is available to discover remediable defects.

2.0 DISCOVERY OF CONDITION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Determine the Discovery of Condition as required by the specific integrity assessment method.

2.1.1.1 Typically, for In-line Inspection (ILI), the Discovery of Condition occurs within 180 days of removing the pig from the line, as noted in procedure GTIM-03-006 “In-Line Inspection and Data Analysis”.

2.1.1.2 For External Corrosion Direct Assessment (ECDA), Discovery of Condition occurs during the direct examination phase of the ECDA process.

2.1.1.2.1 Typically, this will occur within 180 days of receiving the final Indirect Inspection data.

2.1.1.2.2 In some cases, permitting and scheduling issues beyond the control of CNP may make achieving the 180-day timeframe impractical.

Note: Per PHMSA Frequently Asked Question (FAQ) 232, there is no established timeframe between the Indirect Inspection and Direct Examination phase. As prudent pipeline operators, CNP has established a timeframe for this process.

2.1.1.3 For Internal Corrosion Direct Assessment (ICDA), the Discovery of Condition occurs during the direct examination phase of the ICDA process.

2.1.1.3.1 Typically, this will occur within 180 days of completing the Flow Modeling.

2.1.1.3.2 In some cases, permitting and scheduling issues beyond the control of CNP may make achieving the 180-day timeframe impractical.

2.1.1.4 For Subpart J Pressure Test and Spike Hydrostatic Pressure Test, the Discovery of Condition is a failure (a leak or rupture) occurring during the test.

2.1.1.5 For Excavation and In Situ Direct Examination, the Discovery of Condition occurs upon visual inspection of the anomaly.

2.1.1.6 For Guided Wave Ultrasonic Testing, the Discovery of Condition occurs when the tool detects an indication (wall loss anomaly) above the testing threshold.

2.1.1.7 For “Other Technology”, Discovery of Condition occurs once the GTIM Engineer has enough information about an indication to determine that the condition presents a potential threat to the integrity of the pipeline.

2.1.1.7.1 Refer to the specific procedure for the “Other Technology” for further details.

2.1.2 For each integrity assessment, document the date(s) “Discovery of Condition” occurs on GTIM-90501 “Response Schedule”.

2.1.2.1 For ILI, only document the indications to be excavated on GTIM-90501.

2.1.2.2 For Direct Assessments, document all indications, regardless if excavated, on GTIM-90501.

Note: A single assessment may have several Discovery of Condition dates.

3.0 CLASSIFYING CONDITIONS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Identify and classify indications for remediation according to the following criteria and Table 05-001-1 below (refer to the “Scheduled Conditions” section in this procedure):

Note: If an anomaly classification is revised based on observations found during excavation activities, notify the GTIM Engineer and the GTIM Manager, ensure the various databases reflect the change, and document the change according to GTIM-11-001 “GTIM Change Management”.

3.1.1.1 ***Immediate Condition:*** an indication expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

- Metal loss due to corrosion that has a predicted failure pressure less than or equal to 1.1 times the MAOP at the indication;
- An indication with wall loss > 80%;
- A dent that has any indication of metal loss, cracking or a stress riser;
- All indications of Stress Corrosion Cracking (SCC);
- An indication or anomaly that, in the judgment of the person qualified to evaluate the assessment results requires immediate action; or
- Any metal loss indication that is affecting a detected longitudinal seam, if that seam was formed by direct current, or low-frequency electric resistance welding (ERW), or by electric flash welding (EFW).

3.1.1.2 ***One-Year Condition:*** Indications that meet the following criteria:

- Any dent located between the 8 o'clock and 4 o'clock positions (upper two-thirds of the pipe) with a depth greater than 6% of the pipeline diameter [greater than 0.50 inch in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12];
- Any dent with a depth greater than 2% of the pipeline diameter (0.250 inches in-depth for a pipeline diameter less than NPS 12) that affects a pipe curvature at a girth weld or a longitudinal seam weld; or
- An indication that in the judgment of the person qualified to evaluate the assessment results warrants classification as a One-Year Condition provided, the indication does not meet the requirements of an Immediate Condition.

3.1.1.3 ***Monitored Condition:*** an indication where the defect will not fail before the next scheduled inspection.

- A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock and 8 o'clock positions (bottom third of the pipe); or
- An indication that, in the judgment of the person qualified to evaluate the assessment results, warrants classification as a Monitored Condition provided it does not meet the requirements of an Immediate Condition or a One-Year Condition. Evaluation should consider weld properties and include critical strain calculations demonstrating non-exceedance of critical strain levels.

Note: As prudent pipeline operators, CNP has defined criteria that are more stringent than required by 49 CFR 192.933.

3.1.2 Record the classification of “Immediate”, “One-Year”, and “Monitored” conditions on GTIM-90501 “Response Schedule”.

3.1.2.1 For ILI assessments, include the specified “Monitored” conditions listed in section 3.1.1.3.

3.1.3 Retain GTIM-90501 in the IM file.

Table 05-001-1: Indication Categorization for covered and non-covered segments

Indication Type	Features / Criteria	Covered Segment Classification	Non-Covered Segment Classification
Dent	Evidence of metal loss, cracking, stress riser, or with gouges	Immediate	Obligatory
Dent	Upper two-thirds of the pipe Depth ≥ 6% of diameter (or ≥ 0.50” if diameter < NPS 12)	One-Year	Term
Dent	Affects pipe curvature at girth weld or longitudinal seam weld Depth ≥ 2% of diameter (or ≥ 0.250” if NPS < 12)	One-Year	Term
Dent	The bottom third of the pipe Depth ≥ 6% of diameter (or ≥ 0.50” if NPS < 12)	Monitored	Watch
Metal Loss	Predicted failure ≤ 1.1 x MAOP	Immediate	Obligatory
Metal Loss	Greater than 80% wall loss	Immediate	Obligatory
Metal Loss	In a dent	Immediate	Obligatory

Indication Type	Features / Criteria	Covered Segment Classification	Non-Covered Segment Classification
Metal Loss	Affecting a longitudinal ERW or EFW seam	Immediate	Obligatory
SCC	Any indication of Stress Corrosion Cracking	Immediate	Obligatory
Other	Any indication or anomaly expected to cause immediate or near-term leaks or ruptures	Immediate	Obligatory
Other	Any indication or anomaly that, in the judgment of qualified personnel, requires immediate action	Immediate	Obligatory

4.0 SCHEDULED CONDITIONS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Identify Scheduled Conditions according to the following criteria:

4.1.1.1 Scheduled Condition: an indication showing the defect is significant but not at a failure point.

4.1.1.1.1 Scheduled Conditions specifically address corrosion indications and anomalies with a predicted failure pressure greater than 1.1 times the MAOP and include One-Year and Monitored Conditions not repaired at the time of direct assessment. Keeping engineering judgment in mind, classify indications and anomalies with repair times greater than the reassessment interval as Monitored Conditions.

4.1.2 Calculate the “Scheduled Condition” required repair response times per the equations[1] below. (Response time begins at Discovery of Condition.)

At or above 50% SMYS: $x = \left(P_f/MAOP - 1.1\right)\big/0.029$

30% to 50% SMYS: $x = \left(P_f/MAOP - 1.1\right)\big/0.06$

Below 30% SMYS: $x = \left(P_f/MAOP - 1.1\right)\big/0.11$

where:

x = *(the response time in years)*

P_f = *(the predicted failure pressure)*

MAOP = *(the Maximum Allowable Operating Pressure)*

Note: Determine the predicted failure pressure per procedure GTIM-05-003 “RSTRENG”.

4.1.3 Record the “Scheduled Condition” on GTIM-90501 “Response Schedule”.

4.1.4 Retain GTIM-90501 in the IM file.

[1] Equations adapted from Figure 4 of **ASME/ANSI B31.8S-2004.**

5.0 RESPONSE TO IMMEDIATE CONDITIONS

5.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

5.1.1 Upon discovery of an ‘Immediate’ condition:

5.1.1.1 When feasible, determine the operating pressure at the time of discovery.

5.1.1.1.1 Document the operating pressure at the time of discovery on GTIM-90501.

5.1.1.2 Analyze each anomaly or defect remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure and the remaining life of the pipeline segment at the location of the anomaly or defect per GTIM-05-005 “Predictive Failure Pressure”.

5.1.1.3 Determine the operating pressure limit using ASME/ANSI B31G-1991, RSTRENG, or other accepted industry practices.

Note: RSTRENG is not valid for wall loss greater than 80%. Corrosion anomalies with a wall loss greater than 80% are Immediate Conditions requiring repair.

5.1.1.4 Upon discovery of an ‘Immediate’ condition, reduce the operating pressure as soon as practicable as follows:

5.1.1.4.1 Reduce pressure to either:

- 80% of the operating pressure at the time of condition discovery;
  - As an alternative, make the pressure reduction using the highest operating pressure achieved between the end of all field activities related to the assessment and Discovery of Condition;
  - Consider reducing the operating pressure below 30% SMYS; or
- Maximum safe operating pressure as determined per GTIM-05-003 “RSTRENG”.

5.1.1.5 Instead of reducing the operating pressure, take other actions to confirm the safety of the covered segment and the public.

5.1.1.5.1 Document a technical justification as to why the alternative measure will not jeopardize the integrity of the covered segment or the safety of the public.

5.1.1.5.2 Submit the documented justification to the GTIM Manager for approval.

5.1.1.6 If feasible, the pipeline may be removed from service until repairs are completed instead of reducing the operating pressure.

5.1.1.7 Confirm the required temporary pressure reduction does not exceed 365 days, without notification to PHMSA, per GTIM-13-001 “Required Notifications to Regulatory Agencies”.

5.1.1.8 Document the date that the temporary pressure reduction took effect.

5.1.1.9 Document all pressure calculations (ASME/ANSI B31G-1991, RSTRENG) performed to determine the required pressure reduction.

5.1.2 Determine if safety-related condition requirements are applicable per the CNP Emergency Response Plan (ERP).

5.1.2.1 Report and repair ‘Immediate’ repair conditions according to the CNP Emergency Response Plan, section 3.03, “Reporting Natural Gas Safety-Related Conditions”.

5.1.3 Excavate and evaluate each ‘Immediate’ condition within five (5) days.

5.1.4 Perform a Root Cause Analysis per GTIM-04-012 “Root Cause Analysis” on all ‘Immediate’ conditions.

5.1.4.1 If the root cause is corrosion, evaluate similar pipeline segments per GTIM-08-005 “Evaluating Similar Conditions”.

5.1.5 Implement repairs or other remediation activities per O&M 16.0 “Repairs” or CNP O&M XX “Transmission Pipeline Repair”.

5.1.5.1 Document any repairs made and retain in the IM file.

5.1.6 Document the date of reinstating the pressure to normal operating pressure on GTIM-90501.

6.0 RESPONSE TO ONE-YEAR AND SCHEDULED CONDITIONS

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Repair or remediate ‘One-Year’ conditions within one year (365 days) from the Discovery of Condition.

6.1.2 Repair ‘Scheduled’ conditions per the required response time.

6.1.2.1 In some cases, a reassessment of the line segment may occur before the required response time.

6.1.3 Evaluate areas of significant corrosion per GTIM-08-005 “Evaluating Similar Conditions”.

6.1.4 Implement repairs or other remediation activities per O&M 16.0 “Repairs” or CNP O&M XX “Transmission Pipeline Repair”.

6.1.4.1 Document any repairs made and retain in the IM file.

7.0 RESPONSE TO MONITORED CONDITIONS

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Document ‘Monitored’ conditions on GTIM-90501 “Response Schedule”.

7.1.2 Evaluate each ‘Monitored’ condition during the next scheduled reassessment.

7.1.2.1 If the condition no longer meets the criteria for a ‘Monitored’ condition, reclassify the condition as ‘One-Year’, ‘Scheduled’, or ‘Immediate’ as appropriate.

7.1.3 ‘Monitored’ conditions do not require scheduled remediation since response times for mitigation exceed reassessment intervals, and re-evaluation of the conditions occurs as part of the next reassessment process.

8.0 FAILURE TO MEET RESPONSE REQUIREMENTS

8.1 Responsibility: GTIM Engineer or designee

8.1.1 If the evaluation and remediation of a condition exceed the response schedule, and a temporary reduction in operating pressure or other actions do not assure the safety of the covered segment and the public, provide notification to PHMSA and applicable State Regulatory Agencies per GTIM-13-001 “Required Notifications to Regulatory Agencies”.

8.1.2 Upon discovery that a pressure reduction may exceed 365 days, provide notification to PHMSA and applicable State Regulatory Agencies per GTIM-13-001 “Required Notifications to Regulatory Agencies”.

<<END>>

GTIM-05-003 RSTRENG

PURPOSE: To provide an understanding of the RSTRENG program and a consistent method of operating the program to determine the remaining strength of a corroded pipe.

REFERENCES: ASME/ANSI B31G-1991; PRCI PR-3-805-1989; PRCI PR-218-9304-1996;

SECTIONS:
- General
- Defect Interaction and Orientation
- Using RSTRENG
- Data Interpretation
- Example Defect Interactions

1.0 GENERAL

1.1 *RSTRENG* is a computer program used to determine the remaining strength of corroded pipe as provided by Technical Toolboxes.

1.1.1 This program uses the ASME/ANSI B31G-1991 standard and formulas provided by PRCI research.

1.1.2 Pipeline industry regulators and operators generally accept this program.

1.2 Calculation limitations:

- Only valid on steel pipeline;
- Cannot be used for third party damage (i.e., dents; gouges; dings; etc.);
- Cannot be used to evaluate corrosion extending into longitudinal or girth welds (except for submerged-arc seam welds); and
- Applies only to defects that have a relatively smooth contour such as metal loss due to corrosion or due to grinding (i.e., removal of laminations; arc burns; scabs; etc.).

1.3 RSTRENG output provides:

- The original ASME/ANSI B31G-1991 (2/3dL) calculation;
- The modified ASME/ANSI B31G-1991 (0.85dL) calculation;
- The modified ASME/ANSI B31G-1991 (Effective Area) calculation;
- The associated maximum safe pressure for each calculation above; and
- A graphical representation of the corrosion profile (relative to the inner edge, the outer edge, and the effective length).

Note: In general, CNP will use the "Modified ASME/ANSI B31G-1991 (Effective Area)" calculation for determining the remaining strength.

2.0 DEFECT INTERACTION AND ORIENTATION

2.1 **Responsibility:** Direct Examination Crew or GTIM Field Inspector

2.1.1 Document coating and corrosion defects per Procedure GTIM-04-024 "Documentation of Coating and Corrosion Defects".

2.1.2 Determine the boundaries of interactive corroded areas on the pipeline by using the following guidelines and referring to PRCI PR-3-805-1989, Appendix A.

Note: Before using other factors to determine failure interaction, obtain approval from the GTIM Manager.

2.1.2.1 *Pitting.*

2.1.2.1.1 Single pits separated by more than one times the wall thickness (1 wt.) do not interact significantly.

2.1.2.1.2 For longitudinal arrays of pits, if touching or separated by less than one (1) wt., analyze the entire defect by treating as a single defect.

2.1.2.2 *Adjacent Corroded Regions.*

2.1.2.2.1 Type I defects consist of flaws that are separated circumferentially but overlap when projected into a single plane (profile view). Treat these flaws as a single defect so long as a single separation does not exceed six (6) wt.

2.1.2.2.2 Type II defects consist of multiple flaws on the same axial line but separated by full wall thickness pipe. Use RSTRENG to analyze the individual flaws and the overall combination. Use the lowest calculated failure pressure. Flaws must be closer together than one-half of the flaw length to interact.

2.1.2.2.3 Type III defects consist of shorter, deeper defects within longer, shallower defects. RSTRENG provides adequate predictions based on the worst-case projected corrosion area. For very long corroded areas, RSTRENG analysis can be limited to one (1) diameter length, or about twenty (20) inches, whichever is greater, so long as the length includes the deepest pitting.

2.1.2.3 *Long, Narrow Defects.*

2.1.2.3.1 The RSTRENG analysis of long, narrow, near-uniform defects can be limited to a length of two (2) pipe diameters for accurate results. One pipe diameter in length is sufficient, so long as the deepest point is in the center of the region.

3.0 USING RSTRENG

3.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

3.1.1 Run RSTRENG per the software requirements.

3.1.2 Review the results.

Table 05-003-1: Example RSTRENG Report, "Results of Analysis" section

Method	Max. Safe Pressure [psi]	Burst Pressure [psi]	Safety Factor
RSTRENG - Effective Area	638.383	886.643	1.13964
RSTRENG - 0.85 dL	445.427	618.649	0.795178
ASME/ANSI B31G-1991	296.525	411.84	0.529357

- $Maximum\ Safe\ Pressure = Burst\ Pressure\ \times Design\ Factor$
- $Safety\ Factor = {}^{Burst\ Pressure}/_{Established\ MAOP}$

- Burst Pressure is the result of the ASME/ANSI B31G-1991 (original and modified) calculations and is listed using each method previously described.

3.1.3 Save a copy of the results report in the IM file.

3.1.4 Share the results with the Direct Examination crew and GTIM Field Inspector to assist in choosing appropriation remediation.

Note: Some GTIM procedures refer to the "predicted failure pressure". The "burst pressure", as discussed in this procedure, is synonymous with "predicted failure pressure".

4.0 DATA INTERPRETATION

4.1 Responsibility: Direct Examination Crew or GTIM Field Inspector

4.1.1 If the maximum pit depth is greater than 80% wall thickness, repair or replace per O&M 16.0 "Repairs" or CNP O&M XX "Transmission Pipeline Repair".

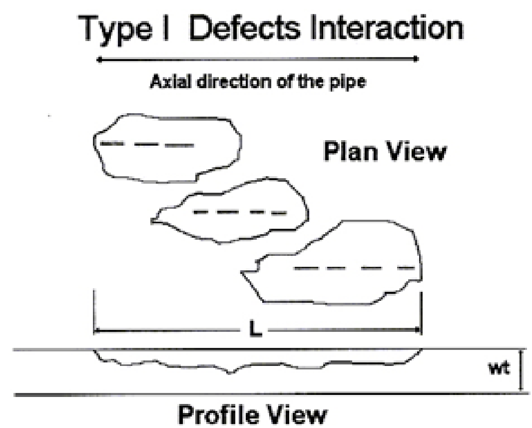
4.1.2 If the maximum pit depth is less than 20% wall thickness, arrest further corrosion per O&M 27.0 "Corrosion Control" or O&M VIII "External Corrosion Control" or CNP O&M IX "Internal Corrosion Control", and continue operating if pressure is less than or equal to 72% SMYS.

4.1.3 If the maximum pit depth is > 20% and < 80% of wall thickness, compare the Maximum Safe Pressure (MSP) to the established MAOP:

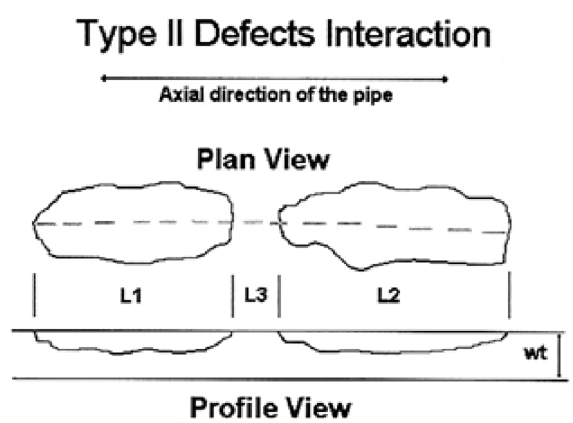
4.1.3.1 If MAOP is less than MSP, continue.

4.1.3.2 If MAOP is greater than or equal to MSP, then repair or replace per O&M 16.0 "Repairs" or CNP O&M XX "Transmission Pipeline Repair".

5.0 EXAMPLE DEFECT INTERACTIONS

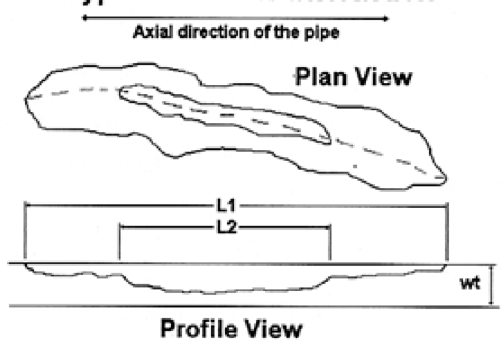


- Type I defects consist of flaws that are separated circumferentially but overlap when projected into a single plane (profile view). Treat these flaws as a single defect so long as a single separation does not exceed **6 wt**.



- Type II defects consist of multiple flaws on the same axial line but separated by full wall thickness pipe. Use RSTRENG to analyze the individual flaws and the overall combination. Use the lowest calculated failure pressure. Flaws must be closer together than **one-half the flaw length** to interact.

Type III Defects Interaction



- Type III defects consist of shorter, deeper defects within longer, shallower defects. RSTRENG provides adequate predictions based on the worst case projected corrosion area. For very long corroded areas, RSTRENG analysis can be limited to one diameter length, or about 20 inches, whichever is greater, so long as the deepest pitting is included.

Long, Narrow Defects Interaction

Uniformly machined defects, .194" deep in
24"OD x .486 wt, X64.9 line pipe

		Failure Pressure, psig Actual	(Predicted)
12" 12"	Failed 1st	2233	(1995)
12"	Failed 2nd	2393	(2173)
6"	Failed 3rd	2683	(2515)
6" 1.5" 6"	No Failure	>2683	(2515) one (2232) both
6" 3" 6"	No Failure	>2683	>(2413) both

- The RSTRENG analysis of long, narrow, near-uniform defects can be limited to a length of two pipe diameters for accurate results. One pipe diameter in length is sufficient, so long as the deepest point is in the center of the region.

<<END>>

GTIM-05-005 Predictive Failure Pressure

PURPOSE: To determine the predicted failure pressure and remaining life of the pipeline segment with corrosion metal loss and cracks or crack-like anomalies or defects at the location of the anomaly or defect.

REFERENCES: 49 CFR 192.712;

SECTIONS:

- Applicability
- Corrosion with Metal Loss
- Cracks and Crack-like Anomalies
- Evaluate Similar Conditions
- Verify Findings
- Documentation

1.0 APPLICABILITY

1.1 This procedure applies to all covered and non-covered steel transmission line pipe and components with discovered and suspected remaining in-service anomalies or defects.

1.1.1 Anomaly types include corrosion with metal loss, gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent.

1.2 Analyses and calculations performed as part of this procedure should use pipe and material properties documented with traceable, verifiable, and complete records (TVC). If TVC records are not available, obtain the undocumented data using GTIM-02-010 “Material Verification”.

1.2.1 GTIM-14-001 “Glossary” contains definitions for Traceable Records, Verifiable Records, and Complete Records.

2.0 CORROSION WITH METAL LOSS

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 For corrosion with metal loss anomalies and defects, calculate the remaining strength at the location of each anomaly or defect using GTIM-05-003 “RSTRENG” or an alternative method that will provide an equally conservative result.

2.1.1.1 If TVC records are not available, use the same values for wall thickness, diameter, or other data as used to determine the current MAOP.

2.1.1.1.1 Assume one of the following for material strength:

- Grade A pipe (30,000 psi), or
- SMYS used to determine the current MAOP.

2.1.1.2 For each anomaly or defect not verified using in situ direct measurements, account for uncertainties and tool variances when analyzing the reported assessment results of the defect dimensions, such as:

- Tool tolerance;
- Detection threshold;
- Probability of detection;
- Probability of identification;

- Sizing accuracy;
- Conservative anomaly interaction criteria;
- Location accuracy;
- Anomaly findings; and
- Unity chart plots or equivalent.

3.0 CRACKS AND CRACK-LIKE ANOMALIES

3.1 Responsibility: GTIM Engineer or designee

3.1.1 For each crack and crack-like defect, determine:

- Predicted failure pressure;
- Failure stress pressure; and
- Crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle, or both), and boundary condition type (pressure test, ILI, or other).

3.1.1.1 Account for cyclic fatigue or other loading conditions that could lead to fatigue crack growth by performing an applicable fatigue crack growth analysis (e.g., Paris Law).

3.1.1.2 Examples of technically proven models for calculating predicted failure pressures of cracks and crack-like defects include:

- For the brittle failure mode:
  - Newman-Raju Model;
  - PipeAssess PI™ Software;
- For the ductile failure mode:
  - Modified Log-Secant Model;
  - API RP 579-1 – Level II or Level III;
  - CorLas™ software;
  - PAFFC Model;
  - PipeAssess PI™ software.

3.1.1.3 Calculate the crack size that would fail at MAOP.

3.1.1.4 Calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at MAOP per GTIM-06-001 “Determining Reassessment Intervals”.

3.1.1.4.1 Before the calculated remaining life of the pipeline reaches 50%, re-evaluate the remaining life.

3.1.1.4.2 Consider additional pressure tests or other assessment methods to verify results.

3.1.1.4.2.1 Document conclusion and justification.

3.1.1.5 When analyzing potential crack defects that could have survived a pressure test, and do not have ILI crack anomaly data, use the same values as the most significant crack defect. If TVC records do not exist for material toughness at the location of the potential anomaly, use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to the most significant crack defect:

- The Charpy v-notch toughness values from a comparable pipe with TVC properties of the same vintage and from the same steel and pipe manufacturer;
- A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in GTIM-02-010 “Material Verification”; or
- The full-size equivalent of Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.

3.1.1.6 If TVC records are not available for any analysis, always use conservative assumptions, and unless verified using in situ direct measurements, account for uncertainties and tool variances when analyzing the reported assessment results of the defect dimensions, such as:

- Tool tolerance;
- Detection threshold;
- Probability of detection;
- Probability of identification;
- Sizing accuracy;
- Conservative anomaly interaction criteria;
- Location accuracy;
- Anomaly findings; and
- Unity chart plots or equivalent.

3.1.1.6.1 Use one of the following to determine material toughness:

- The Charpy v-notch toughness values from a comparable pipe with TVC properties of the same vintage and from the same steel and pipe manufacturer;
- A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in GTIM-02-010 “Material Verification”;
- If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, the maximum Charpy v-notch toughness values of:
    - 13.0 ft.-lbs. (for body cracks); and
    - 4.0 ft.-lbs. (for cold weld, lack of fusion, and selective seam weld corrosion defects); or
- If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, the maximum Charpy v-notch toughness values of:
    - 5.0 ft.-lbs. (for body cracks); and
    - 1.0 ft.-lbs. (for cold weld, lack of fusion, and selective seam weld corrosion).

Note: Use of an assumed Charpy v-notch toughness value or other appropriate values requires prior approval from PHMSA and State Authorities per GTIM-13-001 “Required Notifications to Regulatory Agencies”. Include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in the analysis of crack-related conditions.

3.1.1.6.2 Assume one of the following for material strength:

- Grade A pipe (30,000 psi), or
- SMYS used to determine the current MAOP.

3.1.1.6.3 Use the same values for wall thickness, diameter, or other data as used to determine the current MAOP until TVC records are available.

4.0 EVALUATE SIMILAR CONDITIONS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 For each defect that could adversely affect the integrity of the pipeline, perform a Root Cause Analysis (RCA).

4.1.1.1 Defects that could adversely affect the integrity of the pipeline or pose a threat to the integrity of the pipeline before the next reassessment include:

- Immediate repair conditions:
  - When calculated, the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the MAOP at the location of the anomaly;
  - A dent with metal loss, cracking, or at a stress riser; or
  - If, in the judgment of the GTIM Field Supervisor, it requires immediate action.
- One-year conditions:
  - A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6% of the pipe diameter, and greater than 0.50 inches in depth for a pipe diameter less than Nominal Pipe Size (NPS) 12;
  - A dent with a depth greater than 2% of the pipe diameter, or 0.250 inches in depth for a pipe diameter less than NPS 12, that affects pipe curvature at a girth weld or at a longitudinal seam weld.

4.1.1.2 Based on RCA results, evaluate and remediate all pipeline segments, in both covered and non-covered areas, with similar material coating and environmental characteristics.

4.1.1.3 A detailed analysis may not be required if the root cause is apparent; consult with the GTIM Manager.

4.1.1.4 Attach GTIM-90418 “Pipe Inspection Direct Examination”, if applicable.

5.0 VERIFY FINDINGS

5.1 Responsibility: Subject Matter Expert

5.1.1 Review and confirm all data used and produced results, including deviations and justifications.

5.1.1.1 Notify GTIM Manager as soon as possible if there are issues with the results.

5.1.2 Provide process feedback to GTIM Engineer.

5.1.3 Provide a summary of the data and the SME’s validation to the GTIM Manager for approval.

6.0 DOCUMENTATION

6.1 Responsibility: GTIM Engineer

6.1.1 Retain all records for the life of the pipeline, including investigations, analyses, and other actions. Records must document justifications, deviations, and determinations made for the following:

- The technical approach used for the analysis;
- All data used and analyzed;
- Pipe and weld properties;
- Procedures used;
- The evaluation methodology used;
- Models used;
- Direct in situ examination data;
- In-Line Inspection tool run information evaluated, including any multiple In-Line Inspection tool runs;
- Pressure test data and results;
- In-the-ditch assessments;
- All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
- All finite element analysis results;
- The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
- The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
- Safety factors used for fatigue life;
- Predicted failure pressure calculations;
- Reassessment time interval and safety factors;
- The date of the review;
- Root Cause Analysis documents;
- Confirmation of the results by qualified technical subject matter experts; and
- Approval by the GTIM Manager.

<<END>>

GTIM-06-001 Determining Reassessment Intervals

PURPOSE: To determine reassessment intervals for covered pipeline segments.

REFERENCES: 49 CFR 192.939; 49 CFR 192.937; ASME/ANSI B31.8S-2004, Section 7; NACE SP0502-2010, Section 6;

SECTIONS:

- General
- Pressure Test and Spike Hydrostatic Pressure Test
- In-Line Inspection
- Direct Assessments
- Interim (7- and 14-year) Assessments

1.0 GENERAL

1.1 This procedure refers to three (3) types of reassessment intervals;

1.1.1 **Maximum Reassessment Intervals** – The maximum interval between full assessments per §192.939. See Table 06-001-1: Maximum Reassessment Intervals for HCA Segments, below.

1.1.2 **Calculated Reassessment Intervals** – The reassessment interval is calculated based upon the remaining defects with corrosion. If the Calculated Reassessment Interval is more than the Maximum Reassessment Interval, the Maximum Reassessment Interval takes precedence.

1.1.3 **Interim (Confirmatory) Reassessment Intervals** – If the reassessment interval exceeds seven (7) calendar years, an interim assessment is required. Conduct an interim assessment by the seventh calendar year and at intervals not to exceed seven (7) years for the duration of the Reassessment Interval. Interim assessment methods include Confirmatory Direct Assessment or for pipelines operating below 30% SMYS, Low-Stress Assessment.

1.1.3.1 At this time, CNP has opted not to use Low-Stress Assessment.

Table 06-001-1: Maximum Reassessment Intervals for HCA Segments (adapted from 49 CFR 192.939)

Assessment Method	Pipeline Operating Pressure: At or Above 50% SMYS	Pipeline Operating Pressure: At or Above 30% up to 50% SMYS	Pipeline Operating Pressure: Below 30% SMYS
(Any full assessment method)	10 years [1]	15 years [1]	20 years [2]
Confirmatory Direct Assessment;	7 years	7 years	7 years
Low-Stress Assessment;	**Not Applicable**	**Not Applicable**	7 years + *(refer to §192.941)*

[1] A Confirmatory Direct Assessment, as described in §192.931, must be conducted by year 7 in a 10-year interval, and years 7 and 14 of a 15-year interval.

[2] Conduct a Low-Stress Assessment or Confirmatory Direct Assessment must by years 7 and 14 of the interval.

2.0 PRESSURE TEST AND SPIKE HYDROSTATIC PRESSURE TEST

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Determine the Calculated Reassessment Interval using the nominal test pressure in the appropriate stress level equation below. If the Pressure Test included a Spike Hydrostatic Pressure Test, use the nominal test pressure maintained after the spike test portion of the pressure.

- For pipelines at or above 50% SMYS:

$$x = \frac{(y - 1.1)}{0.029}$$

- For pipelines between 30% and 50% SMYS:

$$x = \frac{(y - 1.1)}{0.06}$$

- For pipelines below 30% SMYS:

$$x = \frac{(y - 1.1)}{0.11}$$

where:

x = Reassessment Interval *(years)*
y = Test Pressure / Maximum Allowable Operating Pressure (MAOP)

Table 06-001-2: Reassessment Intervals for HCA Segments (adapted from ASME/ANSI B31.8S-2004, Table 3)

Calculated Maximum Reassessment Interval	Pipeline MAOP		
	At or Above 50% SMYS	**At or Above 30% up to 50% SMYS**	**Less than 30% SMYS**
5	Test Pressure up to 1.25 x MAOP	Test Pressure up to 1.4 x MAOP	Test Pressure up to 1.7 x MAOP
10	Test Pressure up to 1.39 x MAOP	Test Pressure up to 1.7 x MAOP	Test Pressure up to 2.2 x MAOP
15	**Not Allowed**	Test Pressure up to 2.0 x MAOP	Test Pressure up to 2.8 x MAOP
20	**Not Allowed**	**Not Allowed**	Test Pressure up to 3.3 x MAOP

2.1.2 Determine the lesser interval between the Calculated Reassessment interval and the Calculated Maximum Reassessment Interval.

2.1.3 Review the results of the pressure test, data integration, risk assessment, and repair and prevention activities.

2.1.3.1 Based on this review, determine if a shorter interval than determined in section 2.1.2 is required.

2.1.4 Calculate the reassessment date by adding the interval chosen in section 2.1.3.1 to the completion date of the Pressure Test.

2.1.5 Document the following information:

- Calculated Reassessment interval;
- All calculations;
- The shorter Reassessment Interval, if applicable; and
  - The shorter interval rationale.

2.1.6 Retain all Reassessment Interval information in the IM file.

3.0 IN-LINE INSPECTION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Perform GTIM-05-005 "Predictive Failure Pressure" on each anomaly or defect, discovered and suspected, remaining in-service on covered and non-covered segments.

3.1.2 Use the predicted failure pressure of the most significant discovered or suspected anomaly remaining in-service, determined from section 3.1.1, in the appropriate stress level equation below to determine the Calculated Reassessment Interval.

- For pipelines at or above 50% SMYS:

$$x = \frac{(y - 1.1)}{0.029}$$

- For pipelines between 30 and 50% SMYS:

$$x = \frac{(y - 1.1)}{0.06}$$

- For pipelines below 30% SMYS:

$$x = \frac{(y - 1.1)}{0.11}$$

where:

x = Reassessment Interval *(years)*
y = (Predicted Failure Pressure) / MAOP

Table 06-001-3: Reassessment Intervals for HCA Segments (adapted from ASME/ANSI B31.8S-2004, Table 3)

Calculated Maximum Reassessment Interval	**Pipeline MAOP**		
	At or Above 50% SMYS	**At or Above 30% up to 50% SMYS**	**Less than 30% SMYS**
5	Predicted Failure Pressure greater than 1.25 x MAOP	Predicted Failure Pressure greater than 1.4 x MAOP	Predicted Failure Pressure greater than 1.7 x MAOP
10	Predicted Failure Pressure greater than 1.39 x MAOP	Predicted Failure Pressure greater than 1.7 x MAOP	Predicted Failure Pressure greater than 2.2 x MAOP
15	**Not Allowed**	Predicted Failure Pressure greater than 2.0 x MAOP	Predicted Failure Pressure greater than 2.8 x MAOP

Calculated Maximum Reassessment Interval	Pipeline MAOP		
	At or Above 50% SMYS	**At or Above 30% up to 50% SMYS**	**Less than 30% SMYS**
20	**Not Allowed**	**Not Allowed**	Predicted Failure Pressure greater than 3.3 x MAOP

3.1.3 Determine the lesser interval between the Calculated Reassessment interval and the Calculated Maximum Reassessment interval.

3.1.4 Review the results of the In-Line Inspection (ILI), data integration, risk assessment, and repair and prevention activities.

3.1.4.1 Based on this review, determine if a shorter interval than determined in section 3.1.3 is required.

3.1.5 Add the reassessment interval from section 3.1.4.1 to the date that the last ILI tool was removed from the pipeline to calculate the reassessment date.

3.1.6 Document the following information:

- Calculated Reassessment Interval;
- All calculations;
- The shorter reassessment interval, if applicable; and
    - The shorter interval rationale.

3.1.7 Retain all reassessment interval information in the IM file.

4.0 DIRECT ASSESSMENT METHODS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 If no corrosion or crack-like anomalies, discovered or suspected, remain on the pipeline, (i.e., all anomalies remediated), use the appropriate stress level Maximum Reassessment Interval in Table 06-001-1 as reassessment interval for the pipeline.

4.1.2 If any discovered or suspected corrosion or crack-like anomaly remains on the pipeline, calculate the Remaining Life as follows.

4.1.2.1 Calculate the Predicted Failure Pressure per GTIM-05-005 “Predictive Failure Pressure”.

4.1.2.2 Calculate the Failure Pressure Ratio and MAOP Ratio using the following formulae:

$$Failure\ Pressure\ Ratio = {P'}/{Yield\ Pressure}\ (dimensionless)$$

$$MAOP\ Ratio = {MAOP}/{Yield\ Pressure}\ (dimensionless)$$

where:

P' = Calculated predicted failure pressure from GTIM-05-005
MAOP = MAOP established *(i.e., not calculated)* for the pipe segment

4.1.2.3 Calculate the Growth Rate using the lowest rate possible from the following four (4) options:

1.) Directly compare the measured wall thickness changes over a known time interval (actual corrosion rate).

- Wall thickness documentation from prior excavations, maintenance records, or In-Line Inspection data and applicable to the specific location.

2.) Use 12.16 mpy: *(0.01216 inches/year) when operating records indicate the pipe segment has been under adequate cathodic protection (as determined by regulatory requirements) for at least 90 percent of the time since the pipe installation;*

- Use 16.0 mpy[1]: *without adequate cathodic protection for at least 90 percent of the time since the pipe installation;*

3.) Corrosion rates based on the soil resistivity at the defect[2]:

- 3 mpy: *a soil resistivity greater than 15,000 ohm-cm and no active corrosion;*
- 6 mpy: *a soil resistivity within 1,000-15,000 ohm-cm;*
- 6 mpy: *a soil resistivity greater than 1,000 ohm-cm with active corrosion;*
- 12 mpy: *a soil resistivity less than 1,000 ohm-cm;*

4.) Use other corrosion rates based on sound engineering analysis.

- Using other corrosion rates must be documented, justified, and approved by the GTIM Field Supervisor.

4.1.2.4 Calculate the remaining life of the pipeline by determining the amount of time required for the most significant discovered or suspected remaining anomaly to grow to a size that would fail at MAOP using the following formula.

$$RL = C \times SM \times \frac{t}{GR}$$

where:

RL = Remaining Life *(years)*
C = Calibration factor = 0.85 *(dimensionless)*
SM = Safety Margin = Failure Pressure Ratio – MAOP Ratio *(dimensionless)*
t = Nominal Wall Thickness of the Pipe *(inches)*
GR = Corrosion Growth Rate estimate *(inches/year)*

4.1.2.4.1 Before the calculated Remaining Life of the pipeline reaches 50%, re-evaluate the Remaining Life.

4.1.2.4.2 Consider additional pressure tests or other assessment methods to verify results.

4.1.2.4.2.1 Document conclusion and justification.

4.1.3 Determine the Reassessment Interval based upon ½ the Remaining Life or the following table, whichever is less

[1] Corrosion Growth Rate from NACE SP0502-2010;
[2] Adapted from ASME/ANSI B31.8S-2004 Appendix B;

Table 06-001-4: Reassessment Intervals for HCA Segments (adapted from ASME/ANSI B31.8S-2004, Table 3)

Calculated Maximum Reassessment Interval *(years)*	**MAOP at or above 50% SMYS**	**MAOP 30% up to 50% SMYS**	**MAOP less than 30% SMYS**
10	Maximum Interval[3]		
15	Not Allowed	Maximum Interval[3]	
20	Not Allowed	Not Allowed	Maximum Interval[4]

4.1.3.1 Determine if a lower Reassessment Interval should be established based upon operating experience including, but not limited to:

- Corrosion defects found on the line segment
- Leak history of the line segment
- Extent and severity of corrosion and crack-like defects found during the assessment
- The estimated rate of propagation of the crack clusters, if applicable
- The total length of pipe potentially susceptible to SCC on the pipeline, if applicable
- The potential consequences of failure within the pipe segment

4.1.4 Confirm documentation of information:

- Calculated reassessment interval;
- All calculations;
- The shorter reassessment interval, if applicable; and
- The rationale for a shorter interval, if applicable.

4.1.5 Retain all reassessment interval information in the IM file.

5.0 INTERIM (7- AND 14-YEAR) ASSESSMENTS

Note: Although Low-Stress Assessment is an allowed interim method, at this time, CNP has opted not to utilize Low-Stress Assessment. Instead, CNP will utilize Confirmatory Direct Assessment per procedure GTIM-07-001 “Confirmatory Direct Assessment”. If, in the future, CNP decides to utilize Low-Stress Assessment, CNP will develop and approve an appropriate procedure.

5.1 Responsibility: GTIM Engineer or designee

5.1.1 For reassessment intervals greater than seven (7) years, schedule an interim Confirmatory Direct Assessment for the covered segment(s).

5.1.1.1 Refer to procedures GTIM-07-001 “Confirmatory Direct Assessment” for additional details.

[3] A Confirmatory Direct Assessment (CDA) is required by year 7 in a 10-year interval and by years 7 and 14 of a 15-year interval unless a complete reassessment is performed.

[4] A Low Stress Reassessment or Confirmatory Direct Assessment is required by years 7 and 14 of the interval unless a complete reassessment is performed.

5.1.2 Consider the benefits of performing a full assessment (i.e., DA, ILI) instead of the interim assessment. As appropriate, schedule the full assessment instead.

5.1.3 For reassessment intervals longer than fourteen (14) years, schedule an interim assessment at year seven (7) and year fourteen (14).

5.1.4 Review the timing of interim and future full reassessments. Consider the scheduling and economics to determine if it is more practical to perform a full reassessment at an interim reassessment period rather than a CDA.

<<END>>

GTIM-06-002 Low-Stress Assessment

PURPOSE: To provide a standardized method of using Low-Stress Assessment to evaluate the threats of external and internal corrosion.

REFERENCES: 49 CFR 192.941;

SECTIONS:

- Note

Note: At this time, CNP has opted not to utilize the Low-Stress Assessment. Instead, CNP will utilize Confirmatory Direct Assessment per GTIM-07-001 “Confirmatory Direct Assessment”. If, in the future, CNP decides to utilize Low-Stress Assessment, CNP will develop and approve an appropriate procedure.

<<END>>

GTIM-06-003 Internal Corrosion Control Program

PURPOSE: To provide guidelines for establishing a standardized method for detecting, monitoring, and controlling internal corrosion.

REFERENCES: 49 CFR 192.927(c)(4)(ii); ASME/ANSI B31.8S-2004, Section 6.4.2; NACE RP0104-2004;

SECTIONS:

- Background
- Internal Corrosion Monitoring Overview
- Corrosion Coupons and Probes
- Gas Quality
- Liquids Analysis
- Internal Examination
- Internal Corrosion Remediation, Prevention, and Mitigation
- Chemical Treatment
- Other Considerations
- Internal Corrosion Control Records

1.0 BACKGROUND

1.1 This procedure provides general guidelines for establishing an internal corrosion-monitoring program as needed based on the level of threat.

1.1.1 The guideline details depend on the specific characteristics of each pipeline segment, such as monitoring type and frequency.

1.2 Internal corrosion monitoring is a required Post-Assessment activity for an Internal Corrosion Direct Assessment (ICDA) when finding evidence of internal corrosion.

1.2.1 Refer to GTIM-04-056 “ICDA Post-Assessment”.

1.3 The application of internal corrosion monitoring may result from a Preventive and Mitigative (P&M) measure initiated by another threat or an integrity assessment.

1.4 Periodically evaluate gas pipelines for internal corrosion using the following methods:

- Corrosion coupons and probes;
- Gas, liquid, and solids sampling;
- Internal inspection;
- Historical data and evidence;
- Research; or
- Other methods.

2.0 INTERNAL CORROSION MONITORING OVERVIEW

2.1 **Responsibility:** Corrosion Control or GTIM Field Supervisor

2.1.1 Determine the Internal Corrosion monitoring method(s) most appropriate for each pipeline segment as needed based on the level of threat. Methods include:

2.1.1.1 Evaluate internal corrosion using coupons, probes, or other monitoring devices.

2.1.1.1.1 Refer to section 3.0 “Corrosion Coupons and Probes” of this procedure.

2.1.1.2 Evaluate liquid sampling to determine the potential extent of corrosion and the effectiveness of corrosion inhibitors.

2.1.1.2.1 Refer to section 4.0 “Gas Quality” of this procedure.

2.1.1.3 Monitor the need for internal corrosion mitigation using gas analysis, liquid samples, and internal inspections.

2.1.1.3.1 Refer to section 7.0 “Internal Corrosion Remediation, Prevention, and Mitigation” of this procedure.

3.0 CORROSION COUPONS AND PROBES

3.1 Responsibility: Corrosion Control or GTIM Field Supervisor

3.1.1 Determine appropriate corrosion monitoring devices for pipeline conditions such as coupons or electrical probes.

3.1.1.1 Coupons are available in a variety of shapes and sizes. They are pre-weighed, and a corrosion rate is calculated based on weight loss after exposure.

3.1.1.1.1 Consider using coupons, either alone or in conjunction with electrical probes, to monitor areas of corrosion.

3.1.1.2 Electrical probes measure corrosivity in real-time.

3.1.1.2.1 Consider using electrical probes to monitor areas with high corrosion rates.

3.1.1.2.2 Types include the Electrical Resistance (ER) probe.

3.1.1.2.3 Electrical Resistance (ER) probes determine metal loss by measuring the increase in resistivity.

3.1.1.2.3.1 ER probes are not appropriate for use with pitting corrosion.

3.1.1.2.3.2 ER probes can be susceptible to fouling.

3.1.1.3 Other corrosion monitoring techniques are also available.

3.1.2 Determine appropriate corrosion coupons or probe test locations.

3.1.2.1 Determine locations that are representative of the conditions in the pipeline segment for monitoring.

3.1.2.2 Determine locations that are most likely to have the most severe internal corrosion.

3.1.2.3 Typical coupon placement is at the bottom (6 o’clock position) of the pipeline.

3.1.2.4 Document the coupon or probe location in the GIS or other appropriate databases.

3.1.3 Determine an internal corrosion monitoring frequency for each pipe segment.

3.1.3.1 Per O&M 27.30 “External and Internal Corrosion Inspection and Monitoring”, CNP O&M VIII “External Corrosion Control”, and CNP O&M IX “Internal Corrosion Control” procedures, perform monitoring at least twice each calendar year at intervals not exceeding seven and a half (7 ½) months if evidence of internal corrosion is present.

3.1.3.1.1 Monitoring frequency may depend upon the chemical treatment program.

3.1.3.2 Document the monitoring frequency in the IM file.

3.2 Responsibility: Local Operations

3.2.1 Monitor corrosion coupons at the interval specified for each test location.

3.2.1.1 Remove corrosion coupons from their test location.

3.2.1.1.1 Take care not to touch the surface of the coupon.

3.2.1.1.1.1 Use latex gloves or the coupon's packaging to avoid contaminating the surface.

3.2.1.1.2 Record the date, the location, and the serial number of the removed coupon.

3.2.1.1.3 Visually examine the surface of the coupon.

3.2.1.1.3.1 Document any deposits, damage, or evidence of corrosion found.

3.2.1.1.3.2 If deposits are present, extract a sample for microbiologically influenced corrosion (MIC) bacteria testing per procedure GTIM-04-011 "Field Testing for Microbiologically Influenced Corrosion Bacteria".

3.2.1.1.4 Place the coupon in a protective bag or vial labeled with the location, date, and serial number.

3.2.1.2 Install a new corrosion coupon at the test location.

3.2.1.2.1 Record the date, the location, and the new coupon's serial number.

3.2.2 Retain documentation of the removal and installation in the IM file.

3.2.3 Send used coupons to an appropriate laboratory for corrosion analysis.

3.2.3.1 Confirm the laboratory evaluates the coupons for pitting versus general corrosion.

3.2.3.2 Confirm the laboratory calculates a general corrosion rate.

3.2.3.3 Confirm the laboratory calculates a pitting rate with pitting observations.

3.3 Responsibility: Local Operations

3.3.1 Collect electronic corrosion probe (i.e., Electrical Resistance (ER)) measurements at the interval specified for each test location.

3.3.1.1 Follow the manufacturer's calibration and data collection instructions.

3.3.1.2 If using Remote Data Collection (RDC) devices, follow the manufacturer's operating instructions for maintaining and programming the device as well as for data collection.

3.3.1.3 Calculate a general corrosion rate from the probe data.

3.4 Responsibility: Corrosion Control or GTIM Field Supervisor

3.4.1 Review laboratory analysis for all corrosion coupons.

3.4.1.1 If general corrosion rates are greater than one (1) mil per year, perform a detailed analysis.

3.4.1.2 If observing corrosion pitting, perform a detailed analysis.

3.4.2 Detailed corrosion analysis includes a review of the following factors to determine a likely cause of abnormally high or increased corrosion rates:

3.4.2.1 Review of product quality sampling data.

3.4.2.2 Review of liquid, gas, or solids sampling data.

3.4.2.3 Review of inhibitor or biocide or both injection rates.

3.4.2.4 Review of bacteria testing data.

3.4.3 Identify any deficiencies found during the detailed analysis that could account for the high or increased corrosion rates. Refer to Table 06-003-1:

Table 06-003-1: Unknown Source

Data Source	Examples of Deficiencies
Product quality data;	Changes in concentrations;
Gas or Liquid or Solid sampling data;	Increases in corrosive agents such as: Free water + CO_2 above 2% Free water + H_2S Free water + chloride;
Biocide or Inhibitor Injection rates or consumption, downstream sampling;	Lower than normal injection rates or consumption; Decreased downstream concentration;
Bacteria testing data;	Increase in bacteria colony concentration;

3.4.3.1 Flag any deficiencies deemed an urgent threat to pipeline integrity.

3.4.4 Document any deficiencies found.

3.4.4.1 Include the root cause as well as any planned corrective action.

3.4.5 Resolve all deficiencies found during the detailed analysis within twelve (12) months from the date of discovery.

3.4.5.1 Correct urgent threats to the pipeline as soon as practical.

3.4.5.2 Document the completion date for all corrective actions.

4.0 GAS QUALITY

4.1 Responsibility: Gas Control or GTIM Field Supervisor

4.1.1 Work with the Corrosion Control Supervisor to determine the frequency for obtaining gas quality data.

4.1.1.1 Monitoring frequency may depend upon the chemical treatment program, the severity of internal corrosion, or other requirements.

4.1.2 Obtain gas quality data. Data should include, but is not limited to:

- Hydrogen Sulfide;
- Carbon Dioxide;
- Oxygen;
- Free Water; and
- Chlorides.

4.1.3 Evaluate gas composition per CNP’s gas quality tariff requirements or industry standards.

5.0 LIQUIDS ANALYSIS

5.1 Responsibility: Local Operations

5.1.1 Work with the Corrosion Control Supervisor to determine the frequency for obtaining liquids samples for analysis.

5.1.1.1 Monitoring frequency may depend upon the chemical treatment program, the severity of internal corrosion, or other requirements.

5.1.1.2 Obtain a sample of any liquids removed from the pipeline.

5.1.1.3 Test for the presence of water and pH level immediately, on-site.

5.1.1.4 Label the sample with the company name; contact information for the Corrosion Control Supervisor; pipeline name/number; and sample location.

5.1.1.5 Coordinate with the Corrosion Control Supervisor to send the samples to a qualified laboratory for analysis.

5.2 Responsibility: Testing Laboratory

5.2.1 Perform a complete analysis of the liquids submitted including, but not limited to:

- H_2O;
- Sulfates;
- Manganese;
- Iron Sulfate;
- O_2;
- H_2S;
- CO_2;
- Microbes;
  - Sulfate-reducing;
  - Acid-producing;
  - General aerobic; and
  - Anaerobic.

5.2.2 Test for other constituents that may be present in the liquid to properly identify or evaluate corrosion products or processes.

5.2.3 Send the results to the contact supplied with the sample.

5.3 Responsibility: Corrosion Control or GTIM Field Supervisor

5.3.1 Review the results and determine if chemical treatment is required (see section 8.0 “Chemical Treatment”) or if additional remediation, preventive, or mitigative activities are required (see section 7.0 “Internal Corrosion Remediation, Prevention, and Mitigation”).

5.3.2 File the analysis results in the IM file for the useful life of the pipeline.

6.0 INTERNAL EXAMINATION

6.1 Responsibility: Local Operations

6.1.1 Inspect the internal condition of the pipeline per O&M 27.30 “External and Internal Corrosion Inspection and Monitoring” or CNP O&M VIII “External Corrosion Control” or CNP O&M IX “Internal Corrosion Control”.

6.1.2 Upon finding evidence of pitting, or a leak due to internal corrosion, notify the GTIM Engineer as soon as practical.

7.0 INTERNAL CORROSION REMEDIATION, PREVENTION, AND MITIGATION

7.1 Responsibility: Corrosion Control or GTIM Field Supervisor

7.1.1 For repairs due to internal corrosion, take adequate steps to prevent or mitigate additional internal corrosion for the pipe segment in question. Options may include, but are not limited to:

- Eliminating free water from the line if feasible;
  - Cleaning pigs may be used to remove water from the line;
  - Blowdown drain lines and perform routine maintenance to drips to remove water from the line;
- Removing corrosive components from the line;
  - Wherever possible, minimize the potential for system upsets that could introduce higher levels of corrosive gases such as carbon dioxide, hydrogen sulfide, and oxygen;
- Injecting a corrosion inhibitor or biocide;
  - When properly selected, based on the operating conditions of the line, corrosion inhibitors mitigate corrosion by forming a protective film on the metal surface;
  - Biocide injections may combat microbiologically influenced corrosion (MIC), if properly selected for the type of bacteria present in the line;
  - Refer to section 8.0 “Chemical Treatment” of this procedure.

8.0 CHEMICAL TREATMENT

8.1 Responsibility: Corrosion Control or GTIM Field Supervisor

8.1.1 As applicable, determine suitable chemical treatment methods for each pipeline segment.

8.1.1.1 Tailor a chemical treatment regimen based on the characteristics of the pipeline and considering operating conditions.

8.1.1.1.1 Consider correlating the aggressiveness of the approach with the severity of the corrosion.

8.1.1.1.2 Select the type of chemical appropriate for the type and concentration of liquids and the operating conditions such as flow velocity and temperature.

8.1.1.1.3 Consider an inhibitor or biocide injection for the specific type of bacteria, if present.

8.1.1.1.3.1 Refer to procedure GTIM-04-011 “Field Testing for Microbiologically Influenced Corrosion Bacteria”.

8.1.1.2 Pipe segments with internal corrosion rates less than one (1) mil per year may not require chemical treatment.

8.1.2 Determine a monitoring frequency to confirm corrosion rates remain below one (1) mil per year.

8.1.2.1 Sample from the end of the system to confirm adequate concentration throughout the entire pipe segment.

8.1.2.2 Compare the corrosion coupon or probe data upstream and downstream of the injection point to determine the effectiveness of the treatment program.

8.1.3 Revise the chemical treatment program as necessary.

8.1.3.1 Document any changes in the chemical treatment program.

8.1.3.2 Refer to procedure GTIM-11-001 "GTIM Change Management" to log the change.

9.0 OTHER CONSIDERATIONS

9.1 Responsibility: Corrosion Control or GTIM Field Supervisor

9.1.1 Determine whether internal cleaning of the pipeline segment is necessary to mitigate internal corrosion.

9.1.1.1 Pigging can effectively remove water or accumulated liquids, solids, or sludge.

9.1.1.1.1 Select the type of internal cleaning tool based on the desired effect.

9.1.1.1.2 Determine a pigging frequency based on the quantity of material removed from the pipeline.

9.1.1.1.3 If the pipeline cannot accommodate internal cleaning tools, consider remediation options. Refer to O&M 30.20 "Pigging".

9.1.2 Determine whether drip maintenance frequency is sufficient for the operating conditions of the pipeline.

9.1.2.1 Periodically remove accumulated liquid from drips to maintain effectiveness.

9.1.3 Determine whether design changes could be a cost-effective alternative for controlling internal corrosion. Design change examples include, but are not limited to:

- Modifications to allow the passage of internal inspection cleaning tools;
- Reroutes to eliminate low spots;
- Additional drips to eliminate liquids;
- Internal protective coatings; and
- Gas dehydration to minimize water.

10.0 INTERNAL CORROSION CONTROL RECORDS

10.1 Responsibility: Corrosion Control or GTIM Field Supervisor

10.1.1 Maintain records or maps showing locations of the following:

- Internal corrosion coupons, probes, or other corrosion monitoring devices;
- Liquid sampling locations used for monitoring chemical treatment; and
- Gas sampling locations.

10.1.2 For each monitoring location, document the maximum test interval.

10.1.3 Retain documentation for all chemical injections.

10.1.4 Maintain laboratory results for all internal corrosion analysis for the life of the pipeline.

10.1.5 Record results of internal corrosion inspections or monitoring activities in the IM file.

10.1.6 Refer to O&M 27.90 "Corrosion Control Records" or CNP O&M VI "Miscellaneous Requirements for Corrosion Control".

10.2 Responsibility: GTIM Engineer or designee

10.2.1 Incorporate internal corrosion information into the Integrity Management Program per procedures GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

<<END>>

GTIM-06-004 Continual Data Integration, Management, and Evaluation

PURPOSE: To establish a standardized method for continually gathering and maintaining the pipeline and facility data as well as identifying data trends.

REFERENCES: 49 CFR 192.937;

SECTIONS:
- Data Gathering - Work Order Information
- Data Gathering - Integrity Management Assessment Information
- Data Gathering - Maintenance and Surveillance Information
- Data Integration

1.0 DATA GATHERING - WORK ORDER INFORMATION

1.1 Responsibility: Gas Transmission Engineering or designee

1.1.1 Submit work order(s) and other supporting documentation to integrate new or changed information into the Integrity Management Program.

1.1.1.1 Submit work orders within sixty (60) days of process completion, when possible.

1.1.2 Confirm work orders include documentation appropriate for use as traceable, verifiable, and complete supporting records. Examples include:

- As-built drawings;
- Field checked work order details;
- Pressure Test charts and information;
- Mill specification sheets;
- Assessment results;
- Laboratory results; and
- Remediation details.

1.2 Responsibility: Engineering Support or designee

1.2.1 Review the submitted work order data.

1.2.1.1 Request clarifications or additional information from the work order creator as necessary.

1.2.2 Update or add the work order's information in GIS or other appropriate databases.

1.2.2.1 Updates include changes to pipeline centerline location, adding and retiring routes, and transmission asset attributes.

1.2.3 Complete the request with sixty (60) days when possible.

1.2.3.1 Mark the work order entry complete on the appropriate tracking sheet or system, when complete.

1.2.3.2 Forward a copy of the work order information to the appropriate GTIM Engineer.

1.2.4 Retain original work order information in the IM file.

1.2.5 Ensure appropriate documentation of the revision changes and communicate as necessary.

2.0 DATA GATHERING - INTEGRITY MANAGEMENT ASSESSMENT INFORMATION

2.1 **Responsibility:** GTIM Engineer or designee

2.1.1 Review approved Post-Assessment documentation.

2.1.1.1 Request clarification or additional information from the assessment documentation creator as necessary.

2.1.2 Confirm entry of pipeline attributes, assessment results, and other integrity assessment and transmission asset information in the appropriate IM data source.

2.1.2.1 Request a change to the work order for any data changes.

3.0 DATA GATHERING - MAINTENANCE AND SURVEILLANCE INFORMATION

3.1 **Responsibility:** GTIM Engineer or designee

3.1.1 Periodically review One-Call activity through on-line databases or other CNP One-Call ticket resources for evidence of increased Third-Party or Mechanical Damage threats.

3.1.1.1 Update the One-Call activity in the integrity management data systems as necessary.

3.1.1.2 Consider additional preventive and mitigative measures (i.e., additional patrols, line markers, etc.) in areas of increased activity.

3.1.2 Periodically, and in advance of an assessment, review all transmission pipeline and appurtenance maintenance records, including, but not limited to:

- Leaks;
- Patrols/surveys;
  - Notable occurrences only;
- Facility detail sketches;
- Service records;
  - New, retired or non-routine occurrences only;
- Valve cards;
  - New, retired, replaced only;
- Regulator Station forms;
  - Non-routine maintenance only;
  - Major inspections - non-routine occurrences only;
  - Minor inspections - non-routine occurrences only;
- Corrosion Control records;
  - Test stations - new, relocated, deleted;
  - Pipe-to-soil readings - only if not meeting NACE criteria;
  - Bonds - new, repaired, replaced, relocated, deleted;
  - Bond readings - non-routine occurrences or those not meeting criteria;
  - Anodes - new;
  - Rectifiers and ground beds - new, relocated, retired, refurbished;
  - Rectifier readings - non-routine occurrences or those not meeting criteria;

- Pipe exams;
- Facility Damage reports (FDS reports);
- Encroachment records;
- Non-routine equipment maintenance;
- Material/Equipment Failure/Problem reports (see GMS 4.0 “Resolving Material or Equipment Failures or Defects”);
- Drip logs and filter/dehydrator logs;
  - For those with the water removed;
- Upsets within the system; and
- Gas analysis records.

3.1.3 Review documentation.

3.1.3.1 When reviewed document information does not match GIS or other appropriate databases, submit a work order to correct any discrepancies.

3.1.3.2 Consider process improvements to the Integrity Management Program. Changes may include, but are not limited to:

- GTIM procedures/forms (refer to GTIM-12-002 “Integrity Management Program Review”); and
- Additional P&M activities (refer to GTIM-11-001 “GTIM Change Management”);

Note: Make every effort to meet the above timeframe. However, in some cases, there may be unforeseen circumstances that make meeting the deadline impractical. Notify the GTIM Manager as soon as known.

3.1.4 Retain copies of documentation in the IM file.

4.0 DATA INTEGRATION

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Identify the desired outcome of data integration. Examples include, but are not limited to:

- Identify likely areas for third-party damage;
- Identify potential corrosion anomalies;
- Identify areas with a high leak rate;
- Identify new threats, not previously identified;

4.1.2 Identify the data to include in the integration. Information may include, but is not limited to:

- Pipeline attribute data;
- Operational data;
- Maintenance data;
- Assessment data;
- Leak data;
- Encroachment data; and

- Corrosion data.

4.1.3 Identify a reference system for the data. Reference systems may include, but are not limited to:

- Attribute layers in GIS;
- Pipeline stationing; and
- GPS coordinates.

4.1.3.1 Confirm the reference system allows data sets from various sources to be combined and accurately associated with pipeline locations.

4.1.3.2 Standardize measurement units to the system of reference.

4.1.4 Align the data to the reference system.

4.1.5 Review the data for trends and anomalies.

4.1.5.1 As appropriate, suggest actions based on the data interpretation. Example actions may include, but are not limited to:

- Inclusion of new threats in the risk analysis;
- Implementation of Preventive and Mitigative measures;
- Additional direct examinations;
- Field patrols or inspection activities; and
- PHMSA Annual Reporting.

4.1.5.2 Refer to GTIM-11-001 “GTIM Change Management” to initiate a request.

4.1.5.3 If concluding that there is a potential of a new threat or trend, determine if new or targeted data collection is needed. Refer to procedure GTIM-02-001 “Data Gathering and Research”.

<<END>>

GTIM-06-005 Reassessments

PURPOSE: To provide a standardized method for scheduling and planning reassessments.
REFERENCES: 49 CFR 192.937;
SECTIONS:
- Scheduling Reassessments
- Reassessment Evaluation

1.0 SCHEDULING REASSESSMENTS

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Determine a reassessment method[1] per GTIM-03-001 “Assessment Method Selection” for each reassessment segment.

1.1.2 Document the assessment method(s) and compliance date on the assessment schedule calendar.

1.1.3 If a leak or time-dependent failure occurs on a segment, review the timing for the next scheduled assessment.

1.1.3.1 Perform the reassessment within one (1) year of the event.

1.1.3.2 Update the assessment schedule calendar as appropriate.

1.1.3.3 Initiate a Change Management event per GTIM-11-001 “GTIM Change Management”.

2.0 REASSESSMENT EVALUATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 At least once each calendar year, review the assessment schedule calendar.

2.1.2 Identify line segments scheduled for assessment over the next two (2) years.

2.1.3 Review the integrated data and risk assessment information of each identified line segment.

2.1.4 Review the identified threats for each of the line segments.

2.1.4.1 Review the past GTIM-90209 “Threat Analysis” forms for the line segment.

2.1.4.1.1 If a GTIM-90209 does not exist for the line segment, complete the form per GTIM-02-021 “Threat Identification”.

2.1.4.2 Determine if new threats exist.

2.1.4.2.1 Review current operation and maintenance information as well as feedback from Subject Matter Experts.

2.1.4.2.2 Review any existing Change Management and Root Cause documentation for the line segment.

2.1.4.2.3 Review stable Manufacturing and Construction threats and verify they are still stable per GTIM-02-020 “Determination of Stable Threats”.

[1] The assessment schedule calendar, lists the future assessment date(s), and a primary or ‘suggested’ assessment method(s). The actual assessment method will be determined, based on the review of segment conditions during the Pre-Assessment phase of the next assessment.

2.1.4.2.4 Update GTIM-90209 and the assessment schedule calendar as necessary.

2.1.4.3 Review the past and present assessment results, including remediation decisions.

2.1.4.4 Review Preventive and Mitigative (P&M) measures for the assessment segment per the requirements of GTIM-08-004 “Identifying Preventive and Mitigative Measures”.

2.1.4.4.1 Identify new P&M measures as appropriate.

2.1.4.5 Verify the scheduled assessment method is appropriate for the identified threats.

2.1.4.5.1 If the planned assessment does not address all identified threats, update the assessment schedule calendar.

2.1.4.6 Review the reassessment compliance dates.

2.1.4.6.1 Consider limitations or obstacles in meeting reassessment compliance dates such as:

- Tool or service provider availability;
- Weather restrictions; and
- Impact on customers.

2.1.5 As necessary, create a Change Management entry per GTIM-11-001 “GTIM Change Management”.

2.1.6 Determine and document the reassessment interval per the requirements of GTIM-06-001 “Determining Reassessment Intervals”.

2.2 Responsibility: GTIM Manager or designee

2.2.1 Review the reassessment evaluation for each line segment.

2.2.1.1 Confirm the data review is thorough, complete, and adequate for establishing the reassessment method.

2.2.2 Confirm that the reassessment method(s) and compliance date(s) entries on the assessment schedule calendar.

<<END>>

GTIM-07-001 Confirmatory Direct Assessment

PURPOSE: To establish a standardized method for performing a Confirmatory Direct Assessment.
REFERENCES: 49 CFR 192.931; 49 CFR 192.939; NACE SP0210-2010;
SECTIONS:

- General
- Identifying the Survey Segment
- Assessing for External Corrosion (Previous Assessment Method: In-Line Inspection, Pressure Test, or Other Technology)
- Assessing for External Corrosion (Previous Assessment Method: ECDA)
- Assessing for Internal Corrosion (Previous Assessment Method: In-Line Inspection, Pressure Test, or Other Technology)
- Assessing for Internal Corrosion (Previous Assessment Method: ICDA)
- Immediate Conditions
- Documentation

1.0 GENERAL

1.1 Perform Confirmatory Direct Assessment (CDA) at or before year seven (7) if the reassessment interval for the Consequence Area exceeds seven (7) years.

1.1.1 CDA will be performed at or before years seven (7) and fourteen (14) for 15- or 20-year assessment intervals.

1.1.1.1 In place of a CDA, consider performing a full reassessment.

1.1.1.2 For pipelines operating below 30% SMYS, a Low-Stress Assessment may be used instead of a CDA; however, at this time, CNP has opted not to use Low-Stress Assessments.

1.2 Use a Confirmatory Direct Assessment (CDA) to address external and internal corrosion only.

1.2.1 A Confirmatory Direct Assessment (CDA) for external corrosion requires one (1) indirect inspection method rather than the two (2) required for a full External Corrosion Direct Assessment (ECDA).

1.2.2 A Confirmatory Direct Assessment (CDA) for internal corrosion requires excavation of only one (1) high-risk location in each ICDA region.

1.2.3 If both external corrosion and internal corrosion are considered a threat, perform CDA with both methods.

1.2.4 Non-time dependent threats, such as third-party damage, requires a different assessment method.

1.3 The results of the CDA may prompt a reevaluation of the planned reassessment interval to shorten the interval.

1.3.1 A CDA cannot extend a reassessment interval.

2.0 IDENTIFYING THE SURVEY SEGMENT

2.1 **Responsibility:** GTIM Engineer or GTIM Field Supervisor

2.1.1 Identify Consequence Areas requiring assessment.

2.1.1.1 For ECDA and ICDA, when feasible, utilize the same regions as the previous assessment.

2.1.2 Confirm documentation of the survey segments per the requirements of GTIM-04-002 “ECDA Pre-Assessment” and GTIM-04-051 “ICDA Pre-Assessment” using form GTIM-90701 “Confirmatory Direct Assessment”.

3.0 ASSESSING FOR EXTERNAL CORROSION (PREVIOUS ASSESSMENT METHOD: IN-LINE INSPECTION, PRESSURE TEST, OR OTHER TECHNOLOGY)

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Select a minimum of one (1) indirect inspection tool, instead of the two (2) as required by a full ECDA, for pipeline segments previously assessed using In-Line Inspection.

3.1.2 When the previous assessment method was a Pressure Test, consider performing two (2) indirect inspection techniques. Factors to consider include:

- The incremental cost of performing two (2) methods in tandem;
- Quantity of data from using complementary techniques; and
- Improvements in data quality.

3.1.3 When the previous assessment method was “Other Technology”, consider utilizing two (2) indirection techniques based on the previous assessment’s ability to identify and evaluate external defects and conditions leading to external corrosion.

3.2 Responsibility: GTIM Engineer or GTIM Field Supervisor

3.2.1 Perform the EC-CDA (External Corrosion-Confirmatory Direct Assessment) to address external corrosion per the requirements of the GTIM-04-003 “ECDA Indirect Inspection” and sections 3.1.1 through 3.1.3 above.

3.2.2 For each ECDA region, perform a direct examination on all ‘Immediate’ indications, and at least one (1) identified ‘Scheduled’ indication.

3.2.2.1 Perform the direct examination per the requirements of the GTIM-04-004 “ECDA Direct Examination”.

3.3 Responsibility: GTIM Engineer or designee

3.3.1 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

3.3.2 Consider opportunistically performing other data collection activities such as GTIM-02-010 “Material Verification”.

3.4 Responsibility: GTIM Engineer or designee

3.4.1 Perform the post-assessment per the requirements of the GTIM-04-005 “ECDA Post-Assessment”.

3.4.2 Review the reassessment interval calculated from the EC-CDA and confirm the reassessment date based on this interval is greater than or equal to the date of the next scheduled assessment.

3.4.2.1 If so, the previously determined date for the next reassessment is valid.

3.4.2.2 EC-CDA cannot be used to increase the reassessment interval.

3.4.3 If the calculated reassessment interval identifies a reassessment date less than or equal to the date of the next scheduled reassessment, additional post-assessment activities will apply, including:

- Document the revised reassessment date;
- Review historical data to determine what factors led to an increase in the corrosion growth rate, if any; and
- Review current Preventive and Mitigative (P&M) measures to propose additional Preventive and Mitigative (P&M) measures, as appropriate.

3.4.4 Document Remaining Life and reassessment interval calculations per the requirements of the GTIM-04-005 "ECDA Post-Assessment".

3.4.5 Create a work order to update and incorporate modified attributes.

4.0 ASSESSING FOR EXTERNAL CORROSION (PREVIOUS ASSESSMENT METHOD: ECDA)

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Review the previous ECDA data and verify no changes have occurred since the last ECDA.

4.1.2 Compile and review data from corrosion control surveys and encroachment information since the last assessment.

4.1.3 Document the current EC-CDA regions and, if different from the prior assessment's regions include the rationale for the change.

4.1.4 Select a minimum of one (1) indirect inspection tool instead of two (2) as required by a full ECDA.

4.1.4.1 Consider selecting one (1) of the indirect inspection techniques utilized in the previous assessment to allow for data comparison from the previous assessment.

4.1.5 Create a work order to update and modified attributes.

4.2 Responsibility: GTIM Engineer or GTIM Field Supervisor

4.2.1 Perform the EC-CDA to address external corrosion per the requirements of the GTIM-04-003 "ECDA Indirect Inspection" and section 4 "Assessing for External Corrosion (Previous Assessment Method: ECDA)".

4.2.2 For each ECDA region, perform a direct examination on all 'Immediate' indications, and at least one (1) identified 'Scheduled' indication.

4.2.2.1 Perform the direct examination per the requirements of the GTIM-04-004 "ECDA Direct Examination".

4.3 Responsibility: GTIM Engineer or designee

4.3.1 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 "Predictive Failure Pressure".

4.3.2 Consider opportunistically performing other data collection activities such as GTIM-02-010 "Material Verification".

4.4 Responsibility: GTIM Engineer or designee

4.4.1 Perform the post-assessment per the requirements of the GTIM-04-005 "ECDA Post-Assessment".

4.4.2 Review the reassessment interval calculated from the EC-CDA and confirm the reassessment date based on this interval is greater than or equal to the date of the next scheduled assessment.

4.4.2.1 If so, the previously determined date for the next reassessment is valid.

4.4.2.2 EC-CDA cannot be used to increase the reassessment interval.

4.4.3 If the calculated reassessment interval identifies a reassessment date less than or equal to the date of the next scheduled reassessment, additional post-assessment activities will apply, including:

- Document the revised reassessment date;
- Review historical data to determine what factors have led to an increase in the corrosion growth rate, if any; and
- Review current Preventive and Mitigative (P&M) measures to propose additional Preventive and Mitigative (P&M) measures, as appropriate.

4.4.4 Document Remaining Life and reassessment interval calculations per the requirements of the GTIM-04-005 “ECDA Post-Assessment”.

4.4.5 Create a work order to update and incorporate modified attributes.

5.0 ASSESSING FOR INTERNAL CORROSION (PREVIOUS ASSESSMENT METHOD: IN-LINE INSPECTION, PRESSURE TEST, OR OTHER TECHNOLOGY)

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Perform the Pre-Assessment phase per the requirements of the GTIM-04-051 “ICDA Pre-Assessment”.

5.1.2 IC-CDA (Internal Corrosion-Confirmatory Direct Assessment) will be deemed feasible despite a prior assessment by pressure test or In-Line Inspection provided that the last test was at least five (5) years prior and routine pigging has not occurred since that time.

5.2 Responsibility: GTIM Engineer or GTIM Field Supervisor

5.2.1 Perform the IC-CDA to address internal corrosion per the requirements of GTIM-04-054 “ICDA Indirect Inspection”.

5.2.2 Select one (1) location within a consequence area, instead of two (2) as required by a full ICDA, for direct examination.

5.2.3 The location shall have an inclination angle greater than the critical angle.

5.2.3.1 If all pipeline inclination angles are less than the critical angle, select the location with the largest inclination angle for direct examination.

5.2.4 Perform the direct examination per the requirements of the GTIM-04-055 “ICDA Direct Examination”.

5.3 Responsibility: GTIM Engineer or designee

5.3.1 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

5.3.2 Consider opportunistically performing other data collection activities such as GTIM-02-010 “Material Verification”.

5.4 Responsibility: GTIM Engineer or designee

5.4.1 Perform the post-assessment per the requirements of the GTIM-04-056 "ICDA Post Assessment".

5.4.2 Review the reassessment interval calculated from the IC-CDA and confirm the reassessment date based on this interval is greater than or equal to the date of the next scheduled assessment.

5.4.2.1 If so, the previously determined date for the next reassessment is valid.

5.4.2.2 IC-CDA cannot be used to increase the reassessment interval.

5.4.3 If the calculated reassessment interval identifies a reassessment date less than or equal to the date of the next scheduled reassessment, additional post-assessment activities will apply, including:

- Document the revised reassessment date;
- Review historical data to determine what factors have led to an increase in the corrosion growth rate, if any; and
- Review current Preventive and Mitigative (P&M) measures to propose additional Preventive and Mitigative (P&M) measures, as appropriate.

5.4.4 Document Remaining Life and reassessment interval calculations per the requirements of the GTIM-04-056 "ICDA Post-Assessment".

5.4.5 Create a work order to update and incorporate modified attributes.

6.0 ASSESSING FOR INTERNAL CORROSION (PREVIOUS ASSESSMENT METHOD: ICDA)

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Review the previous ICDA data and verify no changes have occurred since the last ICDA.

6.1.2 Document the current IC-CDA regions and, if different from the prior assessment's regions, include the rationale for the change.

6.2 Responsibility: GTIM Engineer or GTIM Field Supervisor

6.2.1 Utilize a historical ICDA pipeline elevation profile if available.

6.2.1.1 If the review of data indicates physical changes to the segment that could affect the elevation profile, consider collecting additional pipeline elevations for that particular section of the pipe.

6.2.2 Use the same critical angle calculated from the first assessment when selecting a direct examination location for the IC-CDA.

6.2.2.1 If any of the flow modeling inputs (i.e., pressure, temperature, and flow rate) has changed since the prior assessment, calculate a new critical angle for the IC CDA region using the current operating parameters for the pipe at that location.

6.2.3 Select one (1) location instead of two (2) as required by a full ICDA for direct examination.

6.2.4 The location shall have an inclination angle greater than the critical angle.

6.2.4.1 If all pipeline inclination angles are less than the critical, select the location with the largest inclination angle for direct examination.

6.2.5 Perform the direct examination per the requirements of the GTIM-04-055 "ICDA Direct Examination".

6.3 Responsibility: GTIM Engineer or designee

6.3.1 For each corrosion and crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

6.3.2 Consider opportunistically performing other data collection activities such as GTIM-02-010 “Material Verification”.

6.4 Responsibility: GTIM Engineer or designee

6.4.1 Perform the post-assessment per the requirements of the GTIM-04-056 “ICDA Post-Assessment”.

6.4.2 Review the reassessment interval calculated from the IC-CDA and confirm the reassessment date based on this interval is greater than or equal to the date of the next scheduled assessment.

6.4.2.1 If so, the previously determined date for the next reassessment is valid.

6.4.2.2 IC-CDA cannot be used to increase the reassessment interval.

6.4.3 If the calculated reassessment interval identifies a reassessment date less than or equal to the date of the next scheduled reassessment, additional post-assessment activities will apply, including:

- Document the revised reassessment date;
- Review historical data to determine what factors have led to an increase in the corrosion growth rate, if any; and
- Review current Preventive and Mitigative (P&M) measures to propose additional Preventive and Mitigative (P&M) measures, as appropriate.

6.4.4 Document Remaining Life and reassessment interval calculations per the requirements of the GTIM-04-056 “ICDA Post-Assessment”.

6.4.5 Create a work order to update and incorporate modified attributes.

7.0 IMMEDIATE CONDITIONS

7.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

7.1.1 For anomalies meeting the criteria of an Immediate Condition, reduce the operating pressure per one of the following:

- 80% of the operating pressure at the time the condition was discovered;
  - As an alternative, reduce the natural gas pressure to the highest operating pressure achieved between the end of all field activities related to the assessment and Discovery of Condition;
  - Consider reducing the operating pressure below 30% SMYS;
- Maximum safe operating pressure as determined per procedure GTIM-05-003 “RSTRENG”.

7.1.1.1 Maintain the reduced pressure until completion of a full reassessment using one of the following assessment methods:

- Pressure Test;
- In-Line Inspection;
- Direct Assessment; and

- “Other Technology”.

8.0 DOCUMENTATION

8.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

8.1.1 Maintain documentation per the requirements of the GTIM-04-005 “ECDA Post Assessment” and the GTIM-04-056 “ICDA Post-Assessment” for the life of the pipeline.

<<END>>

GTIM-08-001 Monitoring Excavations in a Right-Of-Way

PURPOSE: To establish a standardized method of monitoring excavations that occurs in the pipeline rights-of-way for transmission pipelines.

REFERENCES: 49 CFR 192.935;

SECTIONS:
- Applicability
- Monitoring Excavations

1.0 APPLICABILITY

1.1 This procedure applies to all transmission lines.

Note: Federal regulations require that this procedure be implemented in HCAs and on pipelines operating below 30% SMYS located in a Class 3 or Class 4 location. However, as prudent operators, CNP has decided to implement this procedure on all transmission pipelines.

2.0 MONITORING EXCAVATIONS

2.1 Responsibility: Local Operations

2.1.1 CNP has the opportunity to identify excavation activities in the pipeline rights-of-way during routine O&M activities including but not limited to:

- Continuing surveillance;
- One-Call activities;
- Leak surveys;
- Pipeline patrols;
- Routine daily work processes; and
- Encroachment and land services activities.

2.2 Responsibility: Local Operations

2.2.1 Monitor excavation activities that occur within transmission pipeline rights-of-way per the O&M.

2.2.1.1 Refer to O&M 9.0 “Damage Prevention” or CNP O&M XV “Damage Prevention”.

Note: Monitoring as used in this procedure refers to on-site, continual observations of excavation, and other activities, in private and public rights-of-way.

2.2.2 If a transmission asset is exposed, notify the GTIM Engineer immediately.

2.3 Responsibility: Corrosion Control or GTIM Field Inspector or designee

2.3.1 As required, evaluate the coating condition and corrosion anomalies, per procedure O&M 27.35 “Corrosion Control – Protective Coatings” or CNP O&M VIII “External Corrosion Control”.

2.4 Responsibility: GTIM Field Supervisor or GTIM Engineer or designee

2.4.1 Assign and schedule additional integrity assessment activities, such as an indirect survey or direct examination, as necessary.

2.4.2 Document all repairs to the pipeline.

2.4.2.1 For each corrosion or crack-like anomaly, complete the requirements of GTIM-05-005 “Predictive Failure Pressure”.

2.4.3 Consider opportunistically performing other data collection activities such as GTIM-02-010 “Material Verification”.

2.5 Responsibility: GTIM Field Inspector or Excavation Crew

2.5.1 Make repairs per O&M 16.0 “Repairs” or CNP O&M XX “Transmission Pipeline Repair”.

<<END>>

GTIM-08-002 Finding Evidence of Encroachment Involving Excavation

PURPOSE: To establish a standardized method of responding to evidence of encroachment, involving excavation, on a right-of-way.

REFERENCES: 49 CFR 192.935;

SECTIONS:

- Applicability
- Finding Evidence of an Encroachment Involving Excavation
- Evaluating Pipeline Near an Encroachment
- Performing Indirect Inspections
- Performing Direct Examinations
- Threat Assessment

1.0 APPLICABILITY

1.1 This procedure applies to all transmission lines.

Note: Federal regulations require that this procedure be implemented in HCAs and on pipelines operating below 30% SMYS located in a Class 3 or Class 4 location. However, as prudent operators, CNP has decided to implement this procedure on all transmission pipelines.

2.0 FINDING EVIDENCE OF AN ENCROACHMENT INVOLVING EXCAVATION

2.1 Responsibility: GTIM Engineer or GTIM Field Supervisor or designee

2.1.1 When finding evidence of encroachment involving excavation, determine if CNP personnel monitored the excavation activity.

2.1.1.1 If monitored, no further action is required.

2.1.1.2 If not monitored, and the Land and Field Services (L&FS) department did not provide notification of the excavation, inform Land and Field Services (L&FS) of the encroachment involving excavation, and continue with this procedure.

3.0 EVALUATING PIPELINE NEAR AN ENCROACHMENT

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Locate the pipeline and mark with flags or paint or both.

3.1.2 Photograph the encroachment area showing any disturbed soil and the marked pipeline.

3.1.3 Determine the distance between the pipeline's outside edge and any disturbed soil.

3.1.4 Look for signs/markings/line-markers; talk with landowners and other resources to assist in determining the party or parties responsible for the encroachment involving excavation.

3.1.5 Review all provided and gathered documentation to determine if the encroachment site requires further evaluation.

3.1.5.1 If disturbed soil is within five (5) feet of the pipeline outside edge, investigate the pipeline at the encroachment for Third-Party Damage.

3.1.5.1.1 If the disturbed soil is greater than five (5) feet from the pipeline's outside edge, no further investigation is required.

3.1.5.2 Investigate the pipeline at the encroachment as deemed appropriate if other evidence of excavation exists greater than five (5) feet from the pipeline's outside edge, such as evidence of directional bore use.

3.1.6 As necessary, request the GTIM Field Supervisor or designee to perform a site visit.

3.1.7 Determine the appropriate investigation method and document on GTIM-90802 “Transmission Encroachment”.

3.1.7.1 Refer to sections 4.0 and 5.0, respectively, to perform an indirect inspection or to excavate the pipeline and directly examine.

3.1.7.1.1 When performing an indirect inspection, choose a method capable of assessing the integrity of the coating. Applicable methods include:

- Direct Current Voltage Gradient (DCVG); and
- Alternating Current Voltage Gradient (ACVG).

3.1.7.1.2 Alternatively, direct the GTIM Engineer to prepare a Dig Packet for the encroachment area per the requirements of GTIM-04-026 “Dig Plan Preparation”.

3.1.7.2 Schedule the indirect inspection or direct examination.

3.1.8 If no further investigation is required, retain all provided and gathered documentation in the IM file.

3.1.9 Provide notification to the Land and Field Services (L&FS) department.

4.0 PERFORMING INDIRECT INSPECTIONS

4.1 Responsibility: Indirect Inspection Crew

4.1.1 When using an indirect inspection method to assess third-party damage, perform the indirect inspection according to an applicable procedure:

- GTIM-04-021 “Direct Current Voltage Gradient Survey”; or
- GTIM-04-023 “Alternating Current Voltage Gradient Survey”.

4.1.2 Begin the indirect inspection at a minimum of ten (10) feet before the first sign of encroachment and end the indirect inspection at least ten (10) feet beyond the last sign of encroachment.

4.1.3 Provide the results of the indirect inspection to the GTIM Field Supervisor.

4.2 Responsibility: GTIM Field Supervisor or designee

4.2.1 Review the results of the indirect inspection.

4.2.2 Provide the inspection data to the GTIM Engineer.

4.3 Responsibility: GTIM Engineer or designee

4.3.1 Document all coating indications on GTIM-90411 “Indication Severity Classification and Priority Category”.

4.3.2 Compare the results with previous coating surveys, In-Line Inspection results, and indication information when available.

4.3.3 Identify all indications classified as 'Severe' and 'Moderate' per the criteria in the specific indirect inspection procedure, not identified during previous inspections.

4.3.4 Prepare Dig Packet. Refer to procedure GTIM-04-026 "Dig Plan Preparation".

4.3.4.1 Identify all indications classified as 'Severe' for direct examination.

4.3.4.2 When no 'Severe' indications exist, identify the most severe 'Moderate' indication for direct examination.

4.3.5 Provide Dig Packet to the GTIM Field Supervisor.

5.0 PERFORMING DIRECT EXAMINATIONS

5.1 Responsibility: GTIM Field Supervisor or designee

5.1.1 Perform direct examinations per the requirements of the Dig Packet.

5.1.2 Excavate all indications classified as 'Severe' identified from the indirect inspection.

5.1.2.1 When finding evidence of third-party damage at a 'Moderate' indication direct examination, excavate the next highest risk 'Moderate' indication.

5.1.2.1.1 Continue the process of excavating the next highest risk 'Moderate' indication until third-party damage no longer exists.

5.1.3 Remediate as necessary per O&M 16.0 "Repairs" or CNP O&M XX "Transmission Pipeline Repair".

5.1.3.1 Document each examination on O&M 3105 "Pipe Exam".

5.1.4 Complete GTIM-90418 "Pipeline Inspection Direct Examination".

5.1.5 Document pipeline damage on Form 3112 "Gas Damage Report" and "Facilities Damage Transmission Supplemental".

5.1.5.1 Submit copies of the completed forms to the Manager of Facility Damages.

5.1.6 Place the following forms in the IM electronic file and notify the GTIM Engineer of completion:

- Form 3105 "Pipe Exam";
- GTIM-90418 "Pipeline Inspection Direct Examination" (for each location);
- Form 3112 "Gas Damage Report"; and
- "Facilities Damage Transmission Supplemental" form.

5.1.7 Retain all provided and gathered documentation in the IM file and provide notification to the Land and Field Services (L&FS) department.

6.0 THREAT ASSESSMENT

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Review applicable documentation such as:

- Form 3105 "Pipe Exam";
- GTIM-90418 "Pipeline Inspection Direct Examination";
- Form 3112 "Gas Damage Report";
- "Facilities Damage Transmission Supplemental"; and

- GTIM-90802 “Transmission Encroachment”.

6.1.2 Integrate the appropriate information per GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

6.1.3 Identify additional applicable threats per GTIM-02-021 “Threat Identification”.

6.1.4 Identify and recommend additional Preventive and Mitigative Measures per GTIM-08-004 “Identify Preventive and Mitigative Measures”. Applicable P&M measures may include:

- Additional line markers;
- Increased line patrol frequency; or
- Add test stations to increase cathodic protection.

6.1.4.1 Create a Change Management entry to request the additional P&M measure.

6.1.5 Document Performance Measures, if applicable on GTIM-90901 “Performance Measures”.

6.1.5.1 Refer to GTIM-09-001 “Performance Measures and NPMS Reporting”.

6.1.6 Create a work order to incorporate or update the data in GIS, if needed.

6.1.7 Complete a Summary Report for the IM file. Documentation should include, but is not limited to, the following:

- Executive Summary;
- Form 1043 “Encroachment Report”;
- GTIM-90418 “Pipeline Inspection Direct Examination”, if applicable;
- Form 3105 “Pipe Exam”, if applicable;
- Form 3112 “Gas Damage Report”, if applicable;
- “Facilities Damage Transmission Supplemental”, if applicable;
- GTIM-90804 “Preventive and Mitigative Measures”, if applicable;
- GTIM-91101 “Pipeline Event Evaluation”, if applicable;
- GTIM-90802 “Transmission Encroachment”; and
- GTIM-91102 “Integrity Change Management Record”, if applicable.

<<END>>

GTIM-08-003 Pipelines Operating Below 30% SMYS

PURPOSE: To establish additional Preventive and Mitigative (P&M) measures for pipelines operating below 30% SMYS.

REFERENCES: 49 CFR 192.935;

SECTIONS:
- General
- Below 30% SMYS and in a High Consequence Area
- Below 30% SMYS in Class 3 or Class 4 Locations

1.0 GENERAL

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Determine if the MAOP of the transmission pipeline is below 30% SMYS.

1.1.1.1 For transmission pipelines with an MAOP above 30% SMYS, this procedure is not applicable.

1.1.1.2 For transmission pipelines with an MAOP below 30% SMYS, distinguish further if they contain:

- High Consequence Areas (HCAs);
- Class 3 locations; or
- Class 4 locations.

1.1.1.2.1 Implement required regulatory measures depending on the location of the pipeline, per section 2.0 “Below 30% SMYS and in High Consequence Area” and section 3.0 “Below 30% SMYS in Class 3 or Class 4 Locations” in this procedure.

2.0 BELOW 30% SMYS AND IN A HIGH CONSEQUENCE AREA

2.1 Responsibility: Local Operations

2.1.1 For pipelines operating below 30% SMYS and located in an HCA:

2.1.1.1 Always use qualified personnel for tasks that could adversely affect the integrity of the pipeline, including but not limited to the following activities:

- Marking;
- Locating; and
- Direct supervision of excavation work.

2.1.1.2 Participate in the One-Call program per O&M 9.30 “One-Call Programs” or CNP O&M XV “Damage Prevention”.

2.1.2 Monitor excavations that occur in the right-of-way per O&M 9.10 “Damage Prevention: Compliance” or CNP O&M XV “Damage Prevention”.

2.1.2.1 When observing an indication of unreported excavation activity on a right-of-way, refer to GTIM-08-002 “Finding Evidence of Encroachment”.

Note: 49 CFR 192 Subpart O and §192.935 allows bi-monthly patrols instead of monitoring excavations in the rights-of-way. As prudent pipeline operators, CNP prefers monitoring all transmission pipeline excavations that occur in the right-of-way instead of relying on bi-monthly patrols.

2.1.3 Select additional Preventive and Mitigative (P&M) measures as necessary per GTIM-08-004 “Identifying Preventive and Mitigative Measures”.

2.1.3.1 Create a Change Management entry to request additional P&M measures per GTIM-11-001 “GTIM Change Management”.

3.0 BELOW 30% SMYS IN CLASS 3 OR CLASS 4 LOCATIONS

3.1 Responsibility: Local Operations

3.1.1 For pipelines operating in a Class 3 or Class 4 location, but not located in an HCA:

3.1.1.1 Always use qualified personnel for tasks that could adversely affect the integrity of the pipeline, including but not limited to the following activities:

- Marking;
- Locating; and
- Direct supervision of excavation work.

3.1.1.2 Participate in the One-Call program per O&M 9.30 “One-Call Programs” or CNP O&M XV “Damage Prevention”.

3.1.2 Monitor excavations that occur in the rights-of-way per O&M 9.10 “Damage Prevention: Compliance” or CNP O&M XV “Damage Prevention”.

3.1.2.1 When observing an indication of unreported excavation activity on a right-of-way refer to GTIM-08-002 “Finding Evidence of Encroachment”.

3.1.3 Perform a leak survey, per O&M 17.20 “Gas Leak Surveys and Pipeline Patrols”, or CNP O&M XVII “Patrolling” and CNP O&M XIX “Leak Surveys”, twice per year on these line segments.

3.2 Responsibility: Corrosion Control Supervisor

3.2.1 Identify non-HCA pipelines in Class 3 or Class 4 locations that are:

- Unprotected; and
- Cathodically protected pipelines where electrical surveys are impractical.

3.2.2 Document these line segments in the IM file.

3.2.3 Notify Local Operations that they must perform a leak survey, per O&M 17.20 “Gas Leak Surveys and Pipeline Patrols”, or CNP O&M XVII “Patrolling” and CNP O&M XIX “Leak Surveys”, once every three (3) months on these line segments.

<<END>>

GTIM-08-004 Identify Preventive & Mitigative Measures

PURPOSE: To provide a selection methodology and criteria for identifying and implementing Preventive and Mitigative (P&M) Measures.

REFERENCES: 49 CFR 192.935; ASME/ANSI B31.8S-2004, Section 7 and Appendix A;

SECTIONS:
- Identify P&M Measures
- Continual Evaluation
- Document Existing and Additional P&M Measures

1.0 IDENTIFY P&M MEASURES

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Using the assessment schedule calendar, GTIM-90209 "Threat Analysis", and other sources of threat data, review the identified threats for each Consequence Area.

1.1.2 Determine the significant contributor(s) leading to each threat. Examples include, but are not limited to:

1.1.2.1 External Corrosion:
- Ineffective Cathodic Protection (CP);
- Coating damage; and
- AC Current.

1.1.2.2 Internal Corrosion:
- Entrained liquids;
- Product contaminants; and
- Microbiologically Influenced Corrosion (MIC).

1.1.2.3 Stress Corrosion Cracking (SCC):
- Operating pressure; and
- Operating temperature.

1.1.2.4 Third-Party and Mechanical Damage:
- Previously damaged pipe;
- Vandalism;
- Increased construction activity; and
- Shallow or exposed pipe.

1.1.2.5 Manufacturing:
- Seam defect; and
- Pipe defect.

1.1.2.6 Construction:
- Girth weld defect;
- Fabrication weld defect;
- Coupling failure; and

- Wrinkle bend or buckle.

1.1.2.7 Equipment:

- Gasket or O-ring failure;
- Stripped thread or broken pipe;
- Control or relief valve malfunction;
- A seal failure; and
- A pump-packing failure.

1.1.2.8 Weather-Related and Outside Force:

- Cold Weather;
- Lightning;
- Heavy rains or flood;
- Blasting activities within 600 feet of the pipeline's PIR[1] (refer to O&M 9.38 "Blasting" or CNP O&M XV-A "Damage Prevention"); and
- Earth movement.

1.1.2.9 Incorrect Operations:

- Less than adequate procedures;
- Failure to follow procedures; and
- Less than adequate training.

1.1.3 Identify each Preventive and Mitigative (P&M) measure already in place for each Consequence Area.

1.1.3.1 Refer to Table 08-004-1 as a guideline when considering and identifying P&M measures for each identified threat.

1.1.4 Confirm that the measure(s) prevent or mitigate the risk factors most likely to cause the threat.

1.1.4.1 Solicit the input of Subject Matter Experts (SMEs) to determine the effectiveness of existing P&M Measures. SMEs may include but are not limited to personnel from:

- Corrosion Control;
- Operations;
- Maintenance; and
- Engineering.

1.1.4.2 Consider both the likelihood and consequences of pipeline failure regarding the P&M Measure(s).

[1] The American Gas Association recommends that a blast plan be obtained and evaluated whenever blasting is to occur within 500 feet of a pipeline (Lambeth, Alan, "Blasting Adjacent to In-Service Gas Pipelines" American Gas Association Transmission/Distribution Conference, May 17, 1993, p15). CNP uses an additional safety margin beyond that distance.

Table 08-004-1: Preventive and Mitigative Measures by Threat Type

P & M Measures	CORROSION		ENVIRONMENT	THIRD-PARTY / MECHANICAL DAMAGE			MANU-FACTURE		CONSTRUCTION				EQUIPMENT				INCORRECT OPERATION	WEATHER RELATED / OUTSIDE FORCE			
	External	Internal	SCC	Damage Inflicted by 1st, 2nd, or 3rd parties	Previously Damaged Pipe (delayed failure mode)	Vandalism	Defective Pipe Seam	Defective Pipe	Defective Girth Weld	Defective Fabrication Weld	Coupling Failure	Wrinkle Bend / Buckle	Gasket / O-ring	Stripped Thread / Broken Pipe	Control / Relief Equipment Malfunction	Seal / Pump Packing Failure	Company Procedures	Cold Weather	Lightning	Heavy Rains / Flood	Earth Movement
Monitor/maintain cathodic protection	X		X																		
Increased wall thickness	X	X		X	X	X															X
Leakage control measures	X	X			X	X					X		X	X	X	X					
Rehabilitation	X	X	X		X						X	X									X
Coating repair	X		X																		
O&M procedures	X	X	X		X	X					X	X	X	X	X	X	X	X	X	X	X
Design specifications *(per ASME/ANSI B31.8 code)*	X	X	X						X		X	X	X	X	X	X					X
Material specifications							X	X		X			X	X	X	X					
Internal cleaning		X																			
Reduce moisture		X																			
Biocide/inhibiting injection		X																			
Additional leak surveys					X	X					X		X	X	X	X					
Additional aerial patrols				X	X	X					X							X	X	X	X
Foot patrols	X			X	X	X					X							X	X	X	X
One-Call system				X	X	X															
Public education				X		X														X	
Increase marker frequency				X	X																
Increased test station frequency	X																				
External protection				X	X	X														X	X
Maintain ROW				X	X	X															X
Warning tape mesh				X	X																

P & M Measures	CORROSION		ENVIRONMENT	THIRD-PARTY / MECHANICAL DAMAGE			MANU-FACTURE		CONSTRUCTION				EQUIPMENT				INCORRECT OPERATION	WEATHER RELATED / OUTSIDE FORCE			
	External	Internal	SCC	Damage Inflicted by 1st, 2nd, or 3rd parties	Previously Damaged Pipe (delayed failure mode)	Vandalism	Defective Pipe Seam	Defective Pipe	Defective Girth Weld	Defective Fabrication Weld	Coupling Failure	Wrinkle Bend / Buckle	Gasket / O-ring	Stripped Thread / Broken Pipe	Control / Relief Equipment Malfunction	Seal / Pump Packing Failure	Company Procedures	Cold Weather	Lightning	Heavy Rains / Flood	Earth Movement
Line relocation				X		X												X		X	X
Increase cover depth				X		X						X							X	X	
Pre-service hydrostatic test					X		X	X	X	X	X	X									
Construction Inspection			X		X			X	X	X	X	X	X	X	X	X					
Manufacturer inspection					X		X	X		X					X	X					
Transportation inspection					X		X	X													
Visual/mechanical inspection[2]									X				X	X	X	X		X		X	
Reduce external stress			X								X	X		X							X
Reduce operating temperature			X										X			X					
Compliance audit																	X				
Operator training																	X			X	
Conduct drills with emergency responders				X	X	X					X			X			X	X	X	X	
Strain monitoring																				X	X
Pig-GPS[3]/strain measurement																		X		X	X
Stabilization of the soil																		X		X	X
Install heat tracing																		X			
Install thermal protection																		X			

Note: Adapted from **ASME/ANSI B31.8S-2004**, Table 4, and augmented by CNP SMEs.

[2] Refers to equipment inspections;
[3] In-Line Inspection equipment taking GPS coordinates of pipeline;

2.0 CONTINUAL EVALUATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Review the P&M measures currently in place for the covered pipeline segment(s):

- Before performing an integrity assessment;
- During the Post-Assessment phase of an integrity assessment;
- Upon discovery of a leak;
- Upon identification of a new threat;
- At the determination of an additional risk factor; or
- After the occurrence of a new integrity event requiring repair.

2.1.2 Evaluate the effectiveness of the existing P&M measures.

2.1.3 Identify additional and modify existing P&M Measures as appropriate.

2.1.3.1 As necessary, solicit the input of SMEs.

2.1.4 Review information and the root-cause analyses of excavation damage, when applicable, per GTIM-08-006 “Collecting Information on Excavation Damage”.

2.1.4.1 Determine if additional P&M measures are appropriate based on past occurrences of excavation damage.

3.0 DOCUMENT EXISTING AND ADDITIONAL P&M MEASURES

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Document each P&M method already in place on GTIM-90804 “Preventive and Mitigative Measures”.

3.1.1.1 Include specific details (i.e., GIS begin and end measures; frequency of activity; interactive threats; specialized method; etc.).

Note: P&M measures beyond those explicitly required by 49 CFR Part 192, should be considered for all identified threats and risk factors on the pipeline. In some cases, this may require identifying more than one (1) P&M measure along a pipeline segment.

3.1.2 Determine if the existing P&M method is sufficiently managing or mitigating the identified threat(s).

3.1.2.1 Consult with Subject Matter Experts as needed and document on GTIM-90804.

3.1.2.2 If the existing P&M method is sufficiently managing or mitigating the identified threat(s) and risk factors, provide a reasonable justification, why no additional methods are required.

3.1.2.3 If the existing P&M method is not sufficient to address each identified threat(s) or risk factors, select additional preventive or mitigative measures or both.

3.1.2.3.1 Additional measures may include but are not limited to:

- Performing additional patrols, leak surveys, or aerial patrols;

- Implementing additional training programs;
- Installing additional line markers or test stations or both;
- Schedule a close interval survey (CIS) if finding active corrosion during a Direct Assessment;
- Visual inspections of a submerged pipe by divers;
- In the case of prolonged flooding where pipeline cover may be compromised, consider marking pipe location with identifying buoys or additional markers; and
- Depth of cover surveys;
    - Include Public Awareness efforts to inform landowners of the potential hazard from reduced cover over pipelines.

3.1.2.4 Document each additional or expanded method recommendation on GTIM-90804.

3.1.2.5 Request approval for each additional or expanded method recommendation by completing a GTIM-91102 “Integrity Change Management Record” per GTIM-11-001 “GTIM Change Management”.

3.1.2.5.1 Record each Change Management request record number.

3.1.2.5.1.1 If declined, no further action is required.

3.1.2.5.2 If the request is accepted, follow up with appropriate parties to implement.

3.1.2.5.2.1 Create a work order and include all existing, additional, and expanded methods.

3.1.2.5.2.2 Confirm implementation of P&M measures per applicable sections of the O&M.

3.1.3 Consider notifying the Compliance Department of additional P&M activities and frequencies.

<<END>>

GTIM-08-005 Evaluating Similar Condition

PURPOSE: The purpose of this standard is to provide a consistent approach for evaluating similar conditions on covered and non-covered segments.

REFERENCES: 49 CFR 192.917;

SECTIONS:
- Identifying Corrosion
- Evaluating Similar Pipeline Segments

1.0 IDENTIFYING CORROSION

1.1 Responsibility: GTIM Field Inspector or designee

1.1.1 When finding corrosion (external or internal) greater than 20% wall loss in a Consequence Area, determine the preliminary cause of the corrosion anomaly per GTIM-04-012 “Root Cause Analysis”.

1.1.1.1 Document corrosion anomalies per the requirements of GTIM-04-024 “Documentation of Coating and Corrosion Defects”.

1.2 Responsibility: GTIM Engineer or designee

1.2.1 Review the preliminary cause for the corrosion anomaly.

1.2.2 Determine if the cause for the corrosion is unique and can be considered an isolated incident.

1.2.2.1 Request the assistance of the GTIM Field Supervisor or other corrosion personnel as necessary.

1.2.2.2 If the cause is unique, document the determination on GTIM-90421 “Root Cause Analysis”. No further action is required.

1.2.3 If the cause for the corrosion is not unique and could exist at other locations within the pipeline system as determined on a case-by-case basis, identify the root-cause indicators.

1.2.3.1 Typical root-cause indicators may include, but are not limited to:

- Coating type;
- Coating vintage;
- Soil resistivity;
- AC Current;
- Less than adequate rectifier performance; and
- Depleted anodes.

1.2.3.2 Document the root-cause indicators on GTIM-90421 “Root Cause Analysis”.

1.2.4 Identify other areas in the transmission system, in both covered and non-covered segments, where the similar root-cause indicators exist.

1.2.4.1 Document the locations in a white paper.

2.0 EVALUATING SIMILAR PIPELINE SEGMENTS

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Determine the method(s) to be used to evaluate similar pipeline segments. Depending upon the situation, applicable techniques may include, but are not limited to:

- Close-Interval Survey;
- Direct Current Voltage Gradient (DCVG);
- Direct examination; and
- Interference testing.

2.1.2 Determine a schedule for evaluating similar pipeline segments.

2.1.2.1 Evaluation should occur within one (1) year, not to exceed 15 months, from completing the root-cause analysis.

2.1.3 Document an Action Plan for addressing similar pipeline segments.

2.1.3.1 Confirm the Action Plan includes:

- Line segments to be evaluated;
- Method(s) of evaluation;
- The rationale for choosing the method(s); and
- Timelines and schedule.

2.1.4 Retain the Root-Cause Analysis and Action Plan in the IM file.

2.1.5 Provide the Action Plan to the GTIM Field Supervisor for implementation.

<<END>>

GTIM-08-006 Collecting Information on Excavation Damage

PURPOSE: To establish a standardized approach for collecting excavation damage information occurring in covered and non-covered segments.

REFERENCES: 49 CFR 192.935; 49 CFR Part 191;

SECTIONS:
- General
- Documenting Excavation Damage
- Continual Evaluation

1.0 GENERAL

1.1 This procedure includes excavation damage occurring on transmission pipelines in covered and non-covered segments.

1.1.1 This procedure does not include damage that meets the requirements of a reportable incident per 49 CFR Part 191.

2.0 DOCUMENTING EXCAVATION DAMAGE

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Regardless of the instigator, (e.g., before performing an integrity assessment, upon discovery of a leak, upon identification of a new threat, upon discovery of a new integrity event requiring repair, etc.), obtain a report detailing excavation damage that has occurred within the CNP pipeline system including:

- Location of damage;
- Date of damage, if known, else the date of discovery;
- Cause of damage (i.e., pipe not correctly located, locate not performed, etc.).

2.1.2 Use this information as part of the continual evaluation process described in section 3.0 “Continual Evaluation” of this procedure.

2.1.3 In the case of a leak, log the leak information in the appropriate tracking database.

3.0 CONTINUAL EVALUATION

3.1 Responsibility: GTIM Engineer or designee

3.1.1 As required per GTIM-08-004 “Identify Preventive and Mitigative Measures”, review current P&M measures, and consider additional P&M measures for covered pipeline segments.

3.1.1.1 In the review, consider any excavation damage that occurred on covered or non-covered segments within the pipeline system, along with the results of the root-cause analysis.

3.1.2 Review One-Call activity through the OBIEE 811 Ticket Dashboard on-line database, or other One-Call ticket resources, for increased evidence of the Third-Party and Mechanical Damage threat.

3.1.2.1 Review One-Call activity regularly, typically monthly, for evidence of high activity.

3.1.3 As appropriate, identify additional P&M measures for covered segments, per GTIM-08-004 “Identify Preventive and Mitigative Measures”.

3.1.3.1 Create a Change Management entry per GTIM-11-001 “GTIM Change Management” when identifying new or modified P&M measures.

<<END>>

GTIM-08-007 Automatic Shut-Off & Remote-Control Valves

PURPOSE: To provide considerations for the use of an Automatic Shut-Off Valve (ASV) or a Remote-Control Valve (RCV) as an effective means of adding protection in the event of an unintentional gas release in Consequence Areas.

REFERENCES: 49 CFR 192.935;

SECTIONS:
- Risk Analysis
- Documentation

1.0 RISK ANALYSIS

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Determine, based on risk analysis, if an ASV or RCV would be an efficient means of adding protection to a Consequence Area. ASVs and RCVs enable shutting off the flow of gas in the event of an unintentional gas release or for routine maintenance activities.

1.1.1.1 During the risk determination, consider the following factors:

- Response times (swiftness of leak detection to pipe shutdown);
- Type of transported gas;
- Operating pressure and %SMYS;
- Rate of potential release;
- Pipeline profile;
- Potential for ignition;
- The physical location of nearest response personnel; and
- Pipe diameter.

1.1.2 Evaluate the results of the analysis and determine if installing valves would be useful.

1.1.2.1 If determined useful, work with Gas Control and Operations to determine the best location for a valve.

1.1.2.1.1 Develop a timeline for installing the valves, factoring in the capital budget impact.

1.1.2.2 If determined not useful, no further action is necessary.

2.0 DOCUMENTATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Retain copies of communications with other SMEs, including any discussions or analyses for determining valve installation.

2.1.1.1 Document all forms of communications (i.e., phone conversations, voice messages, meetings, etc.), with either an email to the other parties confirming your understanding of discussion items and outcomes or an equivalent log.

2.1.2 Maintain documentation in the IM file. Documentation should include, but is not limited to:

- Risk Analysis results;
- Recommendation on whether or not valves would be useful;

- Recommended locations to install valves, if applicable; and
- Timeline for installing the valves.

<<END>>

GTIM-08-008 Third-Party Damage & Outside Force

PURPOSE: To establish Preventive and Mitigative Measures (P&M) to address Third-Party Damage and Outside Force threats in Consequence Areas.

REFERENCES: 49 CFR 192.935;

SECTIONS:

- Preventing and Mitigating Third-Party Damage
- Mitigating Outside Force Damage

1.0 PREVENTING AND MITIGATING THIRD-PARTY DAMAGE

1.1 Responsibility: GTIM Engineer or designee

1.1.1 For all pipelines located in an area of consequence:

1.1.1.1 Confirm implementation of additional Preventive and Mitigative (P&M) Measures per GTIM-08-004 “Identifying Preventive and Mitigative Measures”.

1.1.1.2 Review One-Call activity through the OBIEE 811 Ticket Dashboard on-line database or other One-Call ticket resources, for increased evidence of the Third-Party and Mechanical Damage threat.

1.1.2 Document the excavation damage location information per GTIM-08-006 “Collecting Information on Excavation Damage” on all transmission pipelines, in both covered and non-covered segments:

1.1.2.1 Excavation damage information is not limited to reportable incidents.

1.2 Responsibility: Local Operations

1.2.1 For pipelines located in Consequence Areas:

1.2.1.1 Use qualified personnel for tasks within a Consequence Area that could adversely affect the integrity of the pipeline, including, but is not limited to:

- Marking;
- Locating; and
- Direct supervision of excavation work.

1.2.1.2 Participate in the One-Call program per O&M 9.30 “One-Call Programs” or CNP O&M XV “Damage Prevention”.

1.2.1.3 Monitor excavations that occur in the right-of-way per GTIM-08-001 “Monitoring Excavations in a Right-of-Way”.

1.2.1.3.1 When finding evidence of an unreported excavation activity on the right-of-way, refer to GTIM-08-002 “Finding Evidence of Encroachment”.

1.2.2 Consider the following to aid in the prevention of Third-Party Damage.

1.2.2.1 Install additional line markers for pipeline location identification.

1.2.2.2 Install additional test stations to aid with locating surveys.

1.2.2.3 Consider additional foot, all-terrain vehicle (ATV), or aerial patrols, if applicable.

2.0 MITIGATING OUTSIDE FORCE DAMAGE

2.1 Responsibility: GTIM Manager or GTIM Engineer

2.1.1 Using the assessment schedule calendar, GTIM-90209 “Threat Analysis”, and other sources of threat data, identify covered segments with the threat of Outside Force damage.

2.1.1.1 Review the data to determine the significant contributor(s) leading to an Outside Force threat. Examples include, but are not limited to:

- Conditions contributing to loading stress;
- Longitudinal or lateral forces;
- Seismicity of the area, including blasting activities within 600 feet of the PIR;
- Heavy rains or flooding;
- Suspended or unsupported pipeline segments;
- Extreme temperature variations;
- Vehicle or equipment contact, not related to excavation, (e.g., an automobile crash into an aboveground valve, pumping station, or other pieces of pipeline equipment);
- Damage caused by accidents or fires from other businesses or industries that are nearby;
- Vandalism; and
- Sabotage or terrorism.

2.1.1.2 Minimize the consequence of Outside Force damage by selecting suitable P&M measures per GTIM-08-004 “Identifying Preventive and Mitigative Measures”.

2.1.1.2.1 Confirm the selected measure addresses at least one of the conditions, which contributed to the Outside Force threat.

2.1.1.2.2 Consider increasing pipeline patrol frequency for the affected segment(s).

2.1.1.2.2.1 Conduct patrols per O&M 17.20 “Gas Leak Surveys and Pipeline Patrols”, or CNP O&M XVII “Patrolling” and CNP O&M XIX “Leak Surveys”.

2.1.1.2.3 Consider installing additional protection such as:

- Strain monitoring;
- Heat tracing;
- Thermal protection; and
- External protection.

2.1.1.2.4 Consider methods for reducing external stresses on the pipeline segment.

2.1.1.2.5 Consider relocating the pipeline segment to an area less prone to Outside Force damage.

2.1.1.2.6 Consider using in-line inspection geospatial and deformation tools.

2.1.1.2.7 Solicit the input of Subject Matter Experts (SME) to determine the effectiveness of existing P&M Measures. SMEs may include but are not limited to personnel from:

- Operations;
- Maintenance; and

- Engineering.

2.1.1.3 Create a Change Management entry to request additional P&M measures.

2.1.1.4 Document additional or modified P&M measures on the appropriate GTIM-90804 “Preventive and Mitigative Measures”.

<<END>>

GTIM-09-001 Performance Measures and NPMS Reporting

PURPOSE: To establish a standardized method to generate, review, and report Integrity Management Program Performance Measures to the Pipeline and Hazardous Material Safety Administration (PHMSA).

REFERENCES: 49 CFR 192.945; ASME/ANSI B31.8S-2004, Section 9; PHMSA F 7100.2-1; 49 USC 60132;

SECTIONS:
- Data for Performance Measures
- Executive Signature
- Submitting Performance Measures
- Non-Reportable Performance Measures
- Trending Performance Measures
- NPMS Reporting

1.0 DATA FOR PERFORMANCE MEASURES

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Confirm that applicable databases and spreadsheets are up to date through the end of the reporting period.

1.1.1.1 Query reportable examination information for the reporting period.

1.1.2 Send a blank copy of GTIM-90902 “Field Performance Measures” to each applicable Local Operations group to capture additional information including, but not limited to:

- Number of wrinkle bends removed; and
- Near misses due to incorrect operations.

1.2 Responsibility: Local Operations

1.2.1 Complete GTIM-90902, as requested by the GTIM Engineer.

1.2.2 Return GTIM-90902 form to the GTIM Engineer within ten (10) working days.

1.3 Responsibility: GTIM Engineer or designee

1.3.1 Follow-up with Local Operations to confirm the completion of GTIM-90902 if not returned within the ten (10) working days.

1.3.2 Review each GTIM-90902 submitted by the Local Operations groups.

1.3.3 Review the Post-Assessments completed during the reporting period.

1.3.4 Notify the GTIM Manager of any outstanding assessment reports, leak reports, or pipe exams that will not be available for reporting purposes.

1.3.5 Complete GTIM-90901 “Performance Measures”.

2.0 EXECUTIVE SIGNATURE

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Prepare documentation detailing the performance measures and the results to be submitted to PHMSA.

2.1.2 Forward the information to the GTIM Manager.

2.2 Responsibility: GTIM Manager or designee

2.2.1 Review the performance measures and results to be submitted.

2.2.2 Prepare an email or other correspondence for the Senior Executive Officer.

2.2.2.1 The correspondence should include the performance measures to be submitted and their results.

2.2.2.2 Send a copy of the correspondence to the Director of Engineer Gas System Integrity and Reliability.

2.2.3 Request that the Senior Executive Officer respond acknowledging review of the Performance Measures and authorizing submittal to PHMSA.

2.3 Responsibility: Senior Executive Officer or designee

2.3.1 Review the Performance Measures to be submitted.

2.3.1.1 Request clarification as necessary.

2.3.2 If the information presented is believed to be accurate and complete, send a response to the GTIM Manager approving submission to PHMSA.

3.0 SUBMITTING PERFORMANCE MEASURES

3.1 Responsibility: GTIM Manager or designee

3.1.1 For each CNP Operating Company, confirm that Performance Measures are submitted electronically to the Pipeline Hazardous Materials Safety Administration (PHMSA) annually.

3.1.1.1 The reporting period is January 1 to December 31 of the previous year.

3.1.1.1.1 The reporting deadline for PHMSA and all State Regulatory Agencies is March 15.

3.1.2 Submit Performance Measure Reports on the PHMSA website at http://primis.phmsa.dot.gov/pipeline.

3.1.2.1 As part of the submittal process, enter the name of the Senior Executive Officer that certified the Performance Measures.

3.1.2.2 Typing in the name of the Senior Executive Officer represents an official signature.

3.1.3 Review the current instructions for completing the form, PHMSA F 7100.2-1, on the PHMSA website at http://phmsa.dot.gov/pipeline/library/forms, and adhere to the following:

- On PHMSA F 7100.2-1, report Performance Measures for each state based on the designations of intrastate and interstate pipelines.
- Fill each cell of the form; enter ‘0’ if applicable; do not leave any cell blank.
- The total number of transmission system miles should match the number on the annual report.
- Report ‘HCA Miles Inspected’ based on the assessments completed within the reporting period.
- An ILI assessment completion date is the date of removal of the last ILI tool from the pipe.

- The assessment completion date for a Direct Assessment (DA) is the date the last direct examination is complete.
- For Pressure Testing, the assessment completion date is the date of the pressure test.
- For pipe segments abandoned during a reporting period - either, subtract from the total HCA mileage or count the mileage toward the “Number of pipeline miles/HCA miles inspected”. Do not “double-dip” and report in both categories.
- A single excavation may have multiple indications. For the Performance Measure reporting, each Immediate or Scheduled indication repaired counts as a separate repair, even when remediation of all indications occurs with the same repair.

3.1.4 Review the information and submit.

3.1.5 If resubmission of the information is needed, follow the same process as above.

3.1.5.1 The Office of Pipeline Safety saves both the new submission and the previous submission in their database.

3.1.6 Print the confirmation page displayed on the completion of the submission.

3.1.6.1 Keep one (1) copy of the confirmation page in the IM file.

3.1.6.2 Email a copy of the confirmation page to the Director of Engineer Gas System Integrity and Reliability.

3.1.6.3 Send a copy of the appropriate PHMSA report to the applicable state agency; reference Appendix C.

4.0 NON-REPORTABLE PERFORMANCE MEASURES

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Once a year, determine the preceding calendar year’s Threat Specific (non-reportable) Performance Measures before March 15 of each year.

4.1.2 Threat Specific (non-reportable) Performance Measures are as follows:

- External Corrosion Threats;
- Internal Corrosion Threats;
- Stress Corrosion Cracking (SCC) Threats;
- Manufacturing Threats;
- Construction Threats;
- Equipment Threats;
- Third-Party Damage Threats;
- Incorrect Operations Threats; and
- Outside Force Threats.

4.1.2.1 Refer to GTIM-90901 for the documentation required for each threat.

4.1.3 Document Threat Specific Performance Measures on GTIM-90901 “Performance Measures”.

5.0 TRENDING PERFORMANCE MEASURES

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Compare the latest Performance Measures with the prior year’s measures.

5.1.2 Identify any trends.

5.1.3 Evaluate and recommend operating changes, procedural changes, or additional Preventive and Mitigative measures as warranted.

5.1.3.1 Refer to GTIM-11-001 “GTIM Change Management”.

5.1.4 Document the review in a one-page memo to file. Include the following information:

- Date of review;
- Name of person performing the review;
- Trends; and
- Recommendations.

5.2 Responsibility: GTIM Manager or designee

5.2.1 Review the trend analysis and recommended changes.

5.2.2 As appropriate, confirm the implementation of the changes.

5.2.3 If the performance measures do not show improvement between assessment applications, re-evaluate the applicability of the current process, and evaluate alternative methods of assessing the integrity of the pipeline.

6.0 NPMS REPORTING

Note: This section must be completed separately for each operating company.

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Review the instructions in the current NPMS Operators Standards Manual for providing and submitting data to NPMS located at https://www.npms.phmsa.dot.gov/Documents/Operator_Standards.pdf.

6.1.2 Prepare files, geospatial-data, attribute-data, and metadata, compliant with the current NPMS Operator Standards Manual.

6.1.2.1 Ensure that Operator ID numbers in the annual PHMSA report submissions match the same assets and attributes described in the NPMS files.

6.1.2.2 The reporting period is January 1 to December 31 of the previous year.

6.1.2.3 The reporting deadline is March 15.

6.1.3 Forward the files and summarized information to the GTIM Manager.

6.2 Responsibility: GTIM Engineer or designee

6.2.1 Review the NPMS data to be submitted.

6.2.2 Create a cover letter for each operating company’s submission according to the NPMS Operators Standards Manual. Find a template for the cover letter at https://www.npms.phmsa.dot.gov/Documents/Pipeline_CoverLetter_Template.doc.

Note: The submission contact information provided in your metadata and on your cover letter is separate from Public Contact Information. The public contact information will be available to users of the NPMS Web site and web mapping applications. The submission contact information will only be used internally by NPMS staff. Submission of contact information to the public is prohibited.

6.2.3 Review the Public Contact Information that NPMS has on file to determine if the information is still accurate at https://www.npms.phmsa.dot.gov/DataReview/.

6.2.3.1 Make updates to this information using the NPMS form at https://www.npms.phmsa.dot.gov/OperatorPublicContact/OperatorPublicContact.aspx.

6.2.4 Review the information and submit updates if needed.

Note: Once NPMS receives the completed submission, NPMS will send a confirmation receipt accepting your submission.

6.2.4.1 Retain the submitted NPMS data, cover letter, and confirmation receipt in the IM file.

Note: Once processed, NPMS will send a request to perform a final review on the data via the NPMS Submission Reviewer application. The email will include a temporary username and password, along with the review session expiration date. This step finalizes the NPMS submission and concludes the NPMS submission process.

6.2.5 Review the NPMS processed data as directed in the email.

6.2.6 Retain the request to review the email in the IM file along with the submitted data, cover letter, and confirmation receipt.

<<END>>

GTIM-10-001 Record Keeping

PURPOSE: To provide a standardized method for maintaining documentation for the Gas Transmission Integrity Management Program.

REFERENCES: 49 CFR 192.947; 49 CFR 192.67; 49 CFR 192.127; 49 CFR 192.205;

SECTIONS:

- Gas Transmission Integrity Management (GTIM) Records

1.0 GAS TRANSMISSION INTEGRITY MANAGEMENT (GTIM) RECORDS

1.1 Responsibility: GTIM Manager or designee

1.1.1 Confirm a current copy of the CNP Gas Transmission Integrity Management Plan is available on the CNP intranet website.

1.1.2 Maintain documentation of the integrity management program for the life of the pipeline system.

1.1.2.1 Documentation includes, but is not limited to:

- GTIM procedures and forms;
- Documents supporting HCA and MCA analysis;
- Documents supporting threat identification, risk factor determination, and risk analyses, as applicable;
- Records that document the current class location of each pipeline segment, including how the class location was determined;
- Assessment schedules including, but not limited to, Baseline/Reassessment Assessment Plan (BRAP) and the assessment schedule calendar;
- Documents supporting any decision, analysis, processes developed and used to implement and evaluate each element of the Baseline/Reassessment Assessment Plan and the Integrity Management Program per revision change history activities;
  - Include documents used to develop and support any identification, calculation, amendment, modification, justification, deviation, and determination made;
  - Include documents used to develop and support any action taken to implement and evaluate any of the program elements;
- Records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for the line pipe and components;
  - Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time of manufacturing or installation of the pipe;
- Design records documenting that the pipe's ability to withstand anticipated external pressures and loads;
- Records establishing the MAOP of the line pipe and components;
- Documents demonstrating operator qualification and training;
  - Include descriptions of the training programs;

- Scheduled prioritization of conditions found during an assessment for evaluation and remediation;
    - Include technical justifications for the schedule;
    - Include anomaly analyses and remediations;
- Documentation supporting integrity assessments; and
- Verification that CNP has provided any documentation or notification required to PHMSA and other regulatory agencies.

1.1.2.2 This documentation is subject to review during a jurisdictional audit.

1.1.3 Records may be in either electronic or paper format, on a case-by-case basis.

1.1.4 Refer to each procedure individually for additional documentation requirements.

<< END>>

GTIM-11-001 Change Management

PURPOSE: To establish a standardized process for tracking and retaining records of non-routine events and deviations within the CNP Integrity Management Program.

REFERENCES: 49 CFR 192.909; ASME/ANSI B31.8S-2004, Section 11;

SECTIONS:

- General
- Log Entries
- Notification Entries
- Request for Approval Entries
- Change Implementation

1.0 GENERAL

Note: For managing content changes and publishing changes to the Gas Transmission Integrity Management (GTIM) Plan, refer to GTIM-12-002 "Integrity Management Program Review".

1.1 Use this process for logging, tracking, and retaining proposed changes, non-routine events, and deviations involving the Gas Transmission Integrity Management Program that are not already captured by another process or tool, or handled with content changes to the GTIM-Plan.

1.1.1 This process is for GTIM internal use only.

1.2 Proposed changes of high risk, large in scope and duration, or involving actions by departments outside of the CNP Transmission Integrity Management Program usually dictate a greater need for formality and thoroughness around justification and implementation of the change. For example, proposing a Preventive & Mitigative measure to install Remote Control Valves (RCVs) in every Regulatory Station in a region would be better suited as a 'white paper' project proposal.

1.3 There are three (3) types of Change Management entries:

- Log;
  - Log entries typically record past events or actions.
- Notification; and
  - Notifications typically inform on past events or actions.
- Request for approval.
  - Requests for approval allow for review and planning for events and actions.

2.0 LOG ENTRIES

2.1 **Responsibility:** Integrity Management Team Member (Originator)

2.1.1 Create a log entry with the following information:

- Date of the non-routine event or deviation;
- Name and title of the entry originator;
- Describe the incident;

- Describe the impact;
- List other CNP groups potentially affected, if any;
- List any actions required before the event or activity, if applicable;
- List any actions required after the event or activity, if applicable;
- Justify the non-routine event or deviation;
- Add other comments, as necessary; and
- Attach applicable documentation, as necessary.

2.1.1.1 Examples of log entries might include:

- The annual review of the assessment schedule calendar;
- Personnel changes not requiring a content change to the GTIM-Plan; and
  - For example, a promotion that replaces one person with another person who assumes the current role and responsibilities.

3.0 NOTIFICATION ENTRIES

3.1 Responsibility: Integrity Management Team Member

3.1.1 Create a notification entry with the following information:

- Date of the non-routine event or deviation;
- Name and title of the entry originator;
- Describe the incident;
- Describe the impact;
- List other CNP groups potentially affected, if any;
- List any actions required before the event or activity, if applicable;
- List any actions required after the event or activity, if applicable;
- Justify the non-routine event or deviation;
- List the names and email addresses of the people to notify;
- Add other comments, as necessary; and
- Attach applicable documentation, as necessary.

3.1.1.1 Examples of notification entries might include:

- Notification to the GTIM Team that the risk model algorithm changed; and
- Notification to the GTIM Team of a new GTIM-Plan publication.

4.0 REQUEST FOR APPROVAL ENTRIES

4.1 Responsibility: Integrity Management Team Member

4.1.1 Create a request for approval entry with the following information:

- Date of the non-routine event or deviation;
- Name and title of the entry originator;
- Select a priority (i.e., immediate or normal);
- Describe the incident;

- Describe the impact;
- List other CNP groups potentially affected, if any;
- List any actions required before the event or activity, if applicable;
- List any actions required after the event or activity, if applicable;
- Justify the non-routine event or deviation;
- List the names and email addresses of the people to notify, if approved;
- Select an approver;
- Add other comments, as necessary; and
- Attach applicable documentation, as necessary.

4.1.1.1 Examples of request for approval entries might include:

- Suggesting actions based on interpretation of data or observation such as:
  - The inclusion of new threats in the risk analysis process;
  - The implementation of new or expanded Preventive and Mitigative measures;
- Requesting to deviate from a work plan.

4.2 Responsibility: GTIM Manager or designee

4.2.1 Review requests.

4.2.2 Request additional information or clarification, as needed, either verbally or by rejecting and providing feedback to the originator.

4.2.2.1 Provide additional action items, justification, or comments, if needed.

4.2.3 Add to the list the names and email addresses to allow others to view the entry, as needed.

4.2.4 Approve or reject the entry.

4.2.4.1 If rejecting the entry, manager comments are required.

4.2.4.1.1 Provide enough detail for future entry improvement, if appropriate.

5.0 CHANGE IMPLEMENTATION

5.1 Responsibility: Integrity Management Team Member (Originator)

5.1.1 If rejected, review the approver’s comments and any follow-up.

5.1.2 If approved, schedule, coordinate, or implement the action items.

5.1.2.1 Update entry with activity completion or implementation dates and new information.

5.1.2.2 Notify stakeholders on the completion of all activities.

<<END>>

GTIM-11-002 Change Management for Routine O&M Activities

PURPOSE: To establish a standardized process for communicating routine O&M activities that occur within the transmission pipeline system.

REFERENCES: 49 CFR 192.909; 49 CFR 192.922; ASME/ANSI B31.8S-2004, Section 11;

SECTIONS:
- General
- Responding to Routine O&M Changes
- Responding to Pipeline Events

1.0 GENERAL

1.1 This procedure addresses changes occurring or observed during routine O&M activities.

1.1.1 Routine O&M activities include, but are not limited to:

- Continuing surveillance;
- Construction activities; and
- Repairs.

1.1.2 Changes may include, but are not limited to:

- Temporary changes;
- Permanent changes;
- Technical changes;
- Procedural changes;
- Physical changes; and
- Organizational changes.

2.0 RESPONDING TO ROUTINE O&M CHANGES

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Integrate information from routine O&M activities into the Integrity Management Program as dictated by GTIM-06-004 “Continual Data Integration, Management, and Evaluation”.

2.1.2 Determine if follow-up actions are required. Follow-up may include, but is not limited to:

- Identifying additional Preventive and Mitigative (P&M) measures;
- Providing additional training;
- Modifying existing procedures; and
- Modifying CNP databases (e.g., GIS, GeoFields, etc.).

2.1.3 If additional follow-up actions are required, initiate the Change Management process per GTIM-11-001 “GTIM Change Management”.

3.0 RESPONDING TO PIPELINE EVENTS

3.1 Responsibility: Integrity Management Team Member

3.1.1 Review the GTIM-91101 “Pipeline Event Evaluation” submitted by Local Operations when an “unusual” situation occurs, such as:

- Changing the locations of the prescribed direct examination locations when performing a Direct Assessment;
- Finding a leak in a covered segment;
- Finding internal corrosion wall loss greater than 20%; and
- Finding Stress Corrosion Cracking.

3.1.1.1 Include the following on the form:

- Description of the issue;
- Options for addressing the issue; and
- Names of Subject Matter Experts consulted.

3.1.2 Request additional information from the originator, as needed.

3.1.3 Analyze the implications of the change.

3.1.4 Determine if the implications of the change warrant additional follow-up activities.

3.1.4.1 Additional follow-up actions may include, but are not limited to:

- Change to the scheduled assessment method;
- Notification to regulatory agencies;
- Modified procedures; and
- Modifying CNP’s databases (e.g., GIS, GeoFields, etc.).

3.1.4.2 If additional follow-up is warranted, document this follow-up by initiating the Change Management process per GTIM-11-001 “GTIM Change Management”.

Table 11-002-1: Types of Pipeline Events with References to O&M Sections

Pipeline Events	O&M Sections
Third-Party Damage / Environmental	
Vandalism	8.0 Continuing Surveillance or CNP O&M XVI “Other Operating Procedures”;
Encroachments	8.0 Continuing Surveillance or CNP O&M XVI “Other Operating Procedures”; 9.0 Damage Prevention or CNP O&M XV “Damage Prevention”;
Soil movement	8.0 Continuing Surveillance or CNP O&M XVI “Other Operating Procedures”; 9.0 Damage Prevention or CNP O&M XV “Damage Prevention”;
Changes in the environment *(e.g., installation high voltage lines, installation of another pipeline within the row)*	8.0 Continuing Surveillance or CNP O&M XVI “Other Operating Procedures”;

Pipeline Events	O&M Sections
Change in land use	7.0 Class Location or CNP O&M XII "Class Locations";
Operational	
MAOP exceeded	11.0 Pressures or CNP O&M XIII "Maximum Allowable Operating Pressure"; 12.0 Pressure Elevation: Uprating;
Operating pressure increased from historical operating pressure	12.0 Pressure Elevation: Uprating;
Temporary reduction in operating pressure *(other than routine maintenance activities)*	11.0 Pressures or CNP O&M XIII "Maximum Allowable Operating Pressure";
Change in MAOP	11.0 Pressures or CNP O&M XIII "Maximum Allowable Operating Pressure"; 12.0 Pressure Elevation: Uprating;
Change in Odorization	13.0 Odorization or CNP O&M XIV "Odorization of Gas";
Equipment / Material	
A new piece of equipment installed *(i.e., never used in the company)*	29.0 Compressor Stations or CNP O&M XXIV "Compressor Stations"; 31.0 Vaults or CNP O&M XXIV(D) "Compressor Stations/Vault Maintenance"; 38.0 Meters; Gas Material Standards;
Remote Control Valve or Automatic Shut-off Valve installed	24.0 Regulator Stations or CNP O&M XXI "Regulator Stations"; 25.0 Regulators, Relief Valves, and Control Valves or CNP O&M XXI(C) "Regulator Stations/Verification of Relief Valve Capacity"; Gas Material Standards;
Replacement of a defective piece of equipment/part	40.0 Materials; Gas Material Standards;
Using a new type of pipeline material *(e.g., coating type, type of pipe)*	24.0 Regulator Stations or CNP O&M XXI "Regulator Stations"; 26.0 Valves; 27.0 Corrosion Control or CNP O&M VII "Miscellaneous Requirements for Corrosion Control"; 39.0 Pipe Design; 40.0 Materials; Gas Material Standards;
Change Management	
Changes to the O&M	1.0 Introduction to the O&M Plan; SMS Management of Change;
Construction	
Construction of new facilities	35.0 Construction Requirements for Distribution Mains and Transmission Lines;

Pipeline Events	O&M Sections
Abandonment of facilities	22.0 Abandoning or Deactivating Facilities or CNP O&M VII(C) “Other Miscellaneous Procedures/Abandonment or Deactivation of Facilities”.

<<END>>

GTIM-12-000 Quality Control Policy

PURPOSE: To describe the requirements of a quality control program that meets or exceeds the requirements of ASME/ANSI B31.8S-2004, Section 12.

REFERENCES: 49 CFR 192.911(l); ASME/ANSI B31.8S-2004, Section 12; 49 CFR 192.915; 49 CFR 192.801;

SECTIONS:
- Policy
- General
- GTIM QC Elements

1.0 POLICY

It is the policy of CenterPoint Energy and its subsidiaries to conduct Gas Transmission Pipeline Integrity Management (GTIM) activities:

- Ensuring the operational integrity of its natural gas pipeline systems meeting the requirements as detailed in 49 CFR 192 Subpart O - Gas Transmission Pipeline Integrity Management;
- Considering first the safety of its employees, service providers, and all other parties that may be impacted by the operation of the pipeline systems;
- Ensuring reliability and safety to all customers while minimizing any negative impact associated with construction, operation, and maintenance activities; and
- Complying with all environmental regulatory requirements and meeting the requirements of the Company's Environmental Protocols.

Quality Control (QC) is essential to achieving these expectations.

2.0 GENERAL

2.1 *Quality control*, as defined by ASME/ANSI B31.8S-2004[1], is the "documented proof that the operator meets all the requirements of their integrity management program".

2.2 Outlined in ASME/ANSI B31.8S-2004, section 12, are six activities required to document, implement, and maintain an IMP quality control program.

(i) identify the included processes in the quality program;
(ii) determine the sequence and interaction of these processes;
(iii) determine the criteria and methods needed to ensure that both the operation and control of these processes are effective;
(iv) provide the resources and information necessary to support the operation and monitoring of these processes;
(v) monitor, measure, and analyze these processes;
(vi) implement actions necessary to achieve planned results and continuous improvement of these processes.

[1] American Society of Mechanical Engineers. ASME/ANSI B31.8S-2004: Managing System Integrity of Gas Pipelines. ASME, 2005.

3.0 GTIM QC ELEMENTS

3.1 CNP embeds quality control elements as tasks within multiple procedures throughout its GTIM-Plan, while others are standalone processes.

3.1.1 Examples of QC embedded elements:

- Documentation requirements (which may consist of specific media, retention requirements, controls, etc.);
- Responsibility assignments;
- Effectiveness monitoring; and
- Corrective action implementation.

3.1.2 Examples of standalone QC processes:

- Identifying High and Moderate Consequence Areas *(GTIM-01-002 “Identification of Consequence Areas”);*
- Validation of Risk results *(GTIM-02-022 “Risk Assessment and Prioritization”);*
- Root Cause Analysis *(GTIM-04-012 “Root Cause Analysis”);*
- Continuously incorporating activity data into the program *(GTIM-06-004 “Continual Data Integration, Management, and Evaluation”);*
- Performance Metrics *(GTIM-09-001 “Performance Measures and NPMS Reporting”);*
- Maintaining and Controlling documents *(GTIM-10-001 “Record Keeping”);*
- Scheduled GTIM Plan reviews, which may include periodic internal audits or independent third-party reviews *(GTIM-12-002 “Integrity Management Program Review”);*
- Qualifications and training of personnel *(GTIM-12-004 “Qualifications and Training of Company Personnel”); and*
- Use of Third-Party resources *(GTIM-12-003 “Using Third-Party Resources”).*

Note: Appendix A, Table A-1, of this document contains a complete list of GTIM-Plan procedures.

<<END>>

GTIM-12-001 In-Line Data Acceptance

PURPOSE: To establish a set of standardized survey acceptance criteria guidelines for evaluating the quality of the In-Line Inspection (ILI) tool run results and determining when a re-run of the tool may be required.

REFERENCES: NACE SP0102-2010; NACE Publication 35100-2000; API Std 1163-2013;

SECTIONS:

- Sensors
- Distance and Velocity
- Field Acceptance of Tool Run
- Features
- Correlation of Validation Digs Results with Service Provider Report
- Documentation
- ILI Tool Run Acceptance or Rejection

1.0 SENSORS

1.1 Responsibility: GTIM Field Supervisor or designee

1.1.1 Visually examine the sensors for physical damage.

1.1.1.1 Perform the examination as soon as possible after removing the tool from the line.

1.1.1.2 Take photographs of the tool, particularly of any damage.

1.1.2 Review the field log to determine the number of sensor channels that have stopped obtaining data.

1.1.2.1 Lost channels may be acceptable if the lost channels are not adjacent.

1.1.2.2 For lines not previously pigged or with significant integrity concerns, verify there is less than 1% channel loss.

1.1.2.2.1 Higher losses may be acceptable based upon engineering judgment and consultation with the ILI vendor. Unless justified through an engineering white paper, sensor loss should not exceed 5%.

Note: Visually inspect, with the Service Provider, the tool(s) for the loss of adjacent channels. The loss of adjacent channels is more of a concern if the tool does not spiral.

1.1.2.3 For lines without significant integrity concerns, accept losses up to 5%.

1.1.2.4 Verify that there are no more than three (3) adjacent lost channels.

1.1.2.5 Review the field logs to determine the impact of sensor damage on data integrity.

1.1.3 Evaluate the field logs to determine if sensor noise may have affected the data integrity.

Note: Damaged sensors or poor electrical connections on the tool can cause noise, masking the channel data from adjacent undamaged sensors.

1.1.3.1 Re-run the tool if a significant amount of data was affected by the sensor noise.

1.1.3.2 If the minimum number of sensors was maintained throughout the entire footage of the covered segment(s), re-running the tool is not required.

2.0 DISTANCE AND VELOCITY

2.1 Responsibility: GTIM Field Supervisor or designee

2.1.1 Review the accuracy of distance measurements.

2.1.1.1 For lines previously inspected with ILI and less than sixty (60) miles in length, confirm the distance does not vary from the previously measured distance by more than 1%.

2.1.1.1.1 If the length varies by more than 1%, consider a re-run of the tool.

2.1.1.2 For lines previously inspected with ILI and greater than sixty (60) miles in length, confirm the distance does not vary more than 0.5% from the previously measured length.

2.1.1.2.1 If the length varies by more than 0.5%, consider a re-run of the tool, or other adjustments to the data processing.

2.1.2 Review the velocity data from the tool run.

2.1.2.1 Consider a re-run if the mutually agreed upon velocity range is inconsistent throughout the tool run. Typically, velocity ranges are approximately 4 to 7 mph for most in-line inspection tools. Review the vendor's tool specifications and tolerances.

Note: Gas pressure surging may cause velocity excursions.

2.1.2.2 When velocity excursions persisted for more than 2% of the tool-run distance, re-run the tool.

2.1.2.2.1 Temporary excursions over or under the mutually agreed upon velocity limits may be acceptable if they occur infrequently or for relatively short distances, particularly after heavy wall fittings, bends, or other restricted bore locations in the pipeline.

2.1.2.3 With the assistance of the Service Provider, define the effect on data acquisition and anomaly sizing before accepting velocity excursions in the tool run.

3.0 FIELD ACCEPTANCE OF TOOL RUN

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Upon completion of field activities and review of the sensors, distance, and velocity results, consider the following factors when determining whether to allow measurement or performance exceptions outside of the stated tolerances or parameters.

3.1.1.1 Values not significantly outside the tolerance limits may have less of an impact on the acquired data and, therefore, may be deemed acceptable.

3.1.1.2 Significant excursions outside the tolerance limits may be acceptable depending on their duration and the conditions under which they occur.

3.1.1.3 Tolerance or operating parameter excursions of short duration impacting smaller sections of the data may be acceptable depending on their location along the pipeline.

3.1.1.3.1 Acceptability depends upon the number and severity of metal loss and deformation indications in the section of pipe experiencing the excursion.

3.1.1.4 Minor exceptions occurring at a diameter change, valve, weld, or other features are predictable and may be acceptable depending on their duration.

3.1.1.4.1 Lines without significant integrity concerns can tolerate higher exceptions to the acceptance criteria.

3.1.1.4.2 Use caution before allowing exceptions to acceptance criteria for lines with significant integrity concerns.

3.1.1.4.3 Lines with intricate geometry for pigging are prone to more tolerance exceptions.

3.1.1.4.4 Consider these exceptions on a case-by-case basis; rejection of the entire run need not be based solely on the number of exceptions.

3.1.2 Submit recommendations for approval or rejection of the tool run to the GTIM Manager.

3.1.3 If the tool run fails field acceptance criteria, a review of feature data (section 4.0 “Features”) and validation examinations (section 5.0 “Correlation of Validation Digs Results with Service Provider Report”) reject the tool run.

4.0 FEATURES

4.1 Responsibility: GTIM Engineer or designee

4.1.1 Review the pipeline features recorded by the tool.

4.1.1.1 Consider re-running the tool if any significant features (i.e., casings, valves, tees, fittings, taps, or flanges) are missed or not recorded.

Note: The Service Provider specification should include a Probability of Detection (POD) for various feature types. A missed feature with a low POD would not require a re-run.

4.1.1.2 Missed, or unrecorded small features (i.e., pressure gauge fittings, small vents and drains, and taps and fittings less than two (2) inches) do not require a re-run.

4.1.1.3 Consider a re-run if the line contains longitudinal seams (i.e., electric flash weld or double submerged arc weld) with external and internal reinforcement that were not recorded by the tool.

4.1.1.4 Consider re-running the tool if girth welds were missed or not recorded by the tool.

4.1.2 Consider re-running the tool if the number of above-ground reference marker (AGM) locations do not meet the Service Provider’s tolerance for the location from reference points on the pipeline.

4.1.3 Submit recommendations to the GTIM Manager for approval or rejection of the tool-run based on the review of recorded pipeline features.

4.1.4 Rejection of the tool run after reviewing the recorded pipeline features eliminates the requirement for validation examinations (section 5.0 “Correlation of Validation Digs Results with Service Provider Report”).

5.0 CORRELATION OF VALIDATION DIGS RESULTS WITH SERVICE PROVIDER REPORT

5.1 Responsibility: GTIM Engineer or designee

5.1.1 Review validation examination results recorded on GTIM-90315 “In-Line Inspection - Validation Examination”.

5.1.2 Confirm the Service Provider’s performance specification includes a plus (+) and minus (-) percent tolerance for depth and length of anomalies as well as a confidence level expressed as a percent.

5.1.3 Verify anomaly type(s) found agrees with the tool run’s anomaly identification.

5.1.3.1 Verify anomaly sizing and characterization accuracies meet the Service Provider’s performance specification.

5.1.3.2 Consider a re-run if the validation examination anomaly measurements fall outside the Service Provider’s tolerances for depth, length, or type.

Note: Lower confidence levels indicate a higher likelihood that the recorded anomaly size will differ from direct examination measurements.

5.1.4 Verify recorded anomaly locations meet the Service Provider’s performance specification for distance accuracy.

5.1.4.1 Consider a re-run if recorded anomaly locations vary from validation dig findings by more than four (4) inches axially along the pipeline.

5.1.4.2 Consider a re-run if recorded anomaly locations vary from validation dig findings by more than five (5) degrees circumferentially.

5.1.5 Verify the tool recorded wall thickness changes and metal objects (i.e., metallic sleeves, etc.).

5.1.5.1 Consider re-running the tool if a validation examination indicates that the tool missed any significant wall thickness changes.

5.1.5.2 Consider re-running the tool if a validation dig indicates that the tool missed a metallic sleeve or other significant metal objects.

5.1.6 Confirm magnetization levels are within vendor specification limits.

5.1.6.1 Re-run the tool if the magnetization does not meet the Service Provider’s specification.

Note: Magnetization levels outside the vendor specification can impact tool accuracy.

6.0 DOCUMENTATION

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Document results of the survey acceptance criteria analyses on GTIM-90316 “In-Line Inspection - Post-Assessment”.

7.0 ILI TOOL RUN ACCEPTANCE OR REJECTION

7.1 Responsibility: GTIM Engineer or designee

7.1.1 Provide any supporting documentation such as tool logs or validation dig reports to the GTIM Manager for approval or rejection of the tool run.

7.2 Responsibility: GTIM Engineer or designee

7.2.1 Notify the GTIM Manager and Service Provider of the tool run acceptance or rejection.

<<END>>

GTIM-12-002 Integrity Management Program Review

PURPOSE: To confirm a standardized approach for performing periodic reviews of the Gas Transmission Integrity Management Program.

REFERENCES: 49 CFR 192.911(l); ASME/ANSI B31.8S-2004; 49 CFR 192.909;

SECTIONS:
- GTIM Program Updates

1.0 GTIM PROGRAM UPDATES

1.1 Responsibility: GTIM Engineer or designee

1.1.1 At least annually, not to exceed 15 months, review the Gas Transmission Integrity Management (GTIM) Plan to identify potential improvements to the GTIM-Plan.

1.1.1.1 Review natural gas transmission pipeline laws and regulations, including the documents incorporated by reference.

1.1.1.2 Review PHMSA guidance documentation, including but not limited to:

- Advisory Bulletins;
- FAQs; and
- Interpretation Letters.

1.1.1.3 Evaluate solicited feedback and other appropriate sources such as GTIM-91102 “Integrity Change Management Record” entries.

1.1.1.4 Consider reviewing the most current PHMSA Gas Transmission IA Question Set (Audit Protocols) to determine if any updated protocols impact the GTIM-Plan and revise the Plan as needed.

1.1.1.5 Engage the assistance of third-party resources, as appropriate.

1.1.2 Log the items reviewed, the date of the review, and the reviewer.

1.1.2.1 Justify, in the review log, the exclusion of any items.

1.1.3 Create a new ‘draft’ revision of the GTIM-Plan with the recommended improvements highlighted.

1.1.4 Send the draft document and the review log to the GTIM Manager for approval to proceed.

1.1.4.1 If approved, follow the CNP Management of Change process to document formal approval, schedule of training, new GTIM-Plan publication, and notification to stakeholders.

1.1.4.2 If not approved, make requested changes and repeat section 1.1.4.

1.2 Responsibility: GTIM Manager or designee

1.2.1 Review the modified ‘draft’ document and review log.

1.2.2 Notify the requestor of your approval or request changes to the ‘draft’ document.

Note: Changes to the program that may substantially affect the program’s implementation or may significantly modify the program or schedule for carrying out the program elements require notifying regulatory agencies within thirty (30) days after adopting.

1.3 Responsibility: GTIM Engineer or designee

1.3.1 Once the GTIM-Plan is published, log the publication of the new revision per GTIM-11-001 “GTIM Change Management”.

<<END>>

GTIM-12-003 Using Third-Party Resources

PURPOSE: To confirm the quality control of any Integrity Management related work performed by third-party resources.

REFERENCES: 49 CFR 192.915; ASME/ANSI B31.8S-2004, Section 12;

SECTIONS:

- Resources Used to Conduct Integrity Assessments or Evaluate Integrity Assessment Results
- Resources Used to Implement Preventive and Mitigative Measures
- Resources for Other Integrity Management Roles
- Documentation

1.0 RESOURCES USED TO CONDUCT INTEGRITY ASSESSMENTS OR EVALUATE INTEGRITY ASSESSMENT RESULTS

1.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

1.1.1 Review the procedure for the specific assessment method before a service provider performs the Integrity Assessment.

1.1.1.1 Procedures include, but are not limited to:

- In-Line Inspection (ILI);
- Pressure Testing, including Spike Testing if applicable;
- Corrosion Direct Assessment methods (e.g., ECDA, ICDA, SCCDA, etc.);
- Ultrasonic Testing methods (e.g., GWUT, LRUT, etc.);
- Excavation and in situ Direct Examinations (Visual Examinations);
- Samples Testing;
- Survey activities; and
- Other supporting activities.

1.1.2 Verify the following:

- Quality controls exist within the specific assessment method;
- Includes criteria for deeming a service provider qualified to perform their job function;
- Includes controls to confirm field work is performed appropriately according to procedures; and
- Criteria to confirm quality reports and documentation is provided by the service provider;
  - Confirm specific report content is listed.

1.1.3 As required, make entries per GTIM-11-001 “GTIM Change Management”.

1.1.4 Secure Third-party Service Providers that meet the requirements of the specific integrity assessment procedure.

Note: Before beginning work, Third-Party Service Providers must submit a statement (proof) of qualifications for all personnel who will be performing activities, including covered tasks, on the CNP GTIM pipeline system, for review by the CNP.

1.1.4.1 Delay scheduled work and secure alternate resources when Third-Party Service Providers do not meet qualification requirements.

2.0 RESOURCES USED TO IMPLEMENT PREVENTIVE AND MITIGATIVE MEASURES

2.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

2.1.1 Confirm Third-Party Service Providers used to implement Preventive and Mitigative measures meet the requirements of the CNP Operator Qualification Plan and are qualified for the applicable covered tasks.

2.1.1.1 Covered Tasks include, but are not limited to:

- Abnormal Operating Conditions;
- Marking buried structures;
- Locating Pipeline and Cable; and
- Excavating and Backfilling.

2.1.1.2 Delay scheduled work and secure alternate resources when Third-Party Service Providers do not meet qualification requirements.

3.0 RESOURCES FOR OTHER INTEGRITY MANAGEMENT ROLES

3.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

3.1.1 Obtain and review qualifications for Third-Party Service Providers involved in other aspects of the Integrity Management Program.

3.1.1.1 Perform this review before securing the resource.

3.1.1.2 Other aspects include, but are not limited to:

- Consultant roles; and
- IMP procedure development.

3.1.1.3 Documentation for each individual should include:

- Company expertise and area of focus;
- Education and background;
- Pipeline related or task-specific experience; and
- Industry events, meetings, and seminars attended.

3.1.1.4 Documentation may also include:

- Industry recognized certifications such as NACE; and
- Professional engineer licenses.

3.1.2 Determine if the individual(s) are qualified based on documentation provided.

3.1.2.1 Also, consider industry reputation and word-of-mouth feedback.

3.1.3 Reject unqualified Third-Party Service Providers.

4.0 DOCUMENTATION

4.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

4.1.1 Maintain qualifications in the IM file.

4.1.1.1 Maintain qualifications for non-OQ tasks for five (5) years.

<<END>>

GTIM-12-004 Qualifications and Training of Company Personnel

PURPOSE: To identify the qualifications of personnel responsible for the overall implementation and management of, and compliance with the Integrity Management Program, and to ensure personnel are competent and adequately trained.

REFERENCES: 49 CFR 192.915; ASME/ANSI B31.8S-2004, Section 12;

SECTIONS:
- Supervisory Personnel
- Personnel Who Conduct Integrity Assessments
- Personnel Who Evaluate Integrity Assessment Results
- Personnel Who Implement Preventive and Mitigative Measures
- Subject Matter Experts
- Integrity Management Training

Note: CenterPoint Energy (CNP) elects to assign the responsibility for completion of specific activities, functions, and deliverables to roles within the individual procedures, identified with the tag "Responsibility:". (See GTIM-Plan, Appendix B, for a description of roles.)

1.0 SUPERVISORY PERSONNEL

1.1 Responsibility: Director of Engineering Gas Systems Integrity and Reliability

1.1.1 Confirm the GTIM Manager receives the appropriate training and has the appropriate experience to fulfill Integrity Management related duties.

1.1.1.1 Verify the GTIM Manager has at least five (5) years of pipeline or integrity management experience.

1.1.2 Encourage the GTIM Manager to attend at least two (2) industry-recognized events a year with Integrity Management content.

1.1.2.1 Examples include, but are not limited to:

- Public meetings sponsored by the Office of Pipeline Safety of the Pipeline and Hazardous Materials Safety Administration (PHMSA);
- American Gas Association (AGA) meetings or conferences;
- Southern Gas Association (SGA) meetings or conferences; or
- Other industry-recognized classes or conferences.

1.1.3 Confirm other management personnel with Integrity Management supervisory duties have appropriate training and the appropriate experience.

1.1.3.1 Verify supervisory personnel has at least five (5) years of pipeline or related engineering experience.

1.1.3.1.1 Supervisory personnel may include the following:

- GTIM Engineer;
- GTIM Manager; or
- GTIM Field Supervisor.

1.1.4 Encourage supervisory personnel to attend at least one (1) industry-recognized event a year with Integrity Management content.

1.1.5 Recommend additional training for the GTIM Manager and supervisory personnel as needed.

1.1.6 Confirm personnel with Integrity Management supervisory duties have a resume on file.

1.1.7 Periodically review the status of Integrity Management personnel qualifications.

1.1.7.1 Verify that the number of qualified individuals is sufficient to perform anticipated tasks.

1.1.7.2 Arrange for additional training specific to the job functions as appropriate.

1.2 Responsibility: GTIM Manager or GTIM Field Supervisor

1.2.1 Document attendance at meetings, seminars, conferences, or training classes with Integrity Management content on the Form 1021 "Job Safety Briefing Form".

1.2.1.1 Attach copies of completion certificates or certifications as applicable.

1.2.1.2 Provide documents to an Integrity Management team member or meeting host.

1.2.2 Update Integrity Management personnel résumés periodically to incorporate significant changes in project experience and training.

1.3 Responsibility: GTIM Engineer or designee

1.3.1 Retain documents in the appropriate IM folder.

2.0 PERSONNEL WHO CONDUCT INTEGRITY ASSESSMENTS

2.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

2.1.1 Confirm pipeline integrity personnel have the appropriate training and qualifications to conduct the integrity assessments.

2.1.1.1 Assessments may include, but are not limited to:

- In-Line Inspection (ILI);
- Pressure Testing, including Spike Tests, if applicable;
- External Corrosion Direct Assessment (ECDA);
- Internal Corrosion Direct Assessment (ICDA);
- Stress Corrosion Cracking Direct Assessment (SCCDA);
- Guided Wave Ultrasonic Testing (GWUT);
- Excavation and in situ Direct Examination (Visual Examination);
- Confirmatory Direct Assessment (CDA); and
- Low-Stress Assessment.

2.1.1.2 Refer to the specific procedure for the qualification requirements.

2.1.2 Before commencing the field portion of the assessment, verify personnel has the appropriate Operator Qualifications (OQ) on file.

2.1.2.1 Utilize an applicable OQ template to verify qualifications while in the field.

2.1.2.2 Confirm other qualifications for personnel performing integrity assessment tasks are documented, as applicable. Other qualifications may include, but are not limited to:

- NACE; and

- Non-destructive testing.

2.1.3 For personnel not meeting the specified criteria, designate an alternate individual to perform the activity.

3.0 PERSONNEL WHO EVALUATE INTEGRITY ASSESSMENT RESULTS

3.1 Responsibility: GTIM Engineer or designee

3.1.1 Verify personnel who review or analyze integrity assessment results are qualified.

3.1.1.1 Experience or formal training may fulfill the required qualification criteria.

3.1.1.2 Refer to the specific procedure for qualification requirements.

3.1.2 For personnel not meeting the specified criteria, designate an alternate individual to review or analyze the assessment results.

3.1.3 Ensure Integrity assessment documentation is reviewed by one (1) or more qualified GTIM Engineer to provide a check and balance of the process.

3.1.4 Ensure all integrity assessment documentation is reviewed and approved by the GTIM Manager or a designee before the finalization of the assessment.

4.0 PERSONNEL WHO IMPLEMENT PREVENTIVE AND MITIGATIVE MEASURES

4.1 Responsibility: GTIM Engineer or GTIM Field Supervisor

4.1.1 Verify personnel used to implement Preventive and Mitigative measures are Operator Qualified for the respective tasks before commencing work. Operator Qualifications may include, but are not limited to:

- Pipeline locating;
- Performing a leak survey; and
- Excavation work.

4.1.2 For personnel not meeting the appropriate Operator Qualifications, designate another individual to perform the tasks or provide training for the personnel.

5.0 SUBJECT MATTER EXPERTS

5.1 Responsibility: GTIM Manager or designee

5.1.1 SMEs should possess extensive knowledge of any of the following:

- CNP operating assets;
- Conditions of the CNP operating assets;
- The historical knowledge of the CNP operating assets; or
- Specific technical subject matter.

6.0 INTEGRITY MANAGEMENT TRAINING

6.1 Responsibility: GTIM Engineer or designee

6.1.1 Confirm CNP personnel who perform activities within the Integrity Management Program are competent and adequately trained to perform the specific job functions. Qualifications may include, but are not limited to:

- Formal education or Certifications;
- Integrity Management Experience;
- Training and Operator Qualifications; and
- Job Specific tasks completions.

6.1.2 Confirm CNP personnel understand Integrity Management and the applicable CNP Integrity Management Plan and Program.

6.1.3 Provide or arrange for training courses related to Integrity Management and the Integrity Management Plan and Program as appropriate.

6.1.3.1 Include training for internal and contracted resources.

6.1.3.2 Identify personnel to attend the training.

6.1.3.3 Develop an outline for Integrity Management training.

6.1.3.4 Dictate the course content based on personnel levels.

6.1.4 Arrange for qualified internal or contracted resources to provide Integrity Management training.

6.1.5 Schedule the training with appropriate personnel.

6.1.6 Document the names and titles of the personnel attending on the Form 1021 “Job Safety Briefing Form”.

6.1.7 File and maintain documentation of the training including, but not limited to:

- Date training held;
- Name of facilitator(s) and company affiliation;
- Names and titles of individuals attending training;
- Name of Company, if not CNP;
- Course outline, if applicable.

6.2 Responsibility: CNP Personnel Assigned the Responsibility for Executing Specific Activities and Deliverables in the GTIM Program

6.2.1 Review the applicable procedure(s) before performing the specific task within the GTIM Program.

6.2.1.1 Ensure that the following information is understandable and feasible for the specific task:

- Job tasks;
- Materials and resources needed; and
- Documentation and retention requirements.

6.2.2 Consider the following for additional guidance or clarification relating to an Integrity Management process task:

- Consult with an appropriate subject matter expert;

- Review data from similar tasks;
- Review additional documentation relevant to the task, including, but not limited to:
    - Federal and State regulations;
    - Material specifications;
    - Vendor brochures;
    - White papers; and
    - Industry publications.

6.2.3 Complete the specific required CNP training, if necessary.

6.2.4 Consult with GTIM Engineer, GTIM Field Supervisor, or project leader for additional information or instruction before performing a task, if necessary.

<<END>>

GTIM-12-005 Non-Mandatory Statements

PURPOSE: The purpose of this standard is to address non-mandatory statements applicable to the Integrity Management Program.

REFERENCES: 49 CFR 192 Subpart O; PHMSA IMP FAQ-244;

SECTIONS:

- Incorporating Non-Mandatory Statements

1.0 INCORPORATING NON-MANDATORY STATEMENTS

1.1 Responsibility: GTIM Engineer or designee

1.1.1 Incorporate and implement non-mandatory statements (i.e., "should" statements) from industry standards or other documents invoked by Subpart O into the Integrity Management Program.

1.1.2 Utilize one of the following approaches when the incorporation of a non-mandatory statement into the Integrity Management Program will not occur.

1.1.2.1 Incorporate and implement an equivalent alternative method for accomplishing the same objective.

1.1.2.1.1 Document the alternative method in a "white paper" and include:

- The rationale for using an alternative method; and
- Explain why the alternative method will accomplish the same objective as the non-mandatory statement.

1.1.2.2 Incorporate a documented justification in the GTIM-Plan that demonstrates the technical basis for not implementing recommendations from standards or other documents.

1.1.2.2.1 As an alternative, document the technical justification in a white paper.

1.1.2.3 Maintain "white papers" in the IM files.

1.1.2.4 Document the use of an alternative, or the exclusion of a non-mandatory "should" statement(s), per GTIM-11-001 "GTIM Change Management".

<< END>>

GTIM-13-001 Required Notifications to Regulatory Agencies

PURPOSE: To establish a standardized approach for submitting required notifications to the Pipeline and Hazardous Material Safety Administration (PHMSA) and other regulatory agencies.

REFERENCES: 49 CFR 192.18; 49 CFR 192.909(b); 49 CFR 192.921(a)(7); 49 CFR 192.933(a)(1); 49 CFR 192.933(a)(2); 49 CFR 192.506(b); 49 CFR 192.607(e)(4); 49 CFR 192.607(e)(5); 49 CFR 192.624(b)(3); 49 CFR 192.624(c)(2)(iii); 49 CFR 192.624(c)(6); 49 CFR 192.632(b)(3); 49 CFR 192.710(c)(7); 49 CFR 192.712(d)(3)(iv); 49 CFR 192.712(e)(2)(i)(E);

SECTIONS:

- General
- Substantial Changes to the Integrity Management Program
- Schedule Extensions
- Pressure Reductions Exceeding 365 Days
- Use of 'Other Technologies'
- Use of Alternative Analytic Evaluations
  - Alternative (Expanded) Statistical Sampling Approach
  - MAOP Reconfirmation Method 2 (Pressure Reduction)
  - MAOP Reconfirmation Method 6 (Alternative Technology)
  - Analysis of Predicted Failure Pressure
- Documentation

1.0 GENERAL

1.1 PHMSA requires notification from gas transmission operators with the existence of any of the following safety-related conditions involving in-service facilities:

- *Substantial Changes to the Integrity Management Program*: Any change to the integrity management program that may substantially affect the program's implementation, or may significantly modify the program or schedule for carrying out the program elements;
- *Inability to Meet a Remediations Deadline (or Schedule Extensions)*: When an operator cannot meet the schedule for evaluation and remediation required under §192.933(c) and cannot provide safety through the temporary reduction in operating pressure or other action;
- *Pressure Reduction Exceeding 365 Days*: When a pressure reduction exceeds 365 days, submit the reasons for the remediation delay;
- *Using "Other Technology" Evaluation Processes*: To receive approval for the use of "other technology"; include how the technology can provide an equivalent understanding of the condition of the line pipe;
- *Use of Alternative Analytic Evaluations*: To receive approval for the use of alternative technical evaluation and analysis processes that can provide equivalent, consistent results;

1.2 The GTIM Manager is responsible for all communications with regulatory agencies, and auditors, including addressing safety concerns raised by PHMSA, State, or local pipeline safety authorities.

2.0 SUBSTANTIAL CHANGES TO THE INTEGRITY MANAGEMENT PROGRAM

Note: Provide notification to PHMSA within thirty (30) days of implementation.

2.1 Substantial changes include:

- A merger of companies or acquisition of a pipeline;
- Change in HCA mileage greater than or equal to 25%;
- Introduction of an assessment method not previously used;
- Abandonment of an assessment method (example: CNP decides to no longer use in-line inspection as an assessment method);
- Identifying Stress Corrosion Cracking as a threat, when not previously considered a threat; and
- Significant assessment schedule calendar changes.

2.1.1 Substantial changes do NOT include:

- Addition of a new covered segment;
- Actions that do not result in non-compliance with the rule;
- Reprioritization of remedial actions provided the reprioritization does not result in non-compliance with 49 CFR 192 Subpart O;
- Reprioritization for implementing Preventive and Mitigative Measures; and
- An updated risk analysis forced assessment schedule reprioritization.

2.2 **Responsibility:** Integrity Management Team Member

2.2.1 Provide the following and a copy of the Gas Transmission Integrity Management Plan (GTIM-Plan) to the GTIM Manager within thirty (30) days of implementation.

- The reason(s) for substantially changing the program (see section 2.1);
- Detail the substantial program changes;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP's primary contact;
- List of the 'official' PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

2.3 **Responsibility:** GTIM Manager or designee

2.3.1 Review and submit this substantial change notification to PHMSA within thirty (30) days of implementation.

2.3.1.1 Send a copy of the notification to all applicable state jurisdictional authorities.

2.3.1.2 Appendix C contains available submittal methods.

2.3.2 Send a copy of the notification to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

3.0 SCHEDULE EXTENSIONS

Note: Petition PHMSA for an extension of mandated time limits as soon as enough information is available to warrant the request.

3.1 Examples of exceeding mandated schedule limits include:

- The inability to meet established remediation prioritization deadlines and a pressure reduction or other safety actions are not an option;
- When operational or environmental constraints limit the ability to meet MAOP reconfirmation deadlines (petition for an extension of the completion deadlines of up to 1 year); and
- When operational or environmental constraints limit the ability to conduct a reassessment, or confirmatory assessment, within the required seven (7) calendar years (petition for an extension of up to 6-month on the 7-calendar-year reassessment interval).

3.2 **Responsibility:** Integrity Management Team Member

3.2.1 Upon discovery of the inability to meet a required timeline, and safety through a temporary reduction in operating pressure or other action is not an option, provide the following information to the GTIM Manager for submission to PHMSA:

- An up-to-date plan for completing all actions;
- The reason for the requested extension and why a pressure reduction is not an option;
- The current status of the remaining defects and repairs, if applicable;
- The proposed completion date;
- Any outstanding remediation activities, if applicable;
- Temporary measures to mitigate safety and environmental impact (implemented or needed);
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP’s primary contact;
- The applicable ‘official’ PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

3.3 **Responsibility:** GTIM Manager or designee

3.3.1 Review and submit the petition to PHMSA upon discovery of the inability to meet a mandated time limit.

3.3.1.1 Send a copy of the petition to all applicable state jurisdictional authorities.

3.3.1.2 Appendix C contains available submittal methods.

3.3.2 Send a copy of the petition to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

4.0 PRESSURE REDUCTION EXCEEDING 365 DAYS

Note: Provide notification to PHMSA as soon as the information becomes available.

4.1 **Responsibility:** Integrity Management Team Member

4.1.1 Upon discovery that a pressure reduction will exceed 365 days, provide the following information to the GTIM Manager for submission to PHMSA:

- Explain the reasons for the remediation delay beyond the 365-day limit;
- A technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline, public safety, or the environment;
- The current status of the remaining defects and repairs;
- List the outstanding remediation activities;
- The proposed completion date;
- Temporary measures to mitigate safety and environmental impact (implemented or needed);
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP's primary contact;
- The applicable 'official' PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

4.2 Responsibility: GTIM Manager or designee

4.2.1 Review and submit a notification to PHMSA as soon as information becomes available.

4.2.1.1 Send a copy of the notification to all applicable state jurisdictional authorities.

4.2.1.2 Appendix C contains available submittal methods.

4.2.2 Send a copy of the notification to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

5.0 USE OF 'OTHER TECHNOLOGIES'

Note: Provide notification to PHMSA at least ninety (90) days in advance of using the technology.

5.1 The use of an "other technology" is appropriate in the following situations:

- To determine the existence of internal corrosion when acceptable methods such as Internal Corrosion Direct Assessment (ICDA), Pressure Testing, and In-Line Inspection are unfeasible;
- To perform an integrity assessment that does not include Pressure Testing, In-Line Inspection or Direct Assessment as a stand-alone assessment method (i.e., Long Range Ultrasonic Testing, Guided Wave Ultrasonic Testing, etc.);
- When using an indirect inspection method other than Close-Interval Surveys (CIS), AC Current Attenuation surveys, DCVG and ACVG surveys, Pearson surveys, or Cell-to-cell surveys; and
- To use another process that is supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent.

5.2 Responsibility: Integrity Management Team Member

5.2.1 To use a new or alternative technology that demonstrates an equivalent evaluation of pipeline conditions, provide the following information ninety (90) days in advance of using the "other technology" to the GTIM Manager: (Allow enough time for the GTIM Manager to review and submit the notification within the 90 days.)

- Descriptions of the technology or technologies and how the method can provide an equivalent understanding of the condition of the line pipe;
- Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
- Data requirements, including original design, maintenance, and operating history, anomaly or flaw characterization, as applicable;
- Assessment techniques and acceptance criteria;
- Remediation methods for assessment findings;
- Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
- Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required;
- Evidence of a review of all procedures and assessments by a qualified technical subject matter expert;
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP’s primary contact;
- The applicable ‘official’ PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

5.3 Responsibility: GTIM Manager or designee

5.3.1 Review and submit the information at least ninety (90) days in advance of using the “other technology” to PHMSA.

5.3.1.1 Send a copy of the notification to all applicable state jurisdictional authorities.

5.3.1.2 Appendix C contains available submittal methods.

5.3.2 Send a copy of the notification to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

6.0 USE OF ALTERNATIVE ANALYTIC EVALUATIONS

Note: Provide notification to PHMSA at least ninety (90) days in advance of using an alternative analytic evaluation method.

6.1 Responsibility: Integrity Management Team Member

6.1.1 *Alternative (Expanded) Statistical Sampling Approach.* When pipeline material properties and attributes lack documentation with traceable, verifiable, and complete (TVC) records, CNP may employ a sampling program for populating multiple, comparable segments of pipe. If the sampling program’s test results are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, CNP will establish an expanded sampling program or use a different analytic evaluation method.

6.1.1.1 Provide the following information at least ninety (90) days in advance of using the expanded sampling program or a different analytic evaluation to the GTIM Manager:

(Allow enough time for the GTIM Manager to review and submit the notification within the 90 days.)

- Describe how the expanded sampling plan or alternative statistical sampling approach will address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past achieving at least a 95% confidence level;
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP's primary contact;
- The applicable 'official' PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

6.1.2 *MAOP Reconfirmation Method 2 (Pressure Reduction).* When reconfirming the MAOP of a pipeline segment using the pressure reduction method described in §192.624(c)(2), CNP may elect to use a less conservative pressure reduction factor or a longer look-back period.

6.1.2.1 When choosing this approach, provide the following information to the GTIM Manager at least ninety (90) days in advance but no later than seven (7) calendar days after establishing the reduced MAOP: (Allow enough time for the GTIM Manager to review and submit the notification within the 90 days.)

- Describe the operational constraints, any particular circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in §192.624(c)(2);
- A fracture mechanics model for cyclic fatigue crack growth analysis and a failure stress pressure that complies with §192.712;
- A justification that establishing the MAOP for the pipeline by other allowed MAOP reconfirmation methods is impractical;
- A justification that a reduced MAOP is safe based on an analysis of the condition of the pipeline segment, including material properties records, verified material properties, and the history of the pipeline segment (known corrosion and leakage), the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned;
- The planned duration and justification for the time interval of the reduced MAOP, any long-term remediation measures, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP's primary contact;
- The applicable 'official' PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

6.1.3 *MAOP Reconfirmation Method 6 (Alternative Technology).* CNP may elect to use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP.

6.1.3.1 When utilizing an alternative technical evaluation process, provide the following information at least ninety (90) days in advance of using the alternative technical evaluation process to the GTIM Manager: (Allow enough time for the GTIM Manager to review and submit the notification within the 90 days.)

- Descriptions of the technologies for testing, examinations, and assessments;
- A description of the method for establishing material properties;
- Descriptions of the analytical techniques for evaluating the pipeline segment using similar analyses from prior tool runs ensuring the results are consistent with the required corresponding hydrostatic test pressure;
- Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
- Data requirements, including original design, maintenance, and operating history, anomaly or flaw characterization, as applicable;
- Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;
  - If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline per paragraph §192.712;
- Operational monitoring procedures;
- Methodology and criteria used to justify and establish the MAOP;
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP’s primary contact;
- The applicable ‘official’ PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

6.1.4 *Analysis of Predicted Failure Pressure.* When determining the predicted failure pressure and the remaining life on a pipe segment without TVC material records, CNP may elect to use other appropriate values that can provide a conservative Charpy v-notch toughness value for analyzing crack-related conditions.

6.1.4.1 Provide the following information to the GTIM Manager at least ninety (90) days in advance of using an assumed Charpy v-notch toughness value. (Allow enough time for the GTIM Manager to review and submit the notification within the 90 days.)

- The justification that the Charpy v-notch toughness values proposed are appropriate and conservative for use in the analysis of crack-related conditions;
- A description of the evaluation methodology used for the analysis;
- All data used and analyzed;
- Pipe and weld properties;

- Procedures and processes used;
- Any direct in situ examination data;
- Any In-Line Inspection tool run information evaluated, including any multiple In-Line Inspection tool runs, if applicable;
- Pressure test data and results;
- In-the-ditch testing and results, if applicable;
- All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;
- The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;
- The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;
- Safety factors used for calculating fatigue life and predicted failure pressure;
- Reassessment time interval;
- The date of the review;
- Confirmation of the results by qualified technical subject matter experts;
- Methodology and criteria used to justify and establish the current MAOP;
- Information about the pipeline and the covered segments involved;
- List of the inTERstate pipelines affected by the changes, if any;
- List of the inTRAstate pipelines affected by the changes, if any;
- The name, title, phone number and email address of CNP's primary contact;
- The applicable 'official' PHMSA operator name(s); and
- PHMSA 5-digit operator identifier(s).

6.2 Responsibility: GTIM Manager or designee

6.2.1 Review and submit the information to PHMSA at least ninety (90) days in advance of using an expanded sampling program or an alternative analytic evaluation method.

6.2.1.1 Send a copy of the notification to all applicable state jurisdictional authorities.

6.2.1.2 Appendix C contains available submittal methods.

6.2.2 Send a copy of the notification to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

7.0 DOCUMENTATION

7.1 Responsibility: GTIM Manager or designee

7.1.1 Confirm receipt of the submission(s) by PHMSA.

7.1.2 Communicate any responses (i.e., objections noted, no objections, etc.) to the appropriate stakeholders. (For notifications requiring submission 'at least 90 days in advance', sections 5.0 and 6.0, it is acceptable to proceed 91 days after submittal of the notification unless receiving a letter that PHMSA requires additional time to conduct its review or an objection letter.)

7.1.3 Create a change management record per GTIM-11-001 GTIM Change Management.

7.1.3.1 Include the date PHMSA received the submission.

7.1.3.2 Attach all correspondence between CNP and PHMSA and any State jurisdictional authority.

7.1.4 Retain all correspondence between CNP and PHMSA and any State jurisdictional authority for the useful life of the pipeline system.

<<END>>

GTIM-13-002 Internal Communications

PURPOSE: To establish a standardized method for communicating between CNP personnel and Integrity Management team members.

REFERENCES: 49 CFR 192.911(m); ASME/ANSI B31.8S-2004, Section 10.3;

SECTIONS:
- General
- Communications Involving the Integrity Management Program
- Information Provided on the CNP Intranet

1.0 GENERAL

1.1 Internal CNP communications are vital to the reliability of the Gas Transmission Integrity Management (GTIM) Program.

1.2 Internal communications help confirm that CNP personnel have current information about the pipeline system and the GTIM-Plan.

2.0 COMMUNICATIONS INVOLVING THE INTEGRITY MANAGEMENT PROGRAM

2.1 Responsibility: Integrity Management Team

2.1.1 The CNP Management of Change (MOC) process includes communicating GTIM-Plan changes to CNP personnel.

2.1.1.1 Communications include, but are not limited to:

- Changes to the GTIM-Plan;
- New form usage and training; and
- Integrity Management staffing changes.

2.1.2 Other GTIM information communicated between Integrity Management and other CNP personnel includes, but is not limited to:

- Assessment schedules;
- Pressure changes;
- Performance Measures; and
- Regulatory agency compliance-related information.

2.1.2.1 Communication methods include verbal (e.g., video conferences, phone calls, meetings, one-on-one conversations), and written (e.g., letters, memos, emails, reports, forms).

2.2 Responsibility: Director of Engineering Gas Systems Integrity and Reliability

2.2.1 Coordinate Executive Oversight meetings with key stakeholders, as needed.

3.0 INFORMATION PROVIDED ON THE CNP INTRANET

3.1 Responsibility: GTIM Manager or designee

3.1.1 Maintain a copy of the current GTIM-Plan on the CNP intranet.

3.1.1.1 At least once a year, review the GTIM content provided on the CNP intranet and update if appropriate.

3.1.1.2 Consider including the following GTIM related content on the CNP intranet:

- Overview of the GTIM Program;
- Links to GTIM documents, reports, and forms;
- Schedules of upcoming GTIM activities;
- Results of completed integrity assessments;
- Integrity assessment technologies; and
- Integrity Management contact information.

<<END>>

GTIM-13-003 Special Requests (Waivers)

PURPOSE: To establish a standard method for requesting that a jurisdictional authority waives compliance with one or more regulatory requirements.

REFERENCES: 49 CFR 190.341; 49 CFR 192.943;

SECTIONS:
- General
- New Special Permits
- Special Permit Renewals
- Emergency Special Permits
- Review of Application
- Documentation

1.0 GENERAL

1.1 A *special permit*, or *state waiver*, is an order that waives compliance with one or more regulatory requirements for a specified time duration.

1.1.1 Special permits were formerly referred to as "waivers" by the Pipeline and Hazardous Materials Safety Administration (PHMSA).

1.1.2 Special permits are subject to compliance with the terms and conditions of special permits, and if violated, PHMSA will initiate one or more enforcement actions.

1.1.3 Special permits apply only to the company that requested the waiver (no blanket special permits) and only to the specific situation described in the written request.

1.2 'Special permits' authorize performing a function outside of PHMSA regulations or not to perform a function currently required under the PHMSA regulations whereas 'required notifications' authorize the use of provided alternatives, or options, within the PHMSA regulation.

1.2.1 An example of a type of a special permit:

1.2.1.1 When the class location designation changes due to new development or changes in land use near the pipeline, PHMSA may consider waiving compliance of §192.611(a) requiring confirmation of the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location designation. If granted, the special permit allows for the specific pipeline segment(s) to continue to operate at pressures based on the previous class location designation.

Table 13-003-1: PHMSA Special Permit Application Process (Estimated Timeline)

High-Level Special Permit (SP) Process Step	Typical Time Duration to Next Step
Operator notifies PHMSA of SP request;	30 - 45 days
PHMSA publishes the SP request and opens docket;	30 - 60 days
PHMSA starts analyses of the SP request;	
PHMSA requests additional data;	7 - 30 days
PHMSA sends operator list of generic conditions;	14 - 90 days
PHMSA receives additional data from Operator;	
PHMSA reviews additional information;	7 - 30 days
Additional information acceptable or not;	7 days
Analysis and recommendations;	

High-Level Special Permit (SP) Process Step	Typical Time Duration to Next Step
Permit sent regional review;	21 days
Permit sent for legal review;	7 - 30 days
Permit Issued;	

1.3 PHMSA may grant emergency special permit applications, bypassing the public notice and comment or hearing step, if the PHMSA Associate Administrator determines that such action is in the public interest, is not inconsistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation.

1.3.1 An emergency event may be local, regional, or national in scope and includes disruptions of fuel supply, and natural or manmade disasters such as hurricanes, floods, earthquakes, terrorist acts, biological outbreaks, releases of dangerous radiological, chemical, or biological materials, war-related activities, or other similar events.

1.3.1.1 PHMSA will determine on a case-by-case basis what duration is necessary to address the emergency, however, as required by statute, no emergency special permit may be issued for a period of more than 60 days and automatically expires on the date specified in the permit.

1.3.1.2 Emergency special permits may be renewed upon application to PHMSA only after public notice and opportunity for a hearing on the renewal.

2.0 NEW SPECIAL PERMITS

Note: Submit ‘special permit’ applications at least 120 days before the requested effective date.

2.1 Responsibility: GTIM Engineer or designee

2.1.1 When applying for a ‘special permit’ from PHMSA or a State regulatory agency, document at minimum the following information:

2.1.1.1 Operator name, OPID, and mailing address;

2.1.1.2 Name, title, and telephone number of a contact person;

2.1.1.3 A detailed description of the pipeline facilities applicable to the special permit request, including:

- The beginning and ending points of the pipeline, mileage to be covered, and the Counties and States where located;
- Whether the pipeline is interstate or intrastate, and a general description of the right-of-way including proximity of the affected segments to populated areas and unusually sensitive areas;
- Relevant pipeline design and construction information including the year of installation, the material, grade, diameter, wall thickness, and coating type; and
- Relevant operating information including operating pressure, leak history, and most recent testing or assessment results;

2.1.1.4 List the specific regulation(s) to include in the waiver;

2.1.1.5 Rationalize how the unique circumstances make the applicability of that regulation or standard (or portion thereof) unnecessary or inappropriate for the facility;

2.1.1.6 Describe each proposed measure or activity to use as an alternative for complying with the relevant regulation, including an explanation of how the measure mitigates any safety or environmental risks;

2.1.1.7 Describe any positive or negative impacts to affected stakeholders and a statement indicating how operating the pipeline under a special permit would be in the public's interest;

2.1.1.8 A certification that operation of the pipeline under the requested special permit would not be inconsistent with pipeline safety; and

2.1.1.9 Any other information PHMSA may need to process the application, including an environmental analysis where necessary.

2.1.2 Create a Change Management request for approval per GTIM-11-001 "GTIM Change Management" and attach documentation.

3.0 SPECIAL PERMIT RENEWALS

Note: Submissions to renew a current 'special permit' must occur at least 180 days before the permit's expiration date.

3.1 Responsibility: GTIM Engineer or designee

3.1.1 When applying to PHMSA or a State regulatory agency to renew a 'special permit', document at minimum the following information:

3.1.1.1 A copy of the original special permit, the docket number on the special permit, and the following information as applicable:

3.1.1.2 A summary report per the requirements of the original special permit including verification that the Operations and Maintenance (O&M) manual is consistent with the conditions of the special permit;

3.1.1.3 Operator name, OPID, and mailing address;

3.1.1.4 Name, title, and telephone number of a contact person;

3.1.1.5 A detailed description of the pipeline facilities applicable to the special permit request including the pipe's diameter, beginning and ending mileposts, and the county and state location;

3.1.1.6 Describe the applicable usage of the special permit, both original and future;

3.1.1.7 If the segment area identified in the special permit requires additional inspections, as applicable include:

3.1.1.7.1 Pipe attributes such as pipe diameter, wall thickness, grade, seam type; and pipe coatings including girth weld coatings;

3.1.1.7.2 Operating pressure such as Maximum Allowable Operating Pressure (MAOP) and class location(s) (including boundaries on aerial photography);

3.1.1.7.3 Any areas of consequence (including boundaries on aerial photography);

3.1.1.7.4 Material properties such as pipeline material documentation for all pipe, fittings, flanges, and any other facilities included in the special permit. Material documentation must include yield strength, tensile strength, chemical composition, wall thickness, and seam type;

3.1.1.7.5 All hydrostatic pressure testing data including the test pressures and dates, the pressure and temperature, charts, and logs, and any known test failures or leaks;

3.1.1.7.6 In-Line Inspection (ILI) data including the summary of ILI survey results from all ILI tools used on the special permit segments during the previous five years or latest ILI survey result;

3.1.1.7.7 Integrated data for the past five (5) years, as applicable, such as casing shorts, any in-service ruptures or leaks, Close Interval Survey (CIS) surveys, depth of cover surveys, rectifier readings, test point survey readings, alternating current and direct current (AC/DC) interference surveys, pipe coating surveys, pipe coating and anomaly evaluations from pipe excavations, Stress Corrosion Cracking (SCC), Selective Seam Weld Corrosion (SSWC), hard spot excavations and findings; and pipe exposures from encroachments;

3.1.1.7.8 Any in-service ruptures or leaks including repair type and failure investigation findings; and

3.1.1.7.9 Aerial photography of special permit area and inspection areas, if applicable.

3.1.2 Create a Change Management request for approval per GTIM-11-001 “GTIM Change Management” and attach documentation.

4.0 EMERGENCY SPECIAL PERMITS

4.1 Responsibility: GTIM Engineer or designee

4.1.1 When applying for an emergency ‘special permit’ from PHMSA or a State regulatory agency, document the same information as required when applying for a new special permit.

4.1.2 Additionally, include at minimum the following information:

4.1.2.1 An explanation of the actual or impending emergency and how the emergency affects the pipeline segment(s);

4.1.2.2 A citation of the regulations that are implicated and the specific reasons the permit is necessary to address the emergency (e.g., lack of accessibility, damaged equipment, insufficient manpower);

4.1.2.3 A statement indicating how operating the pipeline pursuant to an emergency special permit is in the public interest (e.g., continuity of service, service restoration);

4.1.2.4 A description of any proposed alternatives to compliance with the regulation (e.g., additional inspections and tests, shortened reassessment intervals); and

4.1.2.5 A description of any measures to be taken after the emergency situation or permit expires, whichever comes first, to confirm long-term operational reliability of the pipeline facility.

Note: If PHMSA determines that handling of the application on an emergency basis is not warranted, PHMSA will process the application as a new special permit and provide a notification of a change in the type of application.

4.1.1 Create a Change Management request for approval per GTIM-11-001 “GTIM Change Management” and attach documentation.

5.0 REVIEW OF APPLICATION

5.1 Responsibility: GTIM Manager or designee

5.1.1 Review the Change Management request for applicability and content coverage.

5.1.1.1 If acceptable, discuss the application with other stakeholders and obtain agreement for application.

5.1.2 Approve, or reject with justification, the Change Management request.

5.1.3 Submit the ‘special permit’ application to PHMSA or State regulatory agency, if approved.

5.1.3.1 Appendix C contains available submittal methods.

5.1.4 Send a copy of the notification to the Director of Engineering Gas Systems Integrity and Reliability, for informational purposes.

6.0 DOCUMENTATION

6.1 Responsibility: GTIM Manager or designee

6.1.1 Confirm receipt of the submission(s) by PHMSA.

6.1.2 Communicate any responses (i.e., requests for additional information, objections noted, no objections, etc.) to the appropriate stakeholders.

6.1.2.1 Attach all correspondence between CNP and PHMSA and any State jurisdictional authority to the Change Management request.

6.1.3 Retain all correspondence between CNP and PHMSA and any State jurisdictional authority for the useful life of the pipeline system.

<<END>>

GTIM-13-004 External Communications

PURPOSE: To establish a standardized method for keeping the public informed of CNP's integrity management activities.

REFERENCES: 49 CFR 192.911(m); ASME/ANSI B31.8S-2004, Section 10;

SECTIONS:

- General
- Communications with Stakeholder Audiences
- Integrating Information from Public Officials

1.0 GENERAL

1.1 It is CNP's goal to communicate with various stakeholder audiences to raise awareness of the CNP Gas Transmission Integrity Management (GTIM) Program.

1.2 Refer to the CNP Public Awareness Program for specifics on methods of communication, frequency, and additional communication content.

2.0 COMMUNICATIONS WITH STAKEHOLDER AUDIENCES

2.1 Responsibility: Damage Prevention & Public Awareness Team

2.1.1 As part of the CNP Public Awareness Program, routine communicates with stakeholder audiences. Stakeholder audiences include, but are not limited to:

- Landowners and tenants along the right-of-way;
- Public officials other than emergency responders;
- Local and regional emergency responders; and
- General public.

2.1.2 To meet GTIM requirements, include the information in the following table when communicating with specified stakeholder groups:

Table 13-004-1: Communications Examples

Stakeholder Audience	Information to be Communicated
Landowners and Tenants Along the Right-of-Way	• Company name, locations, and general contact information; • General location information and how to obtain more specific location information; • Commodity transported; • How to recognize, report and respond to a leak; • Contact phone numbers for both routine, and emergency; • General information about CNP's prevention activities, emergency preparedness, and how to obtain a summary of the GTIM-Plan; • Damage prevention information including excavation notification numbers, excavation notification center requirements, and who to contact in the event of damage;
Public Officials Other Than Emergency Responders	• Periodic distribution to each municipality of company contact information; • Provides NPMS information; • Summary of emergency preparedness and the GTIM Program;

Stakeholder Audience	Information to be Communicated
Local and Emergency Responders	• Maintain continuing liaison with emergency responders including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.; • Company name and contact information, both routine and emergency; • Local pipeline location maps; • Facility descriptions and commodity transported; • How to recognize, report, and respond to a leak; • General information about prevention activities, and how to obtain a summary of the GTIM-Plan; • Provides a generic description of stations; • Summary of emergency capabilities; • Coordination of CNP's emergency preparedness with local officials;
General Public	• Information regarding efforts to support excavation notification and other damage prevention initiatives; • Company name, contact, and emergency reporting information, including general business contact.

3.0 INTEGRATING INFORMATION FROM PUBLIC OFFICIALS

3.1 Responsibility: Damage Prevention & Public Awareness Team

3.1.1 Notify an GTIM Engineer when information received through stakeholder audience communications about any CNP transmission pipelines may affect the determination of an Identified Site or Consequence Areas.

3.2 Responsibility: GTIM Engineer or designee

3.2.1 Review the information obtained from the stakeholder audience.

3.2.2 Reconcile information with existing Consequence Areas, Identified Site locations, and Building Density information.

3.2.3 As necessary, update GIS or other appropriate databases with the information.

<<END>>

GTIM-13-005 Submittal of IM Program Documents and Risk Analysis

PURPOSE: To establish a standardized approach of submitting Gas Transmission Integrity Management (GTIM) program documents to the Pipeline and Hazardous Material Safety Administration (PHMSA) and other regulatory agencies.

REFERENCES: 49 CFR 192.911; 49 CFR 192.18;

SECTIONS:
- Submittal of IM Program Documents and Risk Analysis

1.0 SUBMITTAL OF IM PROGRAM DOCUMENTS AND RISK ANALYSIS

1.1 Responsibility: GTIM Manager or designee

1.1.1 Upon request of PHMSA, or other regulatory agency, submit integrity management program documents or risk analyses documentation per the timeline dictated by the requestor of the jurisdictional authority.

1.1.1.1 Provide documents electronically unless another method is specified, using the available submittal options in Appendix C.

1.1.2 Create a Change Management log entry per GTIM-11-001 “GTIM Change Management” to record the request and compliance.

<<END>>

GTIM-14-001 Glossary

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z

Term	Definition

A

Term	Definition
Abandoned	Permanently removed from service;
Active Corrosion	Continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety;
PHMSA Administrator	Administrator of the Pipeline and Hazardous Materials Safety Administration or his or her delegate;
Alarm	An audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters;
Alternating Current Voltage Gradient (ACVG)	A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and classify corrosion activity;
Anomaly	Any kind of imperfection, defect, irregularity, or deviation from the normal that may be present in either measurements or the physical facility. An indication may be generated by non-destructive inspection, such as in-line inspection;
Assessment	The use of testing techniques to ascertain the condition of a covered pipeline segment;

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B

Term	Definition
B31G	A method (from the ASME/ANSI standard) of calculating the pressure-carrying capacity of a corroded pipe;
Baseline Assessment Plan	The initial Long-Term Assessment Plan. This the work scheduling plans for the initial assessments;
Branch Connection	Branch Connections (also known as weldolets or threadolets) are fittings, which provide an outlet from a larger pipe to a smaller one (or one of the same sizes). The main pipe onto which the branch connection is welded is usually called the run or header size. The pipe to which the branch connection provides a channel is usually called the branch or outlet size;
British Thermal Unit (BTU)	A BTU is defined as the amount of heat required to raise the temperature of 1 pound (0.454 kg) of liquid water by 1°F (0.56 °C) at a constant pressure of one atmosphere. BTU is a traditional unit of energy equal to about 1055 joules;

TOP

C

Term	Definition
Caliper Pig	A configuration pig designed to record conditions, such as dents, wrinkles, ovality, bend radius and angle, and occasionally indications of significant internal corrosion, by sensing the shape of the internal surface of the pipe (also referred to as Geometry Tool);
Cathodic Protection (CP)	A technique by which underground metallic pipe is protected against deterioration (rusting and pitting);

Term	Definition
Class Location	***Note:*** *Records <u>must</u> be retained that document the current class location of each pipeline segment including how the operator determined each current class location.* The following criteria apply to location classifications under **49 CFR Part 192**. 1) A ‘‘class location unit’’ is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. 2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy. ***Class 1*** location is: *(i)* An offshore area; or *(ii)* Any class location unit that has 10 or fewer buildings intended for human occupancy. ***Class 2*** location is: *(i)* Any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy. ***Class 3*** location is: *(i)* Any class location unit that has 46 or more buildings intended for human occupancy; or *(ii)* An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) ***Class 4*** location is: *(i)* Any class location unit where buildings with four or more stories above ground are prevalent. *<u>Exceptions</u>: The length of Class locations 2, 3, and 4 may be adjusted if* *(1) a Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground, or* *(2) when a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster;*
Classification	The process of estimating the likelihood of corrosion activity at an indirect inspection indication under typical year-round conditions;
Close Interval Survey (CIS)	An inspection technique that includes a series of above ground pipe-to-soil potential measurements taken at predetermined increments of several feet along the pipeline and used to provide information on the effectiveness of the cathodic protection system;

Term	**Definition**
Complete Records	Complete records are those in which the record is finalized as evidenced by a signature, date, or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed, and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipe segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP. If records are unknown or unknowable, a more conservative approach is indicated;
Compression Wave Ultrasonic Testing	A type of in-line inspection technology in which an electronic tool measures pipe wall thickness and metal loss (e.g., corrosion, gouges, etc.). These tools are equipped with transducers that emit ultrasonic signals perpendicular to the surface of the pipe. An echo is received from both the internal and external surfaces of the pipe and, by timing these return signals and comparing them to the speed of ultrasound in pipe steel, the wall thickness can be determined;
Confirmatory Direct Assessment (CDA)	An assessment method using more focused applications of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment; CDA will typically be performed at 7-year intervals after the baseline assessment;
Consequence	The impact that a pipeline failure could have on the public, employees, property, and the environment;
Consequence of Failure	Consequence of Failure is used as a part of CNP’s risk model algorithm. The Consequence of Failure formula takes into account all potential areas involving the Business, the Environment, and Populations to determine locations along a pipeline where the consequences of pipeline failure are the greatest. Each consequence category is weighted relative to each other.
Control Room	An operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility;
Controller	A qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility;
Covered Segment or Covered Pipeline Segment	A segment of transmission gas pipeline located in a High Consequence Area or Moderate Consequence Area;
Crack or Crack-like Anomaly	A non-blunt flaw that can fail through flow-stress or toughness-controlled modes; *In a flow-stress controlled failure, the anomaly will behave similarly to metal loss, and strength properties determine failure.* *Toughness controlled failures will have burst pressures lower than a metal loss anomaly of the same dimensions, and failure occurs when the crack driving force is greater than the material resistance or toughness.*
Critical Angle	Angle calculated by ICDA Flow Modeling; the lowest angle at which liquid carryover is not expected to occur under stratified flow conditions

Term	Definition
Current Attenuation Survey	A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Associated data collected may include depth, coating resistance and conductance, anomaly location, and anomaly type
Customer Meter	The meter that measures the transfer of gas from an operator to a consumer;

TOP

D

Day	Typical: 24 hours; 8 hours (within a 24-hour time period) for site determination;
Defect	An imperfection of a type and magnitude exceeding acceptable criteria;
Direct Assessment (DA)	An integrity assessment method that utilizes a process to evaluate certain threats (i.e., internal corrosion, external corrosion, and stress corrosion cracking) to a pipeline segment's integrity;
Direct Current Voltage Gradient (DCVG)	An inspection technique that includes aboveground electrical measurements taken at predetermined increments to measure the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays;
Direct Examination	The direct physical inspection of the pipelines by a person and may include the use of nondestructive examination techniques (NDE);
Disbonded Coating	Any loss of adhesion between the protective coating and a pipe surface resulting from adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday;
Discovery of Condition	Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline;
Distribution Line	A pipeline other than a gathering or transmission line;
Dry Gas	Also known as consumer-grade natural gas, Dry Gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is 'wet'. Methane contains one carbon and four hydrogen atoms. A gas above its dew point and without condensed liquids;
Dummy Tool Run	Dummy tool runs are designed to mimic the characteristics of more costly ILI tool runs. Dummy tool runs assess the potential for tool damage by observing the condition of the dummy tool after the run. A successful dummy run should improve the likelihood that the live run will be successful;

TOP

E

Electric Resistance Welded Pipe (ERW pipe)	Pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of pressure and heat obtained from electrical resistance. ERW pipe forming is distinct from flash welded pipe and furnace butt-welded pipe as a result of being produced in a continuous process from coils of flat plate;
Electrical Survey	A series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline;

Term	Definition
Engineering Critical Assessment (ECA)	A documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.
Evaluation	The analysis and determination of a facility's fitness for service under the current operating conditions;
Examination	The direct physical inspection of the pipelines by a person and may include the use of nondestructive examination techniques (NDE);
Exposed Underwater Pipeline	An underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water;
External Corrosion Direct Assessment (ECDA)	A four-step process that combines Pre-Assessment, Indirect Inspections, Direct Examinations, and Post-Assessment to evaluate the impact or threat of external corrosion on the integrity of a pipeline;
ECDA Region	A section or sections of a pipeline that have similar physical characteristics and operating history and in which the same indirect inspections tools are used;

TOP

F

Failure	Indicates that a component has become inoperable, is still operable but incapable of satisfactory performance, or has seriously deteriorated and become unreliable or unsafe in continued use;
Failure Pressure Ratio (FPR)	One of the factors used in calculating Remaining Life for a corrosion defect. The Failure Pressure Ratio is calculated as follows: **Failure Pressure Ratio = P_f / Yield Pressure** *(dimensionless)* *where:* *P_f = Calculated Failure Pressure from RSTRENG or ASME/ANSI B31G-1991 (psi);* *Yield Pressure (P_Y) is calculated as follows:* Yield Pressure = $\frac{2 \times S \times t}{D}$ *where:* *t = Nominal wall thickness of the pipe (inches)* *S = Specified minimum yield strength of pipe (psi)* *D = Outside diameter of pipeline (inches)*

TOP

G

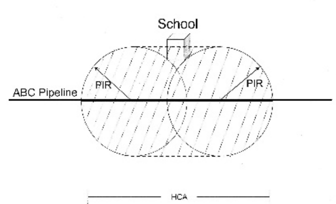
Gas	Natural gas, flammable gas, or gas which is toxic or corrosive;
Gas Transmission Integrity Management (GTIM)	Designation for Center Point Energy's (and legacy Vectren's) integrity management program for natural gas transmission pipelines. The GTIM-Plan includes procedures, forms, and flow charts.
Gathering Line	A pipeline that transports gas from a current production facility to a transmission line or main;

Term	Definition
Geometry Tool	Geometry tools use mechanical arms or electro-mechanical means to measure the bore of pipe. In doing so, it identifies dents, deformations, and other ovality changes. It can also sense changes in girth welds and wall thickness;
Geophones	A geophone is an acoustical monitoring device that is used to magnify sounds in and around pipelines. Geophones are typically used to monitor the passage of pipeline pigs or to detect leaks;
Gulf of Mexico and its inlets	The waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water;

TOP

H

Hazard to Navigation	For the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water;
High Consequence Area (HCA)	An area established by one of the methods described below in (1) or (2). (1) An area defined as: *(i)* A Class Location 3 under 49 CFR 192.5; or *(ii)* A Class Location 4 under 49 CFR 192.5; or *(iii)* Any area within a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet, and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or *(iv)* The area within a potential impact circle containing an identified site. (2) The area within a potential impact circle containing *(i)* 20 or more buildings intended for human occupancy, unless prorated as described in paragraph 4 of the definition in §192.903 applies; or *(ii)* An identified site;
HCA Database Documentation	Include the following information on an HCA during entry/updates into GeoFields: • Name; • Location; • Distance from the pipeline; • Next review year; • Structure use; • Number of units; • Occupancy; • Stories of 4 and greater; • Location with impaired mobility; • Locations difficult to evacuate;

Term	Definition
HCA Extent	HCAs extend axially along the length of the pipe with the following beginning and ending points. 1. Beginning at the farthest upstream edge of the first PIC that contains twenty (20) or more buildings/portions of buildings intended for human occupancy, or an identified site. 2. Ending at the farthest downstream edge of the last PIC that contains twenty (20) or more buildings/portions of buildings intended for human occupancy, or an identified site. **Determining High Consequence Area** 
High-Pressure Distribution System	A distribution system in which the gas pressure in the main is higher than the pressure provided to the customer;
Holiday	A discontinuity (hole) in a protective coating that exposes the pipe surface to the environment;

TOP

I

Term	Definition
Identified Site	Each of the following areas: a) An outside area that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) months (the days need not be consecutive). (Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive). (Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or rolling skating rinks); or c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities, or assisted-living facilities;
In-Line Inspection	A pipeline inspection technique using smart robot tools known as “pigs” or “smart pigs” that provides indications of metal loss, deformations, and other defects;
In-Line Inspection ABLE	*(see Internal Inspection ABLE)*
Incident	An unintentional release of gas due to a failure *See **49 CFR 191.3** for the complete definition.*
Inclination Angle	An angle resulting from a change in elevation between two (2) points on a pipeline, in degrees.
Indication	A finding by a nondestructive testing technique that may or may not be a defect;

Term	Definition
Indirect Inspection	Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or classify corrosion activity, coating holidays, or other anomalies.
Inertial Mapping Unit	Most ILI tools are equipped with an Inertial Mapping Unit (IMU) which measures and records the tool's location within the pipe using built-in gyroscopes and accelerometers. The data acquired positions features such as welds, valves, and defects with GPS coordinates.
Inspection	The use of a nondestructive testing technique;
Integrity Assessment	A process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, and characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis;
Interaction Rules	Specifications that establish spacing criteria between anomalies or defects. If the indications or defects are proximate to one another within the criteria, the anomaly or defect is treated as a single larger unit for engineering analysis purposes.
Intergranular Corrosion	A form of corrosive attack that progresses preferentially along grain boundaries. In the presence of tensile stress, cracking may occur along grain boundaries.
Internal Inspection ABLE	A length of pipeline through which commercially available devices can travel, inspect the entire circumference and wall thickness of the pipe, and record or transmit inspection data in sufficient detail for further evaluation of anomalies.

TOP

L

Term	Definition
Leak	An unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks, separation or pullout, and loose connections;
Likelihood of Failure (LOF)	Likelihood of Failure is used as a part of CNP's risk model algorithm. The Likelihood of Failure formula supplies the probability that a particular pipeline will fail. The formula takes into account frequency, statistics, and characteristics from datasets including Third Party Damage, Manufacturing, External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Construction, Equipment, Design, Operations, Internal Corrosion, and Weather and Outside Forces. Each threat category is weighted based on CNP SME input and statistical trends across the industry for serious and significant incidents.
Line Section	A continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves;
Listed Specification	A specification listed in section I of appendix B of this part;
Long Term Assessment Plan	A schedule for assessing and addressing all identified threats to each covered pipeline segment
Low-Pressure Distribution System	A distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer;
Low Stress Pipeline	A natural gas transmission pipeline that operates below 30% SMYS, as related to the requirements of integrity management programs.

Term	Definition
M	TOP
Magnetic Flux Leakage Tool	A type of in-line inspection technology in which an electronic tool identifies and measures metal loss (e.g., corrosion, gouges, etc.) by applying an axially oriented magnetic field induced in the pipe wall between two poles of a magnet.
Main	A distribution line that serves as a common source of supply for more than one service line;
Maximum Actual Operating Pressure	The maximum pressure that occurs during normal operations over a period of 1 year;
Maximum Allowable Operating Pressure (MAOP)	MAOP is the maximum pressure at which a natural gas system may be operated in accordance with 49 CFR Part 192. *A PHMSA Advisory Bulletin was issued reminding operators that if they are relying on the review of design, construction, inspection, testing, and other related data to establish MAOP they must ensure that the records used are reliable, traceable, verifiable, and complete.*
MAOP Ratio	One of the factors used in calculating Remaining Life for a corrosion defect. The MAOP Ratio is calculated as follows: **MAOP Ratio = MAOP / Yield Pressure** *(dimensionless)* *where:* *MAOP = Maximum Allowable Operating Pressure established (i.e., not calculated) for the pipe segment;* *Yield Pressure (P_Y) is calculated as follows:* $\textbf{Yield Pressure} = \frac{2 \times S \times t}{D}$ *where:* *t = Nominal wall thickness of the pipe (inches)* *S = Specified minimum yield strength of pipe (psi)* *D = Outside diameter of pipeline (inches)*
Mechanical Damage	Any of a number of types of anomalies in pipe including dents, gouges, and metal loss, caused by the application of an external force.
Microbiologically Influenced Corrosion	Localized corrosion resulting from the presence and activities of certain microorganisms, including bacteria and fungi, and nutrients in the soil.
Mitigation	The limitation or reduction of the probability of occurrence or expected consequence for a particular event.

Term	Definition
Moderate Consequence Area (MCA)	*(1)* An onshore area that is within a potential impact circle, as defined in §192.903, containing either: *(i)* Five or more buildings intended for human occupancy; or *(ii)* Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 (*see*: *https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf*), and that does not meet the definition of high consequence area, as defined in §192.903. *(2)* The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.
Municipality	A city, county, or any other political subdivision of a State;

TOP

N

Term	Definition
Nondestructive Examination	An inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic, and dye penetrate methods;

TOP

O

Term	Definition
Offshore	Beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters;
Operations and Maintenance Plan	In compliance with applicable state and federal codes, this plan establishes procedures for persons to perform safely operation and maintenance activities on the gas system and establishes intervals for performing various O&M tasks;
Operator	A person who engages in the transportation of gas;
Outer Continental Shelf	All submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control;

Term	Definition

P

TOP

Term	Definition
Person	Any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof;
Petroleum Gas	Propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C);
Pipe	Any pipe or tubing used in the transportation of gas, including pipe-type holders;
Pipeline	All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;
Pipeline Environment	Includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion;
Pipeline Facility	New and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation;
Potential Impact Circle	A circle with a radius equivalent to the Potential Impact Radius (PIR).
Potential Impact Radius	The radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property. PIR is determined by the formula: $r = c \times \sqrt{(p \times d^2)}$ where, **d** = the nominal diameter of the pipeline in inches **p** = the pipeline segment's maximum allowable operating pressure (MAOP) *(psig)* **r** = the radius of a circular area surrounding the failure *(feet)* ***Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending on their heat of combustion. An operator transporting other than natural gas must use Section 3.2 of ASME/ANSI B31.8S-2004 to calculate the impact radius formula.*
Pressure Test	Strength testing of sections of a pipeline by filling the line with water, air, natural gas, or inert gas and pressurizing it until the nominal hoop stresses in the pipe reach a specified value. It is used to validate integrity and detect construction defects and defective materials. See Hydrostatic Testing.
Preventive and Mitigative Measure	An action, beyond that already required by Part 192, to prevent a pipeline failure or mitigate the consequences of a pipeline failure by reducing or eliminating a threat or other risk factor to the integrity of a pipeline
Probability	The likelihood of an incident occurring.
Pyrophoric Material	Any liquid or solid that, even in small quantities and without an external ignition source, can ignite within 5 minutes after coming into contact with air. A common example is powdered iron sulfide.

Term	Definition

R

TOP

Reliable Records	Reliable records directly support the information as it is presented. A record that cannot be specifically linked to an individual pipe segment is not a reliable record for that segment. Incomplete or partial records should not be considered reliable;
Remediation	A repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event;
Rich Gas	*(See Wet Gas)*
Risk	A measure of potential loss in terms of both the incident likelihood of occurrence and the magnitude of the consequence;
Risk Assessment	A systematic process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are estimated;
Risk Management	An overall program consisting of: identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved;
Risk of Failure (ROF)	Risk of Failure is used as a part of CNP's risk model algorithm. The Risk of Failure formula is the highest-level formula within CNP's risk algorithm and is calculated by multiplying the Likelihood of Failure (LOF) by the Consequence of Failure (COF). The final values resulting from this calculation are applied to dynamic segments along the selected pipelines.
Root Cause Analysis (RCA)	A family of processes implemented to determine the primary cause of an event. These processes seek to examine the cause and effect relationship through the organization and analysis of the data. Such processes are often used in failure analyses;
RSTRENG	A computer program designed to calculate the pressure-carrying capacity of corroded pipe;
Rupture	A complete failure of any portion of the pipeline;

S

TOP

Safety Factor or Factor of Safety	Used to provide a design margin over the theoretical design capacity to allow for uncertainty in the design process. **Safety Factor = Failure Pressure / MAOP** *(psi)*
Safety Margin	One of the factors used in calculating Remaining Life for a corrosion defect. Safety Margin is calculated as follows: **SM = Failure Pressure Ratio – MAOP Ratio** *(dimensionless)*
Segment	A length of pipeline or part of the system that has unique characteristics in a specific geographic location;

Term	Definition
Service Line	A distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter;
Service Regulator	The device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold;
Shear Wave Ultrasonic Testing	(Also known as Circumferential Ultrasonic Testing or C-UT) is the nondestructive examination technique that most reliably detects longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking). Because most crack-like defects are perpendicular to the main stress component *(i.e., the hoop stress)*, UT pulses are injected in a circumferential direction to obtain maximum acoustic response;
Sound Engineering Practice	Reasoning exhibited or based on thorough knowledge and experience as well as logically valid and technically correct premises that demonstrate good judgment or sense in the application of science;
Specified Minimum Yield Strength (SMYS)	(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or (2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b); A required strength level that the measured yield strength of a pipe material must exceed, and which is a function of pipe grade. The measured yield strength is the tensile stress required to produce a total elongation of 0.5% of a gauge length as determined by an extensometer during a tensile test. The minimum yield strength, expressed in pounds per square inch *(psi)* kilopascals *(kPa)* gage, prescribed by the specification under which the material is purchased from the manufacturer;
%SMYS	**%SMYS = MAOP / (2St/D)** where: S = Yield strength in pounds (psi) t = nominal wall thickness of the pipe (inches) D = nominal outside diameter (inches) See stress level.
Spike Test	A spike test is a variant of the hydrostatic test in which the pressure is initially raised to a prescribed level above the minimum test pressure, or stress level, for a short period then reduced for the remaining duration of the test. A spike test's purpose is two-fold: the spike portion will induce failure in the pipe where significant defects may be present, while the subsequent reduction of pressure allows any surviving cracks to stabilize and avoids subcritical crack growth during the hold period to detect leaks;
State	Each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico;

Term	Definition
Stress Corrosion Cracking (SCC)	A cracking process that requires the simultaneous action of a corrosive agent and sustained tensile stress. The stresses may be significantly below the yield strength of the material, and can be residual or applied. Stress-corrosion cracking may occur in combination with hydrogen embrittlement;
Stress Level	The level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength;
Subject Matter Expert (SME)	A person who has demonstrated competency and experience in a particular subject area or topic; *PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.*
Supervisory Control and Data Acquisition (SCADA)	A computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility;

TOP

T

Term	Definition
TVC	*(See definitions for Traceable Records, Verifiable Records, and Complete Records.)*
Third-Party Damage (TPD)	Damage to a pipeline facility by an outside party other than those performing work for the operator;
Traceable Records	Traceable records are those, which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.
Transmission Pipeline	A pipeline, other than a gathering line that: 1. Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; 2. Operates at a hoop stress of 20 percent or more of SMYS; or 3. Transports gas within a storage field; ***Note:*** *A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas;*
Transportation of Gas	The gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce;
Transverse Flux Inspection Tool	A type of in-line inspection technology in which an electronic tool identifies and measures metal loss (e.g., corrosion, gouges, etc.) by inducing a magnetic field that is oriented circumferentially, wrapping completely around the circumference of the pipe. Tool is sensitive to different defect geometries than the axial MFL.

Term	Definition
U	TOP
Underground Natural Gas Storage Facility	A facility that stores natural gas in an underground facility incident to natural gas transportation, including— (1) A depleted hydrocarbon reservoir; (2) An aquifer reservoir; or (3) A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment;
V	TOP
Verifiable Records	Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipe segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by an individual who would have reason to be familiar with the test or inspection.
W	TOP
Weak Link	A device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed;
Welder	A person who performs manual or semi-automatic welding;
Welding Operator	A person who operates machine or automatic welding equipment;
Wet Gas	Natural gas containing other hydrocarbons such as ethane, propane, or butane. Wet gas contains greater than 7 lbs. per MMCF of water vapor.
Y	TOP
Yield Strength	Yield strength is the stress level at which a material begins to deform permanently.

<<END>>

GTIM-15-001 Environmental and Safety

PURPOSE: To provide a standardized approach for confirming that CNP conducts integrity assessments and other Integrity Management activities in a manner that minimizes environmental and safety risks.

REFERENCES: 49 CFR 192.911; 49 CFR 192.919(e);

SECTIONS:
- General
- Documentation

1.0 GENERAL

1.1 CNP personnel and service providers perform all pipeline operations, maintenance, and integrity management activities in a manner to minimize environmental and safety hazards.

1.1.1 Minimize safety risks for both workers and members of the public.

1.1.2 Manage environmental impact in compliance with CNP policies and procedures.

1.2 CNP personnel and service providers perform all activities according to CNP safety and environmental policies and procedures, which are available on the CNP intranet.

1.3 Locations and facilities subject to environmental and safety policies include, but are not limited to:

- In-line inspection tool launchers and receivers;
- Pipeline rights-of-way;
- Meter and regulator sites;
- Compressor stations; and
- Maintenance shops.

1.4 Activities subject to environmental and safety policies include, but are not limited to:

- Integrity baseline and reassessments including, but not limited to:
  - Pressure Tests;
  - In-Line Inspections;
  - External Corrosion Direct Assessment;
  - Internal Corrosion Direct Assessment;
- Pipeline excavation;
- Pipeline patrols; and
- Routine maintenance activities.

2.0 DOCUMENTATION

2.1 Responsibility: GTIM Engineer or designee

2.1.1 Promptly investigate any safety concerns raised by PHMSA or other safety or environmental regulatory agencies and determine a course of action.

2.1.2 Document the event consistent with the nature of the safety concern. Include, at a minimum:

- Root cause determination;

- Assessment of generic implications;
- Proposed actions to prevent or minimize the probability of recurrence; and
- Appropriate remedial corrective measures.

2.1.3 Schedule and complete any corrective actions commensurately with the threat to safety.

2.2 Responsibility: GTIM Manager or designee

2.2.1 Maintain the appropriate level of communication with CNP management and the regulatory authorities throughout the resolution of the safety concern.

<<END>>

Appendix A Referenced Tables

1.0 GTIM-PLAN PROCEDURE LIST

Table A-1: GTIM-Plan Procedure List

GTIM-Plan Procedures	
Document Number	**Title**
GTIM-01: Identify Consequence Areas	
GTIM-01-002	Identification of Consequence Areas
GTIM-02: Threats and Risk	
GTIM-02-001	Data Gathering and Research
GTIM-02-003	MAOP Origination
GTIM-02-004	MAOP Reconfirmation
GTIM-02-006	Engineering Critical Assessment (ECA)
GTIM-02-007	Applying the Transmission Line Definition
GTIM-02-010	Material Verification
GTIM-02-020	Determination of Stable Threats
GTIM-02-021	Threat Identification
GTIM-02-022	Risk Assessment and Prioritization
GTIM-03: Integrity Assessments	
GTIM-03-001	Assessment Method Selection
GTIM-03-002	Baseline/Reassessment Assessment Plan
GTIM-03-003	Pressure Testing
GTIM-03-004	Pigging - Cleaning
GTIM-03-005	In-Line Inspection Pre-Assessment
GTIM-03-006	In-Line Inspection and Data Analysis
GTIM-03-007	ILI Validation Direct Examination
GTIM-03-008	ILI Post-Assessment
GTIM-03-009	Evaluation of Stations and Equipment
GTIM-03-010	In-Line Inspection Request for Proposals
GTIM-03-011	In-Line Inspection Tool Run Preparation
GTIM-03-015	Non-HCA Assessments
GTIM-04: Direct Assessments	
GTIM-04-001	Long-Range Ultrasonic Testing
GTIM-04-002	ECDA Pre-Assessment
GTIM-04-003	ECDA Indirect Inspection
GTIM-04-004	ECDA Direct Examination
GTIM-04-005	ECDA Post-Assessment
GTIM-04-006	Pipeline Elevation Profile
GTIM-04-008	Data Collection for Integrity Management Direct Examination
GTIM-04-009	Laboratory Testing for Soil Samples
GTIM-04-011	Field Testing for Microbiologically Influenced Corrosion Bacteria

GTIM-Plan Procedures	
Document Number	**Title**
GTIM-04-012	Root Cause Analysis
GTIM-04-013	Soil Resistivity with the Wenner 4-Pin Method
GTIM-04-014	Soil Resistivity with the Single Probe Method
GTIM-04-020	Close Interval Survey
GTIM-04-021	Direct Current Voltage Gradient Survey
GTIM-04-022	Current Attenuation Survey
GTIM-04-023	Alternating Current Voltage Gradient Survey
GTIM-04-024	Documentation of Coating and Corrosion Defects
GTIM-04-026	Dig Plan Preparation
GTIM-04-027	Direct Examination Preparation
GTIM-04-028	100% Direct Examination for Station Assessments
GTIM-04-030	Indirect Inspection Survey Field Preparation
GTIM-04-031	Drilling and Coring of Improved Surfaces
GTIM-04-032	Locating and Marking a Survey Segment
GTIM-04-033	Pipe Depth Survey
GTIM-04-043	GPS Coordinates
GTIM-04-051	ICDA Pre-Assessment
GTIM-04-054	ICDA Indirect Inspection
GTIM-04-055	ICDA Direct Examination
GTIM-04-056	ICDA Post-Assessment
GTIM-04-063	SCCDA Pre-Assessment and Indirect Inspection
GTIM-04-064	SCCDA Direct Examination and Post-Assessment
GTIM-04-072	Guided Wave Ultrasonic Testing (GWUT)
GTIM-05: Remediation	
GTIM-05-001	Addressing Conditions Found During an Integrity Assessment
GTIM-05-003	RSTRENG
GTIM-05-005	Predictive Failure Pressure
GTIM-06: Continual Evaluation	
GTIM-06-001	Determining Reassessment Intervals
GTIM-06-002	Low-Stress Assessment
GTIM-06-003	Internal Corrosion Control Program
GTIM-06-004	Continual Data Integration, Management, and Evaluation
GTIM-06-005	Reassessments
GTIM-07: Confirmatory Direct Assessments	
GTIM-07-001	Confirmatory Direct Assessment
GTIM-08: Preventive and Mitigative Measures	
GTIM-08-001	Monitoring Excavations in a Right-of-Way
GTIM-08-002	Finding Evidence of Encroachment Involving Excavation
GTIM-08-003	Pipelines Operating Below 30% SMYS
GTIM-08-004	Identify Preventive and Mitigative Measures
GTIM-08-005	Evaluating Similar Conditions

GTIM-Plan Procedures	
Document Number	**Title**
GTIM-08-006	Collecting Information on Excavation Damage
GTIM-08-007	Automatic Shut-Off and Remote-Control Valves
GTIM-08-008	Third-Party Damage and Outside Force
GTIM-09: Performance Measures	
GTIM-09-001	Performance Measures and NPMS Reporting
GTIM-10: Record Keeping	
GTIM-10-001	Record Keeping
GTIM-11: Management of Change	
GTIM-11-001	GTIM Change Management
GTIM-11-002	GTIM Change Management for Routine O&M Activities
GTIM-12: Quality Assurance	
GTIM-12-000	Quality Control
GTIM-12-001	In-Line Inspection Data Acceptance
GTIM-12-002	Integrity Management Program Review
GTIM-12-003	Using Third-Party Resources
GTIM-12-004	Qualifications and Training of Company Personnel
GTIM-12-005	Non-Mandatory Statements
GTIM-13: Communications	
GTIM-13-001	Required Notifications to Regulatory Agencies
GTIM-13-002	Internal Communications
GTIM-13-003	Special Permits (Waivers)
GTIM-13-004	External Communications
GTIM-13-005	Submittal of IM Program Documents and Risk Analysis
GTIM-14: General	
GTIM-14-001	Glossary
GTIM-15: Environmental and Safety	
GTIM-15-001	Environmental and Safety

2.0 GTIM EVENTS

2.1 Portions of the CNP Gas Transmission Integrity Management Program activities occur at regularly scheduled intervals. Summarized in the following table are the typical timeframes for performing these activities.

Table A-2: Recurring Planned GTIM Events

Recurring Planned GTIM Events	
Process	**Time Frame**
Evaluate New Advisory Bulletins	Continually
Baseline/Reassessment Assessment Planning	1st Quarter Annually
Stakeholder Communication Meeting	1st Quarter Annually
IM Plan/Procedures/Forms Training	1st Quarter Annually
Long Range Assessment/Project Calendar	1st Quarter Annually
Performance Measures Review	1st Quarter Annually
Non-Reportable Performance Measures	1st Quarter Annually
PHMSA and NPMS Reporting	1st Quarter Annually
Risk Analysis	1st Quarter Annually
Indirect Inspection Processes	2nd Quarter Annually
Field Assessment Activities	2nd & 3rd Quarter Annually
HCA and MCA: Field Data Collection	2nd & 3rd Quarter Annually
Risk Model Review	3rd & 4th Quarter Annually
HCA and MCA: Class, and Valve Spacing Reviews	3rd & 4th Quarter Annually
IM Program Review	4th Quarter Annually
Intranet IMP Review	4th Quarter Annually
Post-Assessment Processes	4th Quarter Annually
Review Identified Threats	4th Quarter Annually
Review Data Collection Attributes (all pipelines)	4th Quarter Annually

3.0 STANDARDS AND REFERENCES

3.1 Industry-standards, or portions thereof, incorporated by reference into 49 CFR Part 192, include:

Table A-3.1: Standards Incorporated by Reference (derived from §192.7)

Publisher / Identifier	
American Petroleum Institute (API)	https://www.api.org
API Spec 5L-2013	API Specification 5L, "Specification for Line Pipe", 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.
API Std 1104-2005 (2008)	API Standard 1104, "Welding of Pipelines and Related Facilities", 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B
API Std 1163-2013 (Reaffirmed 2018)	API Standard 1163, "In-Line Inspection Systems Qualification", Second edition, April 2013, Reaffirmed August 2018, (API Std 1163), IBR approved for §192.493
ASME International (ASME)	https://www.asme.org
ASME/ANSI B31G-1991 (Reaffirmed 2004)	ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines", 2004, (ASME/ANSI B31G), IBR approved for §§192.485(c), 192.632(a), 192.712(b), and 192.933(a)
ASME/ANSI B31.8-2007	ASME/ANSI B31.8, "Gas Transmission and Distribution Piping Systems", November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§192.112(b) and 192.619(a)
ASME/ANSI B31.8S-2004	ASME/ANSI B31.8S, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines", 2004, (ASME/ANSI B31.8S), IBR approved for §§192.903 note to Potential impact radius; 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a)
American Society for Nondestructive Testing (ASNT)	https://www.asnt.org
ANSI/ASNT ILI-PQ-2005 (Reapproved 2010)	ANSI/ASNT ILI-PQ-2005 (2010), "In-line Inspection Personnel Qualification and Certification", Reapproved October 11, 2010, (ANSI/ASNT ILI-PQ), IBR approved for §192.493
Gas Technology Institute (GTI)	https://sales.gastechnology.org
GRI 02/0057-2002	GRI 02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology", 2002, (GRI 02/0057), IBR approved for §192.927(c)
NACE International (NACE)	https://www.nace.org
NACE SP0102-2010	ANSI/NACE Standard Practice 0102-2010, "In-Line Inspection of Pipelines", Revised 2010-03-13, (NACE SP0102), IBR approved for §§192.150(a) and 192.493
NACE SP0502-2010	ANSI/NACE Standard Practice 0502-2010, "Pipeline External Corrosion Direct Assessment Methodology", revised June 24, 2010, (NACE SP0502), IBR approved for §§192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a)

Publisher / Identifier	
Pipeline Research Council International, Inc. (PRCI) *https://www.prci.org*	
PRCI PR-3-805-1989	AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d)
Plastics Pipe Institute, Inc. (PPI) *https://plasticpipe.org*	
PPI TR-3-2012	PPI TR-3, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe", updated November 2012, (PPI TR-3/2012), IBR approved for §192.121
PPI TR-4-2012	PPI TR-4, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe", updated March, 2011, (PPI TR-4/2012), IBR approved for §192.121

3.2 Other natural gas pipeline industry-recognized standards utilized by CNP.

Table A-3.2: Natural Gas Pipeline Industry-Recognized Standards

Publisher / Identifier	
ASTM International (ASTM) *https://www.astm.org*	
ASTM A370-2009	ASTM A370-2009, "Standard Test Methods and Definitions for Mechanical Testing of Steel Products", revised 2009, (ASTM A370);
Canadian Energy Pipeline Association (CEPA) *https://cepa.com*	
Stress Corrosion Cracking (2015)	"CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion Cracking", 3rd edition; May 2015;
Gas Technology Institute (GTI) *https://sales.gastechnology.org*	
GRI-04/0178-2004	GRI-04/0178-2004 (L52270), "Basics of Metal Fatigue in Natural Gas Pipeline Systems - A Primer for Gas Pipeline Operators", revised 2006, (PR-302-03152);
NACE International (NACE) *https://www.nace.org*	
NACE RP0104-2004	NACE Recommended Practice 0104, "The Use of Coupons for Cathodic Protection Monitoring Applications", December 3, 2004, (NACE RP0104);
NACE SP0106-2006	NACE Standard Practice 0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems", 2006, (NACE SP0106);
NACE RP0169-2002	NACE RP0169-2002, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems", 2002, (NACE RP0169);
NACE SP0204-2015 (formally NACE RP0204-2004)	NACE Standard Practice 0204-2015, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology", revised 2015, (NACE SP0204);
NACE SP0206-2016 (formally NACE SP0206-2006)	NACE Standard Practice 0206-2016, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)", revised 2016, (NACE SP0206);

Publisher / Identifier	
NACE SP0207-2007	NACE Standard Practice 0207, "Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines", 2007, (NACE SP0207);
NACE SP0210-2010	NACE Standard Practice 0210-2010-SG, "Pipeline External Corrosion Confirmatory Direct Assessment", 2010, (NACE SP0210);
NACE TM0109-2009	NACE Standard TM0109, "Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition", 2009, (NACE TM0109);
NACE TM0497-2018-SG (formally NACE TM0497-2002)	NACE Test Methods 0497-2018-SG, "Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems", revised 2018, (NACE TM0497);
NACE Publication 35100-2000	NACE International Publication 35100-2000, "In-Line Nondestructive Inspection of Pipelines", original December 2000, (NACE Publication 35100);
Pipeline Research Council International, Inc. (PRCI) *https://www.prci.org*	
PRCI PR-218-9304-1996	PRCI Research Report PR-218-9304, "Specifications and requirements for intelligent pig inspection of pipelines", released 12/20/1996, (PRCI PR-218-9304);

<<END>>

Appendix B Responsibility Roles for the GTIM Program

CNP's Gas Transmission Integrity Management (GTIM) Program extends across multiple subsidiaries and multiple states. Because job titles vary across subsidiaries, the GTIM-Plan utilizes roles[1] and a variation of the RACI[2] model, which modifies the application of the "R" and "A" codes of the original scheme, to avoid potential confusion of the terms accountable and responsible.

Within this Plan, GTIM identifies the role responsible for the completion of specified activities, functions, and deliverables. In all cases, personnel assigned to a role will possess the appropriate training or experience in the area for which the person is responsible as per GTIM-12-004 "Qualifications and Training of Company Personnel" and GTIM-12-003 "Using Third-Party Resources".

PROGRAM OVERSIGHT

The Director of Engineer Gas System Integrity and Reliability is responsible for providing program guidance and the overall oversight of CenterPoint Energy's Integrity Management Program.

The table below lists the CNP GTIM-Plan roles.

Table B-1: GTIM-Plan Roles

Role	Responsibilities
Corporate IM Program Sponsor	• Executive Sponsor and overall oversight of the CenterPoint Energy's Gas Transmission Integrity Management Program (GTIM Program);
GTIM Manager	• Overall implementation, management of, and compliance with, the GTIM Program; • Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;
GTIM Field Supervisor	• Coordination of integrity assessments and fieldwork; • Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;
GTIM Engineer	• Coordination of program implementation and technical accuracy of the program; • Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;

[1] ***Role:*** A role is a descriptor associated with a set of tasks that may be performed by many different people, and one person can perform many roles.

[2] ***RACI*** (alternate scheme): RACI is an acronym describing various roles participating in the tasks and deliverables for a process: *Responsible*, *Assists*, *Consulted*, and *Informed*. A RACI matrix visually clarifies and defines the roles and responsibilities of cross-functional and cross-departmental processes.

Responsible: Those who are answerable for the thorough completion of the work by directly doing the work or overseeing those who do the work. There is at least one role with a participation type of responsible, although others can be delegated to assist with the required work.

Note: It is generally recommended that each process or task receive just one role assignment. Where more than one role is shown implies that the task or group of tasks has not yet been fully segregated.

Assists: Those who assist with the completion of the task.

Consulted: Those whose opinions are sought, typically subject matter experts and management; and with whom there is two-way communication.

Informed: Those who are kept up-to-date on progress, often only on completion of the task or deliverable; and with whom there is one-way communication.

Role	**Responsibilities**
GTIM Field Inspector	• Conduct Integrity Assessments and field activities appropriately; • Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;
Local Operations	• Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;
Other CNP departments; (e.g., Gas Transmission Engineering teams; Corrosion Control; Land Services (Encroachment); Gas Control; Damage Prevention & Public Awareness; etc.)	• Answerable for the execution and completeness of activities and tasks as assigned in the GTIM-Plan;

<<END>>

Appendix C Regulatory Agencies

SECTIONS:

- Contact Information
- Pipeline and Hazardous Materials Safety Administration (PHMSA)
- Arkansas Public Service Commission (APSC)
- Indiana Utility Regulatory Commission (IURC)
- Kentucky Public Service Commission (KYPSC)
- Louisiana Department of Natural Resources (LADNR)
- Minnesota Office of Pipeline Safety (MNOPS)
- Mississippi Public Service Commission (MPUS)
- Ohio Public Utilities Commission (PUCO)
- Oklahoma Corporation Commission (OCC)
- Texas Railroad Commission (TX RRC)

1.0 CONTACT INFORMATION

1.1 Pipeline and Hazardous Materials Safety Administration (PHMSA)

Pipeline and Hazardous Materials Safety Administration (PHMSA)
Mailing Address:
ATTN: Information Resources Manager DOT/PHMSA/OPS East Building, 2nd Floor (PHP-20), E22-321 1200 New Jersey Ave, SE Washington, DC 20590
Physical Location:
US Department of Transportation Pipeline and Hazardous Materials Safety Administration 1200 New Jersey Avenue, SE Washington, DC 20590
Telecommunications:
Phone: (202) 366-4433 *Fax:* (202) 366-3666 *Office Hours:* Monday - Friday 9 am - 5 pm (ET)
e-Mail:
InformationResourcesManager@dot.gov

1.2 Arkansas Public Service Commission (APSC)

Arkansas Public Service Commission (APSC)
Mailing Address:
Arkansas Public Service Commission PO Box 400 Little Rock, Arkansas 72203-0400
Physical Location:
Arkansas Public Service Commission 1000 Center Street Little Rock, Arkansas 72201-4314

1.3 Indiana Utility Regulatory Commission (IURC)

Indiana Utility Regulatory Commission (IURC)
Mailing Address:
Indiana Utility Regulatory Commission Pipeline Safety Division 101 W Washington St, STE 1500E Indianapolis, Indiana 46204
Physical Location:
Indiana Utility Regulatory Commission Pipeline Safety Division 101 W Washington St, STE 1500E Indianapolis, Indiana 46204

1.4 Kentucky Public Service Commission (KYPSC)

Kentucky Public Service Commission (KYPSC)
Mailing Address:
Kentucky Public Service Commission PO Box 615 211 Sower Boulevard Frankfort, Kentucky 40602-0615
Telecommunications:
Phone: (502) 564-3940 *Fax:* (502) 564-3460 *Hotline:* 1-800-772-4636 *Office Hours:* Monday - Friday 8 am - 5 pm

1.5 Louisiana Department of Natural Resources (LADNR)

Louisiana Department of Natural Resources (LADNR)
Mailing Address:
Louisiana Department of Natural Resources Department of Natural Resources PO Box 94396 Baton Rouge, LA 70804-9396
Physical Location:
Louisiana Department of Natural Resources LaSalle Building 617 North Third Street Baton Rouge, LA 70802

1.6 Minnesota Office of Pipeline Safety (MNOPS)

Minnesota Office of Pipeline Safety (MNOPS)
Mailing Address:
Minnesota Office of Pipeline Safety 445 Minnesota Street Suite 147 St. Paul MN 55101
Physical Location:
Minnesota Office of Pipeline Safety 445 Minnesota Street Suite 147 St. Paul MN 55101
Telecommunications:
Phone: (651) 201-7230 *Fax:* (651) 296-9641 *Office Hours:* Monday - Friday 8 am - 4 pm

1.7 Mississippi Public Service Commission (MPUS)

Mississippi Public Service Commission (MPUS)
Mailing Address:
(Northern District: Jackson Office) Mississippi Public Utilities Services Woolfolk Building 501 North West Street Suite 201A Jackson, MS 39201 ***(Northern District: Nettleton Office)*** Mississippi Public Utilities Services 218 Main Street Nettleton, MS 38858 ***(Southern District: Biloxi Office)*** Mississippi Public Utilities Services 16516 Switzer Park Rd Biloxi, MS 39532-7420 ***(Southern District: Jackson Office)*** Mississippi Public Utilities Services 501 North West Street Suite 201A Jackson MS 39201
Telecommunications:
Phone: (xxx) xxx-xxxx *Fax:* (xxx) xxx-xxxx *Office Hours:* Monday - Friday 8 am - 4 pm

1.8 Ohio Public Utilities Commission (PUCO)

Ohio Public Utilities Commission (PUCO)
Mailing Address:
Ohio Public Utilities Commission 180 East Broad Street Columbus, Ohio 43215
Telecommunications:
Phone: (800) 686-7826 *Fax:* (614) 752-8351 *Office Hours:* Monday - Friday 8 am - 5 pm

1.9 Oklahoma Corporation Commission (OCC)

Oklahoma Corporation Commission (OCC)
Mailing Address:
Oklahoma Corporation Commission Pipeline Safety Division PO Box 52000 Oklahoma City, OK 73152-2000
Physical Location:
Oklahoma Corporation Commission 2101 North Lincoln Blvd. Oklahoma City, OK 73105
Telecommunications:
Phone: (405) 521-2211 or (405) 521-2331 *Fax:* (xxx) xxx-xxxx *Office Hours:* Monday - Friday 8 am - 4 pm

1.10 Texas Railroad Commission (TX RRC)

Texas Railroad Commission (TX RRC)
Mailing Address:
(Main Office) Texas Railroad Commission PO Box 12967 Austin, Texas 78711-2967 ***(Pipeline Safety Location: Houston)*** Texas Railroad Commission Pipeline Safety 1919 N Loop West Suite 620 Houston, TX 77008-3135
Physical Location:
(Main Office) Texas Railroad Commission 1701 N Congress Austin, Texas 78701
Telecommunications:
(Pipeline Safety Location: Houston) *Phone:* (713) 869-8425 *Fax:* (713) 869-3219 *Office Hours:* Monday - Friday 8 am - 4 pm

<<END>>

Storage Integrity Management Program

(SIMP)

2020.2

Contents

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

Review / Revision History

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

REVISION NUMBER	SECTION(S) IMPACTED	REVIEW / REVISION DATE	EFFECTIVE DATE
Original Version (2018.1)	See Detailed Revision History from Legacy Document for details	1/16/2018	1/18/2018
2018.2	See Audit Trail of Changes - v2018.1 to v2018.2 for details	4/26/2018	5/7/2018
2018.3	See Audit Trail of Changes - v2018.2 to v2018.3 for details	8/16/2018	8/22/2018
2018.4	See Audit Trail of Changes - v2018.3 to v2018.4 for details	10/3/2018	10/8/2018
2018.5	See Audit Trail of Changes - v2018.4 to v2018.5 for details	10/17/2018	10/22/2018

2019.1	See Audit Trail of Changes - v2018.5 to v2019.1 for details	4/9/2019	4/15/2019
2019.2	See Audit Trail of Changes - v2019.1 to v2019.2 for details	9/4/2019	9/12/2019
2020.1	See Audit Trail of Changes - v2019.2 to v2020.1 for details	1/27/2020	2/3/2020
2020.2	See Audit Trail of Changes - v2020.1 to v2020.2 for details	5/15/2020	6/1/2020

NOTE: Minor changes (e.g. typos, spacing, updated reference format, broken links, etc.) are not normally tracked in Audit Trails.

Detailed Revision History from Legacy Document

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

REVISION NUMBER	REVISION DATE	EFFECTIVE DATE	CHANGE DESCRIPTION	APPROVAL DATE
2018.1	1/16/2018	1/18/2018	Initial release	1/16/2018

Audit Trail of Changes - v2018.1 to v2018.2

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

This topic lists all the changes made to the previous version of the online content. There will be an Audit Trail for each new release of the online content. Audit Trails are intended to provide an ongoing audit trail of changes to the content since inception, primarily for training, review and verification, and auditing purposes.

Minor changes (e.g. typos, spacing, reformatting, updated reference format, broken links, etc.) are not normally tracked in the Audit Trails.

Global Changes:

- Updated the Review/Revision History topic to reflect the new version, with a link to this audit trail.
- Updated the version number and effective date in each topic.
- Created this Audit Trail topic to track changes from the previous (original) online content to this first revision.
- Fixed incorrect links as well as broken links resulting from changes.
- Revised links to new manuals that have come online since previous version.
- Applied new layout per software update plus reformatting/new styles as applicable.

Specific changes to topics:

The following topics have been updated for this release; click to view the specific changes made to each (new or updated text is shown in red; deleted or replaced text and/or sections are shown in ~~strikethrough~~ text).

SIMG-08-002 (new topic per CR# 618)

SIMP-04 Changes (per CR# 618)

SIMG-08-002 (new topic per CR# 618)

SIMG-08-002 Evaluating for Emergency Shutdown Valves

PURPOSE:	To establish a consistent process in evaluating natural gas storage wells to determine if an automatic or remote-actuated emergency shutdown valve would be an effective means of adding protection to the well and surrounding area.
REFERENCES:	49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference 49 CFR 192.12 “Underground Natural Gas Storage Facilities” Interim Final Rule, PHMSA Docket #2016-0016
TASK OVERVIEW:	1.0 Background 2.0 Risk Analysis 3.0 Documentation

Responsible Personnel	**Section**
Integrity Management Engineer	2.1, 3.1

Accountable Group	Integrity Management
Consulted, Informed	N/A

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016.

1.2 The purpose for the use of automatic or remote-actuated emergency shutdown valve in a well is to allow an operator to shut-in the well in the case of an emergency or wellhead damage.

1.2.1 These valves are designed to close in cases of loss of wellhead, loss of functionality of wellhead, or when surface conditions are present that endanger the wellhead from functioning properly.

1.2.2 Automatic valves close when pre-programmed conditions are detected.

1.2.3 Remote-actuated valves are typically programmed to alarm upon certain conditions but require operator intervention to signal the valve to close. This can improve response time and enhance safety of personnel who would otherwise have to manually close the valve.

1.2.4 Automatic or remote-actuated emergency shutdown valves may be located at the wellhead, side-gate, or subsurface.

1.3 The use of valve automation should be assessed as part of an overall risk analysis to be performed on a per-well basis. Refer to SIMG-03-002 Risk Process & Annual Review.

2.0 RISK ANALYSIS

2.1 Responsibility: Integrity Management Engineer

2.1.1 Perform a risk analysis of each natural gas storage well to determine if an automatic or remote-actuated valve would be an effective means of risk mitigation. Consider risk factors.

2.1.2 Evaluate the results of the analysis and determine if installing valves would be effective. If it is determined that installing valves would not be an effective means of adding protection to wells, no further action is necessary. Installing valves may not be warranted for the following scenarios.

- Added risk created by installation and servicing of automated valves/actuators

- Risk of vandalism/terrorism that impairs the operation of the automated valves/actuators
- Alternative protection measures in place that provide physical protection to wellhead

3.0 DOCUMENTATION

3.1 **Responsibility: I**ntegrity Management Engineer

3.1.1 Maintain documentation as needed.

SIMP-04 Changes (per CR# 618):

<replaced SIMPResponsibilityMatrix.png>

Audit Trail of Changes - v2018.2 to v2018.3

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

This topic lists all the changes made to the previous version of the online content. There will be an Audit Trail for each new release of the online content. Audit Trails are intended to provide an ongoing audit trail of changes to the content since inception, primarily for training, review and verification, and auditing purposes.

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Global Changes:

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Specific changes to topics:

The following topics have been updated for this release; click to view the specific changes made to each (new or updated text is shown in red; deleted or replaced text and/or sections are shown in ~~strikethrough~~ text).

SIMG-10-001 Changes (per CR# 1422):

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program ~~is being~~has been developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This recordkeeping procedure serves as a framework document within that program.

1.1.1 Records to be kept include the reservoir, individual wells, associated equipment and facilities. This program excludes gathering pipeline systems and associated equipment covered by the Transmission Integrity Management Program (TIMP).

~~1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.~~

~~1.2.1~~1.1.2 Recordkeeping will be updated as assets are added, modified, or removed from the Vectren system.

1.2 Vectren defines risk management records retention schedule and management plan and records retention period in the applicable procedures and in Exhibit 10-001-A – Gas Storage Recordkeeping. Risk management documentation can include data used during risk assessment, preventive and mitigative (P&M) measures employed, and periodic evaluation of performance metrics.

2.0 RECORDKEEPING AND MANAGEMENT

2.1 Records are maintained to document establishment of and compliance with procedures as required.

2.1.1 Records ~~may be~~are kept in an appropriate format (paper or electronic) as documented in Exhibit 10-001-A – Gas Storage Recordkeeping.

2.1.1.1 Electronic records are maintained in the following locations:

- Avocet: Primarily a system utilized by engineering and operations, Avocet typically manages routine or scheduled activities. Examples include but are not limited to reservoir performance data, some storage IM documentation, disposal well Mechanical Integrity Tests (MIT) and volumes, service company tickets, permits as well as other applicable reservoir trending metrics.
- G drive: A storage location for electronic reservoir and engineering data that is not associated to a specific well. This can include permits, geologic reports, annual reports, and white papers.
- Maximo: Includes valve maintenance records, cathodic protection readings, atmospheric corrosion inspection, and annual wellhead leak inspections.

2.1.1.2 Within the electronic and paper storage system, there is also Reservoir Engineering Library, or REL, which houses:

- Geologic records
- Gas quality records
- Reservoir trending metrics
- Records pertaining to the storage well that could be related to the storage reservoir and can also be found on Avocet.

2.1.1.3 Physical records are stored and maintained within Vault and/or REL, which contains land records and inspection records, such as well logging reports and IM forms (i.e., Work Plan Packet and Port Assessment Forms).

~~2.1.2 Records should include superseded procedures.~~

~~2.1.3 Refer to each procedure individually for additional documentation requirements.~~

2.2 Retention intervals for records were established to meet regulatory requirements. See Exhibit 10-001-A – Gas Storage Recordkeeping for retention intervals ~~W~~where no regulatory requirements exist~~, Vectren will define a retention interval~~.

2.2.1 Vectren maintains associated ~~records of~~ storage inventory ~~assessments~~ records for the life of the facility.

~~2.2.2 Vectren will develop a risk management records retention schedule and management plan and define the records retention period.~~

~~2.2.2.1 Risk management documentation can include data used during risk assessment, preventive and mitigative (P&M) measures employed, and periodic evaluation of performance metrics.~~

~~2.3 This documentation is subject to review during a jurisdictional audit.~~

...

7.0 TRAINING RECORDS

7.1 Vectren maintains records for Company personnel that demonstrate compliance with training. ~~Examples of~~ Documentation ~~are as follows~~may include:

- Identification of the trained individual
- Identification of the training and methodology of training provided
- Date(s) training was completed by the individual

7.2 Vectren will follow the Quality Management Program procedure QMP 7.0, Contractor Review Procedure.

8.0 PLANS AND PROCEDURES

8.1 Vectren maintains documentation of the Storage Integrity Management Program for the life of each Vectren asset.

- Written storage integrity management procedure(s)
- Documents supporting threat identification, risk factor determination~~,~~, and risk assessment, as applicable
- Documents supporting the development and implementation of ~~any decision, analysis, and process developed and used to implement and evaluate each element of~~ the Assessment Plan and Storage Integrity Management Program
- Establishment of and compliance with procedures that are verifiable, including superseded procedures

EXHIBIT 10-001-A – GAS STORAGE RECORDKEEPING

Document Population – All forms are used for decision-making. Retain three packets per well per assessment.

< inserted new SIMG-10-001 Exhibit A.png >

Audit Trail of Changes - v2018.3 to v2018.4

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

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Global Changes:

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Specific changes to topics:

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Section SIMG-06-005 Changes (per CR# 661):

4.0 SIGNAGE

4.1 Responsibility: Gas Storage & LP Operations Manager

4.1.1 Signage will be located at storage facilities, as applicable, per O&M 9.32.4, Damage Prevention/Facility Identification/Facility Signage~~may include the Security Operations Center (SOC) contact information for security discrepancy reporting~~.

Audit Trail of Changes - v2018.5 to v2019.1

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Section SIMG-05-004 Changes (per CR# 1533)

Appendix A Changes (per CR# 1533)

Section SIMG-05-004 Changes (per CR# 1533):

SIMG-05-004 Casing Remediation

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3.0 CASING REMEDIATION

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3.2.5 Perform remediation per applicable O&M procedure(s) ~~,~~and Work Instructions.~~, and Plant Equipment Manual (PEM).~~

3.2.6 Perform inspections to confirm remediation has resolved issues and no new issues have occurred. Refer to SIMG-04-003 Performing Integrity Assessments.

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Appendix A Changes (per CR# 1533):

Appendix A - Storage Integrity Management Program Support Documentation

This section contains links to the following documents, which support the Storage Integrity Management Program (SIMP):

- Gas Storage Integrity Management Team Charter
- Gas Storage Integrity Management Team Calendar
- Management of Change (MOC) Process
- Safety Management System (SMS) Framework
- Public Awareness Program (PAP)
- Well Control Emergency Response Plan
- ~~Gas Storage & LP Operations Plant Equipment Manual (PEM)~~

Audit Trail of Changes - v2018.4 to v2018.5

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

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SIMP-04 Changes (per CR#1446)

SIMG-04-003 Changes (per CR# 1446)

SIMP-04 Changes (per CR#1446):

<Replaced graphic>

SIMG-04-003 Changes (per CR# 1446):

SIMG-04-003 Performing Integrity Assessments

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Responsible Personnel	Section
Integrity Management Engineer	2.2, 3.1, 4.1, 5.1, 7.1, 8.1, 9.1
Gas Storage & LP Operations	2.1
Integrity Management	6.1
Integrity Management Field Inspector	5.2
Reservoir Engineering	7.1, 8.1

...

7.0 REVIEW OF FINAL REPORT

7.1 Responsibility: Integrity Management Engineer, Reservoir Engineering

7.1.1 Verify the Contractor provides data as required in the request for proposal (RFP).

7.1.1.1 Verify viewing software is provided if it is required for viewing.

7.1.2 Send copy of final report to Reservoir Engineer.

7.1.3 Perform a preliminary review of the final report.

7.1.4 Document the date the final report is received/accepted.

8.0 POST-ASSESSMENT

8.1 Responsibility: Integrity Management Engineer, Reservoir Engineering

8.1.1 Evaluate the results of the inspection.

...

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SIMG-10-001 Changes (per CR# 1613)

SIMG-13-001 Changes (per CR# 1613)

SIMG-10-001 Changes (per CR# 1613):

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Responsible Personnel	Section
Integrity Management Engineering Manager	2.0 – 8.0
Gas Storage & LP Operations Manager	2.0 – 7.0
Gas Transmission Engineering Manager	2.0 – 7.0
Technical Training Supervisor	7.1
Quality Management Specialist	7.2
Reservoir Engineering Manager	2.0 – 7.0

Accountable Group	Integrity Management
Consulted, Informed	~~Codes and Standards~~SMS Management of Change

...

SIMG-13-001 Changes (per CR# 1613):

...

Responsible Personnel	Section
Gas Storage & LP Operations	2.1

SMS Management of Change~~Codes and Standards~~ Manager	2.2
Damage Prevention and Public Awareness Manager	3.1
Gas Storage & LP Operations Manager	4.1

Accountable Group	Integrity Management
Consulted, Informed	Gas Supply Gas Engineering Gas Control Integrity Management Reservoir Engineering

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2.2 Responsibility: SMS Management of Change~~Codes and Standards~~ Manager

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Audit Trail of Changes - v2019.2 to v2020.1

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SIMP-02 Changes (per MOCR# 1885)

SIMG-14-002 Changes (per MOCR# 1885)

SIMP-02 Changes (per MOCR# 1885):

Orifice Plate Bore Diameter	Measured diameter (dr) is defined as the mean (arithmetic average) of four or more evenly spaced diameter measurements at the inlet edge. For tolerance, see AGA Report 3.
~~PEM~~	~~Plant Equipment Manual~~
...	

...

SIMG-14-002 Changes (per MOCR# 1885):

1.0 BACKGROUND

1.1 ~~A formal~~ The Storage Integrity Management Program is in compliance with~~being developed to meet~~ the requirements of API 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This hydrogen sulfide safety communication procedure serves as a framework document within that program.

...

2.2 Responsibility: Gas Storage & LP Operations

2.2.1 Conduct test in line with the plan communicated by Reservoir Engineering~~ and per Gas Storage & LP Operations Plant Equipment Manual [Section 1.30 Working around Hydrogen Sulfide (H2S)]~~.

2.2.2 All personnel working around wells or equipment where H2S is known to be present or may be present must be trained in advance on the hazards of working around H2S.

2.2.3~~2~~ Use appropriate personal protective equipment (PPE) during testing. See the Corporate Safety Manual.

2.2.4~~3~~ Ensure proper ventilation is at the test location to prevent gas accumulation in the work area.

2.2.5~~4~~ Document and report ~~findings~~ test results to Reservoir Engineering.

...

3.2 Responsibility: Gas Transmission Engineering or Gas Storage & LP Operations as applicable depending on type of work

...

Audit Trail of Changes - v2020.1 to v2020.2

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

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SIMG-04-004 Changes (per MOCR# 1939)

SIMG-13-001 Changes (per MOCR# 1939)

SIMG-04-004 Changes (per MOCR# 1939):

4.0 ASSESSMENT PACKET

4.1.4 Create an assessment packet. Include the following items, as applicable:

- Blank forms to be completed during tool runs if not available electronically.
- Daily log
    - o Site conditions
    - o Personnel on site
    - o Description of any significant events and work completed
- Copy of applicable O&M procedures to reference during the tool runs.

- Communication list of internal and external project stakeholders to update on the progress of the well inspection.
  - Vectren personnel
  - Contractor(s)
- Copy of applicable Well Control Emergency Response Plan, which covers abnormal operating conditions
- Copy of Corporate Response Plan~~Gas and Electric Crisis Communication Plan~~
- Well-specific work plan and applicable permits

...

SIMG-13-001 Changes (per MOCR# 1939):

4.0 EMERGENCY COMMUNICATIONS

4.1 Responsibility: Gas Storage & LP Operations Manager

4.1.1 Refer to the Well Control Emergency Response Plan and Corporate Response Plan~~Gas and Electric Crisis Communication Plan~~.

SIMP-01 Introduction

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

Introduction

Vectren Energy Delivery of Indiana, Inc., VEDI, has established a Storage Integrity Management Program, pursuant to API Recommended Practice 1171, and as required by the Pipeline Hazardous Materials Safety Administration.

Program Structure

VEDI's Storage Integrity Management Program (SIMP) includes within its scope work performed by four VEDI departments:

- Gas Storage Integrity Management
- Reservoir Engineering
- Gas Transmission Engineering
- Gas Storage & LP Operations

Responsibilities

The responsibilities of the four VEDI departments are shown in the Responsibility Matrix (see SIMP-04 Responsibility Matrix).

Governance and Oversight

Consistent with the governance structures already in place for other gas compliance teams within VEDI, the SIMP has the following governance:

Gas Storage Integrity Management Team, comprised of one representative from each of the departments:

- Gas Storage Integrity Management
- Reservoir Engineering
- Gas Transmission Engineering
- Gas Storage & LP Operations

The Gas Storage Integrity Management Team meets monthly to perform program-related duties, including, for example, the following:

- Reviews of Program processes, as necessary
- Annual Reviews of Program documents
- Other duties including reports of the Team's work to the SMS Technical Governance Group

Leadership of the Gas Storage Integrity Management Team rotates among the departments represented on the Team.

To the extent that any of the Gas Storage Integrity Management Team departments engage contractors to perform work in Vectren Storage Fields, those contractors shall comply with the terms of their contracts. All contractors, including contractors performing work in Vectren Storage Fields, are subject to oversight by the Vectren Contractor Compliance Committee, and are subject to periodic reviews conducted by Vectren's QMP team. Reports from both the Contractor Compliance Committee and the QMP team are reviewed by the SMS Technical Governance Group.

SIMP-02 Definitions

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

TERM	DEFINITION
Average Monthly Volume	Average of previous 12 months' volumes. To be recalculated every year.
Bailer	A downhole device, usually run on *slickline*, used to remove fluid or debris from the bottom of the *wellbore*. In operation, an atmospheric chamber within the tool is opened to create a surge of fluids into the chamber. Fluid is then held within the chamber for recovery at surface.

Beta Ratio	Orifice bore size divided by meter tube I.D. Tolerance limits between 0.2 – 0.6. Initiate waiver process if a beta ratio is required outside of the tolerance limits.
Biocide	Any chemical that destroys life by poisoning, especially a pesticide, herbicide, or fungicide. For the purpose of this procedure, the term will refer to specialized chemicals designed to kill off anaerobic bacteria and only used by Vectren through direct batch treating at the individual wells or injection into the field lines.
BOP	Blowout preventer. An assembly at the wellhead that can be closed if gas or fluids begin to flow in an uncontrolled manner from the well.
Brine	Water containing salts in a solution, commonly produced along with natural gas from storage field wells.
Buffer Zone	Area of reservoir monitored for pressure changes. This zone often shows a time-delayed pressure response.
Caprock (or Cap Rock)	A layer of low permeability rock directly above the gas bearing formation. The caprock contains the gas bubble and prevents it from migrating upwards.
Class II Well	US EPA classification of an injection well used only to inject fluids associated with oil and natural gas production.
Collector Zone	Monitoring wells located in collector zones are used to evaluate well integrity. Analysis of gas pressure or liquid levels can reveal a compromised well.
Compressibility Factor (Z)	The ratio of a real gas's volume to that of an ideal gas. Used to more accurately model the behavior of gases.
Corrosion Inhibitor	A chemical compound that, when added to a liquid or gas, decreases the corrosion rate of a material, typically a metal or an alloy. The effectiveness of a corrosion inhibitor depends on fluid composition, quantity of water, and flow regime. A common mechanism for inhibiting corrosion involves formation of a coating, often a passivation layer, which prevents access of the corrosive substance to the metal.
Delta Pressure	The difference between maximum reservoir gas pressure and discovery pressure.
Depth Reference	The point in a well from which depth is measured. The depth reference corresponds to zero depth on well logs.
Discovery Pressure	The pressure of the gas bearing formation before development into a storage field. Also known as native pressure.
Diverter	A chemical agent that blocks the travel of acid. It is used the cover the most permeable or least damaged portions of a formation and guide acid into the areas that require treatment. It can be effectively washed away after treatment.
Dual Chamber Fitting	An *orifice plate* fitting that allows the plate to be removed under flowing conditions.
Formation Fracture Pressure	The pressure above which injection of fluids will cause the formation to fracture hydraulically.
Fracture	When the tensile strength of formation rock is exceeded and cracks in the rock begin to develop.
Fracture Gradient	The pressure required to induce fractures with respect to depth. Fracture pressure increases with depth due to the addition of hydrostatic and overburden pressures.
Fracturing Fluid	A fluid pumped into a well at high pressure to induce fractures in reservoir

	rock. The fluid is comprised mostly of water but may be mixed with *proppant*, lubricants, thickeners, and other materials.
Gravimetry	The measurement of the local gravitational force to determine the density of subsurface layers.
Hand Pump	Device used to flow gas through *stain tube* at a known volume for each pump stroke.
IADC	International Association of Drilling Contractors
Ideal Gas Law	An equation modeling a hypothetical gas (or “ideal gas”) that relates pressure, temperature, volume, and the amount of gas.
Keywell (or Shut-In Well)	A single well selected to provide representative reservoir pressure. A combination of wells and a mathematical weighting system can also be used to represent the *reservoir pressure*.
Material Balance Analysis (MBA)	The analysis of reservoir measurements to relate flow of gas into or out of a reservoir to the change in reservoir pressure. Useful for determining inventory, *water drive* mechanisms, and gas loss.
MEA	Monoethanolamine. A liquid organic compound. Mixed with fluids to increase pH (neutralize acid).
Methanol	A colorless, toxic, flammable liquid, CH_3OH, used as an antifreeze, a general solvent, a fuel, and a denaturant for ethyl alcohol. Also called carbinol, methyl alcohol, wood alcohol, wood spirits.
Microorganism	A microscopic organism, especially a bacterium, virus, or fungus.
MIT	Mechanical Integrity Test. Procedure that obtains data that demonstrates if a well is mechanically fit for service and capable of storing natural gas within design limitations.
Necrosis	The death of most or all of the cells in an organ or tissue due to disease, injury, or failure of the blood supply.
Orifice Fitting	A pressure-containing piping element used to contain and position the orifice plate in the piping system.
Orifice Meter	A flow-measuring device that produces a differential pressure to infer flow rate. The meter consists of a thin, concentric, square edged or beveled orifice plate, an orifice plate holder consisting of a set of orifice flanges (or orifice fitting) equipped with the appropriate differential pressure sensing taps, a meter tube consisting of the adjacent piping sections (with or without flow conditioners). See AGA Report 3.
Orifice Plate	A thin plate in which a circular concentric aperture (bore) has been machined.
Orifice Plate Bore Diameter	Measured diameter (dr) is defined as the mean (arithmetic average) of four or more evenly spaced diameter measurements at the inlet edge. For tolerance, see AGA Report 3.
Plate Bevel	Bevel angle is defined as the angle between the bevel and the downstream face of the plate. The allowable value for the plate bevel angle is 45 degrees + or – 15 degrees.
Plate Bore Edge	The upstream edge of the orifice plate bore shall be square and sharp. The orifice plate bore edge is considered too dull for accurate flow measurement if the upstream edge reflects a beam of light when viewed without magnification or if the upstream edge shows a beam of light when checked with an orifice edge gauge. Reference AGA Report 3.
Plate Bore Thickness	The inside surface of the orifice plate bore shall be in the form of a constant-diameter cylinder having no defects, such as grooves, ridges, pits, or lumps, visible to the naked eye. The length of the cylinder is the

	orifice plate bore thickness (e). Minimum allowable e ≤ 0.02 dr or e ≤ 0.125 dr, whichever is smaller, but shall not be greater than the maximum allowable orifice plate thickness (e). Reference AGA Report 3.
Plate Flatness	Deviations from flatness on the orifice plate of less than or equal to 1% of dam height (that is, 0.010 inch per inch of dam height) under non-flowing conditions are allowed. The dam height can be calculated from the formula (Dm-dm)/2. This criterion for flatness applies to any two points on the orifice plate within the dimensions of the inside diameter of the pipe. Reference AGA Report 3.
Plate Roughness	The surface roughness of the upstream and downstream faces of the orifice plate shall have no abrasions or scratches visible to the naked eye that exceed 50 micron-inches (Ra.) Reference AGA Report 3.
Plate Thickness	The minimum, maximum and recommended values of orifice plate thickness (e) for types 304 and 316 stainless steel orifice plates are given in AGA Report 3.
Primary Element	Consists of meter tube sections, orifice fitting or plate holder, orifice plate, flow conditioner, and tap holes.
Proppant	Particulate mixed with fracturing fluid to hold open fractures. Proppant can range from sand to engineered materials.
Reservoir Pressure	A measure of the static fluid pressure of a hydrocarbon storage formation. The measurement is usually recording using a bottom hole pressure (BHP) sensing device in a shut-in injection/withdrawal well or an observation well that is selected to best represent the reservoir.
Scale	A deposit or coating that forms on a metal or rock surface. Typically composed of calcium carbonate or any number of compounds insoluble or slightly soluble in water.
Seismology	The use of seismic waves to estimate subsurface geology. Waves can be generated with vibrating machines or explosive charges. Recording devices measure the waves that are reflected and refracted back to the surface.
Shut-In Well	See *Keywell*.
Single Chamber Fitting	An orifice plate fitting that requires the operator to bypass the meter tube or block and relieve the pressure from the tube to remove the orifice plate.
Slickline	Similar to *wireline* but referring specifically to the use of a thin, single strand, non-electric cable.
Spill Point Observation	Shows pressure and/or water levels to monitor the expansion and contraction of the gas bubble at the limits of the reservoir structural trap.
Stain Tube	Used for measuring hydrogen sulfide. A sealed glass tube filled with a substance that changes color in proportion to its exposure to a specific chemical.
Subsurface Safety Valves (SSV)	Emergency fail-safe valves. They are designed to stop the flow of gas in a well in the event of catastrophic wellhead failure such as third-party damage to the wellhead or fires.
Surface-Controlled SSVs	Subsurface safety valves that are controlled from the surface by hydraulic pressure. Operate as a failsafe device and will close when pressure is lost in the control line. Can be in installed on wireline or tubing conveyed valves.
Subsurface-Controlled SSVs	Subsurface safety valves that are operated based on a differential pressure. A set pressure is determined and the valve closes when this

	pressure is exceeded. Flow is restricted by a choke bean, which is a short hard tube within the subsurface valve configuration. These valves will not operate in a low-flow condition if the gas and/or liquid flow is less than the present production level. Normal production is restricted below the wells maximum capability.
Tap Holes	Holes drilled radially in the orifice fitting or orifice flanges. Meter tubes using flange taps shall have the center of the upstream pressure tap hole placed 1 inch form the upstream face of the orifice plate. The center of the downstream pressure tap hole shall be 1 inch from the downstream face of the orifice plate.
Threshold Pressure	The pressure at which a gas begins to pass through a liquid saturated medium (such as porous rock).
Tubing-Conveyed SSVs	Subsurface safety valves that are installed as part of the tubing system, typically during well completion. Internal diameter is essentially the same as the tubing string. This minimizes flow disruption. Since the diameter is the full diameter of the tubing, tools and instruments for flow control can be lowered through the SSV. This is the most common SSV used.
Water Drive	The tendency of water in aquifer storage fields to press against the gas bubble and flow inward as gas is withdrawn. Water drive also opposes gas bubble expansion as gas is injected.
Wellbore	The drilled hole portion of the well, including any uncased portions.
Wireline	An electrical cable for lowering or raising tools in a well; an operation where tools are lowered into a well using an electrical cable.
Wireline SSV	Subsurface safety valves that can be used as a primary valve or used as a repair option to a tubing-conveyed SSV. These valves allow for large tubing sizes to be used, are historically cheaper SSVs, and can be pulled independently from the tubing string in order to make repairs.

SIMP-03 References

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

49 Code of Federal Regulations 192.7 incorporating API Recommended Practice 1171	"Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference
49 Code of Federal Regulations 192.12	"Underground Natural Gas Storage Facilities"
Interim Final Rule	PHMSA Docket #2016-0016
312 Indiana Administrative Code 16-3-2	"Permit applications"
312 Indiana Administrative Code 16-5-6	"Protection of underground storage reservoirs of petroleum products"

312 Indiana Administrative Code 16-5-15	"Mechanical Integrity"
312 Indiana Administrative Code 16-5-18	"Monitoring and reporting requirements for Class II wells"
312 Indiana Administrative Code 16-5-19	"Plugging and abandoning wells"
312 Indiana Administrative Code 16-5-22	"Spill containment"
312 Indiana Administrative Code 16-5-23	"Spill reporting"
312 Indiana Administrative Code 16-5-24	"Spill cleanup"
312 Indiana Administrative Code 16-5-25	"Remediation of soils contaminated with oil"
312 Indiana Administrative Code 16-5-26	"Remediation of soils contaminated with saltwater"
312 Indiana Administrative Code 16-5-27	"Disposal"
312 Indiana Administrative Code 16-5-28	"Monitoring"
312 Indiana Administrative Code 16-5-29	"Reporting"
327 Indiana Administrative Code 8	"Public Water Supply"
40 Code of Federal Regulations 124	"Procedures for Decisionmaking"
40 Code of Federal Regulations 144	"Underground Injection Control Program"
40 Code of Federal Regulations 146	"Underground Injection Control Program: Criteria and Standards"
40 Code of Federal Regulations 147	"State, Tribal, and EPA-Administered Underground Injection Control Programs"
49 Code of Federal Regulations 191.7	"Addressee for Written Reports"
49 Code of Federal Regulations 191.17	"Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Annual Report"
49 Code of Federal Regulations 191.22	"National Registry of Pipeline and LNG Operators"
49 Code of Federal Regulations 192	"Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards"
49 Code of Federal Regulations 192.605	"Procedural Manual for Operations, Maintenance, and Emergencies"
AGA Report 3	"Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids"
API Bulletin E3	"Well Abandonment and Inactive Well Practices for U.S. Exploration and Productions Operations, Environmental Guidance Document"
API Guidance Document HF1	"Hydraulic Fracturing Operations – Well

	Construction and Integrity Guidelines”
API Guidance Document HF2	“Water Management Associated with Hydraulic Fracturing”
API Guidance Document HF3	“Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing”
API Manual of Petroleum Measurement Standards 14.3	“Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids”
API Recommended Practice 49	“Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide”
API Recommended Practice 51R	“Environmental Protection for Onshore Oil and Gas Production Operations and Leases”
API Recommended Practice 53	“Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells”
API Recommended Practice 54	“Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations”
API Recommended Practice 76	“Contractor Safety Management for Oil and Gas Drilling and Production Operations”
API Specification 10A	“Specification for Cements and Materials for Well Cementing”
API Specification 11D1	“Packers and Bridge Plugs"
API Specification 6A	“Specification for Wellhead and Christmas Tree Equipment”
API Technical Report 10TR1	“Cement Sheath Evaluation”
API Technical Report 5C3	“Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing”, First Edition
ASTM C150/C150M	“Standard Specification for Portland Cement”
ASTM D4810	“Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detection Tubes”
Indiana Code (IC) 14-37-8	“Plugging and Abandonment”

Storage Integrity Management Program Responsibility Matrix

	Responsibilities																									
Procedure	Codes and Standards Manager	Compliance Director	Corporate Security	Corrosion Control	Damage Prevention and Public Awareness Manager	Environmental Affairs	Environmental Department	Gas Compliance	Gas Storage & LP Operations	Gas Storage & LP Operations Manager	Gas System Integrity Director	Gas Transmission Engineer	Gas Transmission Engineering	Gas Transmission Engineering Manager	Integrity Management	Integrity Management Engineer	Integrity Management Engineering Manager	Integrity Management Field Inspector	Land Services	Reservoir Engineer	Reservoir Engineering	Reservoir Engineering Manager	Safety Management System	Storage & LP Operations Supervisor	Technical Training	Technical Training Supervisor
GES 14.1 Geological Mapping																				X	X					
GES 14.2 Wireline Logging									X												X					
GES 14.3 Material Balance Analysis																					X					
GES 14.4 Delta Pressure															X						X					
GES 14.5 Shut-In Test																					X			X		
GES 14.6 Flow Test															X						X			X		
GES 14.7 Convert to Observation Well									X							X					X					
GES 14.8 Adjust Injection/Withdrawal Rates									X												X					
GES 14.9 Reservoir Analysis and Trending																X				X						
GES 14.10 New Reservoir Design																					X					
GES 14.11 Horizontal and Verical Buffer Zones																					X					
GTEDM 55.0 SF-01 New Storage Well Design													X													
GTEDM 56.0 SF-02 Permitting							X					X	X			X			X	X						
GTEDM 57.0 SF-03 Well Drilling and Completions												X									X					
GTEDM 58.0 SF-04 Well Plugging and Abandonment									X				X							X						
MOC															X								X			
O&M 44.32.1 Assessment Work Plan (Field)									X											X						
O&M 44.32.2 Casing Pressure Test									X							X										
O&M 44.33.1 Casing Remediation									X				X			X										
O&M 44.33.2 Tubing and Packer Remediation									X							X					X					
O&M 44.33.3 Cement Squeeze									X											X						
O&M 44.33.4 Inspect and Repair Subsurface Safety Valve									X															X		
O&M 44.34.1 Annular Pressure Check									X																	
O&M 44.35.1 Biocide or Inhibitor Injection									X												X					
O&M 44.35.2 Use of Methanol to Inhibit Formation of Hydrates									X												X					
O&M 44.36.1 Third-Party Drilling									X										X		X					
O&M 44.37.1 Water Disposal									X				X								X					
O&M 44.37.2 Well Acidizing																					X			X		
O&M 44.37.3 Well Fracturing									X												X					
O&M 44.37.4 Well Perforating									X												X					
O&M 44.37.5 Well Kill									X											X						
O&M 44.37.6 Environmental and Safety Considerations									X				X													
SIMG-01-001 Asset Identification																X				X	X					
SIMG-03-001 Threat/Hazard Identification											X					X	X									
SIMG-03-002 Risk Process & Annual Review																X	X									
SIMG-04-001 Prioritization of Casing Inspections																X	X									
SIMG-04-002 Inspection Method Selection																X	X									
SIMG-04-003 Performing Integrity Assessments									X						X	X		X			X					
SIMG-04-004 Assessment Work Plan						X		X	X							X	X	X								
SIMG-05-001 Requirements to Address Conditions									X				X			X	X			X						
SIMG-05-004 Casing Remediation									X				X			X		X								
SIMG-05-006 Plug & Abandonment																X				X						
SIMG-06-001 Periodic Monitoring				X					X							X					X					
SIMG-06-004 Corrosion Monitoring				X					X							X										
SIMG-06-005 Site Security			X						X	X			X			X										
SIMG-08-001 P&M Selection and Review																X									X	
SIMG-08-002 Evaluating for Emergency Shutdown Valves																X										
SIMG-09-001 Effectiveness Evaluation																X	X									
SIMG-10-001 Recordkeeping										X				X			X					X				X
SIMG-12-002 Training Requirements													X				X				X			X	X	
SIMG-13-001 Communications	X				X					X																
SIMG-13-002 Required Notifications		X									X						X									
SIMG-14-001 Environmental & Safety Considerations													X													
SIMG-14-002 H2S Hazard Communication									X				X			X					X					

This list can be filtered, sorted, etc., by opening the Excel file at this link.

In addition to Storage Integrity Management Procedures, the Storage Integrity Management Program encompasses the following types of procedures:

- Operational procedures are included in the Operations & Maintenance Plan (see O&M 44.0, *Underground Storage*).
- Reservoir procedures are stored the Gas Engineering Standards (see GES 14.0, *Reservoir*).
- Design procedures related to gas storage facilities are part of the Gas Transmission Engineering Design Manual (GTEDM) in the Storage Fields section.

These procedures are listed below. See Appendix A - Storage Integrity Management Program Support Documentation for additional support documentation.

STORAGE INTEGRITY MANAGEMENT PROCEDURES

OPERATIONS & MAINTENANCE UNDERGROUND STORAGE PROCEDURES

GAS ENGINEERING STANDARDS RESERVOIR PROCEDURES

GES 14.9, *Reservoir/Reservoir Analysis and Trending*

GES 14.10, *Reservoir/New Reservoir Design*

GES 14.11, *Reservoir/Horizontal and Vertical Buffer Zones*

GAS TRANSMISSION ENGINEERING DESIGN MANUAL STORAGE FIELDS PROCEDURES

GTEDM 55.0, *Storage Fields/SF-01 New Storage Well Design*

GTEDM 56.0, *Storage Fields/SF-02 Permitting*

GTEDM 57.0, *Storage Fields/SF-03 Well Drilling and Completions*

GTEDM 58.0, *Storage Fields/SF-04 Well Plugging and Abandonment*

SIMG-01-001 Asset Identification

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method to create and maintain a thorough, accurate, and complete inventory of gas storage assets

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

49 CFR 192.605 "Procedural Manual for Operations, Maintenance, and Emergencies"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Asset Identification
3.0 Reservoir Characterization
4.0 Well Characterization
5.0 Records

Responsible Personnel	Section
Reservoir Engineering	2.1, 2.2
Reservoir Engineer	3.1

Integrity Management Engineer	3.2, 4.1, 5.1

Accountable Group	Integrity Management
Consulted, Informed	N/A

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This Asset Identification procedure serves as a framework document within that program.

1.1.1 Storage field assets include the reservoir, individual wells, associated equipment and facilities. This program excludes gathering pipeline systems and associated equipment covered by Transmission Integrity Management Program (TIMP).

1.1.2 Well and reservoir characterization will be based on completion data and reservoir data.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.2.1 This asset information will be the foundation for future evaluations as well as trending analyses.

1.2.2 Asset information will be updated as assets are added, modified, or removed from the Vectren system.

2.0 ASSET IDENTIFICATION

2.1 **Responsibility**: Reservoir Engineering

2.1.1 Identify and characterize Vectren's storage field assets, including but not limited to:

- Injection/withdrawal wells
- Observation wells
- Disposal wells
- Gathering pipelines and appurtenances not included in TIMP
- Processing equipment not included in TIMP
- Physical facilities not included in TIMP

2.1.2 Gather data necessary to maintain a well map for each storage field. This includes but is not limited to the following information, if available:

- Location
- Well type – injection/withdrawal, observation, disposal
- Status – active, plugged and abandoned
- Reservoir detail – formation, *caprock*, structural contours/isopach

- Construction completion details – depth, casing depth(s), cement, valves

2.1.3 Gather data from TIMP and other resources necessary to create and maintain schematic drawings of each storage field's gathering system and associated facilities. This includes the following information, if available:

- Well location and type
- Gathering lines with nominal sizes, reducers, tees (barred for pigging), wyes, radii of bends/elbows and their respective locations
- Mainline valves, Isolation valves
- Processing equipment such as filter-separators, dehydration, compressors, etc.
- Metering points
- Pigging facilities
- Cathodic Protection (CP) system
- Drips
- Pipeline casing and vents
- Blow down risers

2.2 **Responsibility**: Reservoir Engineering

2.2.1 Maintain a well map for each storage field using asset information provided.

2.2.2 Create and maintain schematic drawings of each storage field's gathering system and associated facilities using asset information provided.

3.0 RESERVOIR CHARACTERIZATION

3.1 **Responsibility**: Reservoir Engineer

3.1.1 Review records for existing and abandoned wells that penetrate the formations being characterized.

3.1.1.1 For existing reservoirs, data collection may be limited to historical records which could be supplemented if/when new wells are developed within the reservoir.

3.1.1.2 Reservoir analyses performed at the time of field development may be used and supplemented with data covering the life span of the field from initial development through current operation. Data sources to be used when available include but are not limited to:

- Historical well performance
- Prior gas storage operational records
- Completion and production records
- Vertically and laterally offset well completion, stimulation, and production operation records
- Drilling data and logs
- Fluid samples

- Cores and cuttings from both hydrocarbon and water wells
- Survey data such as seismic, gravity, and/or magnetic surveys

3.1.2 **Mapping:** Maintain a geologic map and analysis for each storage field.

3.1.2.1 Conduct an evaluation of the extent and properties of the porous rock interval, or reservoir encompassing the reservoir itself, adjacent areas, and other applicable features such as:

- Reservoir/geologic data
    - Reservoir rock and sealing mechanism(s)
    - Lithology
    - Geo-mechanical competency
    - Porosity
    - Permeability
    - Homogeneity/ Isotropy
    - Residual pore fluid saturation
    - Vertical interval above and below the reservoir
    - Areas where gas could potentially migrate (i.e., saddles, faults, etc.)
    - Areas adjacent to the reservoir to which gas could migrate or become entrapped
    - Basal and lateral sealing mechanisms for controlling movement of stored gas
    - Competent and impermeable caprock, located above the intended gas-filled reservoir
    - Anomalous geological features (i.e., faulting, folding, natural fracturing, and unconformities)
- Well data
    - Locations
    - Status – active/abandoned,
    - Type – injection/withdrawal/wastewater disposal
- Groundwater depth
- Surface features
    - Surface topography and land use, as applicable
    - Surface water locations

3.1.3 Use geologic characterization to establish or reconfirm the vertical and areal *buffer zone* necessary to protect integrity and maintain performance of the storage field. The scope of the geologic assessment includes but is not limited to:

- Extent of the porous rock interval (reservoir)

- Properties of the porous rock
- Confinement/sealing mechanisms used to contain hydrocarbon accumulation
- Properties of the cap rock
- Characterization of the structural trap

3.1.4 As new data becomes available, review and update characterizations and mapping.

3.1.5 **Pore Fluid Analysis:** Review and/or characterize the pore fluid chemistry data for each active storage field reservoir.

3.1.5.1 Incorporate historical records including but not limited to reservoir development studies, drilling completion records (vertical and/or offset wells), and well stimulation records.

3.1.5.2 Consider the following properties of the pore fluids when available:

- Chemical properties – review for compatibility issues, impurities which could affect gas quality (i.e., above tariff limits)
- Physical properties
- Corrosive potential of fluids
- Drilling or treatment chemicals used (or anticipated to be used) – review for mineralogical and compatibility issues
- Initial and current reservoir pressures

3.1.6 **Reservoir Pressures and Containment:** Retain a documented design basis for maximum *reservoir pressure*.

3.1.6.1 Data acquired is used to reduce or minimize the uncertainties identified by the geologic and engineering reservoir characterization.

3.1.7 Account for the impacts of the intended minimum reservoir pressure.

3.1.7.1 Minimum reservoir pressure determination can utilize supplemental well drilling, coring, and/or laboratory analyses where necessary.

3.1.8 Perform a regional review of the geologic characterization as it relates to geo-mechanical stress, reservoir influx, surface facility gas cleaning and liquid handling, and liquid disposal.

3.1.8.1 These factors affect the maximum cycling capacity of the storage field and may impact mechanical integrity of the facilities.

3.1.9 Evaluate existing well completions for containment assurance by reviewing operation volumes, pressures, and flow rates.

3.1.9.1 Where connectivity with another porous zone is indicated, include mitigation methods in place such as gas migration control, gas recovery, zonal control, pressure limitations, and expansion of the reservoir buffer zone.

3.1.10 Evaluate data collected and reviewed for containment analysis to determine the need for supplemental data gathering.

3.1.10.1 Supplemental evaluations for containment assurance may include:

- Well drilling, logging, and coring of the reservoir, caprock, basal rock, or lateral seals
- Potential extent of the aquifer and its potential or probable influence
- Water pump testing and water level observation
- Site-specific geophysical delineation, including drilling of test wells and observation wells, and identification of reservoir closure, spill points, or vertical containment

3.1.11 **Operational Data Review:** Evaluate operational data from existing storage fields to determine interaction between the storage operation and the rock-fluid system of the reservoir as well as indications of possible mechanical integrity issues at existing wells.

3.1.11.1 Periodically review the following:

- Initial versus current reservoir pressure
- Instances of anomalous pressures or anomalous hydrocarbons
- Water well test data – baseline groundwater data versus current
- Individual well flow rates, pressures, and fluid volumes

3.1.12 Document results of the evaluations described above.

3.2 **Responsibility**: Integrity Management Engineer

3.2.1 **Mapping:** Maintain a geologic map and analysis for each storage field.

3.2.1.1 Evaluate surface feature(s), such as mining or other industrial activities, encompassing the reservoir itself or adjacent areas.

3.2.2 **Pore Fluid Analysis:** Review and/or characterize the pore fluid chemistry data for each active storage field reservoir.

3.2.2.1 Determine corrosion management strategy, as applicable, for potential corrosive pore fluids.

3.2.3 **Mechanical Integrity Review:** Review existing *wellbore* and wellhead records to evaluate their current mechanical integrity.

3.2.3.1 Additional testing/monitoring or data gathering may be performed, if applicable.

3.2.3.2 If results of this reservoir characterization indicate potential mechanical integrity issues or other potential threats, further investigation or mitigation may be undertaken.

3.2.4 Document results of the evaluations described above.

4.0 WELL CHARACTERIZATION

4.1 **Responsibility**: Integrity Management Engineer

4.1.1 Once asset records have been collected and compiled, conduct a thorough review to characterize each well.

4.1.1.1 The intent of this review is to make a preliminary assessment of mechanical integrity, verify suitability for intended design, and protection of reservoir integrity.

4.1.1.2 Items for each well include:

- Casing – materials, configuration, set depths, integrity
- Cement – materials, placement depth, surface return notes, quality
- Pressure rating of ancillary pressure control equipment

4.1.1.3 For plugged and abandoned wells, address plugging practices used to determine whether plugging method was sufficient to prevent migration. Factors to be considered include but are not limited to:

- Plugging materials
- Plug placement

4.1.1.4 Characterization of wells may be prioritized based on preliminary risk data as outlined in SIMG-03-001 Threat/Hazard Identification.

4.1.2 Identify wells that may require integrity testing and/or well logging in order to meet the integrity demonstration requirements of API Recommended Practice 1171, Section 7.2.

4.1.2.1 Selected plugged wells may be re-entered, examined, and replugged or monitored to manage identified containment assurance issues.

5.0 RECORDS

5.1 **Responsibility**: Integrity Management Engineer

5.1.1 Maintain pertinent records and key information in electronic format to ensure accessibility of information.

5.1.1.1 Where possible, Vectren will rely on records that are traceable, verifiable, and complete (TVC).

5.1.1.2 In the absence of TVC records, the asset may be characterized using available records and reasonable engineering assumptions.

SIMG-03-001 Threat/Hazard Identification

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To identify potential threats/hazards and consequences that could impact Vectren storage field assets.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

49 CFR 192.605 "Procedural Manual for Operations, Maintenance, and Emergencies"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	5.1, 6.1, 6.3
Integrity Management Engineering Manager	6.2
Gas System Integrity Director	6.2

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineering Subject Matter Experts Gas Storage & LP Operations Integrity Management Engineering Manager Gas System Integrity Director

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice (RP) 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This Threat/Hazard Identification serves as a framework document within that program.

1.1.1 Threats and hazards are to be identified and analyzed in order to develop the risk analysis process.

1.1.2 The identified threats/hazards are to be sorted into three categories of well threats, reservoir threats, and surface threats.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.2.1 Vectren has utilized criteria from API RP 1171 to identify threats/hazards that are to be the foundation for this document.

1.2.2 Vectren may elect to incorporate additional threats/hazards at their discretion based on site-specific assessments.

1.3 Sections 2.0, 3.0, and 4.0 of this procedure provide descriptions of each threat category under consideration.

2.0 WELL THREATS

2.1 The following threats, associated subtypes, descriptions, common indicators, and possible consequences deemed applicable to storage wells have been identified in accordance with API RP 1171.

2.1.1 *Well Integrity:* Improperly completed storage wells can often lead to gas containment failure. Several unique threats can lead to possible issues involving well integrity and gas containment including but not limited to casing corrosion, cement bond failure, material defect, surface valve failure, subsurface valve failure, and wellhead equipment failures.

2.1.1.1 Well logs, bond logs, and maintenance record documentation should be reviewed for indications of well integrity issues.

2.1.1.2 The possible consequences of these well integrity threats may include loss of stored gas inventory, damage to well site facilities and equipment, safety hazard to Company personnel and the public, loss of use of water source and/or wells, and the decrease or loss of field performance.

2.1.1.3 Conditions found at similar wells should be considered when evaluating threats.

2.1.2 *Well Design:* Inadequate well design can affect new wells, existing wells, or plugged and abandoned wells. It is possible to have gas containment failure from a well with inadequate well design. Inadequate design may be discovered through maintenance records and integrity issues at wells with similar characteristics.

2.1.2.1 Losses subjected to well containment issues may result in release of gas to the atmosphere, loss of stored gas inventory, damage to well site facilities and equipment, safety hazard to company personnel and the public, loss of use of water source and/or wells, and the decrease or loss of field performance.

2.1.3 *Well O&M Activities:* The presence of threats during operation and maintenance activities are most likely to be present in cases of inadequate procedures, failure to follow procedures, inadequate training, and inexperienced personnel and/or supervision.

2.1.3.1 Issues can occur during normal well operations; other hazards may be unique to well shut-in and well work over activities.

2.1.3.2 Threats may be identified by reviewing past incidents, near misses, lessons learned, audits, root cause analysis, and length of service and training records.

2.1.3.3 The possible consequences of the threats involved with O&M activities are loss of stored gas inventory, damage to well site facilities and equipment, safety hazard to company personnel and the public, loss of use of water source and/or wells, and the decrease or loss of field performance.

2.1.4 *Well Intervention:* Instances of well intervention that can precipitate a gas containment failure include drilling, reconditioning, completion, stimulation, logging, and other downhole work.

2.1.4.1 Depending on the circumstances, either the presence or absence of activity may increase likelihood of the threat. Site-specific factors may exist that are known to make activity riskier.

2.1.4.2 Well intervention may result in damage to drilling rig or service rig, loss of tools in *wellbore*, hazard to operator and Contractors on well site, safety hazard to public, decrease or loss of field performance, and the possible loss of the well.

2.1.5 *Third-party Damage:* Damage to the well by a party that is not Vectren or a representative of Vectren. Instances of this type of well damage include vandalism, terrorism, and moving objects such as cars, trucks, farm equipment, etc.

2.1.5.1 Indicators that third-party damage may occur at a well site include but are not limited to the proximity to roadways or farm fields, site security, and barriers.

2.1.5.2 Historical evidence of damage may indicate increased threat of future incidents.

2.1.5.3 Possible consequences of third-party damage may result in loss of ancillary facilities, well on/off status changes, impact to service reliability, and an impact on neighboring public/storage gas loss.

2.1.6 *Outside Force/Natural Causes:* Weather and ground movement-related issues may be caused by heavy rain or flood, lightning, earth movement/seismic, ground water table changes, and subsidence deposits.

2.1.6.1 The chances of these events occurring are often indicated by National Oceanic and Atmospheric Administration (NOAA) climate data, Federal Emergency Management Agency (FEMA) floodplains, U.S. Geological Survey (USGS) databases, state testing information, soil type testing, and known occasions of reduced accessibility due to poor ground conditions.

2.1.6.2 The occurrence of these nature-related incidents can bring possible consequences of damage to facilities and an impact to service reliability.

3.0 RESERVOIR THREATS

3.1 The following threats, associated subtypes, descriptions, common indicators, and possible consequences deemed applicable to storage reservoirs in accordance with API RP 1171.

3.1.1 *Third-party Damage:* Damage to the reservoir caused by a third party can create threats/hazards that vary depending on the type of work being performed.

3.1.1.1 Common indicators for possible third-party damage can be found in state permits or other notification sources.

3.1.1.2 The presence of third-party wells within the proximity of the storage reservoir may result in third-party damage during third-party production, injection, or disposal operations.

3.1.1.3 Possible consequences of third-party drilling are loss of containment, skin damage to the storage reservoir, damage to the storage well's subjected casings and/or cement, loss of stored gas inventory, and damage to third-party/public property and personnel.

3.1.1.4 Possible consequences of a third-party well within proximity of the storage reservoir includes a decrease in field performance (working gas cycling and deliverability), loss of stored gas inventory, safety hazard if pressure rating of production facilities are not as high as storage pressure, and damage to third-party/public property and personnel.

3.1.2 *Geological Uncertainty:* Geological circumstances or events can create additional threats to the reservoir. There are various geological events, both known and unknown, that have the potential to affect a reservoir.

3.1.2.1 Uncertainty of extent of the reservoir boundary can create a threat/hazard. Comparison of operational data against historical reservoir records can indicate whether the data supports the suggested reservoir extent.

3.1.2.1.1 Possible consequences of an uncertain reservoir boundary include gas migration beyond control of storage wells, behavior of field under storage operations different than under production that could result in storage gas loss, the inability to meet design performance requirements, and possible damage to third-party/public property and personnel.

3.1.2.2 Operations causing expansion, contraction, and migration can create a threat/hazard. Some indicators that may identify this is occurring are inventory checks to find loss of gas and periodic monitoring which may find gas in unexplained locations.

3.1.2.2.1 Possible consequences could result in the inability to meet design performance requirements and loss of stored gas inventory.

3.1.2.3 Failure of *caprock* can cause vertical gas migration, likely during testing phase, initial activation, or when initial pressure is exceeded that could result in gas migration into shallower zones including water sources.

3.1.2.3.1 Caprock failure can result in the loss of stored gas inventory, abandonment of wells and/or field, and the requirement of recycling facilities. This issue can also be discovered through inventory checks to find loss of gas and periodic monitoring that may find gas in unexplained locations.

3.1.3 *Outside Force/Natural Causes:* When there is ground movement and weather-related incidents caused by heavy rain or flood, lightning, earth movement/seismic, ground water table changes, and subsidence deposits, it can become a threat/hazard to the reservoir.

3.1.3.1 The chances of these events occurring are often indicated by NOAA climate data, FEMA floodplains, USGS databases, state testing information, and soil type testing.

3.1.3.2 With the occurrence of these events, there can be possible consequences such as damage to facilities and an impact to service reliability.

3.1.4 *Fluid Compatibility Issues:* The storage reservoir could become contaminated through foreign fluids. This contamination can occur from drilling and completion fluids, water/chemical floods, fluids containing hydrogen sulfide (H_2S) generating bacteria, stored gas quality, etc. Fluid compatibility issues may be indicated by the presence of unexpected inventory gain, return, or withdrawal products.

3.1.4.1 The possible consequences of this contamination may include skin damage to the reservoir, which decreases field performance.

4.0 SURFACE THREATS

4.1 The following threats, associated subtypes, descriptions, common indicators, and possible consequences deemed applicable to the surface area of storage field assets have been identified in accordance with API RP 1171.

4.1.1 *Third-party Damage (Intentional/Unintentional Damage):* Third-party damage to the surface is an instance of damage due to excavation, farm operations, and moving objects such as cars, trucks, farm equipment, etc.

4.1.1.1 Common indicators that third party damage may occur near a well/reservoir are proximity to roadways or farm fields, site security, barriers, and a historical evidence of vandalism.

4.1.1.2 These threats can lead to the loss of ancillary facilities, well on/off status changes, impact to service reliability, and impact to neighboring public/storage gas loss.

4.1.2 *Third-Party Damage (Surface Encroachments):* Intrusion of items including buildings/roadways/structures construction, cathodic protection current from pipelines, power line current and overhead wires, expansion of park lands, mining, flood control dams, etc.

4.1.2.1 Typical indicators of these possible threats includes proximity to these types of surface encroachments in addition to cathodic protection (CP) survey readings, CP isolation, power line loads, Pipeline Research Council International (PRCI) modeling results, and state permit records.

4.1.2.2 This type of item at the surface of a well/reservoir may result in the inability to access, operate, or maintain facilities, complete facility abandonment, and reduced ability to site additional wells and facilities due to setback restrictions.

4.1.3 *Outside Force/Natural Causes:* Weather and ground movement events can present a threat/hazard to the surface of a well/reservoir site and are often accompanied by heavy rain or flood, lightning, earth movement/seismic, ground water table changes, and subsidence deposits.

4.1.3.1 The chances of these events occurring can be indicated by NOAA climate data, FEMA floodplains, USGS databases, state testing information, and soil type testing.

4.1.3.2 When these events are present, they can bring along the possible consequences of damage to facilities and an impact to service reliability.

5.0 DATA MANAGEMENT

5.1 **Responsibility:** Integrity Management Engineer

5.1.1 Gather data related to natural gas storage field wells/reservoirs on a continual basis and update asset information at least annually. Key data includes but is not limited to:

- Physical attributes
- Geotechnical data
- Construction/completion circumstances and methods
- Operations and maintenance activities
- Other events

5.1.2 Incorporate the data at least annually into the risk model. This data is then used to help identify and evaluate possible threats/hazards for storage field assets.

5.1.3 Save compiled data.

6.0 DOCUMENTATION

6.1 **Responsibility:** Integrity Management Engineer

6.1.1 Review threat/hazard categories during annual risk process.

6.1.1.1 Incorporate additional threat categories, if applicable, based on input from Subject Matter Experts, Reservoir Engineering, and Gas Storage & LP Operations.

6.1.1.2 Document any new threat categories or sub-categories and include justification or rationale for their inclusion. Submit to Integrity Management Engineering Manager and Gas System Integrity Director for approval.

6.2 **Responsibility:** Integrity Management Engineering Manager and Gas System Integrity Director

6.2.1 Review and approve any changes to threat/hazard category classifications and written justifications.

6.3 **Responsibility:** Integrity Management Engineer

6.3.1 Update this procedure to reflect approved changes and save written justifications for the life of the system.

6.3.2 Update risk model to include new categories.

SIMG-03-002 Risk Process & Annual Review

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized risk analysis process in order to prioritize storage field well/reservoir assessments, monitoring, and P&M

measures.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

49 CFR 192.605 "Procedural Manual for Operations, Maintenance, and Emergencies"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	3.1, 4.1, 5.1, 6.1
Integrity Management Engineering Manager	4.2

ACCOUNTABLE GROUP	Integrity Management
CONSULTED, INFORMED	Subject Matter Experts Integrity Management Engineering Manager Integrity Management Engineer Reservoir Engineer PHMSA State Authorities

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice (RP) 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016.

1.2 Vectren has a risk assessment process that includes the natural gas storage fields.

1.3 This procedure documents the process that is used in the prioritization and assessment of risk for wells/reservoirs within Vectren's natural gas storage fields.

2.0 RISK MODEL DEVELOPMENT

2.1 To comply with API RP 1171, Vectren Subject Matter Experts (SMEs) have developed Storage Risk Model as a relative risk model.

2.1.1 The objectives of the risk assessment process may include, but are not limited to:

- Prioritize wells/reservoirs for scheduling integrity assessments as well as preventative and mitigating (P&M) actions
- Assess the benefits of P&M actions based on the most effective P&M measures
- Provide a consistent decision making process for applying resources
- Determine effectiveness or need for other integrity assessment technologies
- Enable a relative evaluation of specific threat risks within the threat identification process
- Assess the integrity impact from modified inspection intervals
- Provide for data feedback and validation
- Consider the consequences of a potential failure

2.2 The risk algorithms for the Risk Model were developed by Vectren personnel.

2.2.1 The Risk Model incorporates well, reservoir, surface, business, environment, and population data to determine a Risk of Failure (ROF) score for each well.

2.2.1.1 Risk of Failure is a function of Likelihood of Failure (LOF) and Consequence of Failure (COF)

2.3 Factors and datasets incorporated into the Risk Model are discussed within SIMG-03-001 Threat/Hazard Identification.

2.3.1 At a minimum, this document includes threats/hazards listed in API RP 1171. Refer to SIMG-03-001 Threat/Hazard Identification for more detailed information.

2.3.1.1 Each threat/hazard category is weighted based on Vectren SME input.

2.3.2 In accordance with API RP 1171, the Risk Model considers interactive threats.

2.3.2.1 Interactive threats are also discussed within SIMG-03-001 Threat/Hazard Identification.

3.0 DATA MANAGEMENT

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Collect relevant data and populate the Risk Assessment per SIMG-03-001 Threat/Hazard Identification and SIMG-01-001 Asset Identification. Data to be collected may include, but is not limited to:

- Physical attributes
- Geotechnical data
- Construction/completion circumstances and methods
- Operations and maintenance activities
- Other events that could impact the assets

3.1.1.1 New information is captured on a continual basis per SIMG-03-001 Threat/Hazard Identification and incorporated into the risk model.

Additional data collection and record keeping will enable a more thorough risk assessment and prioritization process.

3.1.1.2 This data is to be used to identify and evaluate the potential threats for each well per SIMG-03-001 Threat/Hazard Identification.

3.1.2 Ensure data incorporated into the risk model is the most current, available information to produce the most accurate and valid risk results.

3.1.2.1 Initiate the Management of Change process if known data attributes need to be corrected or changed within the GIS System.

3.1.3 Capture data from other Vectren databases and SMEs that need to be manually added or verified in the Risk Assessment program.

3.1.3.1 Initiate the Management of Change process if known data attributes need to be corrected or changed within GIS System.

3.1.4 Review the higher risk scores and compare the last risk run results against known data or algorithm changes.

3.1.5 Maintain data to be incorporated into the Risk Assessment.

4.0 RISK ASSESSMENT

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Run the Risk Assessment at least once each year to calculate risk scores.

4.1.1.1 Compare risk results with the risk results from the previous run or year.

4.1.1.1.1 Document significant risk score changes, if the variation in risk resulted from changes made to the risk model algorithm.

4.1.2 Review and check the risk scoring results for validity to ensure that the assessment, prioritization, scores and/or ranking correctly represents facilities and characterizes the risks.

4.1.2.1 Perform “What If” scenarios to validate the risk scores, if necessary.

4.1.2.2 Re-run the Risk Assessment, if necessary.

4.1.3 Risk scores are used in the prioritization and selection of inspections and P&M measures.

- SIMG-04-001 Prioritization of Casing Inspections
- SIMG-04-002 Inspection Method Selection
- SIMG-08-001 P&M Selection and Review

4.1.4 Document the final risk result datasets and assessment schedule, and retain this documentation.

4.1.5 Reevaluate the integrity assessment schedule as needed to address high risk wells/reservoirs.

4.1.5.1 Engineering judgment may be used to prioritize assessments for wells/reservoirs based on other special consideration for those storage field wells containing a large number of features, accelerated corrosion growth, or other circumstances of concern.

4.1.5.2 Notify the Integrity Management Engineering Manager of significant changes to the integrity assessment schedule to determine if notification to Pipeline and Hazardous Materials Safety Administration (PHMSA) and state authorities is necessary.

4.2 **Responsibility:** Integrity Management Engineering Manager

4.2.1 Notify PHMSA and state authorities if significant changes to the assessment schedule occur.

5.0 ANNUAL RISK REVIEW

5.1 **Responsibility:** Integrity Management Engineer

5.1.1 Review Risk Model algorithms with SMEs at least annually

5.1.1.1 Evaluate risk score results generated to identify trends and new threats.

5.1.1.2 Review weightings and scorings within the risk model with reference to storage field wells/reservoirs. Confirm them as being valid representations, or make modifications.

5.1.1.2.1 Recommend new or revised data gathering if substantial improvement in risk assessment can be achieved.

5.1.1.2.2 Recommend new or revised scoring criteria if applicable or as additional data types become available.

5.1.1.3 Perform “What If” scenarios to validate the risk scoring and results, if necessary.

5.1.2 Make required changes to the risk model algorithm or the risk assessment process.

5.1.2.1 Initiate the Management of Change process when a change to the Risk Model is made.

5.1.2.2 Submit updated risk model and assessment schedule to the Integrity Management Engineering Manager, if necessary.

6.0 DOCUMENTATION

6.1 **Responsibility:** Integrity Management Engineer

6.1.1 The risk assessment algorithms, risk results, and corresponding assessment schedule are to be documented and maintained.

6.1.2 Prior years’ risk models, prioritizations, and assessment schedules are to be retained.

PURPOSE: To establish a standardized method for prioritizing casing inspections of natural gas storage field wells.

REFERENCES: API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs"

Interim Final Rule, PHMSA Docket #2016-0016

Indiana Department of Natural Resources (IDNR) 29-28-1 & 29-28-3

Vectren Storage Integrity Management Program Outline

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	3.2, 4.1, 5.1, 6.1
Integrity Management Engineering Manager	5.2

Accountable Group	Integrity Management
Consulted, Informed	Integrity Management Engineering Manager Gas Storage & LP Operations Manager Reservoir Engineering Manager Reservoir Engineering Gas Storage & LP Operations

1.0 BACKGROUND

1.1 Vectren has committed to perform baseline casing inspections on natural gas storage field wells not having a previous inspection within three to eight years from the effective date of the rule.

1.2 A formal Storage Integrity Management Program is being developed to meet the requirement of API Recommended Practice 1171, Interim Final Rule PHMSA Docket #2016-0016, and Indiana Department of Natural Resources proposed storage field rules.

1.3 Vectren started its casing inspection program in advance of these proposed regulations. This procedure documents the process used to prioritize and schedule wells for inspection.

2.0 CASING INSPECTION REVIEW

2.1 In 2016, as a preliminary approach to prioritizing casing inspections of natural gas storage field wells, Vectren used available data such as previous inspection results to formulate a schedule.

2.1.1 In developing their initial criteria, Vectren personnel evaluated the following factors:

- Number of well casings inspected vs. not inspected
- North vs. South fields
- Corrosion level (% wall loss) of previously inspected casings

2.2 The baseline Integrity Management review began in 2016 and wells will be scheduled for assessment based on previous inspections and risk evaluations.

2.2.1 Inspections will be reprioritized as a more detailed prioritization method and Risk Model is developed.

2.3 Wells not previously inspected are scheduled for inspection within three to eight years from the effective date of the rule. Wells with prior casing inspections were considered lower priority unless maximum wall loss recorded met one of these criteria:

2.3.1 Previous casing inspections containing a defect with a wall loss percentage ≥80% will be re-inspected within the first two years of the casing inspection program.

2.3.2 Previous casing inspections containing a defect with a wall loss percentage <80% and ≥60% will be re-inspected within the first two years of the program or within 5 years of the last inspection whichever is later.

2.3.3 Previous casing inspections containing a defect with a wall loss percentage <60% will be re-inspected within 15 years of the last inspection.

2.4 In addition to casing inspection status and well completion date, Vectren considered other factors when developing a feasible schedule. These include but were not limited to:

2.4.1 Wells within the same storage field and/or area of the field may be scheduled to run in sequence for increased efficiency.

2.4.2 Well inspection work was spread between the various storage fields to minimize adverse impact on operations and to obtain results from each of the fields in a timely manner.

2.4.3 Well work may be timed to accommodate seasonal demand (i.e., well shut-in dates), crop planting or harvesting, weather, and vendor availability.

2.4.4 Where modifications or repairs were deemed necessary in advance of downhole work, casing inspections were scheduled accordingly.

3.0 BASELINE CASING INSPECTION SCHEDULE

3.1 As the Storage Integrity Management Program is more fully developed, additional data collection and recordkeeping will enable a more thorough prioritization process.

3.2 **Responsibility:** Integrity Management Engineer

3.2.1 Incorporate additional data into the prioritization criteria as it becomes available. Refer to SIMG-01-001 Asset Identification.

3.2.2 Score each well according to the table below then compile the results for each criterion to determine the overall prioritization.

CRITERION	SCORE
Well type	Injection/Withdrawal = 2 Observation = 1 Disposal = 0 N/A = 1
Well completion date	More than 30 years = 2 15 – 30 years = 1 Less than 15 years = 0
Well pressure rating	More than 600 = 2 400 – 600 = 1 Less than 400 = 0
Well configuration	Single = 2 Double = 0 N/A = 1
Casing nominal thickness	Less than 0.3725" = 2 0.3725" – 0.45" = 1 More than 0.45" = 0
Date of last casing inspection	Last inspection more than 10 years ago = 1 Last inspection within 10 years = 0 N/A = 2
Maximum defect depth from last casing inspection	More than 70% = 2 50% - 70% = 1 Less than 50% = 0 N/A = 2
Repair history	For casings previously inspected but repaired (e.g. liner or patch), the depth of the repaired defects can be excluded from the prioritization scoring.
Total number of defects from last casing inspection	More than 100 = 2 50 – 100 = 1 Less than 50 = 0 N/A = 2
Average number of defects per lineal foot from last casing inspection	More than 10 = 2 1 – 10 = 1 Less than 1 = 0
Leak history in vicinity of well	Yes = 1 No = 0
Indications of internal corrosion (H_2S > 30 ppm, APB or SRB bacteria > 1,000 colonies/mL, engineering judgement)	Yes = 2 No = 0 N/A = 1
Indications of external corrosion (CP interference, CP below an established current demand criteria, engineering judgment)	Yes, on adjacent well/similar reservoir zone = 2 Yes, on wells at different zone = 1 No = 0 N/A = 1
Adjacent wells (or wells in same storage field) with severe or moderate casing wall loss	Yes, but remediated = 1 No = 0 N/A = 1

3.2.2.1 Engineering judgment may be used to prioritize wells or fields based on other special consideration for those storage field wells containing a large number of features, accelerated corrosion growth, or other circumstances of concern.

3.2.3 Re-prioritize casing inspections scheduled for years 2018 and beyond using the risk model results.

3.2.4 Review prioritization scores and develop inspection schedule.

3.2.4.1 Consult with Reservoir Engineering and Gas Storage & LP Operations.

3.2.4.2 Where feasible, divide work evenly across the years to be scheduled.

3.2.4.3 Consider field conditions such as accessibility or other planned projects as well as vendor availability when scheduling.

3.2.4.4 Separate crews may run projects concurrently at different fields.

3.2.5 Compare to the previous Casing Inspection Schedule, and provide rationale for any significant changes.

3.2.6 Submit a draft Baseline Casing Inspection Schedule to the Reservoir Engineering Manager and Gas Storage & LP Operations Manager for affected fields for review.

3.2.7 Retain documents.

4.0 ANNUAL BASELINE AND REASSESSMENT SCHEDULE UPDATE

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Incorporate data from the annual status report (refer to SIMG-13-001 Communications) as well as results of any casing inspections performed during the year into the casing prioritization spreadsheet. Items requiring updates may include:

- Well characteristics for new or modified wells
- Repair history – change in maximum defect depth if remediated by liner or patch
- Date and results of last casing inspection
- Condition of similar or adjacent wells

4.1.2 Re-analyze casing prioritization scores per section 3.0 and modify Casing Inspection Schedule if necessary.

4.1.3 Schedule next inspection of casings in accordance with the following criteria:

4.1.3.1 Casing with defects greater than 80% wall thickness will require remediation plans to be executed within two years from the date of discovery of the defect. Re-inspection should be scheduled in accordance with those plans. If a repair is made the next inspection may be scheduled based on the most severe defect remaining in the casing.

4.1.3.2 For defects less than 80% wall loss, calculate remaining life of the casing to determine subsequent inspection.

4.1.3.3 For defects less than 80% wall loss where remaining life cannot be calculated, use the following criteria:

4.1.3.3.1 Casings with wall loss greater than or equal to 60% and less than or equal to 80% will be re-inspected within 5 years.

4.1.3.3.2 Casings with wall loss less than 60% will be re-inspected within 15 years.

4.1.4 Submit updated Casing Inspection Schedule to Integrity Management Engineering Manager.

5.0 ANNUAL PRIORITIZATION PROCESS REVIEW

5.1 **Responsibility:** Integrity Management Engineer

5.1.1 Review the casing inspection prioritization process annually.

5.1.1.1 Assess the effectiveness of prioritization assessment process.

5.1.1.2 Recommend improvements as necessary.

5.1.1.3 Document follow-up actions and assign to specific personnel.

5.1.1.4 Evaluate prioritization assessment results to identify trends and new criteria.

5.1.1.5 Recommend new or revised data-gathering processes if substantial improvement in prioritization assessment can be achieved.

5.1.1.6 Recommend new or revised scoring criteria, if applicable, or as additional data types become available.

5.1.1.7 Obtain input or guidance from Reservoir Engineering and Gas Storage & LP Operations.

5.1.1.8 Make required changes to the prioritization assessment process.

5.1.1.8.1 When a change to the prioritization assessment process is made, follow the Management of Change process.

5.2 **Responsibility:** Integrity Management Engineering Manager

5.2.1 Review and approve recommended changes to prioritizations process and casing inspection schedule as appropriate.

6.0 DOCUMENTATION

6.1 **Responsibility:** Integrity Management Engineer

6.1.1 Document the final Baseline Casing Inspection Schedule and retain.

6.1.2 Document the annual prioritization assessment review and retain documentation.

6.1.2.1 Documentation will include the Casing Inspection Schedule along with the data used to generate the schedule.

6.1.3 Retain prior years' prioritization and inspection schedule for historical purposes.

PURPOSE: To establish a standardized method for selecting casing inspection methods for natural gas storage field wells.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

49 CFR 192.605 “Procedural Manual for Operations, Maintenance, and Emergencies”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1
Integrity Management Engineering Manager	2.2

Accountable Group	Integrity Management
Consulted, Informed	None

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This Inspection Method Selection procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 Storage wells should be tested on a frequency determined to be appropriate to ensure integrity of the well and reservoir. Various inspection methods can be used to assess integrity. A risk assessment should be used to determine the frequency of these tests on a well-by-well basis.

1.4 In addition to assessment or Mechanical Integrity Test (*MIT*) routine testing, monitoring and reviews are necessary to ensure a well is operating properly.

1.5 This procedure focuses on Mechanical Integrity Assessment of downhole components.

2.0 INSPECTION METHOD SELECTION

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Review the identified threats for the well to be evaluated. Refer to procedure SIMG-03-001 Threat/Hazard Identification.

2.1.1.1 MIT may be warranted to address specific conditions or concerns outside of the scheduled integrity assessment process. In such cases, document the reason for the test and which component(s) require assessment.

2.1.2 Review well documentation:

- Configuration – casings, tubing, packer, surface and subsurface valves
- Previous downhole inspection records
- Well pressure monitoring, testing and gas sampling records

2.1.3 Identify the well components to be tested during the inspection.

2.1.4 Consider inspection methods based on site-specific and/or the following factors:

- Availably of equipment and qualified contractors
- Type and configuration of well
- Design changes or other preparatory work necessary prior to running tool
- Risk to well operations during inspections
- Budget
- Time of year tests are being performed – impact on storage operations, accessibility to site
- Each active third-party well that penetrates the storage reservoir or *buffer zone* or areas influenced by storage operations
- Sequence of tests to be performed to augment investigation
- Spatial requirements and accessibility conditions for equipment and operation

2.1.5 Evaluate the suitability of each method to address the threats that are identified and the components of the well being tested.

2.1.5.1 Refer to Table 1: Threats Addressed by Component Being Tested.

Table 1. Threats Addressed by Component Being Tested

MECHANICAL INTEGRITY TESTING METHODS	I/E	TEST/LOG OBJECTIVE	WELL PREPARATION	CONSIDERATIONS/ COMMENTS
Mechanical Integrity Test				
Standard Annular Pressure Test	I	• Demonstrates no leaks in the casing-tubing annulus • Casing/Packer	• *Wellbore* and well must be full of fluid. • Must	• Pass/Fail Criteria can be established. • Can be used on any well • No unapproved fluid

		leak detection	stabilize temperature in well and annulus • Must pull tubing and set bridge plug for wells without a packer.	additives • Testing pressure should be equal to at least maximum allowable inj. Pressure
Annular Pressure Build up Test	I/E	• Identify gas flow outside of casing (annular pressure)	• Annuli and casing must be bled to 0 psig to initiating test • Shut-in annuli should be allowed to vent for a period of time prior to testing	• Pass/Fail Criteria can be established • Interpretation is relatively straightforward (type curves are available for comparison) • Test can be influenced by outside factors such as barometric pressure, mud clogging or freezing of lines, etc. • Gauges must be properly sized for the anticipated pressures • Continuous data recording are important to confirm quality of results
Annular Venting Flow Rate Test	I/E	• Identify flow of gas to surface as an indication of leak	• Shut in annuli should be allowed to vent for a period of time prior to testing.	• Pass/Fail Criteria can be established • Simple Interpretation • Two test types: o Manometer Tests o Balloon Test/Bubble Test
Wellhead Methane Monitoring	I/E	• Identify flow of gas to surface as an indication of leak	N/A	• Pass/Fail Criteria can be established. • Simple Interpretation • Various direct reading instruments are

				available that can detect methane directly or as a component of combustible gas. • Field procedures must be standardized to ensure consistent results
Geophysical Logging				
Temperature Log	I/E	• Casing Leak Detection • Identify behind casing flow • Entry/Exit Point Delineation	• Remove Tubing • Wellbore must be full of fluid • Stabilization period (12-24 hrs.)	• Misinterpretation of result is possible • Run logs in sets: production casing closed and surface casing open; production casing open and surface casing closed • Sensitive to the differing thermal conductivities of different sedimentary rock types.
Audio Log	I/E	• Casing Leak detection • Identify Behind Casing flow • Entry/Exit point delineation • Distinguish flow types	• Remove Tubing • Wellbore must be full of fluid • Stabilization period (12-24 hrs.)	• Misinterpretation of result is possible • Run logs in sets: production casing closed and surface casing open; production casing open and surface casing closed
Ultrasonic Noise Log	I	• Casing Leak detection • Can detect leaks through tubing and casing	• Remove Tubing • Operate in dry hole • Maybe run inside tubing • Logging rate approx. 30fpm	• Run logs in sets: production casing closed and surface casing open; production casing open and surface casing closed
Gamma Ray Neutron Log (GRN)		• Gas presence indicator • Correlate depth when run in combination of		

		other logs • Other geophysical characterization		
Cement Evaluation Logs – 1st Generation				
Cement Bond Log (CBL)	E	• TOC Determination • Casing/Formation Bond Evaluation	• Remove Tubing • Wellbore must be full of fluid	• Tool widely available • Historical use results in consistent interpretation • Sensitive to wellbore conditions.
Radial Cement Bond Log (RCBL)	E	• TOC Determination • Casing/Formation Bond Evaluation • Casing Bond Radial Display	• Remove Tubing • Wellbore must be full of fluid .	• Tool widely available • Historical use results in consistent interpretation • Sensitive to wellbore conditions
Cement Evaluation – 2nd Generation				
Cement Evaluation Tool (CET)	I/E	• Casing cement bond evaluation • Identify cement channeling • Cement compressive strength • Casing wear/corrosion indication	• Remove Tubing • Wellbore must be full of fluid	• Simpler interpretation • Less sensitive to borehole conditions • No cement to formation bond information
Segmented Bond Tool (SBT)	E	• Determine cement seal • Identify cement channeling • Cement compressive strength	• Remove Tubing • Can be run in fluid or gas	• Insensitive to wellbore conditions
Ultrasonic Imager Tool (USIT)	I/E	• Casing Cement Bond Evaluation • Identify cement channeling • Cement compressive	• Remove Tubing • Scrap casing • Wellbore must be full of fluid	• Simpler Interpretation • Less sensitive to wellbore conditions • No formation to cement bond information • Newer tools such as slim

		strength • Casing corrosion detection • Casing thickness measurement		memory CBL and radial CBL can be run through tubing.
Corrosion Logs				
Multi-Finger Caliper log	I	• Radial measurement of tubing/casing inside diameter	• Remove Tubing • Scrap Casing	• Used to identify zones of thinned casing well thickness assuming a uniform (constant) external diameter
Electromagnetic Casing Inspection Log	I	• Casing Internal and External Corrosion Indication • Casing thickness measurement	• Some can be run through tubing	• Operates in liquid or gas environments • Low frequency pass can scan multiple casing strings
Magnetic Flux Leakage Tool (MFL)	I	• Casing Corrosion Indication • Casing thickness measurement	• Remove tubing • Scrap casing	• The tool can measure metal loss both internally and externally • May not be effective if corrosion is continuous or has limited variation over an entire segment of casing.
Ultrasonic Imager Tool (USIT)	I/E	• Casing Cement Bond Evaluation • Identify cement channeling • Cement compressive strength • Casing corrosion detection • Casing thickness measurement	• Remove Tubing • Scrap casing • Wellbore must be full of fluid	
Cathodic Potential Profile (CPP)	E	• Determines levels of cathodic potential (CP) current on well • Identifies areas of	• Remove tubing	

		current discharge or kickback		
Imaging Equipment				
Infrared Camera	I/E	• Identify flow of gas to surface as an indication of a leak	• Not necessary to remove tubing	• IR camera does not identify chemical species and does not estimate flow rate • Baseline monitoring should be conducted prior to operations in order to establish background conditions • Periodic monitoring is required to demonstrate ongoing containment/compliance .
Downhole Video Log	I	• Identify compromised casing (corrosion, mechanical wear, collapse of breach)	• Remove Tubing	• Downhole video equipment not usually available through traditional logging service companies.

Abbreviations and Acronyms

E	External Integrity
I	Internal Integrity
I/E	Internal or External Integrity
CBL	Cement Bond Log
CET	Cement Evaluation Tool
CPP	Cathodic Potential Profile
CPET	Corrosion Protection Evaluation Tool
Fpm	Feet per minute
GRN	Gamma Ray Neutron
IR	Infrared
RCBL	Radial Cement Bond Log
SBT	Segmented Bond Tool
TOC	Top of Casing
USIT	Ultrasonic Imager Tool
URS	Ultrasonic Radial Scanner

2.1.6 Determine which technology will be used for each well component being evaluated. Select the technologies to achieve a comprehensive evaluation of components. Consider the order testing should take place.

2.1.6.1 As tubing is removed from the well. It should be visually examined for defects.

2.1.7 Identify resources needed and generate Request for Service including work scope.

2.2 **Responsibility:** Integrity Management Engineering Manager

2.2.1 Review and approve inspection method for each well.

3.0 DOCUMENTATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Document the test method(s) selected for each well to be assessed. Include rationale for which components and threats will be addressed by each method.

3.1.1.1 Document the tests to be run, technology to be used, components to be tested, and schedule.

3.1.1.2 Verify components listed in section 2.1 are accounted for in the selection of the tests.

3.1.1.3 List primary and supplemental tests to be run in order to adequately determine well and reservoir integrity.

3.1.2 Update the Casing Inspection Schedule accordingly and retain documentation for the duration of well operation.

SIMG-04-003 Performing Integrity Assessments

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for prioritizing casing inspections of natural gas storage field wells.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

49 CFR 192.605 “Procedural Manual for Operations, Maintenance, and Emergencies”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Pre-Assessment
3.0 Well Assessment Work Plan Review
4.0 Personnel Training
5.0 Performance of Well Inspection
6.0 Field Review of Inspection Data

Responsible Personnel	Section
Integrity Management Engineer	2.2, 3.1, 4.1, 5.1, 7.1, 8.1, 9.1
Gas Storage & LP Operations	2.1
Integrity Management	6.1
Integrity Management Field Inspector	5.2
Reservoir Engineering	7.1, 8.1

Accountable Group	Integrity Management
Consulted, Informed	Integrity Management Reservoir Engineer Reservoir Engineering Gas Transmission Engineering (GTE) Storage & LP Operations Supervisor Contractor

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This Quality Assurance procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 Integrity assessment consists of a pre-assessment, well inspection, and post-assessment.

1.4 The well inspection phase consists of performing the Mechanical Integrity Test (*MIT*) and evaluating the inspection data. A remediation plan is developed when applicable based on the inspection results.

1.5 Well inspection may determine the integrity of the casing, tubing, cement, packer, and/or plug.

1.6 Test result validation is also completed in this phase.

2.0 PRE-ASSESSMENT

2.1 **Responsibility:** Gas Storage & LP Operations

2.1.1 Perform a site visit to verify well conditions.

2.1.1.1 Determine if work needs to be performed to the well head in order to perform inspection.

2.1.1.2 Determine if vegetation clearing or fencing removal is required to access the well or the well pad.

2.2 **Responsibility:** Integrity Management Engineer

2.2.1 Collect and integrate data for the well to be assessed.

2.2.1.1 Use information compiled per SIMG-01-001 Asset Identification as well as other sources when available.

2.2.2 Prepare aerial maps of the well to be inspected and show areas of impact during testing.

2.2.3 Review list of inspection tools and methods selected for the Assessment. Refer to SIMG-04-002 Inspection Method Selection.

2.2.4 Identify any conditions from the data collection that are not compatible with the planned inspection method(s).

2.2.5 Consider wellhead design and well downhole configuration, which may have significant influence on feasibility.

2.2.5.1 Identify casing obstructions or deformations that could impede inspection method, such as accumulation of solids or *scale* from prior inspections.

2.2.5.2 Know access restrictions at the well site during scheduled work period.

2.2.6 Identify site-specific hazards and conditions for each well and address each appropriately.

2.2.7 Consult with Reservoir Engineering to confirm the well can be shut in during the planned work period without adverse impact to field operations.

2.2.8 Identify design or configuration changes, both permanent and temporary, which require implementation prior to inspection.

2.2.8.1 Work with Reservoir Engineering, Storage & LP Operations Supervisor, and Gas Transmission Engineering (GTE) to initiate projects as applicable.

2.2.8.2 Revise the well assessment plan based on findings if applicable.

2.2.9 Document feasibility and the rationale of the inspection method selected. If a well inspection method cannot be used, document reasons the method cannot be used.

2.2.10 Conduct and document pre-assessment review with Reservoir Engineering, Gas Storage & LP Operations, and other stakeholders as necessary.

2.2.10.1 If changes are required to pre-assessment after stakeholder review, document the reasons.

3.0 WELL ASSESSMENT WORK PLAN REVIEW

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Coordinate project with internal stakeholders in accordance with SIMG-04-004 Assessment Work Plan and O&M 44.32.1, *Underground Storage/Assessments and Inspections/Assessment Work Plan (Field)*.

3.1.2 Review approved pre-assessment documentation for any changes that occurred to the well between pre-assessment completion and well inspection execution.

3.1.2.1 Amend the approved pre-assessment documentation and review with Integrity Management and Reservoir Engineer, if applicable.

3.1.2.2 Adhere to industry-recommended practices for well inspection.

3.1.2.3 Review site-specific hazards and conditions for each well, and address any changes accordingly.

4.0 PERSONNEL TRAINING

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Confirm Contractors have the appropriate training to conduct the integrity assessments. Reference SIMG-12-002 Training Requirements.

5.0 PERFORMANCE OF WELL INSPECTION

5.1 **Responsibility:** Integrity Management Engineer

5.1.1 Review the inspection criteria with the Contractor prior to beginning the inspection.

5.1.1.1 Decide on criteria and document the new criteria in cases where Gas Storage & LP Operations, Reservoir Engineering, and the Contractor mutually agree that different survey acceptance criteria are appropriate.

5.1.2 Review the *wellbore* entry plan.

5.1.2.1 Inform Contractor of stored hydrocarbons and the presence of hydrogen sulfide (H_2S) or other hazardous or corrosive agents, as applicable.

5.1.2.2 Provide Contractor with wellbore and storage zone pressures.

5.1.2.3 Inform Contractor of anticipated presence of water, fluids, deposits, or scale and restrictions in the wellbore.

5.1.2.4 Define operating conditions and activities where pressure equipment is required. Inform Contractor of the pressure for which the equipment must be rated.

5.1.2.5 Consider use of a caliper tool prior to other tests in assessment plan to ensure adequate downhole clearance, particularly if the well has not previously been logged.

5.1.2.6 Review environmental and safety considerations.

5.1.3 Coordinate the well inspection in accordance with the established inspection schedule.

5.1.3.1 Communicate any deviations from the existing inspection schedule (i.e., additional runs, running additional tools) to the appropriate stakeholders.

5.2 **Responsibility:** Integrity Management Field Inspector

5.2.1 Verify pressure control equipment is rated for the maximum anticipated surface pressure to be encountered during operations.

5.2.2 Verify Contractor(s) onsite meet the training requirements

5.2.3 Test the data recording unit operability prior to beginning the inspection.

5.2.4 Visually examine tools and note any damage. Take photographs to supplement any notes. Notify Integrity Management of any significant issues.

5.2.5 Perform inspection in accordance to proper procedure.

5.2.5.1 Refer to GES 14.2, *Reservoir/Wireline Logging* and O&M 44.32.2, *Underground Storage/Assessments and Inspections/Casing Pressure Test* for procedures related to casing mechanical integrity tests.

6.0 FIELD REVIEW OF INSPECTION DATA

6.1 **Responsibility:** Integrity Management

6.1.1 Re-perform the inspection as appropriate if the acceptance criteria failed to be met.

6.1.2 Inspect each tool after it is removed from the well.

6.1.2.1 Examine tool for any damage. Photograph and note any damage.

6.1.3 Evaluate Preliminary Indications

6.1.3.1 Review available data logs for indications that require attention prior to the next test or the Contractor leaving the job site.

6.1.3.2 Refer to SIMG-05-001 Requirements to Address Conditions.

6.1.3.3 Determine if any immediate remediation is required for the well either prior to the next test within the planned work plan or before returning the well to normal operating condition.

6.1.4 Repeat steps 6.1.1 through 6.1.3 for each tool in the work plan.

6.1.5 Verify the following are complete prior to release of the Contractor and leaving the job site:

- The appropriate depths were logged
- Receipt of the raw data printout and/or electronic file
- Documentation of any tool damage

7.0 REVIEW OF FINAL REPORT

7.1 **Responsibility:** Integrity Management Engineer, Reservoir Engineering

7.1.1 Verify the Contractor provides data as required in the request for proposal (RFP).

7.1.1.1 Verify viewing software is provided if it is required for viewing.

7.1.2 Send copy of final report to Reservoir Engineer.

7.1.3 Perform a preliminary review of the final report.

7.1.4 Document the date the final report is received/accepted.

8.0 POST-ASSESSMENT

8.1 **Responsibility:** Integrity Management Engineer, Reservoir Engineering

8.1.1 Evaluate the results of the inspection.

8.1.1.1 Determine the effectiveness of the inspection in identifying well anomalies.

8.1.1.2 Review inspection data and note abnormalities in data. Determine reasons for these abnormalities and the criteria for redoing a test.

8.1.2 Determine if additional action is required based on test results.

8.1.3 Schedule reassessment date based on findings. Refer to SIMG-04-001 Prioritization of Casing Inspections.

8.1.4 Update well history with results of the assessment.

9.0 DOCUMENTATION

9.1 **Responsibility:** Integrity Management Engineer

9.1.1 Documents to be stored for the life of the facility.

- Logs, reports, and test data
- Accepted final report

SIMG-04-004 Assessment Work Plan

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a work plan for natural gas storage field wells.

REFERENCES:

49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

49 CFR 192.605 “Procedural Manual for Operations, Maintenance, and Emergencies”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.2, 3.1, 4.1, 6.2, 6.4, 7.1, 8.1
Gas Storage & LP Operations	2.1, 5.1
Gas Compliance	3.2

Environmental Affairs	2.3
Integrity Management Field Inspector	6.1
Integrity Management Engineering Manager	6.3

Accountable Group	Integrity Management
Consulted, Informed	Integrity Management Engineer Integrity Management Gas System Integrity Director Gas Transmission Engineering (GTE) Gas Storage & LP Operations Environmental Affairs Reservoir Engineering Gas Control Contractors

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

2.0 SITE INSPECTION

2.1 **Responsibility:** Gas Storage & LP Operations

2.1.1 Determine site-specific requirements (site leveling, tree clearing, fence removal, etc.).

2.1.2 Photograph and sketch site to document existing site conditions for restoration and for permitting, if applicable.

2.1.3 Perform visual inspection of wellhead.

2.1.3.1 Visually inspect the wellhead for any damage or corrosion.

2.1.3.2 Listen for any leaking valves or casing vents. Use a natural gas detector or soap to detect any leaks identified.

2.1.4 Notify Integrity Management Engineer of findings.

2.1.4.1 Send photographs and/or site sketches to Integrity Management Engineer.

2.1.5 Procure any Contractors and materials needed that are not covered by Integrity Management to perform inspections and site restoration.

2.1.5.1 Notify Integrity Management of any changes and coordinate Contractors and materials that will be needed.

2.2 **Responsibility:** Integrity Management Engineer

2.2.1 Determine if areas of environmental concern are present or if site work will affect more than one (1) acre, as additional permitting requirements may exist.

2.2.1.1 Submit supporting documentation to Environmental Affairs.

2.3 **Responsibility:** Environmental Affairs

2.3.1 Review the site locations for, but not limited to, the following:

- Erosion control
- Wetlands
- Sensitive areas

2.3.2 Determine need for supplemental site preparation if waterways and wetlands are adjacent to the worksite and storm water runoff from the worksite will affect these areas of concern.

2.3.3 Provide required environmental-related permits/plans to the Integrity Management Engineer. Information may include, but is not limited to:

- Storm Water Pollution Prevention Plan (SWPPP)
- Floodway permits
- Wetland/stream permits

3.0 ASSESSMENT PREPARATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Document inspection work to be performed. Refer to pre-assessment as described in SIMG-04-003 Performing Integrity Assessments.

3.1.2 Create a map of the work location that may include the following:

- Boundaries of Vectren property and private property
- Easements and right of way
- Laydown areas for equipment, material and stock piles
- Footprint of workover rig
- Temporary access roads, if applicable
- Location of water tanks
- Environmental areas of concern

3.1.3 Provide notifications to landowners, if applicable.

3.1.4 Gather wellhead information as described in SIMG-04-003 Performing Integrity Assessments, including *wellbore* diagram.

3.1.5 Identify any modifications to the well or wellsite necessary before an inspection can be safely and effectively performed.

3.1.5.1 Use information gathered in Section 2.1 “Site Inspection”.

3.1.5.2 Confirm capital projects are complete with Gas Transmission Engineering (GTE) if applicable.

3.1.5.3 Work with Gas Transmission Engineering (GTE), Gas Storage & LP Operations, and others needed if additional work is needed prior to assessment. Update planned assessment schedule accordingly.

3.1.6 Review current regulations to determine if notification is required to federal, state and/or local regulatory agencies to perform well inspection. Ensure necessary permits are being obtained.

3.2 **Responsibility:** Gas Compliance

3.2.1 Notify federal, state and/or local regulatory agencies to perform well inspection, if applicable.

3.2.2 Communicate to stakeholders when known that jurisdictional agencies will be present during performance of the assessment.

4.0 ASSESSMENT PACKET

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Prepare aerial maps with representation of area impacted by inspection for the duration of the work. Refer to section 3.0 “Assessment Preparation”.

4.1.1.1 Include schematics showing the system’s normal configuration and the configuration during the inspection.

4.1.1.2 Determine where waste water will be stored or taken upon completion of project.

4.1.1.2.1 If necessary, contact Environmental Affairs to characterize waste for disposal.

4.1.2 Define the process for preparing and performing each applicable test.

4.1.2.1 Refer to applicable O&M procedures for the tests to be performed

4.1.3 Schedule tests to be performed.

4.1.3.1 Assessments are typically scheduled after withdrawal and before injection seasons to minimize any operational impacts, land-use conflicts, and seasonal ground conditions.

4.1.3.2 Consult with Gas Storage & LP Operations, Reservoir Engineering, and Gas Control of planned well work and proposed timeline for work to be completed.

4.1.3.2.1 Schedule wells at the same or nearby field with similar inspections being performed in sequence.

4.1.3.3 Confirm Contractor(s) can meet the schedule requirements.

4.1.4 Create an assessment packet. Include the following items, as applicable:

- Blank forms to be completed during tool runs if not available electronically.
- Daily log
  - Site conditions
  - Personnel on site

- Description of any significant events and work completed

- Copy of applicable O&M procedures to reference during the tool runs.
- Communication list of internal and external project stakeholders to update on the progress of the well inspection.
  - Vectren personnel
  - Contractor(s)
- Copy of applicable Well Control Emergency Response Plan, which covers abnormal operating conditions
- Copy of Corporate Response Plan
- Well-specific work plan and applicable permits

4.1.5 Select Contractor(s).

4.1.6 Provide compiled assessment packet to Contractor(s) to be available on-site during field activities.

5.0 SITE SAFETY

5.1 **Responsibility:** Gas Storage & LP Operations

5.1.1 Conduct daily job briefing.

5.1.1.1 Review safety guidelines and hazards pertaining to scheduled work with affected stakeholders before beginning work.

5.1.1.2 For personnel that arrive to the job site after the daily job briefing has been conducted, discuss the material covered in the job briefing.

6.0 WORK PLAN OVERSIGHT

6.1 **Responsibility:** Integrity Management Field Inspector

6.1.1 After each test, communicate inspection results.

6.1.1.1 Notify Integrity Management Engineer if inspection was incomplete. Incomplete inspection may include:

- Adverse weather
- Broken or inoperable tools
- Inaccessible site
- Well remediation necessary

6.2 **Responsibility:** Integrity Management Engineer

6.2.1 Determine if remediation is needed prior to next test being run.

6.2.1.1 Perform a root cause analysis to determine necessary action to remediate impediments, if applicable.

6.2.1.2 Communicate results to Reservoir Engineering and Gas Storage & LP Operations

6.2.2 Document justifications for well assessment delays if assessment deadline is exceeded.

6.2.3 Notify Gas System Integrity Director if schedule delays will impact ability to complete planned well assessments in the calendar year.

6.3 **Responsibility:** Integrity Management Engineering Manager

6.3.1 Review and approve remediation plans.

6.3.2 Review and approve justifications documenting the reasons scheduled well assessments could not be completed within the required timeframe.

6.4 **Responsibility:** Integrity Management Engineer

6.4.1 Schedule remediation with Contractors as necessary.

6.4.1.1 Consult with Reservoir Engineering, Gas Control, and Gas Storage & LP Operations.

6.4.2 Coordinate inspections to be completed after the remediation is complete.

7.0 LESSONS LEARNED

7.1 **Responsibility:** Integrity Management Engineer

7.1.1 Upon completion of work plan, discuss lessons learned from the work with parties involved in the work. This may include:

- Scope of work well defined
- Schedule realistic and obtainable
- Roles and responsibilities clear and communicated
- Process and procedures well defined
- Safety equipment and measures adequate
- Resolutions to onsite issues
- Over/under budget

7.1.2 Incorporate lessons learned into future work plans as necessary.

7.1.2.1 Amend work plans already in progress if applicable.

8.0 DOCUMENTATION

8.1 **Responsibility:** Integrity Management Engineer

8.1.1 Retain permit applications as necessary.

8.1.2 Ensure documentation is compiled in assessment packet.

8.1.3 Ensure information and data collected from the completed forms are entered into database and/or tracking sheets.

8.1.4 Maintain documentation.

PURPOSE: To establish a standardized process for determining well remediation resulting from well mechanical integrity testing or other anomalous indication.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

49 CFR 192.605 "Procedural Manual for Operations, Maintenance, and Emergencies"

Interim Final Rule, PHMSA Docket #2016-0016

API Technical Report 5C3 "Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing", First Edition

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1
Reservoir Engineer	2.2
Integrity Management Engineering Manager	2.3
Gas Storage & LP Operations	2.4
Gas Transmission Engineering (GTE)	2.4

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineering Gas Storage & LP Operations Gas Control Gas Transmission Engineering (GTE) Contractors

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim

Final Rule PHMSA Docket #2016-0016. This procedure serves as a framework remediation document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

- In some cases remediation may be necessary prior to conducting further well inspection tests.

2.0 ANALYSIS

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Analyze data received from Mechanical Integrity Test (*MIT*) or routine monitoring.

2.1.2 If one of the following conditions are present, further review is needed:

- Casing or tubing wall loss greater than 60%
- Remaining casing or tubing wall insufficient to withstand burst, collapse or axial pressures
- Anticipated wall loss will exceed 80% before the next scheduled assessment
- Evidence of anomalous gas pressure at well annulus
- Other conditions, which based on engineering judgment, may pose a risk to well integrity

2.1.2.1 Consult with Reservoir Engineering regarding anticipated loads and pressures. Consider normal operating parameters as well as conditions reasonably expected to occur during well workover, mechanical integrity testing, well stimulation, or other activities.

2.1.2.1.1 Evaluate minimum wall thickness to withstand pressures in accordance with API Technical Report 5C3 or similar.

2.1.2.2 Use a conservative burst, collapse, and/or axial pressure calculation.

2.1.2.3 Where well-specific corrosion rates are unknown, a conservative value may be applied based on findings at similar wells when calculating remaining life.

2.1.2.4 Perform additional tests as needed. Review historical and current data trends to adequately characterize and remediate the indication.

2.1.2.4.1 Refer to SIMG-04-002 Inspection Method Selection, and consult with Reservoir Engineering regarding additional tests.

2.1.3 If wall loss percentage is ≥80% perform a Root Cause Analysis (RCA).

2.1.3.1 RCA can also be performed for less severe indication at the discretion of the Engineer, Integrity Management.

2.1.4 Identify remediation, mitigation measures, or additional monitoring to address the condition found based on analysis.

2.1.4.1 Consider the threats and risk associated with the location along with *reservoir pressure* when planning remediation.

2.1.4.2 When possible, perform remediation at low inventory and low pressure to minimize risk.

2.1.4.3 Consult with Reservoir Engineering and Gas Storage & LP Operations regarding remediation activities.

2.1.4.4 For casing remediation, reference SIMG-05-004 Casing Remediation.

2.1.5 Develop an action plan that will be reviewed and approved by Reservoir Engineering, Gas Transmission Engineering, and Gas Storage & LP Operations. This action plan will consider:

- Justification of remediation
- Supporting documentation
- Notification requirements
- Timeline for the remediation selected
- Expected outcome
- Contingency plan
- Necessary tests to ensure remediation was successful
- Permits

2.1.5.1 Multiple alternatives may be developed and evaluated based on factors such as:

- Feasibility
- Risk
- Operational and capital budget impacts
- Resource availability/timeline

2.1.6 Consult with Reservoir Engineering, Gas Transmission Engineering, Gas Control, and Gas Storage & LP Operations to schedule remediation. Involve Contractors, as necessary.

2.1.7 Compare test results after remediation to initial results before remediation. Begin process at Section 2.1.1 of this procedure.

2.1.7.1 If remediation does not resolve issues related to well integrity, another remediation technique may be attempted or well operations terminated.

2.1.8 Incorporate industry guidance and regulatory requirements when determining if remediation is required prior to next scheduled MIT.

2.1.9 Compare test results after remediation to initial results before remediation. Begin process at Section 2.1.1 of this procedure.

2.2 **Responsibility:** Reservoir Engineer

2.2.1 Review the action plan(s) as well as impact on reservoir storage capability and predicted changes in injection and withdrawal rates.

2.3 **Responsibility:** Integrity Management Engineering Manager

2.3.1 Review and approve justifications documenting reasons remediation is needed.

2.3.2 Review and approve justifications if scheduled well assessments could not be completed within the required timeframe. Refer to SIMG-13-002 Required Notifications.

2.3.3 Review and approve significant changes to storage field as a result of the remediation using the Management of Change (MOC) Process.

2.4 **Responsibility:** Gas Storage & LP Operations and/or Gas Transmission Engineering (GTE)

2.4.1 Perform necessary remediation according to appropriate O&M procedure.

2.4.2 Perform necessary tests according to the action plan to ensure well remediation technique selected was successful.

3.0 DOCUMENTATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Document action plan for planned remediation. Include:

- Justification of remediation
- Supporting documentation
- Notification requirements
- Timeline for the remediation selected

3.1.2 Include additional reports from tests run after remediation is completed.

3.1.3 Complete Management of Change (MOC) documents.

3.1.4 Retain documentation, and ensure that data is shared with necessary informed parties, such as Reservoir Engineering and Gas Storage & LP Operations.

SIMG-05-004 Casing Remediation

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for casing remediation of natural gas storage field wells.

REFERENCES: API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	3.1, 4.1
Gas Storage & LP Operations	3.2
Gas Transmission Engineering (GTE)	3.2
Integrity Management Field Inspector	3.3

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineering Gas Storage & LP Operations Gas Transmission Engineering (GTE) Contractor

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This remediation procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ, and serves as a roadmap for future development.

2.0 METHOD DETERMINATION

2.1 Reference SIMG-05-001 Requirements to Address Conditions.

3.0 CASING REMEDIATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Consult with Reservoir Engineering, Gas Transmission Engineering, and Gas Storage & LP Operations to review schedule of remediation activities.

3.1.2 Confirm remediation was effective.

3.1.2.1 Schedule additional inspections if needed as required by SIMG-04-003 Performing Integrity Assessments.

3.1.2.2 If inspection is unsuccessful and/or identifies underlying issue, additional remediation may be required. Repeat this procedure as applicable.

3.1.3 Review remediation documentation. This may include, but is not limited to:

- As-builts for work completed
- Record of cement mixture used in remediation, if applicable
  - Cement type
  - Additives used in final mixture
- Post-remediation Mechanical Integrity Test (*MIT*) results

3.1.4 Update Asset Identification and Risk Model to reflect remediations and modifications. Refer to SIMG-01-001 Asset Identification and SIMG-03-001 Threat/Hazard Identification.

3.1.4.1 The impact of this change on the prioritization and schedule of the next casing assessment will be accounted for during the annual review process.

3.2 **Responsibility:** Gas Storage & LP Operations and/or Gas Transmission Engineering (GTE)

3.2.1 Schedule remediation activities with appropriate Contractor and procure materials and/or equipment needed to perform approved remediation.

3.2.1.1 Refer to section SIMG-05-001 Requirements to Address Conditions.

3.2.1.2 Potential remediation materials and/or equipment may be available on-site if accounted for in Contingency Plan.

3.2.2 Monitor and record well pressures throughout the remediation process.

3.2.2.1 Also monitor adjacent wells if specified in Work Instructions.

3.2.3 Complete remediation documentation. This may include, but is not limited to:

- As-builts for work completed
- Record of cement mixture used in remediation, if applicable
  - o Cement type
  - o Additives used in final mixture
- Post-remediation Mechanical Integrity Test (MIT) results

3.2.4 Install or construct additional equipment needed to perform remediation.

3.2.5 Perform remediation per applicable O&M procedure(s) and Work Instructions.

3.2.6 Perform inspections to confirm remediation has resolved issues and no new issues have occurred. Refer to SIMG-04-003 Performing Integrity Assessments.

3.3 **Responsibility:** Integrity Management Field Inspector

3.3.1 Monitor and ensure that remediation work is done per procedure and work instructions.

3.3.1.1 Gather and ensure Integrity Management (IM) documentation is certified by Contractors as needed.

4.0 DOCUMENTATION

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Store the following records:

- Copy of Work Instructions and procedures utilized
- Recorded pressure test data during remediation
- As-builts for work completed
- Record of cement mixture used in remediation, if applicable
  - o Cement type
  - o Additives used in final mixture

- Results of MIT work after remediation is complete
- Contractor training and/or certifications

4.2 Retain remediation records for the life of the facility.

SIMG-05-006 Plug & Abandonment

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for plugging and abandoning natural gas storage field wells.

REFERENCES: API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs"

Interim Final Rule, PHMSA Docket #2016-0016

Indiana Department of Natural Resources (IDNR) 312 IAC 29-33 "Temporary Abandonment of Wells and Well Plugging Requirements"

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.1, 4.1, 5.1
Reservoir Engineering	3.1

Accountable Group	Integrity Management
Consulted, Informed	Gas Transmission Engineering Manager Integrity Management Engineering Manager Reservoir Engineering Manager Gas Storage & LP Operations Manager Reservoir Engineering

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirement of API Recommended Practice 1171, Interim Final Rule PHMSA Docket #2016-0016.

1.2 At the end of a well's life cycle, the purpose of plugging a well is to isolate the permeable hydrocarbon bearing formation in order to protect underground resources, prevent potential contamination of potable water sources, and preclude surface leakage.

1.3 Plugging precedes abandonment, which is the act of retiring the gas well from service. Typically plugging and abandonment are done in conjunction with each other.

1.4 Wells may be temporarily abandoned and put back in service at a later date.

1.5 Plugging and abandoning a well shall be planned and performed in accordance with guidelines defined by the State of Indiana.

1.6 Gas storage reservoirs typically have several wells. Individual wells in a reservoir can be abandoned without abandoning the entire reservoir.

1.7 Definitions

- Emergency condition exists when there is an immediate threat to public health, safety, or substantial harm to the environment.
- Urgent condition exists if delay in plugging a well is likely to result in a substantial increase in the cost to plug the well due to impending weather or other conditions that are beyond control of the owner or operator.

2.0 REASONS FOR PLUGGING WELLS

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Identify wells and document rationale for proposed plugging and abandonment (P&A). Recommend temporary or permanent P&A.

2.1.2 Notify affected stakeholders of proposed abandonment plan.

2.1.2.1 Submittals may cover multiple well conversions, abandonments, and/or new wells recommended as part of a larger overall field management program.

2.1.2.2 Affected stakeholders include, but are not limited to:

- Gas Transmission Engineering Manager
- Integrity Management Engineering Manager
- Reservoir Engineering Manager
- Gas Storage & LP Operations Manager

2.1.3 Work with Reservoir Engineering to plan P&A design.

3.0 WELL ABANDONMENT AND PLUGGING

3.1 **Responsibility:** Reservoir Engineering

3.1.1 Refer to GTEDM 58.0, *Storage Fields/SF-04 Well Plugging and Abandonment* for P&A planning, design, and execution.

4.0 TEMPORARY WELL ABANDONMENT

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 File for permits 60 days in advance of termination of well operations. Refer to [GTEDM 56.0, *Storage Fields/SF-02 Permitting*].

4.1.1.1 Demonstration of engineering, geological and economic reasons will be necessary to provide supporting documentation showing that temporary abandonment is more beneficial than maintaining operation or permanently abandoning the well.

4.1.1.2 Refer to Indiana Administrative Code (IAC) “Temporary abandonment of wells” for specific plugging requirements.

5.0 DOCUMENTATION

5.1 **Responsibility:** Integrity Management Engineer

5.1.1 Document decision and justification for abandonment.

5.1.2 Documents related to well work, including permits, should be retained for the life of the facility.

5.1.3 Maintain documentation that may include, but is not limited to:

- Application for temporary abandonment, if applicable
- Methods used to plug well
- Well plugging plan
- Affidavit certifying well was plugged under Indiana Code (IC) “Plugging and Abandonment”
- Cement tickets
- Job tickets and logs for *wireline* services
- Cement bond-variable density logs

SIMG-06-001 Periodic Monitoring

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for periodic monitoring including techniques to monitor the reservoir, injection/withdrawal wells, observation wells, third-party activity in the vicinity of the reservoir, and corrosion.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.1, 4.1, 6.3, 7.2
Reservoir Engineering	3.1, 3.3, 3.5, 3.7, 5.2, 6.2
Gas Storage & LP Operations	3.2, 3.4, 3.6, 3.8, 4.2, 5.1, 6.1, 7.1
Corrosion Control	4.1, 4.2

Accountable Group	Integrity Management
Consulted, Informed	Compliance Reservoir Engineering Gas Storage & LP Operations Gas Storage & LP Operations Manager Integrity Management Engineer

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 Wells and related facilities shall be periodically monitored in order to allow for the discovery and correction of abnormal operating conditions.

1.3.1 Storage wells and reservoirs can have different characteristics resulting in unique requirements in approaching monitoring.

1.3.2 Wellheads, well safety systems, well piping, and site locations should be inspected for operability, leaks, and mechanical or other faults.

1.4 Surface and subsurface monitoring is utilized to evaluate wellheads, well safety systems, well piping, site locations, and pertinent downhole assets.

1.5 Risk assessment can be used as a basis for developing the monitoring tasks and evaluating their frequency requirements.

2.0 VALVE INSPECTIONS

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Incorporate the valve inspection program per O&M 26.0, *Valves* into Storage Integrity Risk Assessment.

3.0 RESERVOIR SURVEILLANCE

3.1 **Responsibility:** Reservoir Engineering

3.1.1 Ensure wellheads are monitored for unexpected changes indicative of mechanical fault.

3.1.1.1 Monitoring frequency should be based on factors such as reservoir and geologic characterization, inventory loss potential and flow potential.

3.1.2 Establish schedule and document.

3.1.3 Notify Gas Storage & LP Operations of reservoir surveillance schedule.

3.1.4 Consider performing Pressure Transient Analysis (PTA) or Rate Transient Analysis (RTA) to help quantify mechanical faults.

Pressure and Flow Test

3.2 **Responsibility:** Gas Storage & LP Operations

3.2.1 Measure surface pressure and injection and withdrawal flow rates at injection/withdrawal (I/W) wells at least semiannually.

3.2.2 Measure surface pressure or flow rates at the following locations:

- Observation
- Disposal wells
- Offset hydrocarbon production or disposal operations

3.2.3 Notify the appropriate stakeholders, including Reservoir Engineering, Integrity Engineer, and Gas Storage & LP Operations Manager, if pressure and/or flows deviate from expectations or to alert operators of potential *wellbore* integrity issues.

3.2.3.1 Refer to O&M 16.0, *Repairs* for repair, as appropriate.

3.2.4 Record measurements.

3.2.4.1 Document tubing and casing injection pressures and volumes for Underground Injection Control (UIC) wells (i.e., disposal wells) on Operators Monthly Report of operations to the Indiana Department of Natural Resources (IDNR).

3.2.4.2 Provide monthly and annual pressure readings to the Reservoir Engineer.

3.3 **Responsibility:** Reservoir Engineering

3.3.1 Evaluate annular gas occurrence that is unexpected or is of concern.

3.3.1.1 Consult with Gas Storage & LP Operations and the Integrity Management Engineer, as necessary.

3.3.2 Promptly investigate changes in annular pressure whenever it could be the result of casing or packer failure.

3.3.2.1 Monitor the pressure between the casing and tubing as well as between surface and internal casings for wells that have packer.

3.3.2.2 Test wellhead seals when annulus pressure is detected and where injectable packing and/or test ports are present.

3.3.2.3 Notify Compliance if found to potentially be due to casing or packer failure.

Shut-In Test

3.4 **Responsibility:** Storage & LP Operations Supervisor

3.4.1 Ensure field shut-in test to confirm reservoir inventory is performed on a semi-annual basis.

3.4.2 Notify the appropriate stakeholders, including Reservoir Engineering, Integrity Management Engineer, and Gas Storage & LP Operations Manager, if pressure deviates from expectations or to alert operators of potential wellbore integrity issues.

3.4.2.1 Refer to O&M 16.0, *Repairs* for repair, as appropriate.

3.4.3 Record measurements.

3.5 **Responsibility:** Reservoir Engineering

3.5.1 Evaluate trends indicative of inventory verification in terms referencing working and cushion gas volumes.

3.5.1.1 Refer to GES 14.9, *Reservoir/Reservoir Analysis and Trending*.

3.5.1.2 Consult with Gas Storage & LP Operations, as necessary.

Gas and Liquid

3.6 **Responsibility:** Gas Storage & LP Operations

3.6.1 Monitor I/W and observation wells for wellbore produced fluids and solids. If disposal wells penetrate the storage formation, then record disposal volumes and related pressures.

3.6.1.1 Consider collecting a sample(s) for compositional analysis. Refer to applicable O&M procedure(s).

3.6.2 Consult with Integrity management and Reservoir Engineering to schedule monitoring of observation wells in the vicinity of spill points within an aquifer and above the *caprock* in potential collector formations.

- Fluid levels
- Geophysical logging
- Gas composition

- Other

3.6.2.1 Observation wells may be used around, above, or below the reservoir to monitor pathways of potential communication and/or migration.

3.6.3 Notify the appropriate stakeholders, including Reservoir Engineering, Integrity Management Engineer, and Gas Storage & LP Operations Manager, if unexpected gas migration is detected.

3.6.4 Offset hydrocarbon production or disposal operations may be monitored for unexplained changes.

3.6.4.1 Monitoring should include operations in zones above and below the storage reservoir as well as laterally offset locations when access is available.

3.6.4.2 Work with contractors to complete subsurface correlation and gas identification logs such as gamma ray and neutron log suite as identified by Integrity Management and Reservoir Engineering. These logs may be used by Integrity Management and Reservoir Engineering as part of a periodic integrity assessment, if applicable, by monitoring results.

3.6.5 Collect gas samples from available shallower zones or casing annuli to obtain compositional analysis for comparison to gas analysis from the storage reservoir to identify potential gas leakage or gas migration pathways.

3.7 **Responsibility:** Reservoir Engineering

3.7.1 Evaluate trends for the impact of gas, fluids, and solids on well integrity or loss thereof.

3.7.1.1 Refer to GES 14.9, *Reservoir/Reservoir Analysis and Trending*.

3.7.1.2 Consider the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures.

3.7.1.3 Consult with Gas Storage & LP Operations and Integrity Management Engineer, as necessary.

Monitoring During Reservoir Stimulation

3.8 **Responsibility:** Gas Storage & LP Operations

3.8.1 Inspect adjacent active and plugged wells during or following a stimulation or hydraulic fracturing treatment to verify integrity maintenance when a well located within the reservoir area and *buffer zone* is being treated at pressures exceeding maximum storage *reservoir pressure* through a method and period of time identified by Reservoir Engineering.

4.0 CORROSION MONITORING

4.1 **Responsibility:** Integrity Management Engineer and Corrosion Control

4.1.1 Monitor tubular corrosion and evaluate corrosion impact on well integrity and operating pressure through assessments. This may include some or all of the following:

- Wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures

- Annular and packer fluid corrosion potential
- Corrosion potential of current flows associated with cathodic protection systems
- Injected and withdrawn gas compositions for changes in characterization

4.1.2 Monitor and assess flow conditions to limit the potential for erosion due to flow velocity.

4.1.2.1 Consider the differences in erosion of flow velocity for dry gas flow and for wet or particulate-laden flow.

4.1.2.2 Consider collecting wall thickness measurements on casing and wellhead component where the conditions are suitable for erosion to occur.

4.1.2.3 Wall thickness monitoring should be based on the risk assessment.

4.1.3 Compositional analysis of water samples taken from the storage reservoir or other formations may be obtained for potential comparison to water that may accumulate within the well during storage operations to identify possible well integrity problems.

4.2 **Responsibility:** Gas Storage & LP Operations

4.2.1 Perform corrosion monitoring activities in accordance with schedule in consultation with the Integrity Management Engineer and/or Reservoir Engineering.

- Wellbore produced fluids and solids sampling
- Annular and packer fluid sampling
- CP testing
- Gas sampling

4.2.1.1 Refer to O&M 27.0, *Corrosion Control*.

4.2.2 Record corrosion monitoring activities.

5.0 LEAK PATROLS / LEAK SURVEYS

5.1 **Responsibility:** Gas Storage & LP Operations

5.1.1 Perform annual leak survey of transmission lines and wellheads per O&M 17.0, *Gas Leak Surveys and Pipeline Patrols*.

5.2 **Responsibility:** Reservoir Engineering

5.2.1 Identify the recorded location of plugged wells that penetrate the storage reservoir, within the buffer zone, or areas influenced by storage operations.

5.2.2 Review plugging records to augment the plugged well site inspections.

6.0 THIRD-PARTY ACTIVITY / ENCROACHMENT

6.1 **Responsibility:** Gas Storage & LP Operations

6.1.1 Monitor for third-party activity that could compromise the integrity of the storage reservoir. Such activities may include, but are not limited to:

- Plugging and abandonment
- Production

- Mining
- Other site-specific activities

6.1.2 Identify third-party activities being conducted in vicinity of the reservoir and/or wellheads during O&M activities including, but not limited to:

- Continuing surveillance
- One-Call activities
- Leak surveys
- Routine patrols
- Routine daily work processes

6.1.3 Monitor active and plugged well sites for encroachment activities.

6.1.4 Communicate with landowners and tenants in the vicinity of the storages fields to take note of any activities near the storage field.

- Document and maintain records if applicable.
- Communicate this information to the Integrity Management Engineer, if applicable.

6.2 **Responsibility:** Reservoir Engineering

6.2.1 Monitor for third-party activity that could compromise the integrity of the storage reservoir. Such activities may include, but are not limited to:

- Drilling
- Completion
- Production
- Plugging and abandonment

6.2.2 Analyze if the third-party activity in the vicinity of the storage field could adversely affect the storage reservoir.

6.2.2.1 Document and maintain records of concerns.

6.2.3 Request well integrity evaluation data from third-party well owner/operators following the frequency established using conclusions from the risk assessment.

6.3 **Responsibility:** Integrity Management Engineer

6.3.1 Monitor and evaluate third-party activity that could compromise the integrity of the storage reservoir. Such activities may include, but are not limited to:

- Mining
- Other site-specific activities

7.0 DOCUMENTATION

7.1 **Responsibility:** Gas Storage & LP Operations

7.1.1 Document periodic monitoring data as discussed in previous sections.

7.1.2 Maintain the documentation.

7.2 **Responsibility:** Engineer, Integrity Management

7.2.1 Ensure the periodic monitoring documentation listed in section 7.1.1 is retained for the life of the well.

SIMG-06-004 Corrosion Monitoring

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for monitoring internal and external corrosion on natural gas storage field wells.

REFERENCES: API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Corrosion Evaluation
3.0 Monitoring Internal Corrosion
4.0 Monitoring Cathodic Protection
5.0 Documentation

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1, 4.1, 5.2
Gas Storage & LP Operations	3.2
Corrosion Control	5.1

Accountable Group	Integrity Management
Consulted, Informed	Gas Storage & LP Operations Corrosion Control Integrity Management Engineer

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 This document prescribes requirements for protecting tubulars and wellheads from corrosion.

1.3.1 Vectren operates two types of underground gas storage (UGS) fields: depleted hydrocarbon reservoirs and aquifer reservoirs. The distinct geographic and physical characteristics for each field can impact the corrosion potential.

1.3.2 A corrosive gas stream is defined as a combination of natural gas and contaminants in the presence of liquid water or other electrolyte, which can result in metal loss.

2.0 CORROSION EVALUATION

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Review current and historical corrosion records for wellheads including, but not limited to:

- Gas sampling
- Liquid sampling
    - o *Wellbore* produced fluids and solids sampling
    - o Annular and packer fluid sampling
- Mechanical Integrity Tests (*MIT*) or *Wireline* Logging
- Leaks/failures history, including failed MIT pressure test
- Visual inspection records
- Cathodic protection (CP)

2.1.1.1 Work with Gas Storage & LP Operations and Corrosion Control to determine presence and/or extent of corrosion.

2.1.1.2 Corrosion information collected from in-service equipment at the wellhead or at adjacent equipment (that is, downstream of wellhead) may be utilized.

2.1.2 Evaluate tubular corrosion through current and historical periodic monitoring and consider the following:

- Defects caused by corrosion or other chemical or mechanical damage
- Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures
- Annular and packer fluid corrosion potential
- Corrosion potential of current flows associated with cathodic protection systems

2.1.2.1 Refer to SIMG-04-003 Performing Integrity Assessments and SIMG-06-001 Periodic Monitoring for additional details on routine monitoring and assessments.

2.1.3 Review and compare other wells with similar characteristics to determine if corrosion is common in comparable conditions.

2.1.4 Perform assessments/inspections to determine the extent of the threat.

2.1.4.1 If remediation is required due to internal corrosion, take adequate steps to prevent or mitigate additional corrosion for the tubular segment in question. Options may include, but are not limited to:

2.1.4.1.1 Injecting a corrosion inhibitor or *biocide*

2.1.4.1.2 Replace or repair any tubing damaged by the corrosion

2.1.4.1.3 Incorporate corrosion management techniques into design and operation strategies.

2.1.4.1.3.1 Refer to GTEDM 55.0, *Storage Fields/SF-01 New Storage Well Design* for design considerations.

2.1.5 Corrosion analysis may include, but is not limited to, review of the following factors to determine a likely cause of abnormally high or increased corrosion rates:

2.1.5.1 Review of product quality sampling data

2.1.5.2 Review of liquid, gas, or solid sampling data

2.1.5.3 Review of inhibitor and/or biocide injection rates

2.1.5.4 Review of bacteria testing data

3.0 MONITORING INTERNAL CORROSION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Work with Gas Storage & LP Operations and Corrosion Control to determine internal corrosion monitoring method(s) most appropriate for storage field and/or wellhead as needed based on the level of threat. Methods may include:

- Gas, liquid, and solids sampling
- Visual Inspections of tubing or casing removed from the well (when available)
- Casing Mechanical Integrity Test (MIT)/wireline logging

3.1.1.1 Monitoring should be done in accordance with O&M 27.30, *Corrosion Control/External and Internal Corrosion Inspection and Monitoring*.

3.1.2 Determine appropriate corrosion monitoring locations. This may include:

- Wells with history of elevated levels of corrosive constituents in the gas stream
- Water-gas interface depth within the production casing
- Wells prone to sand production on withdrawal, which can lead to erosion-corrosion

3.1.2.1 Document the monitoring location.

3.1.2.2 Samples may be taken from in-service equipment at the wellhead or at adjacent equipment (that is upstream of gas processing equipment).

3.1.3 Determine an internal corrosion monitoring frequency for each pipe segment.

3.1.3.1 Monitoring frequency may depend upon chemical treatment program, severity of internal corrosion, or other requirements.

3.1.3.2 Document the monitoring frequency.

3.1.4 Work with Storage & LP Operations and Corrosion Control to identify any deficiencies found during the analysis that could account for the high or increased corrosion rates.

3.1.5 Document any deficiencies found, and plan corrective actions.

3.2 **Responsibility:** Gas Storage & LP Operations

3.2.1 Perform internal corrosion monitoring at the interval specified for each test location in accordance with O&M 27.30, *Corrosion Control/External and Internal Corrosion Inspection and Monitoring*.

3.2.1.1 Obtain gas quality sample/data, which may include, but is not limited to:

- Hydrogen Sulfide
- Carbon Dioxide
- Oxygen
- Free Water
- Chlorides

3.2.1.2 Samples should be collected while the well is on withdrawal, where practicable.

3.2.1.2.1 Label the sample.

3.2.1.2.2 Coordinate with the Integrity Management Engineer to send the samples to a qualified laboratory for analysis.

3.2.1.3 Inspect the internal condition of the tubing string, when accessible.

3.2.1.3.1 If internal corrosion, pitting, or a leak due to internal corrosion is found, notify the Integrity Management Engineer as soon as practicable.

3.2.2 Document monitoring activities, which may include:

- Date
- Location
- Monitoring observations
- Field results

4.0 MONITORING CATHODIC PROTECTION

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Review CP to ensure new or existing wells are adequately protected.

4.1.1.1 Cathodic protection application is subject to environmental and geologic strata variations.

4.1.1.2 Review may include the following information pertaining to the well(s) and storage field:

- Corrosion history
- Well configuration
- Environmental Corrosivity
- Casing Mechanical Integrity Test (MIT)

4.1.1.3 Consult with Gas Storage & LP Operations and Corrosion Control.

4.1.2 Determine if existing CP considered adequate to protect the well casing based on asset historical data.

5.0 DOCUMENTATION

5.1 **Responsibility:** Corrosion Control

5.1.1 Maintain records or maps showing monitoring locations:

5.1.2 Maintain corrosion monitoring data.

5.1.2.1 Maintain internal corrosion monitoring records.

5.1.2.2 Record relative data to CP corrosion control facilities maintenance, including remedial actions and repairs made.

5.1.3 Refer to OM 27.90, *Corrosion Control/Corrosion Control Records*.

5.2 **Responsibility:** Integrity Management Engineer

5.2.1 Retain corrosion monitoring records for the life of the facility.

5.2.1.1 Maintain CP monitoring records including surveys, inspections and test results or comments for the life of the facility.

5.2.2 Incorporate corrosion information into the Storage Integrity Management Program.

SIMG-06-005 Site Security

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To provide for incorporating safeguards in design, construction, and operation of the Vectren natural gas storage system for purposes of site security.

REFERENCES: API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineer	2.2
Corporate Security	2.3, 3.1, 5.2, 6.1
Gas Storage & LP Operations Manager	2.4, 4.1
Gas Transmission Engineering	2.5
Gas Storage & LP Operations	5.1

Accountable Group	Integrity Management
Consulted, Informed	Corporate Security Gas Storage & LP Operations Manager Integrity Management Gas Transmission Engineering

1.0 BACKGROUND

1.1 This procedure was developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016.

1.2 This procedure addresses requirements for assessment and monitoring of site security to ensure the protection of operating personnel, the public, and underground natural gas storage facilities.

2.0 SITE SECURITY

2.1 Vectren will maintain a process to limit access to storage wells during drilling, workover, operation, and abandonment activities.

2.2 **Responsibility:** Integrity Management Engineer

2.2.1 Provide storage threat and hazard analysis data related to site security (i.e., third-party damage, population density, history of third-party incident data) to Corporate Security periodically.

2.2.2 Update Asset Identification and Threat and Risk model to incorporate security measures during the annual review. Refer to SIMG-01-001 Asset Identification and SIMG-03-002 Risk Process & Annual Review.

2.3 **Responsibility:** Corporate Security

2.3.1 Conduct a threat and vulnerability assessment to evaluate storage field sites.

- Consider localized conditions.

- Proximity to roadways and potential for damage from moving vehicles
- Historical data related to security incidents (i.e., vandalism, theft)
- Current threat indicators as reported by government entities

2.3.2 Document and implement site security measures, which may include:

- Barricades (i.e., bollards, barriers)
- Fencing and/or gates
- Lighting
- Signage
- Locking devices (i.e., padlock)
- Security awareness and company policy training

2.4 **Responsibility:** Gas Storage & LP Operations Manager

2.4.1 Ensure security procedures are followed by site personnel.

2.4.2 Ensure security equipment is maintained in good operating order.

2.4.3 Maintain a process to limit access to storage wells.

2.4.4 Provide access to secured areas, as necessary, to perform assigned tasks.

2.5 **Responsibility:** Gas Transmission Engineering

2.5.1 Design physical security measures, upon request.

3.0 INGRESS AND EGRESS

3.1 **Responsibility:** Corporate Security

3.1.1 Ingress or egress of the site may be controlled by fences or enclosures and, when applicable, shall comply with fire codes and regulations.

4.0 SIGNAGE

4.1 **Responsibility:** Gas Storage & LP Operations Manager

4.1.1 Signage will be located at storage facilities, as applicable, per O&M 9.32.4, *Damage Prevention/Facility Identification/Facility Signage*.

5.0 SITE INSPECTIONS

5.1 **Responsibility:** Gas Storage & LP Operations

5.1.1 Perform site security inspection periodically to confirm physical security measures are in place and functioning properly.

5.1.1.1 Measures may include items such as:

- Barricades
- Fencing and/or gates
- Lighting
- Signage
- Locking devices (i.e., padlocks)

5.1.1.2 Site walk may be performed in conjunction with scheduled integrity assessments.

5.1.1.3 Document on Site Security Inspection Checklist form, which includes:

- Purpose of the inspection
- Identity of the trained person conducting the inspection
- Frequency of inspection
- Items to be inspected

5.1.2 Submit findings to Gas Storage & LP Operations Manager, Integrity Management, and Corporate Security.

5.2 **Responsibility:** Corporate Security

5.2.1 Conduct review of site security inspection results for each storage field periodically, including reassessment of potential threats.

5.2.2 Review Site Inspection Checklist form for a listing of well sites inspected since the last annual review.

5.2.2.1 Identify security discrepancies, and work with appropriate personnel for resolution.

5.2.3 Plan and implement site security risk mitigation steps, as appropriate.

5.2.4 Evaluate effectiveness of process and recommend additional measures, as warranted.

5.2.5 Work with Gas Transmission Engineering to design physical security control measures, as applicable.

6.0 DOCUMENTATION

6.1 **Responsibility:** Corporate Security

6.1.1 Document the site security measures and retain site security inspection documentation for the life of the well.

6.1.2 ID Access Card Policy

6.1.3 Key Management Policy

6.1.4 Site Security Assessment Checklist

SIMG-08-001 P&M Selection and Review

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for selecting Preventive and Mitigative (P&M) Measures for wells/reservoirs within Vectren's natural gas storage fields.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

49 CFR 192.605 "Procedural Manual for Operations, Maintenance, and Emergencies"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Annual P&M Program Review
3.0 Annual P&M Selection Process
4.0 Documentation

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1, 4.1
Technical Training	3.2

Accountable Group	Integrity Management
Consulted, Informed	Gas Storage & LP Operations Reservoir Engineering Technical Training Subject Matter Experts

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016.

1.2 Vectren has committed to developing a preventive and mitigative (P&M) measures Selection process within this Storage Integrity Management Program. This procedure documents the consistent process that Vectren will employ when selecting P&M measures.

1.2.1 Measures are selected in regard to a specific threat or threats. They may be implemented programmatically for all fields or on a case-by-case basis for particular well site location(s).

1.2.2 Design elements or monitoring activities implemented above and beyond current code requirements may be considered P&M measures.

1.2.3 P&M Measures may apply system-wide, to a specific storage field, to an individual well, or to a group of wells. Some measures require construction or installation of new equipment, others merely procedural changes.

2.0 ANNUAL P&M PROGRAM REVIEW

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Identify existing P&M measures for the wells and/or reservoirs.

2.1.1.1 Annual Pipeline and Hazardous Materials Safety Administration (PHMSA) report may also be utilized to gather information. Refer to SIMG-09-001 Effectiveness Evaluation.

2.1.2 Review current risk model to determine if changes to selection criteria and/or scoring factors are necessary to reflect new P&Ms implemented since the last review.

2.1.2.1 Consider reviewing measures alongside prior year's operating history to determine whether current P&M measures are effectively reducing likelihood or consequence of failure.

2.1.2.2 Consider evaluating whether trends show unanticipated or unintended increases in operational risks, costs, etc., as a result of P&M measures. If so, reevaluate, modify and/or remove that P&M measure from the program.

2.1.3 Determine whether additional measures apply.

2.1.3.1 Incorporate additional or different P&M measures if any of the following show increased risk (refer to API Recommended Practice 1171 Table 2 – Preventive and Mitigative Programs):

- Number of failures
- Number of near-misses
- Number of required repairs
- Number or severity of casing metal loss indications found during assessment
- Audit or root cause findings

2.1.3.2 Consider lessons learned both internally and through industry events during the current review period to determine if additional P&M measures are appropriate.

2.1.4 Document follow-up actions and assign to specific personnel.

2.1.4.1 Assess the effectiveness of the P&M selection process.

2.1.4.2 Recommend improvements as necessary.

3.0 ANNUAL P&M SELECTION PROCESS

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Review the threats/hazards and risk assessment results identified for the well(s) and/or reservoir(s) in SIMG-03-002 Risk Process & Annual Review.

3.1.1.1 Consider well and/or reservoir threats with the highest overall relative risk scores for additional P&M measures.

3.1.1.2 Determine the significant contributor(s) to each threat/hazard. Refer to SIMG-03-001 Threat/Hazard Identification.

3.1.2 Select P&M measures for well(s) and/or reservoir(s) on an annual basis.

3.1.2.1 Confirm that the selected P&Ms are applicable to the major threat contributor(s) for the locations under consideration.

3.1.2.2 Consult with affected stakeholders including Gas Storage & LP Operations and/or Reservoir Engineering when selecting P&M measures.

3.1.3 Perform what-if analysis using risk model and consider feasibility of proposed P&M.

3.1.3.1 Consult with Subject Matter Experts as necessary.

3.1.3.2 Recommend new or revised P&Ms if substantial improvement in risk reduction can be achieved.

3.1.4 Determine the impact of a proposed measure and identify affected stakeholders.

3.1.5 Develop an implementation schedule for P&M measures.

3.1.5.1 Consult with affected stakeholders such as Gas Storage & LP Operations and/or Reservoir Engineering when developing implementation schedule.

3.1.5.2 Implementing measures may depend on the prioritization schedule determined per SIMG-03-002 Risk Process & Annual Review as well as other factors that affect time and difficulty in implementation.

3.1.5.3 Adjustments may be made in order to consider dividing work evenly across the years to be scheduled. Scheduling to consider field conditions, vendor availability, and separate crews running concurrent projects at different fields.

3.1.6 Re-evaluate the current P&M schedule as needed to address high-risk wells and/or reservoirs.

3.1.7 If additional training is needed or a new P&M measure is selected and must be trained, contact Technical Training.

3.2 **Responsibility:** Technical Training

3.2.1 Provide additional training to Gas Storage & LP Operations personnel on new P&M procedures or equipment, as necessary.

4.0 DOCUMENTATION

4.1 **Responsibility:** Integrity Management Engineer

4.1.1 Document P&M measures (existing and additional) and retain documentation.

4.1.2 Consider an Integrity Management (IM) peer review to ensure the appropriate P&M measure was chosen.

4.1.3 Retain prior years' P&M selections for each well and/or reservoir and use as historical basis.

SIMG-08-002 Evaluating for Emergency Shutdown Valves

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a consistent process in evaluating natural gas storage wells to determine if an automatic or remote-actuated emergency shutdown valve would be an effective means of adding protection to the well and surrounding area.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 192.12 "Underground Natural Gas Storage Facilities"

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:
1.0 Background
2.0 Risk Analysis
3.0 Documentation

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1

Accountable Group	Integrity Management
Consulted, Informed	N/A

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016.

1.2 The purpose for the use of automatic or remote-actuated emergency shutdown valve in a well is to allow an operator to shut-in the well in the case of an emergency or wellhead damage.

1.2.1 These valves are designed to close in cases of loss of wellhead, loss of functionality of wellhead, or when surface conditions are present that endanger the wellhead from functioning properly.

1.2.2 Automatic valves close when pre-programmed conditions are detected.

1.2.3 Remote-actuated valves are typically programmed to alarm upon certain conditions but require operator intervention to signal the valve to close. This can improve response time and enhance safety of personnel who would otherwise have to manually close the valve.

1.2.4 Automatic or remote-actuated emergency shutdown valves may be located at the wellhead, side-gate, or subsurface.

1.3 The use of valve automation should be assessed as part of an overall risk analysis to be performed on a per-well basis. Refer to SIMG-03-002 Risk Process & Annual Review.

2.0 RISK ANALYSIS

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Perform a risk analysis of each natural gas storage well to determine if an automatic or remote-actuated valve would be an effective means of risk mitigation. Consider risk factors.

2.1.2 Evaluate the results of the analysis and determine if installing valves would be effective. If it is determined that installing valves would not be an effective means of adding protection to wells, no further action is necessary. Installing valves may not be warranted for the following scenarios.

- Added risk created by installation and servicing of automated valves/actuators
- Risk of vandalism/terrorism that impairs the operation of the automated valves/actuators
- Alternative protection measures in place that provide physical protection to wellhead

3.0 DOCUMENTATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Maintain documentation as needed.

SIMG-09-001 Effectiveness Evaluation

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method to evaluate the effectiveness of the risk monitoring and risk management programs and continually review and make improvements to ensure functional integrity of the storage facilities.

REFERENCES: API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs”

Interim Final Rule, PHMSA Docket #2016-0016

Responsible Personnel	Section
Integrity Management Engineer	2.1, 3.1
Integrity Management Engineering Manager	2.2

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineer Gas Storage & LP Operations

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirement of API Recommended Practice 1171, Interim Final Rule PHMSA Docket #2016-0016, and Indiana Department of Natural Resources (IDNR) proposed storage field rules.

1.2 This procedure documents the process used for performance measures and reporting of Vectren's natural gas storage fields.

1.3 This document is utilized to assess the effectiveness of risk monitoring and risk management programs and maintain a continual review and improvement cycle in risk management activities to provide functional integrity of the storage operation.

1.3.1 The interval of review and reassessment should be short enough to identify operational and monitoring trends and measure the effectiveness of preventive and mitigative (P&M) measures, but long enough that the data and information that can be brought into the analysis are meaningful.

2.0 TRENDING UNDERGROUND STORAGE METRICS

2.1 **Responsibility:** Integrity Management Engineer

2.1.1 Ensure Underground Gas Storage (UGS) metric data are up-to-date through the end of the reporting period.

2.1.1.1 UGS metrics are documented for the prior calendar year per SIMG-13-002 Required Notifications.

2.1.2 Ensure threat-specific non-reportable performance measures are up-to-date.

2.1.3 Identify trends observed between the latest metrics and prior metrics.

2.1.4 Evaluate trends and determine if risk management actions need revisions or additional P&M measures are warranted.

2.1.4.1 Consult with Reservoir Engineer and Gas Storage & LP Operations before making recommendations.

2.1.5 Document the following:

- Date
- Reviewed by
- Trends identified
- Recommendations

2.2 **Responsibility:** Integrity Management Engineering Manager

2.2.1 Refer to the Management of Change (MOC) Process.

2.2.2 Review trending documentation and approve recommended changes, as applicable.

3.0 DOCUMENTATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Maintain metric trending information.

SIMG-10-001 Recordkeeping

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method to create and maintain a thorough, accurate, and complete inventory of gas storage assets.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

49 CFR 192.605 “Procedural Manual for Operations, Maintenance, and Emergencies”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Recordkeeping and Management
3.0 Original Design Basis/Construction/Completion
4.0 Well Work Records
5.0 Permitting, Procedures, Personnel, and Equipment Records
6.0 Testing and Monitoring Activities Records

Responsible Personnel	Section
Integrity Management Engineering Manager	2.0 – 8.0
Gas Storage & LP Operations Manager	2.0 – 7.0
Gas Transmission Engineering Manager	2.0 – 7.0
Technical Training Supervisor	7.1
Quality Management Specialist	7.2
Reservoir Engineering Manager	2.0 – 7.0

Accountable Group	Integrity Management
Consulted, Informed	SMS Management of Change

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program has been developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This recordkeeping procedure serves as a framework document within that program.

1.1.1 Records to be kept include the reservoir, individual wells, associated equipment and facilities. This program excludes gathering pipeline systems and associated equipment covered by the Transmission Integrity Management Program (TIMP).

1.1.2 Recordkeeping will be updated as assets are added, modified, or removed from the Vectren system.

1.2 Vectren defines risk management records retention schedule and management plan and records retention period in the applicable procedures and in Exhibit 10-001-A - Gas Storage Recordkeeping. Risk management documentation can include data used during risk assessment, preventive and mitigative (P&M) measures employed, and periodic evaluation of performance metrics.

2.0 RECORDKEEPING AND MANAGEMENT

2.1 Records are maintained to document establishment of and compliance with procedures as required.

2.1.1 Records are kept in an appropriate format (paper or electronic) as documented in Exhibit 10-001-A - Gas Storage Recordkeeping.

2.1.1.1 Electronic records are maintained in the following locations:

- **Avocet:** Primarily a system utilized by engineering and operations, Avocet typically manages routine or scheduled activities. Examples include but are not limited to reservoir performance data, some storage IM documentation, disposal well Mechanical Integrity Tests (MIT) and volumes, service company tickets, permits as well as other applicable reservoir trending metrics.

- **G drive:** A storage location for electronic reservoir and engineering data that is not associated to a specific well. This can include permits, geologic reports, annual reports, and white papers.
- **Maximo:** Includes valve maintenance records, cathodic protection readings, atmospheric corrosion inspection, and annual wellhead leak inspections.

2.1.1.2 Within the electronic and paper storage system, there is also Reservoir Engineering Library, or ***REL***, which houses:

- Geologic records
- Gas quality records
- Reservoir trending metrics
- Records pertaining to the storage well that could be related to the storage reservoir and can also be found on Avocet.

2.1.1.3 Physical records are stored and maintained within ***Vault*** and/or ***REL***, which contains land records and inspection records, such as well logging reports and IM forms (i.e., Work Plan Packet and Port Assessment Forms).

2.2 Retention intervals for records were established to meet regulatory requirements. See Exhibit 10-001-A - Gas Storage Recordkeeping for retention intervals where no regulatory requirements exist.

2.2.1 Vectren maintains associated storage inventory records for the life of the facility.

3.0 ORIGINAL DESIGN BASIS / CONSTRUCTION / COMPLETION

3.1 Vectren maintains design, construction, inspection, and maintenance documents for each Vectren asset for the life of the facility. Examples of documentation are as follows:

- Design basis for maximum *reservoir pressure*
- Accurate and comprehensive records of design activities maintained for life of facility
  - o Geologic records (well logs, cutting reports, core reports, geophysical records, maps)
  - o Engineering records (hydrocarbon production, data used in reservoir characterization, reservoir design data, reservoir operational data)
  - o Storage land and mineral ownership, rights, and control
  - o Facility integrity plan includes design criteria, work plan, and procedural documents
  - o Well drilling, completion, workover, and plugging records
  - o Regulatory records (permit applications, permits, reports, correspondence)
- Baseline pressure and volume conditions of reservoir

- Well test records and well actions taken during commissioning
- Permitting
- Regulatory records for project commissioning

4.0 WELL WORK RECORDS

4.1 Vectren maintains records of well completion (as-built), well construction, and well work activities, as applicable and available, for the life of the facility. Records include, but are not limited to:

- Wellhead equipment and valves
- Well casing
- Casing cementing practices
- Completion and stimulation considerations
- Well remediation
- Well closure
- Testing and commissioning
- Monitoring of construction activities

4.1.1 Records that relate to the current state of completion and functional integrity are most relevant.

5.0 PERMITTING, PROCEDURES, PERSONNEL, AND EQUIPMENT RECORDS

5.1 Vectren maintains records relating to permitting, procedures, personnel, and equipment, as applicable and available. Records include, but are not limited to:

- Environmental, health, and safety (on-site safety meeting records)
- Monitoring of construction activities (qualifications, equipment suitability records, contractor safety orientation)

6.0 TESTING AND MONITORING ACTIVITIES RECORDS

6.1 Vectren maintains records of natural gas storage testing and monitoring activities, permitting, procedures, personnel, and equipment. Records are retained, as applicable and available, for the life of the facility. Records include, but are not limited to:

- Reservoir and well mechanical integrity records that demonstrate functional integrity during commissioning, including monitoring data and analyses
- Well testing records and records of well actions taken during commissioning
- Regulatory records for project commissioning including permit applications, permits, and all reports and correspondence with regulatory agencies

6.2 Inspections, tests, patrols, and/or analyses are documented according to the applicable procedure(s).

7.0 TRAINING RECORDS

7.1 Vectren maintains records for Company personnel that demonstrate compliance with training. Documentation may include:

- Identification of the trained individual

- Identification of the training and methodology of training provided
- Date(s) training was completed by the individual

7.2 Vectren will follow the Quality Management Program procedure QMP 7.0, *Contractor Review Procedure*.

8.0 PLANS AND PROCEDURES

8.1 Vectren maintains documentation of the Storage Integrity Management Program for the life of each Vectren asset.

- Written storage integrity management procedure(s)
- Documents supporting threat identification, risk factor determination, and risk assessment, as applicable
- Documents supporting the development and implementation of the Assessment Plan and Storage Integrity Management Program
- Establishment of and compliance with procedures that are verifiable, including superseded procedures

EXHIBIT 10-001-A – GAS STORAGE RECORDKEEPING

Document Population – All forms are used for decision-making. Retain three packets per well per assessment.

	Who									Current Storage Practice												
Document	**Contractor**	**GTE**	**IM**	**Land**	**OPS**	**RE**	**Storage Station**	**Technical Records**	**Technical Training**	**Admin**	**Avocet**	**GDrive**	**GeoFields**	**GIS**	**GTE**	**IM**	**Maximo**	**OnBase**	**REL**	**Station**	**Vault**	**Retention Policy**
IM Forms (WorkPlan Packet, Port Assessment Forms)			X								X	X									X	At least 15 years
Inspection reports (Well Logging Reports)			X								X	X							X		X	Life of the facility
Shut in Pressure Documentation					X						X	X							X			At least 15 years
Wellhead Survey Record					X											X				X		Life of the facility
Observation Pressures					X						X								X			At least 15 years
Eco Meter					X						X								X			At least 15 years
Flow Test Information/Orifice plate change					X						X								X			At least 15 years
Drip Location					X						X								X			At least 15 years
Well Stimulation						X					X								X			Life of the facility
H2S Trending					X						X								X			At least 15 years
Well Document						X					X								X			Life of the facility
Well Bore Diagram WBD						X					X								X			Life of the facility
Pressure Transient Analysis PTA						X					X											At least 15 years
Annual Reports			X									X										At least 15 years
Material Specifications/Pressure Test Records					X						X											Life of the facility
MOC, White Papers			X									X										At least 15 years
Completion Work Certificates									X		X											Life of the facility
Well Downtime					X	X					X											At least 15 years
Accounting						X					X											At least 15 years
Liquid Sample Analysis			X		X	X					X											At least 15 years
Well Drilling, Workover, and Plugging		X									X								X			Life of the facility
Permits		X	X			X					X	X							X			Life of the facility
Geophysical records						X					X								X			Life of the facility
Land records				X																	X	Life of the facility
Gas Test | Corrosion					X		X				X	X				X						Life of the facility
Service company Tickets	X									X		X										At least 15 years
Geologic Reports						X						X							X			Life of the facility
Contractor Qualification		X	X		X	X						X										At least 15 years
RCA Reports			X									X										At least 15 years
WO Packet (capital work)		X									X							X				Life of the facility
Valve Maintenance record					X												X					Life of the facility
Risk Model Output (Snapshot, trending)			X									X	X									At least 15 years
Training Records								X				X				X						At least 15 years
Gas Quality Records			X									X				X						At least 15 years

SIMG-12-002 Training Requirements

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To confirm Company personnel involved with the Storage Integrity Management Program are competent and properly trained to perform their specific job function.

REFERENCES: API Recommended Practice 1171 “Functional Integrity of Natural Gas

Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs"

Interim Final Rule, PHMSA Docket #2016-0016

Indiana Department of Natural Resources (IDNR) 29-28-1 and 29-28-3

Vectren Storage Integrity Management Program Outline

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineering Manager	2.1
Gas Transmission Engineering (GTE)	4.1
Storage & LP Operations Supervisor	3.2
Technical Training	3.1, 5.1

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineering Storage & LP Operations Supervisor Integrity Management Engineering Manager Gas Storage & LP Operations Manager Gas Compliance Contractors Technical Training

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This Quality Assurance procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

2.0 STORAGE INTEGRITY MANAGEMENT TRAINING

2.1 **Responsibility:** Integrity Management Engineering Manager

2.1.1 Define required training courses related to storage integrity management and the Storage Integrity Management Plan/Program. Requirements may include, but are not limited to:

- Education and/or certifications
- Storage integrity management experience
- Training programs
- Job-specific tasks completed

2.1.2 Confirm supervisory personnel who oversee activities within the Storage Integrity Management Program are able to provide competent and effective supervision of the procedures being carried out.

2.1.3 Submit documentation of training to Technical Training.

3.0 OPERATIONS AND MAINTENANCE TRAINING

3.1 **Responsibility:** Technical Training

3.1.1 Coordinate with Reservoir Engineering, Storage & LP Operations Supervisor, Integrity Management Engineering Manager, and Gas Compliance to develop training and testing of persons assigned to operate and maintain storage wells and reservoirs.

3.1.2 Conduct, file, and maintain documentation pertaining to the training.

3.2 **Responsibility:** Storage & LP Operations Supervisor

3.2.1 Confirm personnel who perform activities within the Storage Integrity Management Program are competent and trained to perform the specific job function and procedures. These may include but not limited to:

- Preventive and mitigative measures
- Well integrity assessments
- Storage integrity assessments
- Recognition of abnormal operating conditions

4.0 CONTRACTOR PERSONNEL

4.1 **Responsibility:** Gas Transmission Engineering (GTE)

4.1.1 Provide and specify scope of work performed by Contractors.

4.1.2 Confirm Contractors have the appropriate training to conduct the specific job function.

4.1.3 Review procedures with Contractor prior to work being performed.

4.1.4 Ensure persons performing work in storage field are familiar with the procedures and recordkeeping requirements.

5.0 DOCUMENTATION

5.1 **Responsibility:** Technical Training

5.1.1 File and maintain documentation pertaining to training including, but not limited to:

- Date training held
- Names of individuals attending training
- Course outline, if applicable

5.1.2 Retain documentation per regulatory requirements

5.1.3 Consult Integrity Management Engineering Manager, Reservoir Engineering, Gas Storage & LP Operations Manager, and Gas Compliance to define retention intervals where no regulatory requirements exist.

SIMG-13-001 Communications

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for communication with various stakeholders of storage field activities and operations during normal, abnormal, and emergency operations.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

Responsible Personnel	Section
Gas Storage & LP Operations	2.1
SMS Management of Change Manager	2.2
Damage Prevention and Public Awareness Manager	3.1
Gas Storage & LP Operations Manager	4.1

Accountable Group	Integrity Management
Consulted, Informed	Gas Supply Gas Engineering Gas Control Integrity Management Reservoir Engineering

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This procedure is one component within that program.

1.2 It is Vectren's goal to communicate with various stakeholder audiences to raise awareness of the Vectren Storage Integrity Management Program.

1.3 Vectren will utilize Public Awareness Program and Damage Prevention plans where possible to coordinate communication related to the storage fields.

1.3.1 Refer to Vectren Public Awareness Program.

1.3.2 Refer to O&M 9.10, *Damage Prevention/Compliance*.

2.0 INTERNAL COMMUNICATIONS

2.1 **Responsibility:** Gas Storage & LP Operations

2.1.1 Interact with Gas Supply, Gas Engineering, Gas Control, Integrity Management, and Reservoir Engineering as needed to maintain reservoir and well integrity during normal, abnormal, and emergency conditions, as required.

2.1.1.1 Communications may include, but are not limited to:

- Authority for initiating flow
- Operating natural gas storage facilities
- Shutting in natural gas storage facilities
- Planned assessments
- Scheduled monitoring activities
- Preventive and mitigative (P&M) measures

2.2 **Responsibility:** SMS Management of Change Manager

2.2.1 Follow O&M 3.30, *Priority Alerts/Priority Alert Process* to communicate updates.

3.0 EXTERNAL COMMUNICATIONS

3.1 **Responsibility:** Damage Prevention and Public Awareness Manager

3.1.1 Refer to Vectren Public Awareness Program.

3.1.2 Refer to O&M 9.10, *Damage Prevention/Compliance*.

4.0 EMERGENCY COMMUNICATIONS

4.1 **Responsibility:** Gas Storage & LP Operations Manager

4.1.1 Refer to the Well Control Emergency Response Plan and Corporate Response Plan.

PURPOSE: To establish a standardized method to generate, review and report changes made to Underground Storage Facilities to the Pipeline and Hazardous Materials Safety Administration (PHMSA); the Indiana Utility Regulatory Commission (IURC); and the Indiana Department of Natural Resources (IDNR).

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" by reference

49 CFR 191.7 "Addressee for Written Reports"

49 CFR 191.17 "Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Annual Report"

49 CFR 191.22 "National Registry of Pipeline and LNG Operators"

Interim Final Rule, PHMSA Docket #2016-0016

PHMSA Form 7100.4-1

TASK OVERVIEW:

Responsible Personnel	Section
Integrity Management Engineering Manager	2.1
Gas System Integrity Director	3.1
Compliance Director	4.1

Accountable Group	Integrity Management
Consulted, Informed	Gas Storage & LP Operations SMS Executive Governance Committee IDNR PHMSA

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice 1171, incorporated by reference in Interim

Final Rule PHMSA Docket #2016-0016. This procedure is one component within that program.

1.2 All underground gas storage fields operated by Vectren are within the state of Indiana.

1.3 Notification requirements for incident, national registry, and safety-related condition reporting became effective on January 18, 2017.

2.0 UNDERGROUND STORAGE METRICS

2.1 **Responsibility:** Integrity Management Engineering Manager

2.1.1 Review information with Gas Storage & LP Operations as necessary to confirm information complete.

2.1.2 Prepare documentation detailing the metrics and the results to be submitted to PHMSA.

2.1.3 Forward the information to the SMS Executive Governance Committee.

3.0 SUBMITTAL OF METRICS

3.1 **Responsibility:** Gas System Integrity Director

3.1.1 For each Operating Company, confirm that metrics are submitted electronically to PHMSA annually.

3.1.1.1 Submit program information as requested by PHMSA.

3.1.1.2 Subsequent annual reports are expected to be due on or about March 15, for the previous calendar year.

3.1.2 Submit notifications to PHMSA electronically through PHMSA Portal.

3.1.3 As part of the submittal process, enter the name of the Senior Executive Officer that certified the metrics.

3.1.3.1 Entering the name of the Senior Executive Officer represents an official signature.

3.1.4 Review the current instructions for completing the form, PHMSA FORM 7100.4-1, on the PHMSA website.

3.1.5 Report metrics for each UGS facility and each reservoir or geological storage formation within a facility.

3.1.5.1 A single Annual Report is permitted each year, which includes a separate entry (Part B) for each UGS facility and a separate entry (Part C) for each reservoir or geological storage formation within a facility.

4.0 REQUIRED NOTIFICATIONS AND SUBMITTALS

4.1 **Responsibility:** Compliance Director

4.1.1 Complete the following notifications as required.

4.1.1.1 Sixty days prior to changes, notifications are required for the following:

- Changes to a UGS facility
- Abandonment, drilling, or well workover (including replacement of wellhead, tubing, or casing) of an injection, withdrawal, monitoring, or observation well.

- Change in the entity (including company, municipality, etc.) responsible for an existing UGS facility and acquisition or divestiture of an existing UGS facility
- Justification for deviations from the mandatory or non-mandatory provisions in the API Recommended Practice 1171

4.1.1.1.1 Routine maintenance or repairs to existing components do not require notification to PHMSA.

4.1.1.2 Other notifications to IDNR may be required, such as:

- Casing failure suspected or indication of potential casing failures, including abnormal fluid accumulation
- Hydrogen sulfide (H_2S) test results indicating concentrations above threshold limits
- Conducting mechanical integrity test (*MIT*)
- Actions taken at each storage field to perform testing and/or monitoring of well integrity, including any corrective measures.
- Quarterly reports
- Other request from authorized representative of IDNR

SIMG-14-001 Environmental & Safety Considerations

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To provide a standardized approach to confirm that environmental and safety assessment is conducted in a manner that minimizes environmental and safety risks.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Environmental and Safety Considerations
3.0 Directions for Design and Construction of New Gas Storage Wells
4.0 Considerations During Well Work Activities of Gas Storage Wells

Responsible Personnel	Section
Gas Transmission Engineering	3.1, 4.1, 5.1

Accountable Group	Integrity Management
Consulted, Informed	Integrity Management Engineer Integrity Management Engineering Manager Gas Storage & LP Operations Reservoir Engineering Environmental Affairs Integrity Management

1.0 BACKGROUND

1.1 A formal Storage Integrity Management Program is being developed to meet the requirements of API Recommended Practice (RP) 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 Environmental Compliance Protocols incorporate safeguards for the environment, safety and health of workers and the public into natural gas storage design, well design and well work activities.

1.3.1 Safeguards incorporated correspond with environmental regulations and/or are founded on industry-recommended practices and applicable to process safety in storage operations.

2.0 ENVIRONMENTAL AND SAFETY CONSIDERATIONS

2.1 Vectren personnel and Contractors perform activities consistent with Vectren safety and environmental policies and procedures, which are available on the Vectren intranet.

2.1.1 Refer to the Safety Bulletin Board on the intranet for safety Policies and Procedures.

2.1.2 Refer to the Environmental Affairs page on the Vectren intranet for Vectren Energy Delivery Environmental Compliance Protocols.

2.1.3 Vectren project managers are responsible for providing Contractors with reference materials.

2.2 Reservoir and storage wells, including associated facilities, are subject to environmental and safety policies.

2.3 Activities subject to environmental and safety policies include, but are not limited to:

- Reservoir design
- Well design
- Well work activities
  - Well integrity assessments
  - Periodic monitoring
  - Routine storage maintenance or remediation activities

2.3.1 Refer to the Gas Transmission Engineering Design Manual (GTEDM), Gas Transmission Engineering Construction Manual (GTECM), and Environmental Compliance Protocols.

2.4 In the event that a safety concern poses a risk to the environment or health of the workers or public, follow procedures detailed in the Corporate Safety Manual. After immediate safety and environmental risks are mitigated, the responsible supervisor or project manager shall consult with other relevant stakeholders to assist in determining a course of action, which may include:

- Appropriate remedial corrective measures
- Root cause determination
- Assessment of generic implications
- Proposed actions to prevent recurrence

The Integrity Management Engineer shall ensure that the event is documented (consistent with the nature of the safety concern) and that corrective actions are scheduled and completed.

The Integrity Management Engineer shall notify the Integrity Management Engineering Manager. The Integrity Management Engineering Manager shall ensure that an appropriate level of communication is maintained with Vectren management and with the regulatory authorities until the safety concern is resolved.

3.0 DIRECTIONS FOR DESIGN AND CONSTRUCTION OF NEW GAS STORAGE WELLS

3.1 **Responsibility:** Gas Transmission Engineering

3.1.1 Vectren incorporates safeguards to environment, safety, and health of workers and the public into natural gas storage design.

3.1.1.1 Consult with the appropriate stakeholders including Gas Storage & LP Operations, Reservoir Engineering, Environmental Affairs, and Integrity Management.

3.1.1.2 Incorporate protection of surface water and groundwater resources in design of storage facilities.

3.1.1.3 Ensure an environmental impact review is conducted prior to well drilling, facility modifications, and facility construction.

3.1.1.4 Incorporate plans for monitoring worksite conditions related to storage development and well drilling into the design of natural gas storage facilities to protect the environment and the safety and health of workers and the public.

3.1.1.5 Design for long-term viability and functional integrity in order to maintain and operate storage facility consistent with environmental regulations and maintain worker and public safety for life of the storage facility.

3.1.2 Incorporate safeguards to environment, safety, and health of workers and the public into natural gas storage design, well design, and well work activities.

3.1.2.1 Monitor worksite conditions during well construction in order to protect the environment and the safety and health of workers and the public.

3.1.3 Consider using the guidelines in the following publications as reference:

- API RP 49 “Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide”
- API RP 51R “Environmental Protection for Onshore Oil and Gas Production Operations and Leases”
- API RP 54 “Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations”
- API RP 76 “Contractor Safety Management for Oil and Gas Drilling and Production Operations”

4.0 CONSIDERATIONS DURING WELL WORK ACTIVITIES OF GAS STORAGE WELLS

4.1 **Responsibility:** Gas Transmission Engineering

4.1.1 Incorporate safeguards to environment, safety, and health of workers and the public into natural gas storage well work activities.

4.1.1.1 Consult with the appropriate stakeholders including Gas Storage & LP Operations, Reservoir Engineering, Environmental Affairs, and Integrity Management, as required.

4.1.1.2 Consider an environmental impact review before and after well work activities.

4.1.1.3 Incorporate plans for monitoring worksite conditions related to storage development and well drilling into the design of natural gas storage facilities to protect the environment and the safety and health of workers and the public.

4.1.2 Incorporate safeguards to environment, safety, and health of workers and the public while performing well work.

4.1.2.1 Take actions to protect surface water and groundwater resources during well servicing

4.1.2.2 Account for the long-term viability and functional integrity of the well during well work activities to maintain and operate the well consistent with environmental regulations and to maintain worker and public safety throughout the life of the well.

4.1.2.3 Ensure procedures are followed while performing maintenance functions, including options of venting, flaring, blow-down, or other isolation procedures, as well as an assessment of the characteristics and volume of fluids in the context of safety and environmental protection.

4.1.3 Consider using the guidelines in API RP 49, API RP 51R, API RP 54, and API RP 76 as reference.

5.0 REQUIREMENTS FOR ABANDONMENT OF GAS STORAGE WELLS

5.1 **Responsibility:** Gas Transmission Engineering

5.1.1 Incorporate safeguards to environment, safety, and health of workers and the public into natural gas storage well plug and abandonment operations.

5.1.1.1 Consult with the appropriate stakeholders including Gas Storage & LP Operations, Reservoir Engineering, Environmental Affairs, and Integrity Management.

5.1.2 Refer to applicable state or local plug and abandonment (P&A) environmental regulations.

6.0 WELL SITE SECURITY AND SAFETY

6.1 Refer to SIMG-06-005 Site Security and O&M 44.37.6, *Underground Storage/Environment and Safety/Environmental and Safety Considerations* for well site security and safety.

SIMG-14-002 H2S Hazard Communication

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

PURPOSE: To establish a standardized method for identifying and communicating hydrogen sulfide (H_2S) hazards to field personnel and contractors prior to any well work in natural gas storage fields.

REFERENCES: 49 CFR 192.7 incorporating API Recommended Practice 1171 “Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs” by reference

49 CFR 192.12 “Underground Natural Gas Storage Facilities”

49 CFR 192.605 “Procedural Manual for Operations, Maintenance, and Emergencies”

Interim Final Rule, PHMSA Docket #2016-0016

TASK OVERVIEW:

1.0 Background
2.0 Hydrogen Sulfide Testing/Readings
3.0 Hydrogen Sulfide Safety Communication
4.0 Documentation

Responsible Personnel	Section
Integrity Management Engineer	3.1
Reservoir Engineering	2.1, 4.1
Gas Storage & LP Operations	2.2, 3.2
Gas Transmission Engineering	3.3

Accountable Group	Integrity Management
Consulted, Informed	Reservoir Engineering Gas Storage & LP Operations Contractors

1.0 BACKGROUND

1.1 The Storage Integrity Management Program is in compliance with the requirements of API 1171, incorporated by reference in Interim Final Rule PHMSA Docket #2016-0016. This hydrogen sulfide safety communication procedure serves as a framework document within that program.

1.2 Vectren intends to incorporate additional detail into this framework document as the program is developed. This framework document outlines the processes that Vectren will employ and serves as a roadmap for future development.

1.3 Storage wells should be tested on a frequency determined to be appropriate to determine the presence of H_2S in the produced fluids.

1.4 In addition to the routine H_2S testing, additional monitoring may be required to ensure safety of the personnel working on the fields and the integrity of the storage assets.

1.5 This procedure focuses on the communication of H_2S hazard.

2.0 HYDROGEN SULFIDE TESTING/READINGS

2.1 **Responsibility:** Reservoir Engineering

2.1.1 Plan optimal frequency for H_2S testing of each storage field.

2.1.2 Select appropriate testing method.

2.1.3 Communicate test plan and method to Gas Storage & LP Operations as necessary.

2.2 **Responsibility:** Gas Storage & LP Operations

2.2.1 Conduct test in line with the plan communicated by Reservoir Engineering.

2.2.2 All personnel working around wells or equipment where H_2S is known to be present or may be present must be trained in advance on the hazards of working around H_2S.

2.2.3 Use appropriate personal protective equipment (PPE) during testing. See the Corporate Safety Manual.

2.2.4 Ensure proper ventilation is at the test location to prevent gas accumulation in the work area.

2.2.5 Document and report test results to Reservoir Engineering.

3.0 HYDROGEN SULFIDE SAFETY COMMUNICATION

3.1 **Responsibility:** Integrity Management Engineer

3.1.1 Consult with Reservoir Engineering and Gas Storage & LP Operations for fields that have the presence of hydrogen sulfide or other hazardous or corrosive agents.

3.1.2 Ensure that work plan packet for *wireline*, *slickline*, and logging operations has information on H_2S presence and appropriate H_2S safety plan.

3.1.3 Ensure work plan is communicated to the Contractor(s) and field personnel on the job.

3.2 **Responsibility:** Gas Transmission Engineering or Gas Storage & LP Operations as applicable depending on type of work

3.2.1 Ensure proper communication of H_2S presence to Contractor(s) and field personnel performing well work and/or preparation for identified fields.

3.2.2 Ensure appropriate H_2S PPE is used during well work and/or preparation for identified fields.

3.3 **Responsibility:** Gas Transmission Engineering

3.3.1 Consult with Reservoir Engineering and Gas Storage & LP Operations for fields that have the presence of hydrogen sulfide or other hazardous or corrosive agents prior to drilling new wells.

3.3.2 Consider API Recommended Practice 49 while preparing the H_2S safety plan.

3.3.3 Ensure work plan is communicated to the Contractor(s) and field personnel on the job.

4.0 DOCUMENTATION

4.1 **Responsibility:** Reservoir Engineering

4.1.1 Maintain H_2S readings and communication documentation.

Appendix A - Storage Integrity Management Program Support Documentation

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

This section contains links to the following documents, which support the Storage Integrity Management Program (SIMP):

- Gas Storage Integrity Management Team Charter
- Gas Storage Integrity Management Team Calendar
- Management of Change (MOC) Process

- Safety Management System (SMS) Framework
- Public Awareness Program (PAP)
- Well Control Emergency Response Plan

State and Federal Cross Reference

Vectren Storage Integrity Management Program (SIMP) - Revision 2020.2 - Effective Date 6/1/2020

FEDERAL CROSS REFERENCE:

FEDERAL REGULATION	MANUAL LOCATION FOUND IN (CHAPTER/SECTION #)
40 CFR 124 "Procedures for Decisionmaking"	SIMP-03
40 CFR 144 "Underground Injection Control Program"	SIMP-03
40 CFR 146 "Underground Injection Control Program: Criteria and Standards"	SIMP-03
40 CFR 147 "State, Tribal, and EPA-Administered Underground Injection Control Programs"	SIMP-03
49 CFR Part 191	
191.7	SIMP-03 SIMG-13-002
191.17	SIMP-03 SIMG-13-002
191.22	SIMP-03 SIMG-13-002
Part 192	SIMP-03
192.7	SIMP-03 SIMG-01-001 SIMG-03-001 SIMG-03-002 SIMG-04-002 SIMG-04-003 SIMG-04-004 SIMG-05-001 SIMG-06-001 SIMG-08-001 SIMG-08-002 SIMG-10-001 SIMG-13-001 SIMG-13-002

	SIMG-14-001 SIMG-14-002
192.12	SIMP-03 SIMG-01-001 SIMG-03-001 SIMG-03-002 SIMG-04-002 SIMG-04-003 SIMG-04-004 SIMG-05-001 SIMG-06-001 SIMG-08-001 SIMG-08-002 SIMG-10-001 SIMG-14-001 SIMG-14-002
192.605	SIMP-03 SIMG-01-001 SIMG-03-001 SIMG-03-002 SIMG-04-002 SIMG-04-003 SIMG-04-004 SIMG-05-001 SIMG-08-001 SIMG-10-001 SIMG-14-002