Delaware G&P, LLC (EnLink) is submitting this midstream operations plan under the State of New Mexico Oil Conservation Division's new waste rules, 19.15.28 NMAC, that took effect on May 25,2021. Pursuant to section 19.15.28.8(C)(1) NMAC, natural gas gathering system operators must implement an operations plan, including operational and best management practices, to minimize the waste of natural gas. Please see the accompanying non-exclusive practices that include routine maintenance programs, cathodic protection, corrosion control, liquids management, and integrity management along with additional practices that are intended to minimize natural gas waste.

This plan is intended to be used as a reference document for gathering pipeline operation and maintenance, gas or liquid pipeline and pipeline facilities, or any other Company owner or operated property or facilities. This document is to be used in combination with other Company documents when necessary and is subject to review and continued edification.

Company Name and associated Affected Facilities under Operations Plan:

Delaware G&P, LLC (EnLink)

Facility Name	Facility ID
Alamo Compressor Station	fAPP2123137223
Charro Compressor Station	fAPP2123137223
Corral Canyon Compressor Station	fAPP2123137578
Coyote Station	fAPP2123137806
Falcon Station	fAPP2123137987
Horned Frog Compressor Station	fAPP2123138181
Macy J Compressor Station	fAPP2123138290
Raptor Terminal	fAPP2123138444
Rico Compressor Station	fAPP2123138572
Lobo Gathering System	fAPP2123145107
NGGS as built map for Lobo Gathering System	fAPP2123145107

If you have any questions or need any additional information, please contact me by phone at (225) 892-2487 or Mike.Luckett@enlink.com.

Sincerely,

Mike Luckett

Mike Luckett
Lead Environmental Engineer

1 PURPOSE

This procedure is established to state general procedures to be carried out when operating and maintaining gas pipelines, repairing or removing unsafe pipeline segments from service, responding to emergencies or other abnormal operating conditions, and repairing of hazardous leaks, in accordance with the Title 49 Code of Federal Regulations.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• All operations, maintenance and repairs made to the pipelines.
Engineering and Operations	• Final determination of whether or not a pipeline segment is safe.
Senior Vice President, Operations	• Granting written waivers to this procedure.
Engineering	• Upon request by Vice President of Operations to deviate from normal operating practices, conduct a study of the issue to determine the best approach to ensure safe operations.
Regulatory Department	• File a new construction report with the State, as required by the State Compliance regulations.
Engineering	• May provide technical guidance, when necessary, on pipeline maintenance such as pipe and valve specifications, etc.

3 PROCEDURES

- Prior to beginning service through any pipeline facility, such facility will be in compliance with state and federal regulations and applicable portions of this manual. Non-jurisdictional gas gathering systems are not required to comply with this manual.
- Changes or deviations from this procedure must first be approved by the Senior Vice President of Operations and should in no way diminish the intent of protection of employees, the public or the environment.
- All work performed in complying with this procedure will be performed in a safe manner. Existing industrial safety regulations pertaining to the work area, safety devices, and safe working practices are not intended to be supplanted by these procedures.
- This procedure will be reviewed at least once each calendar year, not to exceed 15 months. Annual procedure reviews are the responsibility of the DOT Compliance Group. The annual review is conducted by a Committee of Company personnel from various departments within the Company. The DOT Compliance Group will revise and distribute revisions to this procedure.
- Appropriate parts of this procedure will be kept at locations where operations and

maintenance activities are conducted.

- All pipelines, offshore gathering lines and regulated onshore gathering lines will be operated, designed, installed, constructed, initially inspected/tested, replaced, relocated or otherwise changed according to the requirements of CFR 49 Part 192 and these procedures. This includes pipelines that have been converted to service according to the requirements of Part 192.14.
- If a segment or fitting of a pipeline becomes unsafe to operate, that segment or fitting will be replaced, repaired or removed from service immediately.
- Any leaks determined to be hazardous to the safety of personnel, the public, or the environment will be repaired immediately.

4 ✓ELIMINATING HAZARDOUS LEAKS AND MINIMIZING METHANE EMISSIONS

The following procedures are currently being done or possibly will be done, as the situation warrants, for the Company to address the elimination of hazardous leaks and efforts to reduce total methane emissions. Part of this process was already in progress before the PIPES Act of 2020 came into effect. This section is also meant to meet the requirements on Section 114(b) of the PIPES Act.

Eliminating Hazardous Leaks

The Company currently addresses hazardous leaks, per O&M Procedures ENL-GOM-00006 and ENL-GOM-00032.

Minimizing Methane Emissions

The Company has set a goal of zero greenhouse gas emissions by 2050. The Company plans to execute substantial emissions reduction strategies along the way that will systematically move the company toward its net zero goal.

The Company has joined The Environmental Partnership, a coalition of industry companies committed to pursuing emissions reductions.

The Company will strive to achieve emissions reduction milestones, all as part of our goal to reach net zero emissions by 2050, including:

- Achieving a 30% reduction in methane emissions intensity by 2024, as compared to 2020 levels
- Pursuing a path to reach a 30% reduction in our total CO_2e emissions intensity by 2030, as compared to 2020 levels

The company is evaluating numerous emissions reduction innovations, process improvements, and opportunities, which may include:

- Replacing or retrofitting natural gas-driven pneumatic controllers to lower-emitting alternatives
- Increasing usage of renewable energy to power our operations
- Converting natural gas-driven equipment, such as compressor engines, to run on electricity
- Implementing carbon capture technologies for beneficial reuses or sequestration of carbon dioxide
- Increasing the use of portable flares, when possible, during pigging operations or any other maintenance activities, to reduce intentional venting
- Replacing natural gas instrument fuel supply with air from air compressors, where possible

5 AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/19/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/16/2019	Completed 2019 annual review. No changes.
1.0	9/28/2020	For future review dates, see EnLink Gas O&M Manual.

1 PURPOSE

These procedures establish guidelines for start-up and shutdown of compressor units and any part of a pipeline in a manner designed to assure operation within MAOP limits.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• Responsible for implementing and following the procedures in this section.

3 PROCEDURES

✓Operations shall prepare a written procedure to insure that the MAOP of a compressor station and/or pipeline will not be exceeded, and which includes the following topics, as applicable:

- Facilities affected by shutdown or start-up; including off site and outside operators.
- Order of operating valves and devices.
- Verification of valve positions and disposition of automatic valves.
- Settings of safety devices, regulators and control devices.
- Location and disposition of affected meter stations.
- Gas flow capacity of all affected equipment and facilities.
- Monitoring of pressures during each phase of operation.
- Blow-down and vent locations and elevations, and surrounding conditions.
- Purging sources, methods and procedures.
- Pressuring or re-pressuring into service.
- When starting a unit that shut down on an automatic shutdown, check for the cause of the shutdown and clear any safety issues prior to start-up.
- Control Room Management Procedures.

Appendix A. AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/19/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/16/2019	Completed 2019 annual review. No changes.
1.0	9/28/2020	For future review dates, see EnLink Gas O&M Manual.

1 PURPOSE

These procedures establish the Company program to ensure continuing surveillance of Company pipeline facilities and for actions to be taken by employees concerning changes in Class Location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, encroachments and other unusual operating and maintenance conditions.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations, Corrosion Technician	• Responsible for review of corrosion inspections.
Management, with assistance from Engineering, Operations, other appropriate personnel	• Responsible for review of failure investigations.
Operations	• Responsible for written reports, further notifications.
Operations	• Responsible for review and analysis of patrols, leakage surveys, valve inspections, vault inspections, regulating equipment inspections, relieving equipment inspections, limiting equipment inspections, and other appropriate inspections.
Individual Employee	• Any employee involved in the identification of an encroachment shall document the contact with the encroaching party to have a permanent record. The encroachment should be reported to Operations.

3 PROCEDURES

- Continuing surveillance shall be conducted on all pipeline facilities. Surveillance is awareness of:
  - Surface deterioration;
  - Conditions on and adjacent to pipeline rights-of-way;
  - Indications of leaks;
  - Construction activity and movement of heavy equipment near facilities;
  - Fires near installations;
  - Right-of-way obstructions;
  - Encroachments;
  - Vandalism of pipeline facilities;
  - Population buildup (changes in class location); and
  - Other factors which might affect operations of the pipeline system or result in possible injury or damage to people or property, including suspicious activity that might be terrorist-related.

- Periodic review and analysis of records shall be conducted by appropriate Company personnel. These records may include the following:
  - Patrols;
  - Leakage surveys;
  - Valve inspections;
  - Vault inspections;
  - Pressure regulating, relieving, and limiting equipment inspections;
  - Corrosion control inspections;
  - Facility failure investigations; and
  - Aerial photography.
- When a pipeline facility is determined to be in an unsatisfactory condition by inspection or record review, action must be taken to recondition or phase out the segment where no immediate hazard exists or reduce the maximum allowable operating pressure. Reduction of MAOP by ≥ 20 % may require reporting as stated in the "Safety-Related Conditions" procedure. A segment determined to be unsafe by Engineering or Pipeline Operations shall immediately be removed from service and replaced or repaired.
- Operations shall respond promptly to a report of gas odor inside or near a building as per the Company Emergency Response Plan and site-specific emergency action plans.
- During periods of heavy rainfall, areas of concern such as pipeline crossings at washes, streams and rivers should be monitored for conditions that could impair the integrity of a pipeline.
- Encroachments include any and all activity crossing, paralleling, or approaching Company rights-of-way, such as:
  - Road, highway, railroad, canal, and lateral construction;
  - Drilling or blasting;
  - Moving heavy equipment across or along the right-of-way and co-use of roads;
  - Plowing or cultivating along or over a pipeline;
  - Housing, commercial, subdivision, or other public developments;
  - Foreign utility crossings; or
  - Storage or placement of trees, debris, structures, or equipment.
- There are two primary types of encroachments:
  - When an outside party is engaging in excavation or construction activities on or near the Company's right-of-way;
  - When an outside party contacts the Company with preliminary plans for proposed construction, development, or moving heavy equipment near Company facilities.

- Any building activity within 660 feet of a pipeline such as a subdivision, trailer park, playground, or the erection of any structure designed for human occupancy must be reported to Pipeline Operations. When the activity could change the class location, Pipeline Operations will notify the appropriate personnel.
- The following information will be secured from the encroaching party to expedite the encroachment research process:
    - Name, address, and phone number of the encroaching party;
    - Specific time and date of expected encroachment;
    - Name of individual to contact; and any information available about the nature or type of encroachment. Encroachments shall be immediately communicated to Operations and/or the right-of-way representative.
- Whenever blasting or explosives are used by the encroaching party, the Company's representative must request that all activities on or near the Company's right-of-way be halted until it can be determined if there is a potential for damage to Company facilities and, if necessary, what remedial measures must be taken. A leak survey shall be conducted before and after such operations.
- Company personnel must be present during construction of a foreign facility that crosses a Company pipeline to ensure that the integrity of the pipeline and coating are maintained. The Company line must be protected from damage that might result from the proximity of the foreign structure.
- When a landowner feels that a Company pipeline should be lowered or relocated, the landowner should be informed to make the request to Operations. The employee who was contacted by the landowner should also inform the supervisor regarding the contact with the landowner.

Appendix A. AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/19/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/16/2019	Completed 2019 annual review. No changes.
1.0	9/29/2020	For future review dates, see EnLink Gas O&M Manual.

1 PURPOSE

1.1 Scope

- This procedure describes the process for correctly and safely launching pipeline pigs in a natural gas service from a pipeline launching station to a pipeline receiving station.
- Pipeline launching and receiving stations vary in configuration. This procedure provides steps associated to the primary valve operation of a typical pig trap. Careful on-site assessment of trap valve configuration should be performed to determine any adjustments of this procedure prior to performing work.

2 ✓ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• Responsible for safe pipeline pigging operations.

3 ✓GENERAL

- All launchers and receivers in natural gas pipeline service must be equipped with a relief device capable of safely relieving pressure in the barrel and a suitable device, such as a pressure gage, to indicate that pressure has been relieved, before insertion or removal of scrapers or spheres. This can be accomplished by the use of blowdown valves installed on opposite ends of the launcher or receiver to allow pressure to be removed on both sides of the scraper or sphere and/or by a device on the door of the launcher or receiver which will not allow the door to be opened with pressure on the unit.
- Before the pigging operation, the pig or pigs to be used will be visually inspected, repairs made as needed, and spheres run through sizing rings.
- Before beginning the pigging operation, the employee in charge will:
  - Notify Pipeline Control, the supervisor and any affected plants;
  - Know the maximum allowable operating pressure (MAOP) for the pipeline being pigged;
  - Monitor the line pressure at the pig launcher and receiver during the pigging operation;
  - Use a properly calibrated combustible gas detector to monitor and assure a safe working environment.

4 SAFETY

- All persons involved in a pigging operation shall follow appropriate safety requirements. These requirements include, but are not limited to:

- Use of fire resistant clothing (FRC);
- Use of required other personal protection equipment, being at minimum hard hat, protective eye wear, steel toed boots;
- A fire extinguisher must be positioned within the work area for emergency use.
- Safe Evacuation Plan;
- Position personnel and vehicles/equipment to not be in conflict of vented vapor drifts;
- Position personnel and vehicles/equipment to not be exposed to the rear of the launcher or receiver barrel closure;
- Lock-out & Tag-Out procedures shall be performed;
- Hearing protection is required when blowing down pig traps;
- Address all ignition sources (i.e. cell phones, electronic devices, vehicle entry and exits, vehicle engines, lightening, and static charges, etc.).

5 PRE-PROJECT STEPS

5.1 Pipeline Records Evaluation

- Determine any obstruction that may exist in the pipeline such as siphons, internal coupons, check valves, plug valves, reduced port valves, or unbarred branch connections.
- Check alignment drawings and construction records for other unknown appurtenances configurations that may exist.
- Field review launching station, receiving station, and valve sites for available work space that will be required for determination of additional work space, and of any pre-pig valve maintenance that may be required.
- Perform necessary modifications as per above evaluations.

5.2 Pig Travel Speed

- Perform pressure and volume calculations to determine the current pipeline operating velocity (mph) and determine the prescribed pig travel speed.
- Pigs are most effective if run at a constant speed. When the flow rate is low the pig may run in a series of start/stop motions, and it will not be very effective under these circumstances.
- Pigs will not be effective if run at too high a velocity. This is seldom a problem with on-stream pigging as flow rates are usually moderate. The following are ‘typical’ speeds for utility pigging as reference only:

Application	Speed (mph)
New Construction	1-5
On-Stream Gas	3-10
On Stream Liquids	2-10

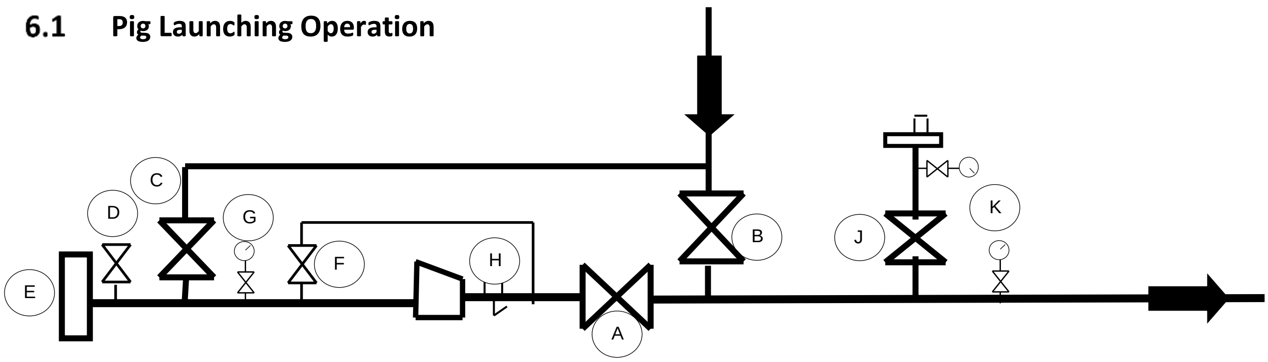
For In-Line Inspection tool speeds, refer to the inspection tool vendor for recommended optimum speeds. In most cases, the acceptable range is 2-7 mph, and proved very effective results.

5.3 Pig Tracking for ILI or Smart Pigs

- Method of following the path of a moving pig, by pre-selecting tracking points along the pipeline and monitoring time verses distance as the pig travels by.
- Develop a pig tracking plan, defining locations along the pipeline where project team personnel are assigned to be positioned with listening devices and/or Above Ground Markers (AGMs) to identify when the pig passes by the tracking point.
- A map should be prepared showing the tracking locations and each person assigned. Distances should be reflected on the tracking map.
- Pig tracking provides real time information to the project coordinator, specifically speed performance during the actual pig runs.
- Tracking locations should begin at the launching station, and +/- every 1 mile thereafter to the receiving station. Distances may be greater where access is limited. Common locations for tracking are at road crossings, block valves and immediately downstream of critical pipeline turns.
- AGMs function best at pipe depths 6 feet deep or less.
- Pre-organized communication planning is essential, preparing a list of team members and a determined method of communicating. A tracking log sheet allows documentation from team members to the coordinator for immediate speed calculation to validate expected pig mph, and estimated time of arrival.
- Pig tracking may be used as an option during regular maintenance pig runs.

6 PROCEDURES

6.1 Pig Launching Operation



LAUNCHING TRAP NOMENCLATURE	
A	MAINLINE VALVE
B	SIDE VALVE
C	KICKER VALVE
D	BARREL VENT VALVE
E	BARREL CLOSURE
F	EQUALIZATION VALVE
G	BARREL PRESSURE GAGE
H	PIPELINE PIG PASSAGE INDICATOR
J	PIPELINE BLOWDOWN VALVE
K	PIPELINE PRESSURE GAGE

6.1.1 Blow Down Launcher Trap Barrel

- Ensure Side Valve B is in the full open position.
- Close Kicker Valve C.
- Close Mainline Valve A.
- Open Gage Valve G to read barrel pressure.
- Open Equalization Line Valve F.

- Slowly open vent Valve D to blow down barrel. (Vent Valve D to remain in open position after venting is complete)
- Ensure pressure gage reads zero pressure.
- Open any drain valves that may be located on the bottom side of the blow down barrel. (Any present drains are to be left in the open position)
- According to Manufacturer's specific safety instructions, open barrel closure door.

6.1.2 Load and Launch Pipeline Pig

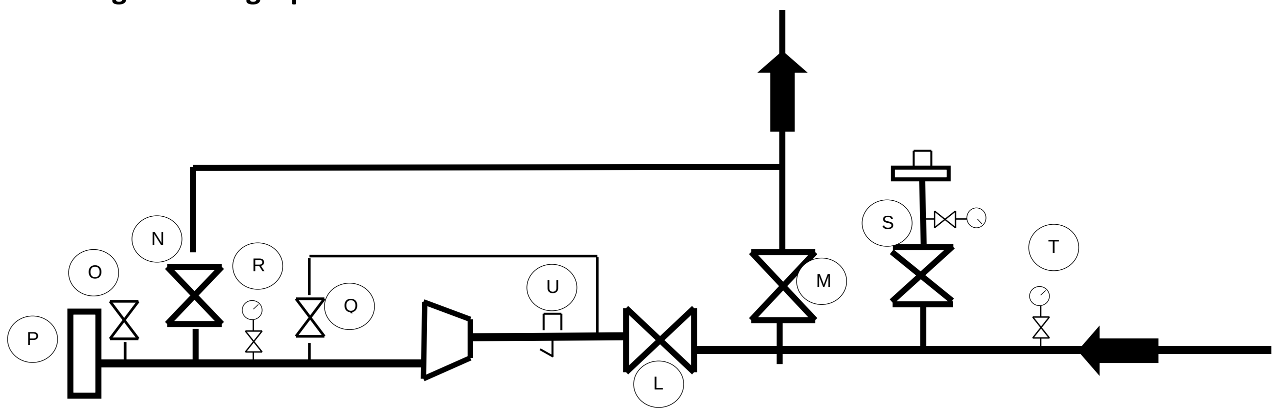
- Close any barrel drains that may exist on the bottom side of the barrel.
- Fully insert pipeline pig into barrel. (Pipeline pig front cups to be fully engaged through barrel reducer neck)
- Ensure equalization Valve F is in the open position.
- According to manufacturer's specific safety instructions, close barrel closure door.
- Ensure pipeline pig Passage Indicator H is in the reset position.
- Slowly crack open Kicker Valve C to purge barrel of air. (Process is to be performed at a slow rate of flow into barrel to prevent pig from unseating from its position at reducer)
- Close Vent Valve D after purge is complete.
- Pressure Gage G reading must equal Pressure Gage K reading.
- Slowly open Kicker Valve C to full open position.
- Open Mainline Valve A.
- Close Equalization Valve F.
- Partially close Side Valve B to launch pig from barrel.
- Verify Pig Passage Indicator H has been triggered.

6.1.3 Return Launcher to Normal Operation

- Ensure pipeline pig passage indicator is in the reset position.
- Ensure Side Valve B is in the full open position.
- Close Kicker Valve C.
- Close Mainline Valve A.
- Open Gage Valve G to read barrel pressure.
- Open Equalization Line Valve F.
- Slowly open Vent Valve D to blow down barrel.
- Ensure pressure gage reads zero pressure.

- Close Vent Valve D. (Launcher barrel is depressurized)

6.2 Pig Receiving Operation



RECEIVING TRAP NOMENCLATURE	
L	MAINLINE VALVE
M	SIDE VALVE
N	KICKER VALVE
O	BARREL VENT VALVE
P	BARREL CLOSURE
Q	EQUALIZATION VALVE
R	BARREL PRESSURE GAGE
S	PIPELINE BLOWDOWN VALVE
T	PIPELINE PRESSURE GAGE
U	PIPELINE PIG PASSAGE INDICATOR

6.2.1 Prepare Receiver to Receive Pig

- Ensure Pig Passage Indicator U is in the reset position.
- Open Barrel Pressure Gage Valve R to read barrel pressure.
- Ensure Side Valve M is in the full open position.
- Ensure any drain valves that may be located on the bottom side of the barrel are closed.

- Ensure Barrel Vent Valve O is closed.
- Open Equalization Valve Q.
- Ensure Barrel Closure Door P is closed according to manufacturer's specific safety instructions.
- Open Barrel Pressure Gage Valve R to read barrel pressure.
- Slowly partially open Barrel Vent Valve O.
- Slowly open Kicker Valve N to purge air from barrel.
- Close Vent Valve O after purge is complete.
- Open Kicker Valve N.
- Open Main Line Valve L.
- Close Side Valve M.

6.2.2 Receive Pig at Receiver

- Pig travels into Receiver Trap.
- As passage indicator is tripped, and pig fully passes through Main Line Valve L, fully open Side Valve M.
- Close Main Line Valve L.
- Close Kicker Valve N.
- Open Barrel Vent Valve O.
- Check Barrel Pressure Gage Valve R to read zero-barrel pressure.
- Open any drain valves that may be located on the bottom side of the blown down barrel. (Any present drains to be left in the open position).
- Open barrel closure door according to manufacturer's specific safety instructions.
- Collect sample of any liquids retained in the barrel for analysis sampling.
- Remove pig from barrel.
- Inspect pig for damage, such as tears, scrapes, gouges, metal shavings, unusual wear.

6.2.3 Return Receiver to Normal Operation

- Main Line Valve L is presently in closed position. (receiver barrel is de-pressurized)
- Close Barrel Closure Door P according to manufacturer's specific safety instructions.
- Ensure Side Valve M is in the full open position.
- Ensure Kicker Valve N is closed.
- Close any drain valves that may be located on the bottom side of the barrel.
- Close Barrel Vent Valve O.

- Open Barrel Gage Valve R.
- Ensure Pipeline Pig Passage Indicator U is in the reset position.

Appendix A. AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/23/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/16/2019	Completed 2019 annual review. No changes.
2.0	12/14/2020	Completed 2020 annual review with Committee. See DOT Team for list of detailed changes. For future review dates, see EnLink Gas O&M Manual.

ENLINK MIDSTREAM	Patrolling and Leak Surveys	Department: Gas Operations and Maintenance
Effective Date: 1/1/2018 Revision Date: 5/2/2022		Standard Number: ENL-GOM-00029 Version 2.0

This document applies to EnLink employees when working for or acting on behalf of EnLink Midstream Operating, LP or any of its subsidiaries and / or joint ventures.

1 PURPOSE

These procedures prescribe the methods, frequency, and responsibilities for the patrolling and leakage surveys of Company gas pipeline facilities, including compressor stations.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• Responsible for assuring that pipeline patrol and leakage survey procedures are followed and performed by qualified personnel, and records are maintained. • Responsible for initiating actions or steps necessary to protect the public and the pipeline as may be indicated by patrol or leakage reports.

3 PROCEDURES

3.1 Patrolling Procedures

- Pipeline patrols shall be performed by vehicular, aerial, marine, or walking observation, as appropriate.
- Each gas pipeline facility shall be patrolled to observe surface conditions on and adjacent to the pipeline and pipeline right-of-way, including but not limited to:
  - Indications of possible leaks;
  - Construction activity in area;
  - Exposed pipe;
  - Erosion;
  - Foliage in the R/W that could lead to misunderstanding of pipeline direction;
  - Alert for dead or dying vegetation;
  - Past or Future Encroachments;
  - Potential class location changes;
  - Protective fencing damages around valves, meter stations and unmanned stations;
  - Damage to pipeline markers and/or R/W signs needing attention;
  - Damage to CP Stations and CP power sources;
  - Damage to guardrails and/or protective barriers; or
  - Any other factors that could affect safety or operations.
- Right-of-ways are to be maintained to protect the pipeline and to provide access to all sections of pipeline, valve installations, meter stations and other pipeline facilities.

- The frequency of patrols shall be as prescribed as follows:

Maximum Interval Between Periods		
Class Location of Line	**At Water, Highway or Railroad ROWs or Crossings**	**At All Other Places**
1, 2	7½ months, but at least twice each calendar year	15 months, but at least once each calendar year
3	4½ months, but at least four times each calendar year	7½ months, but at least twice each calendar year
4	4½ months, but at least four times each calendar year	4½ months, but at least four times each calendar year

- All line patrols can be recorded in the Maintenance Connection Program.
- The pipeline patrol is also responsible for noting and reporting pipeline encroachments in a timely manner.
- In the event of an abnormal operating condition, the patrolling person or aerial patrol observer shall take appropriate action to protect the public and pipeline, and then notify Operations of any imminent danger.
- Scheduled or completed remedial actions, where required, shall be documented with completion dates or planned completion dates.

3.2 Leak Survey Procedures

- The frequency of leak surveys shall be as prescribed in the following table:

Maximum Interval Between Leak Surveys	
Class Location of Line	**Intervals**
1 & 2	15 months, but at least once each calendar year
3	7½ months, but at least twice each calendar year. For un-odorized gas, use leak detection equipment.
4	4½ months, but at least four times each calendar year. For un-odorized gas, use leak detection equipment.

- In the event of blasting near company facilities where the company believes that facilities are at risk of being damaged, a leak survey shall be conducted before, if possible, and after such blasting operations.
- Leaks may be indicated by, but not limited to, the following:
  - Signs of dead or discolored vegetation;
  - Smell;
  - Ice accumulation;
  - Dust cloud;
  - Bubbles in water;
  - Product puddling/pooling;
  - Sheen on water;
  - Vaporous fog;
  - Unexpected noise;
  - Inspecting casing vents using gas detection equipment, if necessary.
- ✓In Class 3 & 4 locations with un-odorized gas, use leak detection equipment following manufacturer's operating procedures. These requirements also apply to regulated onshore Type B gathering lines.
- ✓Certain segments of Type C gathering lines will be required to be leak surveyed with a gas detector once every calendar year, not to exceed 15-months. See procedure ENL-GOM-00014 to determine which segments apply.

Appendix A. AMENDMENT RECORD

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0	1/1/2018	Initial version.
0	10/23/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/17/2019	Completed 2019 annual review. No changes.
1.0	10/1/2020	For future review dates, see EnLink Gas O&M Manual.
2.0	5/2/2022	Final review completed by PINDOT Team. Minor changes due to new gas gathering MEGA rule. For future review dates, see EnLink Gas O&M Manual.

1 PURPOSE

These procedures establish a program for installing and maintaining pipeline markers and for identifying offshore pipeline facilities.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• Responsible for assuring that adequate pipeline markers are properly placed and maintained. • Responsible for establishing the location of offshore transfer points, ensuring that the required identifications are made and maintained, and providing information necessary for preparing any schematics, drawings, or maps required by this procedure.

3 PROCEDURES

Pipeline markers shall be placed and maintained in accordance with the following guidelines:

- Buried Pipelines
  - Except as otherwise provided, a pipeline marker shall be placed and maintained as close as practical over each buried gas pipeline as follows:
    - At all railroad and road crossings;
    - At any other locations, identified by Operations, which are necessary to reduce the possibility of damage or interference.
  - Pipeline markers are not required for buried pipelines that are:
    - Located offshore or at water crossings and other bodies of water; or
    - In Class 3 or 4 locations where placement of a marker is impractical.
- Aboveground Facilities
  - Line markers shall be placed and maintained along each section of a pipeline that is in an area accessible to the public. In the case of aboveground spans or pipe exposed by erosion, sufficient markers shall be placed so that a sign is clearly visible from each side of the span or exposed section, when possible;
  - In areas accessible to the public, line markers shall be placed such that they are visible from all normal angles of approach to compressor station facilities, block valves/crossovers, measurement stations, and spans of pipe normally aboveground.

- Marker Warnings must be legible on a background of sharply contrasting color on each pipeline marker, and shall include:
  - *"Warning," "Caution," or "Danger,"* followed by the words *"Natural Gas Pipeline,"* all of which, except for markers in heavily developed urban areas, must be in letters at least 1-inch high with 1/4-inch stroke;
  - The Company name and emergency telephone number where the company can be reached at all times.
- Offshore Facilities
  - All offshore facilities that are on the Outer Continental Shelf (3 geographical miles distant from the coastline) and are receiving gas from a producing operator shall have the specific transfer point(s) identified;
  - This identification will be above water and will be at a flange or other easily identified point. Differences in paint colors or other durable marking is sufficient in these instances;
  - For those instances in which the transfer points are not easily identifiable by a durable marking, the transfer points shall be delineated on a schematic or other similar drawing or map. This document shall be maintained at or near the point of transfer, such as on the applicable platform or at the nearest upstream location. An underwater transfer point is an example where a schematic or other drawing should be used to identify the transfer.

Appendix A. AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/23/2018	Compared to current Gas O&M, revised and finalized.
1.0	12/17/2019	Completed 2019 annual review. No changes.
1.0	10/2/2020	For future review dates, see EnLink Gas O&M Manual.

1 PURPOSE

These procedures establish guidelines for maintaining records of pipelines and pipeline facilities.

2 ROLES AND RESPONSIBILITIES

Position	Responsibility
Operations	• Responsible for implementing and following these procedures.

3 PROCEDURES

- The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.
- The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of 49CFR Part 192 must be retained in accordance with paragraph (c) of this section.
- A record of each patrol, survey, inspection, and test required by subparts L and M of 49CFR Part 192 must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

Appendix A. AMENDMENT RECORD

Version	Review Date	Comments/Affected Pages
0	1/1/2018	Initial version.
0	10/23/2018	Compared to Gas O&M and finalized.
1.0	12/17/2019	Completed 2019 annual review. Major changes. See DOT Team for list of detailed changes.
1.0	10/2/2020	For future review dates, see EnLink Gas O&M Manual.

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1.0 Scope

This standard describes the pressure testing requirements of all EnLink Midstream facilities in compliance with applicable pipeline and plant regulatory requirements.

2.0 Applicable Facilities- Regulations

2.1 This standard shall be applicable for hydrostatic and pneumatic testing of the following facilities:

- Buried Mainline pipeline, Compressor, Pump or Meter Station facilities;
- Above ground Fabricated Assemblies or pre-tested pipeline sections;
- Process piping (plants, PSM facilities, etc.);
- Coast Guard Facilities.

2.2 The intent of this document is to comply with applicable governmental regulations. Any conflict to clarity this document may create, those regulations provide authority:

- 49 CFR 192.503 through 192.517;
- 49 CFR 195.300 through 195.310;
- 33 CFR 156.170 Coast guard facilities testing;
- ANSI B31.3, B31.4, and B31.8;
- ASME PCC-2 2008;
- ASME Boiler & Pressure Vessel Code, Sections I, IV & VIII;
- ASTM Standards where applicable.

2.3 Applicable EnLink Standards:

- EnLink O&M Procedures;
- EnLink Safety Standards;
- EnLink Environmental Procedures;
- EnLink OQ Manual.

3.0 Definitions

“Authorized Representative" means the person(s), firm(s), or company(s) designated by the Company to exercise the functions entrusted to him/her under the Contract Documents.

"Chief Inspector" means the Company's authorized on-site representative appointed by the Company to exercise the functions entrusted to him/her under the Contract Documents.

“Company” means EnLink Midstream and shall include contractors, agents, inspectors, and other authorized representatives.

"Contract Documents" means the Agreement, Conditions of Contract, Scope of Work, Construction Specifications, this plan, drawings and all other components of the Contract Document. Collectively, these documents describe “the Work”.

“Contractor” means those who have contracted to conduct the pressure testing.

“Design Pressure” means the intended maximum allowable operating pressure (MAOP) for gas pipeline/facilities or maximum operating pressure (MOP) of liquid pipeline/facilities. This is the pressure used to select the wall thickness and grade of pipe and fittings and to specify the rating (or pressure class) of pressure rated components to meet the applicable design code requirements.

"Documented Test Pressure" means the pressure used for record summaries and determination of MAOP/MOP. It will be the minimum test pressure at the highest elevation of the pipeline during the test period. The test period is the minimum required test period established by this standard in accordance with the applicable regulation (49 CFR Part 192 or Part 195) and need not be continuous.

"Leak Test" - For piping that is entirely visible during the test, the leak test will consist of observation of the piping, joints and connections, while under pressure to check for visible or audible evidence of a leak. For piping below ground or otherwise not visible, the leak test will consist of an approved procedure whereby pressure variations during strength testing are accounted for, considering the effects of temperature and pressure on the test medium and pipe. For process piping it could be at least 1.5 times the design pressure. Refer B31.3 section 345.4.2 for details.

"Maximum Allowable Operating Pressure (MAOP)" -– For covered segments under Part 192, MAOP is the maximum pressure at which the facility may be operated in accordance with the provisions of the applicable code or regulation. For facilities yet to be qualified for service, MAOP means design pressure or intended MAOP.

"Maximum Operating Pressure (MOP)" – For covered segments under Part 195, MOP means the maximum pressure at which a pipeline or segment of pipeline may be normally operated.

"Marine Transfer Area (MTA)" means that part of a waterfront facility handling oil or hazardous materials in bulk between the vessel, or where the vessel moors, and the first manifold or shutoff valve on the pipeline encountered after the pipeline enters the secondary containment required under 40 CFR 112.7 or 49 CFR 195.264 inland of the terminal manifold or loading arm, or, in the absence of secondary containment, to the valve or manifold adjacent to the bulk storage tank, including the entire pier or wharf to which a vessel transferring oil or hazardous materials is moored.

"OQ" – Operator qualification applies to any testing done on a regulated pipeline facility.

"Pipeline (Gas)" means 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 or pipeline system (Liquid)" means all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

"Pipeline Component" - A pipeline component is a valve, flange, standard fitting, fabricated assembly or similar item. A fabricated assembly is one which is constructed prior to installation and installed as a single unit.

"PM" – Project Manager.

"Strength Test" - A strength test is the pressurization of piping to a minimum predetermined stress level or pressure and maintaining this stress level or pressure for a predetermined time interval or hold period.

"Test Inspector" - Company person or persons appointed by and reporting to the Chief Inspector. The Test Inspector will determine the acceptability of the tests.

"Test Media" – May include natural gas, water, air, nitrogen or other inert gas.

"Test Supervisor" - Contractor's foreman, superintendent, or Company approved Subcontractor foreman or equivalent, which is responsible for conducting the hydrostatic testing work in compliance with this plan and all other Contract Documents. At all times the Contractor shall be responsible for all actions of, and instructions given by, the Test Supervisor.

"Yield Test" - A yield test is one in which the pressure is elevated to a level which produces a predetermined stress more than 100% SMYS or a controlled amount of yield of the pipe.

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4.0 Assignment of Responsibility

4.1 Pressure testing shall be carried out by the Contractor, utilizing qualified personnel and appropriate equipment. If the Contractor chooses to subcontract the testing, the Contractor must obtain the Company's written approval of the subcontractor prior to the start of testing. The Contractor shall confirm to the Company that it's subcontractor is qualified.

4.2 The Contractor shall appoint a Test Supervisor who will be responsible for conducting the Pressure testing work in compliance with this plan and all other Contract Documents. At all times the Contractor shall be responsible for all actions of, and instructions given by, the Test Supervisor.

4.3 The Company's Test Inspector is primarily responsible for ensuring the Contractor complies with this Plan and the other Contract Documents. The Contractor performing the test shall be accountable to the Company Test Inspector. The Contractor shall be responsible for completing all test records including charts, reports, forms, calculations, etc. The signatures of both the Contractor's Test Supervisor and Company's Test Inspector shall approve all test records.

4.4 Prior to the start of the actual testing program, the Company's Test Inspector shall meet with the Contractor's Test Supervisor. The Test Inspector must be certain that the Test Supervisor clearly understands the Contract Documents and the Drawings. A step-by-step discussion of the specifications, drawings, and forms shall be made to ensure that no questions remain unanswered. It is especially important that the Contractor understands what test equipment and instruments are required, and that these items be in good working condition prior to the test.

4.5 The Company will have an authorized representative available to witness all testing activities. No activities or specified procedures shall be carried out or occur at the fill point, pressurizing point, main test pressure monitoring point, or water discharge point without a Company representative being present. At the discretion of the Company, non-compliance with this provision may result in the Contractor repeating that portion of the Work at no cost to the Company.

4.6 Company PM and CONTRACTOR shall develop a written project-specific step-by-step procedure to be reviewed and accepted by all Company personnel involved with the project, encompassing all aspects of the project, before the project begins.

5.0 Personnel Safety

Refer to Appendix A for Safety Guidelines

6.0 Notifications- Permits

6.1 The project engineer or project manager in charge shall coordinate with the Environmental Department to arrange for hydrostatic water discharge permit, if applicable, laboratory analysis and other necessary reporting to the proper authorities.

7.0 Equipment and Materials

7.1 General

The Contractor shall furnish, operate, and maintain all test equipment including pumps, air compressors, caps, temporary receivers, test headers, pigs, temporary piping and all other materials and equipment required to perform and complete the cleaning, filling, pressure testing, dewatering, drying and tie-in operations. Equipment shall include but not be limited to the items described in the following Sections:

7.2 Communication

Contractor's test personnel must be equipped with a sufficient quantity of two-way communication devices with adequate power output to maintain communications along the entire length of the test section.

Communication shall be maintained during all phases of the pressure test including, but not limited to, cleaning (if required), filling, pressure testing, dewatering and drying.

7.3 Centrifugal Pump

Lo-Head Pump: Shall lift water from an approved source and deliver 1,400 gpm maximum at 120 psig unless otherwise specified by the "EnLink Scope of Work". Intake will be screened to prevent fish entering or impingement. Strainers/filters, for use in the water supply line intake, having a 100-mesh screen/cartridge to prevent pumping foreign materials into the pipeline.

Hi-Head Pump: Shall take 120 psig suction from the Lo-Head Pump and deliver 1,400 gpm maximum to test section at 350 psig unless otherwise specified by the "EnLink Scope of Work". The fill pump shall develop sufficient discharge pressure to achieve the specified fill rate and to provide sufficient pressure for the hydrostatic test profile.

7.4 Reciprocating Pump

This pump will be used to apply test pressure to section under test. It must be a positive displacement reciprocating pump suitable for pumping at the maximum test pressure and equipped so that flow rate can be varied from 0 to 100 gpm and the volume indicated by a stroke counter.

The PD pump with pressure capability at least 120% of required maximum test pressure shall be used. The pump shall be capable of maintaining a constant and uniform pressurization rate. The pump shall be equipped with either a solenoid-type stroke counter or meter to measure the amount of test liquid added during pressurization or removal from the pipeline.

Pump shall have tested relief valve set to pressure as specified in the scope of work.

7.5 Filling Service Meter

The Filling Service Meter shall be sized to meet the requirements of the maximum fill rate and tested/ calibrated by the manufacturer or an approved neutral third party satisfactory to Company and installed according to the manufacturer's specifications to ensure proper measurement. The manufacturer's calibration and test report shall be furnished to the Company prior to start of any testing. It shall be of a type and capacity to accurately measure water volumes to within plus or minus 0.5% of actual volume.

7.6 Low Pressure Tap

A low-pressure tap must be installed for water sample collection if the discharge is directly to the water body and inaccessible.

7.7 Minimum Required set of gauges and recorders:

Item No.	Quantity	Description
1	1	(Preferred) Deadweight balance tester with individual weights required for measuring up to the specified endpoint test pressures in maximum increments of 1 psi. Deadweights shall be identified and traceable through a serial number permanently affixed to the balance.
2	1	(Optional) High pressure deadweight gauge 50-3,000 psi range or range to be compatible with maximum test pressure; sensitivity to be greater of 0.5 psi or 0.1% of reading. NOTE: Use of advanced Crystal Gauges for pressure test recording should be limited to non-jurisdictional pressure testing only unless approved by pipeline integrity. Calibration of Crystal Gauge will be required.
3	3	Portable type 12" recording thermometer, Bristol Model or equal, temperature element fully compensated, range -20º to 120º F, spring wind or battery chart drive, 24-hour movement, capillary or disposable inking system, 15' S.S. armored cover capillary tubing and 7-1/2" S.S. separable socket, 3/4" NPT.

4	1	Portable type 12" pressure recorder, Bristol Model or equal, pressure element S.S., range 0-3,000 psi, spring wind or battery chart drive, 24-hour movement, capillary inking system, 15' long high pressure flexible hose, 1/4" NPT both ends (one at each end of test section). Range to be compatible with the maximum test pressure with continuous, 24-hour charts graduated to at least 2% of minimum test pressure.
5	Optional	Gauge, pressure indicating, liquid filled, 4-1/2" dial, 0-3000 psi range, 1/2" NPT lower connection, Ashcroft Duragauge 1279D or equal (as required).
6	Optional	Gauge, pressure indicating, liquid filled, 4-1/2" dial, 0-600 psi range, 1/4" NPT lower connection, Ashcroft Duragauge 1279B or equal (as required).

7.8 Test Headers

All test headers must be fitted with welded end caps. Test headers with closures shall not be permitted. Test headers used on previous pipeline construction projects will be made available from the Company for use by the Contractor, at the Contractor's option. The Company makes no warranty or guarantees about the condition, usefulness or capability of these materials. If the Contractor chooses to use Company supplied test headers, any additional pipe, valves, fittings, and fabrication work shall be furnished and installed by the Contractor. All test headers, either supplied by the Company or fabricated by the Contractor, shall be pretested to a pressure higher than the target test pressure of the pipeline section to be tested for a minimum period of one hour.

7.9 Temporary Launchers/Receivers

If specified in the contract documents that a cleaning tool is run prior to pressure testing and/or a caliper tool is to be run after pressure testing, the Contractor shall provide suitable launcher/receiver headers with full diameter closures.

7.10 Spheres or bi-directional pigs

The Contactor shall furnish spheres or bi-directional pigs. If, in the opinion of the Company Test Inspector, there is evidence of significant wear or cuts, the spheres or rubber disks shall be replaced. A minimum of two spheres or pigs is required for each pressure test. The Contractor shall be responsible for performance of the pigs used for the filling, dewatering, and drying operations (and, cleaning, if required), either supplied by the Company or furnished by the Contractor.

7.11 Compressor Equipment

The Contractor shall furnish, operate, and maintain air compressor equipment, with a minimum capacity of 3600 SCFM, to propel the dewatering and drying pigs (and, if required, cleaning and pipe sizing tools) through the pipeline while maintaining moderate discharge rates. It should be capable of overcoming static head pressures in excess of 500 psig during dewatering and transfer operations.

7.12 Lighting/Enclosures

If deemed necessary by the company representative, the Contractor shall furnish an enclosed shelter of sufficient size to house the pressure recorders, deadweights and test personnel at the data procurement site of each test section during the complete fill, pressurization, test, depressurization, water disposal and pipeline drying periods. To assure stabilization of the instruments, the above enclosure shall rest on the ground or be stabilized with jacks at all times during operation of the test instruments.

The Contractor shall furnish ample light for operating compressors, pumps, accessing test manifolds and connecting piping and sensing lines throughout all hours of darkness during pipeline cleaning (if required), filling, pressurizing, retesting, sampling, depressurizing, disposal of water and while performing drying operations.

8.0 Location and Calibration of Test Equipment

8.1 Deadweights shall have been calibrated by a neutral third party satisfactory to the Company. The calibration shall have been performed within one (1) year of the beginning of the test and the certificates must be presented to Company prior to commencement of testing.

8.2 The temperature recorders shall be installed prior to commencement of the test water filling procedure and shall be used to continuously record the pipe and ground temperature from commencement of filling through to the depressurizing procedure. This device should be calibrated immediately before each use with certified thermometer.

8.3 ✓Temperature recorders shall be located so that they will not be affected by (1) ambient temperatures or (2) changes in injection fluid temperature because of proximity to the injection pump. Temperature recorders shall be installed to record ground temperature, ambient temperature and pipe temperature.

8.4 The temperature bulbs for the pipeline test sections shall be secured directly to the exposed pipe with suitable heat transfer compound, insulated and then backfilled to ground level at least eight (8) hours prior to the pressure test. The eight (8) hours is required to provide adequate time for the fill water, pipe, and ground temperatures to stabilize.

8.5 A "Hydrostatic Test Profile" drawing may be included in the contract documents for each test section included in the “Work”. These drawings show the test header locations, contour length of test section, elevation of the test headers at each end of the test section, both the high and low points of the test section.

9.0 Pipeline - General Instructions

9.1 Responsibilities

9.1.1 The EnLink Engineer or PM shall be responsible for setting the test parameters.

9.1.2 The Company representative shall supervise all pressure testing, which shall be performed in accordance with this specification.

9.1.3 All pressure test operations shall be attended by the Contractor and the Company test personnel at all times.

9.1.4 The testing operation shall not be commenced or terminated without the Company Representative’s approval.

9.1.5 Leak tests, pressurizing, and associated yield plotting shall be conducted during daylight hours unless impractical. If testing at night is necessary, adequate lighting acceptable to the Company shall be provided.

9.2 New, Relocated, or Replaced Pipe Segments

9.2.1 The Company shall not operate a new segment of pipeline, or return to service a segment of pipeline, that has been relocated or replaced until it has been successfully pressure tested in accordance with the applicable requirements to substantiate the maximum allowable operating pressure (MAOP) or maximum operating pressure (MOP).

9.3 Test Medium

9.3.1 The test medium shall be water, air, inert gas, natural gas, or other medium applicable to the service - that is:

- Compatible with the material of which the pipeline is constructed.
- Relatively free of sedimentary materials.
- Nonflammable, except that as applicable.
- Water containing corrosive chemicals and detergents shall not be used. The water used shall not contaminate the pipe through deposition or corrosion. The Company may specify water filtration to maintain relative freedom from sedimentary materials.

9.3.2 Air, inert, or natural gas may be used as a test medium, provided that:

- 49 CFR 192 or 195 minimum safety requirements provide the allowance for consideration of such test medium, and:
- VP of Engineering and Pipeline Integrity provides agreement for such a test medium.
- *The Maximum and Minimum* Test Pressure is complied with for maximum hoop stress.
- When testing to a pressure of 50% SMYS or greater using Air or Inert Gas, buildings intended for human occupancy located within 300 ft of the pipe segment(s) are evacuated (ref 49 CFR 192.505(a)), 49 CFR 195.306.
- Natural Gas cannot be used to test to a pressure more than 30% SMYS in a class 2, 3 or 4 locations.

9.4 Test Heads and Drag Caps

9.4.1 Prior to each pressure test, the Company Representative and the Contractor shall thoroughly inspect the test heads to ensure that all gaskets, O-rings, fittings, valves, and components are such that no leakage or loss of the test will result, and that all safety considerations are met.

9.4.2 There shall be no field changes to the design of the test heads without specific approval of the Company.

9.4.3 Repairs to the test head or attached fittings are specifically prohibited without approved procedures from the Company.

9.4.4 Test heads and drag caps shall be constructed in accordance with Part 192, Subpart J, and ASME B 31.8, Part 195, B31.4. B31.3

9.4.5 Welding of test heads and drag caps shall be in accordance with the requirements of the Company Welding Manual.

9.4.6 Examination and acceptance of attachment girth welds shall be in accordance with the requirements of the Welding Manual, API 1104.

9.4.7 The design of the test heads shall provide for the pigging operations included with pressure testing and adequate valve connections for filling/dewatering, testing instrumentation and the squeeze pump. Any repairs, revisions or replacements of any components deemed necessary by the Company shall be completed at the Contractor's expense.

9.5 Exclusions

9.5.1 No pressure test is required for vent or drain lines which are open to atmosphere and do not include in-line items which could restrict or block flow such as valves or tanks.

9.5.2 Components or vessels pressure tested by the vendor in the manufacturing plant according to DOT or ASME Pressure Vessel Standards, need not be re-tested in the field. However, the components or vessels may be included in the field test with the rest of the system if the test pressure is less than 1.5 times the stamped working pressure of the vessel or component.

9.5.3 Sensitive components such as relief valves, regulators, instruments, control valves and related items which may be damaged at elevated pressures shall either be removed or isolated from the system during testing.

9.5.4 Minor modifications or repairs of non-hazardous fluid piping are not required to be strength tested provided such modifications or repairs are a maintenance function, the system will be operated at a pressure which is less than 100 psi, and which produces less than 30 percent hoop stress and the piping is inspected for leaks under operating conditions.

9.5.5 Each tie-in weld or flange used to tie in a test segment of pipeline is exempted from the pressure test. The Contractor shall test all piping and assemblies in such a configuration as to minimize the number of final tie-in welds.

9.5.6 Fabricated assemblies which cannot be tested with the pipeline shall undergo the same test performed in the same manner as the pipeline to which it is welded except that the ambient temperature shall be recorded instead of the pipe temperature. Should such assembly contain valves or fittings, the test pressure shall not exceed 1-1/2 times the maximum operating pressure of the valve or fitting. Pressure-volume plots are unnecessary on these sections. The test shall be a minimum of 8 hours in duration or 4 hours if the section is entirely exposed to the atmosphere during the test.

9.6 Cold Weather Testing

9.6.1 Winter testing is defined as testing where, in the opinion of the Company, low ambient temperatures require the fill water to be heated. The enclosing and heating of open lengths of pipe shall not be considered winter testing.

9.6.2 Special procedures shall be used to prevent freezing during cold weather testing. These shall include the use of water heaters and the circulation of warm water to obtain the desired ground and water temperatures. The use of antifreeze or other additives is not permitted.

9.6.3 For all pressure testing conducted during winter construction or when ambient temperatures are expected to drop below freezing, the Contractor shall enclose and sufficiently heat all exposed piping including all pipe in the open ditch and fabricated assemblies. The pipe in the open ditch shall be heated to a minimum of 38º F at the bottom of the excavation and verified by a recording chart prior to the filling operation.

9.6.4 All pressure sensing lines between the deadweight and pressure recorder and test header shall be purged of water and filled with glycol. An additional reserve of glycol shall be placed in the flange neck of the test header where the pressure sensing line is connected. If at any point during pressurizing, if either the dead weight or pressure chart appears unresponsive to increased volume the sensing lines may be frozen, and pressurizing shall immediately be stopped.

9.6.5 All enclosures shall be designed and erected such that they will support snow loads and will not be affected by high winds. Prior to backfilling, all enclosure materials shall be hauled away and disposed in an approved location.

9.6.6 A temperature recorder shall be installed by means of a thermowell to monitor the temperature of water added to the test section and the temperature of the water extracted from the test section during warm water passage. Pipe and ground temperatures shall be monitored at several points along the test section as directed by the Company.

9.6.7 Test heads and other piping which has not been backfilled shall be adequately sheltered and heated. The heat sources shall not be in direct contact with piping. The contractor shall furnish a heated shelter for all exposed piping facilities when the temperature is cold enough to cause freezing in testing equipment and in the pipeline. Instrument piping will be wrapped with heat tracing tape with insulation being installed over to ensure no freezing in the tubing. All instruments are to be protected from the cold by enclosing them in an insulated enclosure.

9.6.8 During winter testing, water shall be passed through the section to a site previously identified as acceptable to the Company, landowner and regulatory authorities. During water passage the Contractor shall provide and install an energy absorbing diffuser satisfactory to the Company for dewatering the Pipeline, at the discharge to prevent erosion, bottom scour or damage to vegetation. Damage to the pipeline, the right-of-way and/or adjacent property caused by such disposal shall be repaired by the Contractor to the satisfaction of the Company at the Contractor's expense.

9.6.9 The initial 5% of the fill water, a blend of warm and cold water, shall be pumped into the mainline at a temperature of 95°F or greater. Thereafter the fill water blend shall be added to the mainline at a minimum temperature of 37.4°F as illustrated in above Figure 1. Water shall be passed through the test section until a discharge temperature greater than 35.6°F has been achieved for a minimum of two hours following discharge of the initial 5% volume. Provisions shall be made so that dewatering of the line may be conducted readily to prevent freezing of the water. Such dewatering may be necessary as in the case of delays due to equipment failure or line rupture under test.

9.7 Maximum and Minimum Test Pressure

9.7.1 The maximum test pressure is to define a pressure range above the specified minimum test pressure to allow for such variables as change in elevation in the test section, temperature changes, piping or equipment limitations, etc., but shall not exceed the lowest as listed below in Table 1 thru 4.

9.7.2 Pipeline Integrity may specify a higher Test Factor for tests specific to Pipeline Integrity reassessment criteria. Requalification of pipe using a test medium other than water requires Pipeline Integrity approval.

9.7.3 Compressor and Meter Station Piping

In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, shall be tested to at least Class 3 test factor requirements. Natural Gas cannot be used for testing if the required test pressure will result in a hoop stress of more than 30% SMYS in the test section.

9.7.4 River/ Road Crossings

All major river/ road crossings or directional drill bores identified by the Project manager shall be pre-tested next to the proposed installed location prior to installation. The pre-test pressure shall be at least equal to the 8-hour test pressure. The pre-test duration shall be a minimum of 4 hours. Also, water, road and/or other crossing drill bores which require a drill profile as identified by the Project Manager shall be pre-tested next to the proposed installation location prior to installation. The pre-test pressure shall be at least equal to the mainline 8-hour test pressure. The pre-test duration shall be a minimum of 1 hours.

TABLE 1
ONSHORE GAS PIPELINES – TEST REQUIREMENTS

Facility Description	% Hoop stress at MAOP	Test Medium	Min. Test Pressure	Max. Test Pressure ✓ (See Note 2)	Hold Period	
					Leak Test	Strength Test
Transmission and Gathering Pipelines Operating at ≥ 30% SMYS ✓ (See Note 1)	≤ 72%	Water	1.25XMAOP (Class 1,2) 1.5XMAOP (Class 3,4)	95% SMYS or 1.5 X Flg (whichever of the assy. is lower)		8 hours (4-hours if above ground)
Transmission and Gathering Pipelines Operating at ≥ 30% SMYS	≤ 72%	Air/ inert	1.25XMAOP (Class 1,2) 1.5XMAOP (Class 3,4)	Class 1 - 80% SMYS Class 2 – 75% SMYS Class 3 – 50% SMYS Class 4 – 40% SMYS or 1.5 X Flg (whichever of the assy. is lower)		8 hours (4-hours if above ground)
✓ Transmission and Gathering Pipelines Operating at ≤ 30% SMYS	≤ 30%	Natural Gas	1.5XMAOP (CL,2,3,4)	Class 2 – 30% SMYS Class 3 – 30% SMYS Class 4 – 30% SMYS or 1.5 X Flg (whichever of the assy. is lower) Reference 192.503	1 Hour	
✓ Transmission and Gathering Pipelines Operating at ≥30% SMYS	> 30%	Natural Gas	1.5XMAOP (CL1)	Class 1 – 80% SMYS	1 Hour	

✓- denotes update

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Compressor Station, Regulator Station and Meter Station	≤ 72%	Water	1.5 X MAOP	95% SMYS or 1.5 X Flg (whichever of the assy. is lower)		8 hours (4-hours if above ground)
Compressor Station, Regulator Station and Meter Station in Class 1, 2 or 3	≤ 72%	Air/Inert	1.5 X MAOP	50% SMYS or 1.5 X Flg (whichever of the assy. is lower)		8 hours (4-hours if above ground)
Low stress pipelines installed after 11/12/70	≤ 30%	Air/ inert	Reference 192.507		1 hour	
Low stress pipelines installed before 11/12/70	≤ 30%	Air/ inert	Reference 192.507		1 hour	

✓Note 1: For transmission lines only, if it's determined that a spike test is warranted, a 15 minute spike test will be done to 100% of SMYS or 1.5 times MAOP per CFR 192.506. The hydrostatic spike pressure testing requirements in § 192.506 applies only when conducted as required by §§ 192.710 and 192.921.

✓Note 2: For non-Jurisdictional compressor stations, a 2-hour minimum pressure test can be adopted per B31.8 (para 841.321). Such deviation would require approval from Pipeline Integrity and VP Engineering.

✓Note 3: Flanged joints and flanged fittings may be subjected to system hydrostatic pressure not to exceed 1.5 times the 100F rating rounded off to the next higher 25 psi. Testing at any higher pressure would require PM approval:

Rating	**MAOP**	**Max test pressure**
150	**285**	**450**
300	**740**	**1125**
600	**1480**	**2225**
900	**2220**	**3350**

TABLE 2
ONSHORE LIQUID PIPELINES – TEST REQUIREMENTS

Facility Description	% Hoop stress at MOP	Test Medium	Min. Test Pressure	Max. Test Pressure	Hold Period	
					Leak Test	Strength Test
Transmission Lines	≤ 72%	Water	1.25 X MOP (Spike test requires min 1.39 MOP)	95% SMYS or 1.5 X Flg (whichever of the assy. is lower)		8 hours (4-hours if above ground)
Pump station Piping	≤ 50%	Water	1.5 MOP	90% SMYS for SMLS 95% SMYS for ERW		8 hours (4-hours if above ground)

TABLE 3
✓SUMMARY OF TEST REQUIREMENTS OFFSHORE PIPING AND INLAND NAVIGABLE WATERS

			TEST PRESSURE		
ITEM	FACILITY	TEST MEDIUM	MINIMUM	MAXIMUM	DURATION (AFTER STABILIZATION)
1	Offshore Platform & Risers that Operate at a Pressure Equal to or Greater Than 100 psig	Water	1.5 x MAOP	100% SMYS	8 hours (2)
2	Offshore Platform & Risers that Operate at a Pressure Less Than 100 psig	Pneumatic	Operating Pressure, but not lower than 90 psig	Depends Upon Medium	1 hour
3	All Offshore Facilities other than Risers and Platform Facilities	Water	1.25 x MAOP	The Lesser of 110% SMYS or Double Deviation	8 hours (2)

1. For pipe of 12¾ inch diameter and under, for which a test at 90 % SMYS would be impractical, the minimum test pressure may be 2160 psig, or 1.5 times MAOP, whichever is less.
2. ✓For fabricated assemblies and short sections of pipe, the duration of a pre-installation test must be a minimum of 4 hours. Within the jurisdiction of the Railroad Commission of Texas, a short section of pipe is 100 feet or less. Post installation test is required unless it is justified as impractical.

TABLE 4
BREAKOUT TANKS WITH INSERVICE DATE AFTER 10/2/2000– TEST REQUIREMENTS

BUILT TO	TEST MEDIUM	TESTED TO
API SPEC 12F	AIR/INERT	SECTION 5.3 OF API SPEC 12F
API STD 620	WATER AND AIR/INERT	SECTION 7.18 OF API STD 620
API STD 650		SECTION 7.3.5 AND 7.3.6 OF API STD 650
API 650 OR 12C*	WATER**	SECTION 12.3 OF API STD 653
API STD 2510		✓SECTION VIII, DIVISION 1 OR 2 OF 2007 ASME BOILER AND PRESSURE VESSEL CODE (BPVC)

* For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated tanks.

** For the hydrostatic testing of repair, alteration, and reconstruction.

9.8 Preparation for Test

9.8.1 Facilities shall be provided to protect test personnel and instruments from inclement weather conditions if deemed necessary by the company representative. These facilities shall consist of a portable shelter complete with adequate lighting and heating facilities. Temporary shelters shall also be provided where required.

9.8.2 All testing shall be contained by blind flanges, weld caps, tubing caps, or plugs having a maximum test working pressure equal to or greater than the maximum test pressure of the system. Fabricated caps shall not be used. Pancake, skillet or steel plate blinds shall not be used to separate tests unless properly rated by the Company Engineer or Pipeline Integrity.

9.8.3 Where required, existing valves or other equipment shall be replaced by temporary spool pieces fabricated from pipe equivalent to the pipe on either side of the valve.

9.8.4 Testing against a closed valve is not permissible unless approved by pipeline integrity. Plug valves shall be tested in the full open position, ball and gate valves in the half open position. Seat testing of valves shall not exceed the noted manufacturing working pressure.

9.8.5 Prior to starting the test all fittings, flanges, bull plugs, etc. shall be checked to ensure tightness. New gaskets shall be used whenever possible to minimize the possibility of flange leaks. Provision shall be made for releasing pressure safely at any time by means of a needle type valve or a bleeder plug. All threaded plugs shall be removed, and the integrity of threads checked.

9.8.6 All valves shall be greased, stroked, and the packing tightened prior to testing.

9.8.7 All welds contained in a system test shall be cleared by Non-destructive testing prior to initiating the pressure test.

9.8.8 Testing of more than one individual section simultaneously may be achieved by connecting sections with suitable tie-over or jumper lines prior to the commencement of filling. The material in these connections and lines shall be fabricated using pipe and components having a greater pressure capacity than those in the tested section.

9.8.9 Filling shall be carried out according to the Company Representative's instructions. Provisions shall be made for bleed-off and drain points in the test section.

9.8.10 The Contractor shall profile survey the test section to confirm the actual elevation differences between the low point, high point, start point and end point of each test section. If actual elevations do not match the elevations shown on the "Hydrostatic Test Profile" included in the drawing section of the Contract Documents, test pressures shall be adjusted by the Company, as is practical. If adjustment of the test pressure is not acceptable, test headers shall be relocated, as required, to account for actual elevations. In either case, the Hydrostatic Test Profile Drawing will be re-issued by the Company and must be received by the Contractor prior to commencing the pressurizing procedure.

9.8.11 Test section length should be limited to prevent elevation differences within a test section from exceeding 300feet unless approved by pipeline integrity.

9.9 Internal Cleaning

If internal cleaning is needed, then the following conditions apply:

9.9.1 For new construction only - Prior to filling and pressure testing, the Contractor shall clean the pipeline by running cleaning pig(s) using compressed air to propel the pig(s). The pig(s) shall be run completely through the pipeline test section. Additional cleaning pigs shall be repeated as required until the test section is cleaned to the satisfaction of the Company's Testing Inspector.

9.9.2 The recommended velocity for the cleaning pig is three to four miles per hour.

9.9.3 For new construction only - If the pig becomes lodged in the line, attempts shall be made to move it by increasing the pressure. The pressure shall not normally be increased beyond 50 psig. If the presence of water is determined to be the cause of the stoppage, the Company may authorize higher pressures to facilitate movement of the water. In such a case, the Company may require the pressure to be released and a dewatering line to be installed at the downstream receiver. A cleaning pig that cannot be dislodged using this procedure shall be cut out and the pipeline repaired by the Contractor at its expense. The Contractor shall obtain approval of the Testing Inspector prior to cutting of the pipeline for removal of lodged pigs.

9.9.4 Company's representative shall be present to approve the cleanliness of the line. The contractor shall run the brush pigs and squeegees continuously through the line until all solids, dust, and mill scale are removed, unless otherwise approved by Company's representative. Company's representative shall be present for the first and last brush pig run to compare their respective conditions. No red dust shall be blowing out of the line when the final brush pig is run. This will assure that all rust has been removed from the interior walls of the pipeline. Foam squeegees shall be run after the final brush pig run to enhance the removal of dust and mill scale. Brushes and foam squeegees shall continue to be run until accepted by Company's representative. The contractor shall provide and utilize dust bags on each test segment to reduce dust emissions.

9.9.5 Upon completion of the cleaning operation, the temporary receiver and the test header used for launching shall be removed and the ends of the pipeline section shall be sealed by installation of the test headers or with caps properly supported/braced to ensure the safety of testing personnel. The pipeline test section shall be sealed to prevent the entry of dust, water or foreign substances and preserve the internal cleanliness of the pipeline until filling and pressure testing operations are commenced. The Contractor shall tie-in cleaned sections of the pipeline as required to complete the test sections and shall exercise care in the tie-in operations to maintain the internal cleanliness of the pipeline.

9.10 P-V Plot vs Yield Plot

9.10.1 Yield plots shall be performed on all major pipeline tests or as directed by the Company Engineer or Pipeline Integrity. When required, on any pipeline planned to exceed 90% SMYS, and others deemed necessary by the Company Engineer or Pipeline Integrity, plotting shall commence at the pressure which results in a hoop stress of 80% of the specified minimum yield strength of the pipe, at any point along the pipeline. For practical reasons, yield plots are not required on any test section less than 1,000 feet in length.

9.10.2 The pressure-volume plot shall consist of a graph showing water volume added (pump strokes, gallons, etc.) versus pressure at 5 - 10 psi intervals.

This should plot a straight line if the following conditions exist:

- No air remains in segment (if Volume is plotted on the x-axis the curve will tend to bend upwards if there is significant air in the pipeline);
- Pipe pressure at the lowest point does not exceed the SMYS;
- Pipeline has no leaks.

The graph shall be plotted by hand for the purpose of immediately identifying any deviation from a straight line. The scale selected for plotting the pressure-volume curve shall be chosen so that the plotted line lies between 45° and 75° from the horizontal. The pressure pump shall be capable of increasing the pressure of any test section at a rate of 10 psig per minute at full test pressure. A constant pumping rate must be maintained during pressurization, and sufficient water shall be provided to complete the plot without stopping until full test pressure is reached.

9.10.3 Each yield plot shall show a record of volume of water added in relation to the increase in test pressure. Readings shall be recorded at intervals of pressure of 5 psi.

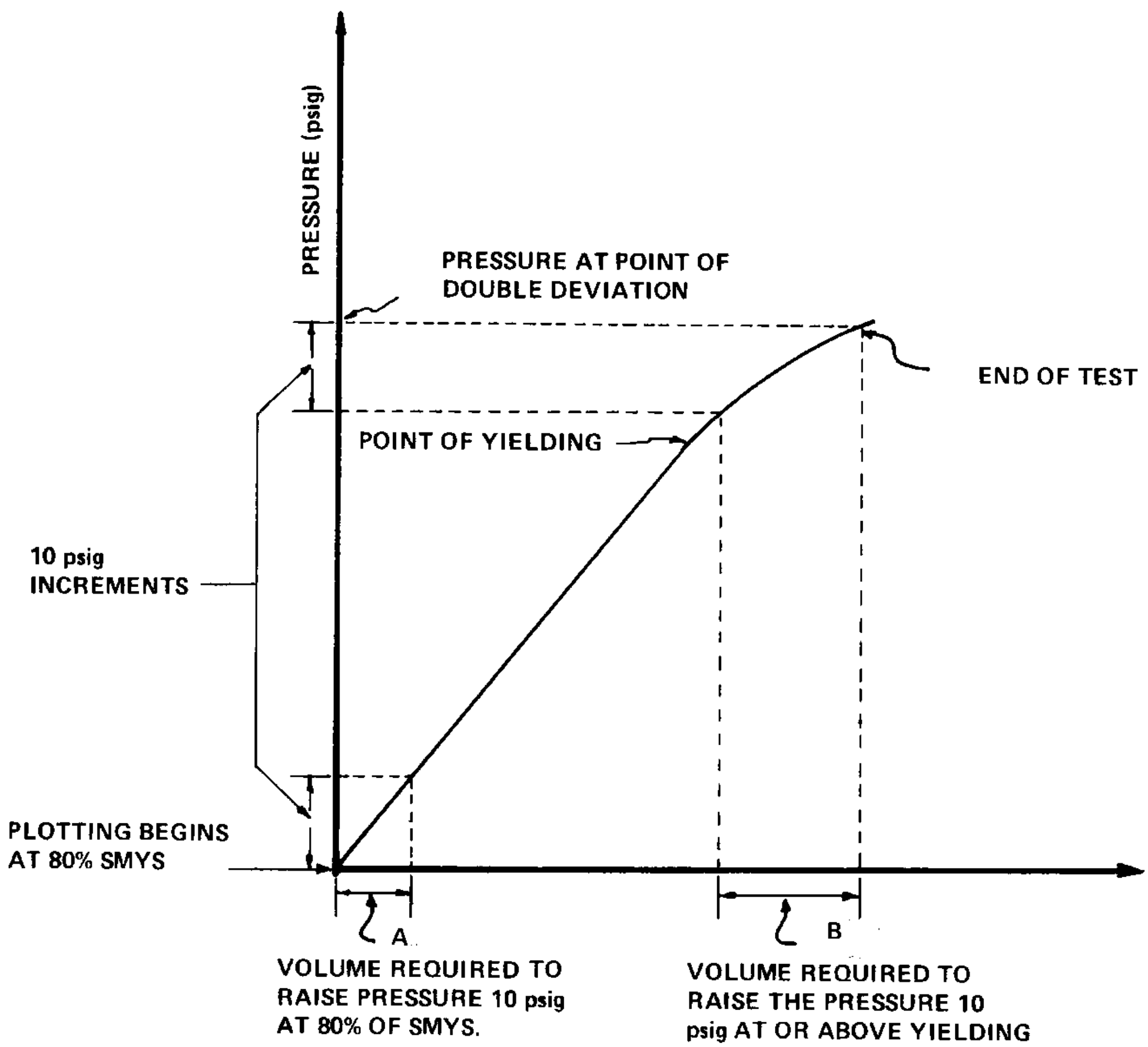
9.10.4 Yield plots shall continue without interruption until the pre-determined commencement pressure has been reached or a maximum deviation of 0.1% from straight-line proportionality is observed.

9.10.5 If for any reason the pressure is reduced below the yield plot starting pressure, another yield plot is required.

9.10.6 For a yield test conducted as part of a strength test, the leak test and hold period requirements should be the same as for the strength test except that the minimum test pressure must meet only the minimum strength test requirements for the entire hold period.

FIGURE 1

PRESSURE-VOLUME PLOT WITH DOUBLE-DEVIATION



[1]Note: Double deviation occurs when the volume required to raise the pressure 10 psi is double the volume which is required to raise the pressure 10 psig to an 80% SMYS stress level. Therefore, the measure volume B in gallons of filling water will be twice the gallons for volume A.

9.11 Times-Pressure Record

9.11.1 Upon reaching the test commencement pressure, the pump shall be stopped, the line stabilized, and the pressure locked in. During the test, deadweight readings shall be recorded in the following manner and order:

- 5-minute intervals for 30 minutes;
- 10-minute intervals for 30 minutes;
- ✓ 15-minute intervals for the rest of the test is recommended, but the Project Manager on site has the option of 30-minute intervals;

9.11.2 A Company representative and Contractor (if applicable) shall be present at all times while a test is in progress.

9.12 Deviation from Test Parameters

9.12.1 Buried Piping - 8 hour mainline or station tests

Any re-pressuring of a buried pipeline under test shall be accompanied by a pressure equalization period, as well as a re-start of the 8-hour test duration.

Pressure increases up to the limits allowed by Section 9.7 - Maximum and Minimum Test Pressure, may be relieved by bleeding off water without restarting the test period.

Three conditions must be satisfied for a successful pressure test:

- The test pressure must not fall below the specified minimum test pressure;
- A minimum two-hour pressure hold shall be attained near the end of the 8-hour minimum test period, or the test shall be extended until a two-hour hold is achieved. A pressure increase commensurate with a temperature increase is acceptable;
- The test pressure must not vary from the commencement pressure by more than (2.5% of the specified minimum test pressure.

Any deviation from this condition for a successful pressure test requires written approval from pipeline integrity.

If the test pressure varies from the commencement pressure by more than ± 2.5% of the specified commencement test pressure, arrangements shall be made to return to the original commencement pressure level. Such adjustment shall be affected only by adding or relieving the test medium, provided the increase/decrease in pressure can be correlated with a corresponding increase/decrease in test medium temperature or soil/water/air temperature surrounding the pipe.

The Contractor must perform calculations to show that any pressure changes are due to temperature change and provide written calculations to Company. If the calculations do not indicate this is the case the potential existence of a leak must be investigated.

9.12.2 Exposed Piping - visually exposed 4-hour and 1-hour tests

To maintain these conditions the piping may be re-pressurized or bled-off without an extension of the test period, provided no leakage has been visually displayed and the increase or decrease in pressure can be correlated with a corresponding increase or decrease in test medium temperature with the ambient air temperature.

9.13 Test Duration

9.13.1 Test Durations are established by the applicable DOT criteria in Part 192 and Part 195 for the facility being tested.

9.13.2 Buried Piping to operate at Hoop stress of 30% or more SMYS - minimum 8 hours.

9.13.3 Fabricated units, and Short Sections of Above Grade Piping to operate at Hoop stress of 30% or more SMYS (i.e. Compressor, pump and meter station piping) - minimum 4 hours.

9.13.4 Facilities to operate at Hoop stress less than 30% SMYS - minimum 1 hour.

9.14 Filling and Pressurizing

9.14.1 Prior to filling a test section with water, the Contractor shall make a final check to verify the following:

- Valve body drain plugs have been removed, carefully cleaned, taped (Teflon) and replaced;
- All valves are in open position for filling;
- All pipe, hose and bolt connections are tight;
- Test manifolds are properly fabricated;
- Pumps or compressors are in good working condition;
- Instruments are ready for use (proper charts installed, ink pens filled, clocks wound, correct calibration, etc.);
- Pigs are installed properly with respect to directional discharge.

9.14.2 For large test sections, a properly calibrated flow meter shall be installed in the fill line to enable the rate of fill and volume of water which enters the test section to be determined and recorded. Confirmation of calibration shall be done through renewing applicable paperwork and placing a calibrated transfer tank on the inlet. A record shall be maintained which records the amount of water used and the number of strokes. This data shall be used to confirm the squeeze pump output.

9.14.3 Filling shall not begin until all temperature recorders, including a thermowell in the fill line at the test head to monitor the fill water, have been installed and allowed adequate time to stabilize as directed by the Company.

9.14.4 Pressure records of the fill in each test section shall be recorded. Ambient, pipe and water temperatures shall be recorded during the fill operation and these records shall be turned over to the Testing Inspector after completion of the pressure tests.

9.14.5 All mainline valves within the fill section must be open for passage of the fill pigs and valves equipped with gear operators closed one-half way in order to fill the body cavity after passage of the pig. For gate valves supplied in the full open position without gearing a connection from the test section shall be applied to the body bleed valve to equalize the pressure across the valve seat.

9.14.6 Connections made between the fill pump and test head and between test heads, when two sections are jumpered together for filling and/or testing shall employ rigid piping and be secured to the Company's satisfaction. Approved high Pressure Hoses with approved Fittings should be considered for use as jumper between test pieces and fill pump.

9.14.7 The fill pump shall be set on a metal or polyethylene catch pan of sufficient dimensions to contain all leaking lubricants or fuel and prevent them from entering the water source.

9.14.8 The Contractor shall measure water volumes added to or removed from the pipeline.

9.14.9 Water used for testing shall be screened at the source and the intake shall be located at a depth that will not permit air to be drawn in with the water. The Contractor shall provide a filter of the backflushing or cartridge type with a means of cleaning without disconnecting the piping. The filter shall have the capabilities of 100 mesh screen. If the cartridge type is used, a sufficient quantity of cartridges shall be on hand at the filter location. The Contractor shall install the filter between the fill pump and the test header. The Contractor shall be responsible for keeping the backflush valve on the filter closed during the filling operation. The Contractor shall be responsible for the proper disposal of materials backflushed from the filter or filter cartridges. The Contractor will not be allowed to backflush the filter into the stream or other water source.

9.14.10 If necessary, spheres or pigs shall be used to remove free air as the section is filled. Air must be limited to a maximum of 1% of the pipeline volume to avoid an unsafe level of stored energy and unstable pressures during test.

The Contractor shall insert fill pig(s) into the test head and immediately ahead of the water column to prevent air pockets from forming. The rate of travel of the fill pig shall be controlled to prevent the acceleration of the fill pig during filling downhill portions of the test sections and insure that the water column behind the fill pig is not broken during the filling operation. The fill pig travel rate will be controlled by maintaining sufficient back pressure based upon the elevation profile of the test section, on the fill pig to prevent breaking the fill water column by venting the air in the test section as the fill pig progresses. The Contractor is responsible for controlling the velocity of the fill pig and insuring proper water fill.

9.14.11 Water filling shall commence at a slow rate in order to remove all the air from the system. During this operation, the air shall be vented at the high points of the piping sections.

9.14.12 On completion of filling, all vents shall be closed, and the system pressurized to a pressure equivalent to 50% of the calculated test pressure of the piping being tested. The temperature of the pipe shall be monitored until it remains relatively unchanged (stabilized) with time to a minimum of 8 hours or until it is at or near the temperature of the surrounding environment along the test section.

9.14.13 The piping shall be held at the above pressure during which time it shall be visually inspected, and a leak test conducted. If there is evidence of a leak, the leak shall be located, repaired, (or noted, if the leak is minor and it is on a temporary structure such as a flange) and the leak test repeated until satisfactory.

9.14.14 When the above has been satisfied, pressure shall be increased slowly, at a constant pumping rate such that minimum cycling and surging results. From the stabilization point at 50% of test pressure to the final test pressure, pressure should then be increased at a maximum of 50psi/ min in increments of 1/10th of test pressure with a hold period at the end of each increment.

Note: If ambient temperature is below 60°F, rate of pressurization should be held to 1/2 the allowable pressurization rate for each step given above.

9.14.15 If the test pressure is to exceed 80% SMYS the pumping rate past 80% SMYS must be at a constant rate of 5 psig/ min until the test pressure is reached.

9.14.16 After test pressure has been attained, all fittings, valves, flanges, etc. shall be checked for leaks.

9.14.17 Elimination of leaks on any fittings, by tightening, shall not be carried out while the system is under a pressure greater than 50 psi. In the event of a leak, the system shall be bled-down to 50 psi or below and the leak(s) repaired.

9.14.18 A leak test, immediately following pressurization, shall be repeated until it is evident to the test inspector that no remaining leak exists.

9.15 Test Breaks and Leaks

9.15.1 In the event of a leak or break during testing, the test shall be terminated, and the leak or break repaired. Test leaks must be reported to the Company Engineer and Pipeline Integrity for evaluation with Company and Contractor representatives. Yield plots for any tests following repair of the line shall be made and compared in relation to a line parallel to the proportionality line established in the original test.

9.15.2 In the event of a line pipe failure during testing, the Contractor's Testing Supervisor and Company's Testing Inspector shall locate and determine the cause of the failure. The failure shall be thoroughly photographed in place by the Company's Testing Inspector prior to its removal. The Company's Testing Inspector must complete EnLink's Pressure Test Failure Report PT-04 as soon as practical. If the failure is in the seam of the pipe, the entire joint in which the seam failure exists shall be removed from the pipeline. The Contractor shall remove a minimum of 5 feet or as determined by the company representative. The piece(s) removed shall be marked for orientation with respect to the position in the pipeline and with the alignment sheet station number of the failure. The Contractor shall not cut on or damage the failed edge of the pipe during removal, transit or unloading at the Company's designated storage location. If the failed portion is too long for transport or handling, it may be cut at right angles to the failure edge. All portions are to be retained and turned over to the Company.

9.16 De-pressurizing and De-watering

9.16.1 As soon as possible after the test has been completed, the pressure shall be reduced at such a rate that vibrations do not develop. Extreme caution shall be exercised throughout the depressurizing process. If the adjacent test section is to be filled from or through this section, the bleed down shall be into the section to be filled.

9.16.2 The test medium shall be removed in accordance with the applicable permits. The system shall be purged to the satisfaction of the Company Representative. Care shall be taken to ensure that all water is removed after the pressure test if applicable.

9.16.3 All depressurizing of mainline test sections shall be accomplished by venting water to atmosphere through an assembly which is attached directly to the test head. All connections shall be welded. All welds shall be inspected for cracks with dye-penetrate prior to pressurizing the test section. Care shall be taken that nobody is in the path of the water jet and that the person turning the valve is safely behind and below the depressurizing assembly. Only when the test section has been reduced to atmospheric pressure may dewatering or water transfer piping be connected to the test heads.

9.16.4 Prior to commencing any dewatering activities the Contractor shall ensure that all mainline valves have been returned to the full open position. Air pressure shall be used to displace the water from the section. The air pressure shall be placed behind displacement pigs. Extreme caution shall be used to prevent air lock with the test section to be dewatered. The pig velocity for dewatering the pipeline shall be 3 to 4 miles per hour.

9.16.5 The Contractor shall use an experienced operator to control the back pressure on the system and control the volume of water being vented. Discharge rates may be specified in the governing permits. Also, the volume vented must be controlled to prevent erosion damage at the discharge point.

9.16.6 For large test sections, dewatering shall be carried out by propelling both spheres or the bidirectional pigs in, normally, the reverse travel direction from that used during filling. Where a booster is used, an after-cooler and a scrubber between the booster discharge and the test head shall be used.

9.16.7 After the test section has been dewatered, valve body drain plugs shall be removed, carefully cleaned, taped (Teflon) and replaced after the valve body is drained. Valves shall be placed in the full open position.

9.17 Drying

9.17.1 Following dewatering, the piping shall be dried. For large sections, spheres or the bidirectional pig, or a drying pig acceptable to the Company, shall be propelled through each Pressure test section. The propellant shall be compressed air. Back pressure sufficient to cause a smooth run shall be supplied and shall consist of the same medium as the propellant. When spheres are used, they shall be run separately. A Company Representative shall be present prior to commencement of the drying run and shall witness the arrival of the drying spheres or pig. Should visible quantities of liquid water be expelled from the test head blow off, further drying runs shall be required until, in the opinion of the Company, the line is sufficiently dry.

9.17.2 The Contractor shall be required to furnish, operate, and maintain air compressor equipment with a capacity to propel the drying pigs (and pipe-sizing tool if required) through the pipeline at minimum of 200 ft/min.

9.17.3 When the test sections have been dewatered, the test section shall be dried by running a minimum of 2 pigs or spheres using compressed air through the length of the test section with sufficient backpressure to result in a smooth run at approximately 10 mph. When spheres are used, they shall be run separately.

9.18 Dehydrating to Low Dew Point

9.18.1 Where dehydrating by low dew point is specified, a procedure shall be explicitly detailed in the Project Description. This operation would be conducted after the installation of all fabricated assemblies. Brush Pigs and Swabs will be ran with Super-Dry Air to Clean/Dry each section. The contractor may choose nitrogen for drying to speed up drying process.

9.18.2 Certified Dew Point Meters will be used to verify Dew Points. A target dew point of -40F is required unless specified different in the contract documents. Dust Bags will be used on the receiving end(s) for Dust control. Roll-Off Dumpsters will be used to store used pigs at receiving ends.

9.19 Tie-in Test Sections

9.19.1 Unless otherwise directed by the Company, all welding or cutting is to be done cold, i.e., after gas in the immediate area of work has been evacuated using an air mover device. The air mover device will be provided, installed, and operated by the Company. A 3/8" to 1/2" diameter hole shall be drilled by the Contractor using an air drill to test for gas. No welding or cutting shall proceed in this situation without the approval of the Company. Company approved welding and construction procedures shall be used.

9.19.2 Upon completion of the drying procedure, the test headers shall be removed. All open ends shall be sealed to prevent ingress of water in the event of rain or if trench dewatering pumps fail. The sections shall be tied together to become a continuous pipeline.

9.20 Sourcing and Disposal of Test Water

9.20.1 The Company is responsible for acquiring all permits required by federal, state and local agencies for procurement of water and for the discharge of water used in the hydrostatic testing operation. The Company will provide the Contractor with a copy of the appropriate withdrawal/discharge permit for hydrostatic test water. For new construction, the contractor may be required to acquire all necessary permits. The Contractor shall keep the water withdrawal/discharge permit on site at all times during testing operations. Any water obtained or discharged shall be in compliance of permit notice requirements and with sufficient notice for the Company's Testing Inspector to make water sample arrangements prior to obtaining or discharging water. Under no circumstances will an alternate water source be used without prior authorization from the Company. Discharge locations other than those listed in the permits will not be allowed.

9.20.2 The Company's designated representative shall be responsible for obtaining any required water analyses from each source to be used in sufficient time for the Company to have a lab analysis performed prior to any filling operations. The sample bottle shall be sterilized prior to filling with the water sample. The analysis shall determine the PH value and settlement and suspended solids. Each bottle shall be marked with:

- Source of water with pipeline station number;
- Date taken;
- Laboratory order number;
- Name of person taking sample.

9.20.3 The Company's representative shall be notified at least one day prior to obtaining water and/or discharging water and the Contractor shall provide the designated representative access to the test water for obtaining samples. The Contractor will identify the source of water for hydrostatic testing and will provide permits for use of same.

9.20.4 Staging/work areas for filling the pipeline with water shall be located a minimum of 50 feet from the water's edge of any stream and, if topographic conditions permit, located 10 feet beyond the "high bank" to prevent runoff towards the stream. Refueling of construction equipment will be conducted a minimum distance of 100 feet from the stream. The Contractor will install temporary sediment filter devices adjacent to all streams that runoff may enter.

9.20.5 The test medium shall be disposed of in compliance with applicable environmental rules and regulations.

9.20.6 The Environmental Department shall select discharge points and specify measures to be taken to control pollutants and prevent erosion. Measure taken shall be in accordance with the Company Environmental practices.

9.20.7 All dewatering activities shall conform to erosion and sediment control measures as specified in the "Environmental Compliance Procedures". The Contractor shall assist the designated representative in collecting samples of the test water for analysis and be familiar with the requirements of the Test Water Disposal Permit.

9.20.8 Mitigation Measures

The following measures, devices, etc., shall be utilized to lessen the impact of hydrostatic test discharges:

To ensure that the source water is of adequate quality to protect the existing quality of the receiving waters, the pipe should be sufficiently cleaned prior to testing and the wash water discharged to a straw bale structure, geotextile filter bag, or collected in a truck. Wash water shall not be allowed to flow into streams, wetlands or other surface water bodies. To reduce the velocity of the discharge, there are a number of energy-dissipating devices (EDD's) that can be used. This section describes some of the more common EDD's and the practical uses of each. The list is by no means exhaustive, but the essential element that ties them all together is that they are inexpensive but effective and are relatively simple for the Contractor to fabricate with materials on hand.

9.20.9 Mitigation Devices

Splash Pup - It consists of a piece of large diameter pipe (usually over 20" diameter) of variable length with both ends partially blocked that is welded perpendicularly to the discharge pipe. As the discharge hits against the inside wall of the pup, the velocity is rapidly reduced, and the water is allowed to flow out either end. This device is most effective in flowing rivers and streams but can also be used in dry washes and vegetated channels. The pup itself should be laid parallel to the direction of flow of the stream. An angle off the parallel could result in erosion of the receiving banks. A variation of the splash pup concept, commonly called a diffuser, incorporates the same design, but with capped ends and numerous holes punched in the pup to diffuse the energy into the receiving stream.

Splash Plate - the splash plate is a quarter section of 36-inch pipe welded to a flat plate and attached to the end of a 6-inch discharge pipe. The velocity is reduced by directing the discharge stream into the air as it exits the pipe. This device is very effective for use around rivers or lakes with significant sport fish populations. This device is more commonly used when discharging to a water environment, though it is effective for most on-land flow type discharges as well.

Plastic Liner - In areas where highly erodible soils exist or in any low flow drainage channel, it is a common practice to use layers of visqueen (or any of the new construction fabrics currently available) to line the receiving channel for a short distance. One anchoring method may consist of a small load of rocks to keep the fabric in place during the discharge.

Strawbale Dewatering Structure - Strawbale dewatering structures are designed to dissipate and remove sediment from the water being discharged. Design specifications are shown in the "Environmental Compliance Procedures". Straw bale structures are used for on-land discharge of wash water and hydrostatic test water.

10.0 U.S COAST GUARD FACILITIES

10.1 Equipment tests and inspections per 33CFR156.170

(a) Except as provided in paragraph (d) of this section, no person may use any equipment listed in paragraph (c) of this section for transfer operations unless the vessel or facility operator, as appropriate, tests and inspects the equipment in accordance with paragraphs (b), (c) and (f) of this section and the equipment is in the condition specified in paragraph (c) of this section.

(b) During any test or inspection required by this section, the entire external surface of the hose must be accessible.

(c) For the purpose of paragraph (a) of this section:
   (1) Each nonmetallic transfer hose must:
   (i) Have no unrepaired loose covers, kinks, bulges, soft spots or any other defect which would permit the discharge of oil or hazardous material through the hose material, and no gouges, cuts or slashes that penetrate the first layer of hose reinforcement as defined in §156.120(i);
   (ii) Have no external deterioration and, to the extent internal inspection is possible with both ends of the hose open, no internal deterioration;
   (iii) Not burst, bulge, leak, or abnormally distort under static liquid pressure at least 1½ times the maximum allowable working pressure; and
   (iv) Hoses not meeting the requirements of paragraph (c)(1)(i) of this section may be acceptable after a static liquid pressure test is successfully completed in the presence of the COTP. The test medium is not required to be water.

   (2) Each transfer system relief valve must open at or below the pressure at which it is set to open;

   (3) Each pressure gauge must show pressure within 10 percent of the actual pressure;

   (4) Each loading arm and each transfer pipe system, including each metallic hose, must not leak under static liquid pressure at least 1½ times the maximum allowable working pressure; and

   (5) Each item of remote operating or indicating equipment, such as a remotely operated valve, tank level alarm, or emergency shutdown device, must perform its intended function.

(d) No person may use any hose in underwater service for transfer operations unless the operator of the vessel or facility has tested and inspected it in accordance with paragraph (c)(1) or (c)(4) of this section, as applicable.

(e) The test fluid used for the testing required by this section is limited to liquids that are compatible with the hose tube as recommended by the hose manufacturer.

(f) The frequency of the tests and inspections required by this section must be:
   (1) For facilities, annually or not less than 30 days prior to the first transfer conducted past one year from the date of the last tests and inspections;

   (2) For a facility in caretaker status, not less than 30 days prior to the first transfer after the facility is removed from caretaker status; and

   (3) For vessels, annually or as part of the biennial and mid-period inspections.

(g) If a facility or vessel collects vapor emitted to or from a vessel cargo tank with a vapor control system, the system must not be used unless the following tests and inspections are satisfactorily completed:
   (1) Each vapor hose, vapor collection arm, pressure or vacuum relief valve, and pressure sensor is tested and inspected in accordance with paragraphs (b), (c), and (f) of this section;

   (2) Each remote operating or indicating device is tested for proper operation in accordance with paragraph (f) of this section;

   (3) Each detonation arrester required by 33 CFR 154.2105, 154.2108(b), 154.2109, 154.2110, 154.2111, and 154.2204, or 46 CFR 39.4003, and each flame arrester required by 33 CFR 154.2103, 154.2105(j), and 154.2203 has been inspected internally within the last year, or sooner if operational experience has shown that frequent clogging or rapid deterioration is likely; and

   (4) Each hydrocarbon and oxygen analyzer required by 33 CFR 154.2105(a) and (j), 154.2107(d) and (e), and 154.2110 or 46 CFR 39.4003 is calibrated:
   (i) Within the previous two weeks, or

(ii) Within 24 hours prior to operation when the vapor control system is operated less frequently than once a week.

(h) Upon the request of the owner or operator, the COTP may approve alternative methods of compliance to the testing requirements of paragraph (c) of this section if the COTP determines that the alternative methods provide an equal level of protection.

(i) Notwithstanding the general provisions of 33 CFR 156.107(a) relating to the authority of the Captain of the Port to approve alternatives, the owner or operator may request the written approval of the Commandant (CG-ENG), U.S. Coast Guard, 2100 2nd St. SW., Stop 7126, Washington, DC 20593-7126, for alternative methods of compliance to the testing and inspection requirements of paragraph (g)(3) of this section. The Commandant (CG-ENG) will grant that written approval upon determination that the alternative methods provide an equivalent level of safety and protection from fire, explosion, and detonation. Criteria to consider when evaluating requests for alternative methods may include, but are not limited to: operating and inspection history, type of equipment, new technology, and site-specific conditions that support the requested alternative.

Refer APPENDIX D – US Coast Guard Pipeline Testing Guide

11.0 Process Piping - General Procedures

11.0.1 No pressure test is required for vent or drain lines which are open to atmosphere and do not include in-line items which could restrict or block flow such as valves or tanks.

11.0.2 Components or vessels pressure tested by the vendor in the manufacturing plant according to ASME Pressure Vessel Standards, need not be re-tested in the field. However, the components or vessels may be included in the field test with the rest of the system if the test pressure is calculated according to the procedures in Section 10.5 of this document.

11.0.3 Sensitive components such as relief valves, regulators, instruments, control valves and related items which may be damaged at elevated pressures shall either be removed or isolated from the system during testing.

11.0.4 Minor modifications or repairs of non-hazardous fluid piping are not required to be strength tested provided such modifications or repairs are a maintenance function, the system will be operated at a pressure which is less than 100 psi, and which produces less than 30 percent hoop stress and the piping is inspected for leaks under operating conditions.

11.0.5 Each tie-in weld or flange used to tie in a test segment of pipe is exempted from the pressure test. The Contractor shall test all piping and assemblies in such a configuration as to minimize the number of final tie-in welds.

11.0.6 Fabricated assemblies which cannot be tested with the pipe system shall undergo the same test performed in the same manner as the pipe system to which it is welded. Should such assembly contain valves or fittings, the test pressure shall not exceed 1-1/2 times the maximum operating pressure of the valve or fitting. Pressure-volume plots are unnecessary on these sections.

11.1 Responsibilities

11.1.1 Company Engineer or PM is responsible for setting the test parameters.

11.1.2 The Company representative shall supervise all pressure testing, which shall be performed in accordance with this specification.

11.1.3 All pressure test operations shall be attended by the Contractor and the Company test personnel at all times.

11.1.4 The testing operation shall not be commenced or terminated without the Company Representative's approval.

11.1.5 Leak tests, pressurizing, and associated yield plotting shall be conducted during daylight hours unless impractical. If testing at night is necessary, adequate lighting acceptable to the Company shall be provided.

11.1.6 Testing will be performed to the requirements of ASME B31.3 Section 345.

11.2 Test Medium

11.2.1 The test medium shall be water, air, inert gas or other medium applicable to the service – that is:

- Compatible with the material of which the pipe is constructed;
- Relatively free of sedimentary materials;
- Nonflammable, except that as applicable;
- Water containing corrosive chemicals and detergents shall not be used. The water used shall not contaminate the pipe through deposition or corrosion. The Company may specify water filtration to maintain relative freedom from sedimentary materials;
- If a liquid is used which is flammable, its flash point shall be at least 120 deg F (49 C).

11.3 Test Heads and Drag Caps

Refer to Section 9.4 of this document.

11.4 Exclusions

Refer to Section 9.5 of this document.

11.5 Maximum and Minimum Test Pressure

11.5.1 Hydrostatic test pressure will be at least 1.5 times the design pressure.

11.5.2 For design temperature that exceeds the test temperature, the minimum test pressure shall be calculated by the following equation, except that the valve of S_T/S shall not exceed 6.5:

$$P_T = \frac{1.5 \times P \times S_T}{S}$$

where:

P_T = *minimum test gage press*

P = *internal design gage pressure*

S_T = *stress value at test temperature*

S = *stress value at design temperature (see B31.3 Table A-1)*

11.5.3 Where the test pressure of piping attached to a vessel is the same as or less than the test pressure for the vessel, the piping may be tested with the vessel at the piping test pressure.

11.5.4 Where the test pressure of the piping exceeds the vessel test pressure, and it is not considered practicable to isolate the piping from the vessel, the piping and the vessel may be tested together at the vessel test pressure, provided the vessel test pressure is not less than 77% of the piping test pressure calculated in accordance with Paragraph 10.5.2 above.

11.6 Leak Test

11.6.1 A required Leak Test will be conducted prior to initial operations, to ensure tightness, according to the requirements of B31.3 Section 345.1.

11.6.2 The Leak Test will be a hydrostatic leak test, unless it is determined that a hydrostatic leak test would be impractical according to the requirements of B31.3 Section 345.1(b) & (c).

11.6.3 Precautions will be taken to avoid excessive pressure which could be caused by thermal expansion of the test media.

11.6.4 A preliminary test using air may be made prior to hydrostatic testing to locate major leaks. Air pressure **will not exceed 25 PSIG**.

11.6.5 The Leak Test shall be maintained for at least 1 hour.

11.6.6 Leak Tests will be conducted after any heat treatment has been completed.

11.6.7 The possibility of brittle fracture must be considered for leak tests being done at low temperatures near the metal ductile-brittle transition temperature.

11.6.8 Testing after any repairs or modifications may be waived if precautionary measures are taken to assure sound construction.

11.6.9 Records shall be made of all testing, including:

- date of test;
- identification of the piping system;
- test fluid;
- test pressure;
- certification of results by examiner;
- records shall be maintained in project job books for a minimum of 5 years.

11.7 Preparation for Leak Test

11.7.1 All joints are to be left uninsulated during the test, except joints which have been previously tested.

11.7.2 Piping designed for vapor or gas will be provided with additional temporary supports during testing to support the weight of the test media.

11.7.3 Piping with expansion joints will be done according to the requirements of B31.3 Section 345.3.3.

11.7.4 Equipment which is not to be tested will be isolated from the test piping using blinds or be disconnected, or by some other means. A valve may be used for isolation provided the valve is suitable for the test pressure.

11.8 Pneumatic Leak Test

11.8.1 Test temperature is very important and will be considered to minimize the chance of brittle failure.

11.8.2 A pressure relief device shall be used, having a set pressure not higher than:

- test pressure plus 50 PSI; or
- 110% of the test pressure, whichever is lesser.

11.8.3 Test pressure will be 110% of design pressure.

11.9 Pneumatic Leak Test Procedure

11.9.1 Gradually increase pressure until PSIG is one-half the test pressure or 25 psi, whichever is lesser:

- at this time a preliminary leak check will be made.

11.9.2 Gradually increase the pressure in steps (35% to 50% to 60% to 70% to 80% to 100% or 50 psi increments whichever is greater) until the test pressure is reached:

- hold the pressure at each step long enough (no less than 10 min) to equalize piping strains.

11.9.5 Once full test pressure is reached, block supply and observe pressure gage for a minimum of 10 min.

Refer **Appendix C** for Safe Working Distance and Stored energy limitation

11.10 Hydrostatic-Pneumatic Leak Test

11.10.1 If a combination hydrostatic-pneumatic leak test is used, the requirements of B31.3 Section 345.5 will be followed.

11.11 Records

11.11.1 Records of testing will be retained for at least 5 years, which include:

- examination procedures;
- examination personnel qualifications.

12.0 ✓Plastic Pipeline – General Procedures

12.1 Responsibilities

12.1.1 The EnLink Engineer or PM shall be responsible for setting the test parameters.

12.1.2 The Company representative shall supervise all pressure testing, which shall be performed in accordance with this specification.

12.1.3 All pressure test operations shall be attended by the Contractor and the Company test personnel at all times.

12.1.4 The testing operation shall not be commenced or terminated without the Company Representative's approval.

12.1.5 Leak tests, pressurizing, and associated yield plotting shall be conducted during daylight hours unless impractical. If testing at night is necessary, adequate lighting acceptable to the Company shall be provided.

12.2 Safety

12.2.1 Restrain pipe, components and test equipment against movement in the event of failure. Joints may be exposed for leakage inspection, provided that restraint is maintained.

12.2.2 Keep persons not involved in testing a safe distance away while testing is being conducted.

12.2.3 Refer to Appendix A.

12.3 Regulatory Limitations

12.3.1 All potentially hazardous leaks must be discovered and repaired. [192.513(b)]

12.3.2 The test pressure must be at least 150 percent of the maximum operating pressure or 50 psig (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test. [192.513(c)]

12.3.3 During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater. [192.513(d)]

12.4 Test pressure and duration

12.4.1 Leak Test Pressure and Duration – The maximum allowable leak test pressure and leak test time including initial expansion, and time at leak test pressure should be in accordance with equation (5) and Tables 1 and 2 below:

$$^{(5)}\quad P_{(T)} = \frac{2 \times HDS \times F_t \times H_T}{(DR - 1)}$$

WHERE:

$P_{(T)}$ = Leak Test Pressure, psi (MPa), for Leak Test Time, T
T = Leak Test Time, hours
HDS = PE material hydrostatic design stress for water at 73°F (23°C), psi (MPa)
F_t = PE material temperature reduction factor per specific manufacture's specifications.
H_T = Leak test duration factor for leak test time, T (See Table 2)
DR = Pipe dimension ratio

Ft = 1 if test medium temperature is $\leq$ 80 F

Fill and then thermally stabilize the pipeline with no air entrapment, pressurize the pipeline at test pressure for 4-hours, slightly reduce the pressure (by 10 psi) , and then observe the pressure for the test duration to remain essentially constant (within 5% variation) to achieve an acceptable test.

12.4.2 The maximum permissible test pressure is measured at the lowest elevation in the test section.

12.4.3 The maximum permissible test pressure is the lower of (a) 150% of the system design operating pressure provided that all components in the test section are rated for the test pressure, or (b) the pressure rating of the lowest pressure rated component in the test section.

12.4.4 For leak testing purposes, the maximum allowable test pressure in polyethylene pipe is 150% of the pipe's design pressure rating for the application and the application service temperature.

12.4.5 Do not subject lower pressure rated, non-polyethylene parts or devices to pressures above their pressure rating. Lower pressure rated parts may be removed or isolated from the test section to avoid damage or failure. Vent isolated parts or equipment to atmosphere.

12.4.6 All thermoplastic pipes have reduced strength at elevated temperature. Test pressure must be reduced when the test section is at elevated temperature either from service conditions or from environmental conditions such as being warmed by the sun. Multiply the test pressure by the Table 1 multiplier to determine the allowable elevated temperature test pressure.

TABLE 1 – Example Chart Temperature Reduction Factor, “F_t”

Manufactured by Performance Pipe, Inc.

Test Section Temperature °F (°C)	≤ 80 (≤ 27)*	≤ 90 (≤ 32)	≤ 100 (≤ 38)	≤ 110 (≤ 43)	≤ 120 (≤ 49)	≤ 130 (≤ 54)	≤140 (≤ 60)**
Multiplier	1.00	0.90	0.80	0.75	0.65	0.60	0.50

*Use the 80°F (27°C) multiplier for 80°F (27°C) and lower temperatures. **The maximum service temperature for Performance Pipe PE pressure piping is 140°F (60°C).

TABLE 2 - Leak Test Duration Factor, “H_T”

Leak Test Pressure, $P_{(T)}$, psi (MPa)	**Leak Test Time, T, Hours**	**Leak Test Duration Factor, H_T**
$P_{(8)}$	≤ 8	1.50
$P_{(48)}$	≤ 48	1.25
$P_{(120)}$	≤ 120	1.00

TABLE 3 - PE Material Hydrostatic Design Stress

PE Material Designation	**HDS for Water at 73°F (23°C), psi (MPa)**
PE2606 (PE2406)	630 (4.3)
PE2708	800 (5.5)
PE3608 (PE3408)	800 (5.5)
PE3710 & PE4710	1000 (6.9)

12.5 General

12.5.1 The construction of the pipeline shall not be accepted, and the pipeline shall not be placed in service until the pipeline has been pressure tested and found free of all hazardous leaks.

12.5.2 Pneumatic test section shall not exceed 200,000,000 ft-lbs of stored energy. See Stored Energy Specifications in Appendix C of this standard. Any test exceeding the above the 200,000,000 ft-lbs would require VP approval and risk mitigation plan.

12.5.3 Minimum test pressure shall be calculated to achieve the desired MAOP for the appropriate Class Location.

- Crystal gauges are acceptable for recording test pressures during a test < 300 psig. The instrument must be calibrated within 1 year and have current calibration documentation.

12.5.4 The temperature of the pipe must not exceed 80°F during the test. Test pressures must be reduced when the test section is at higher temperature. A contact thermometer shall be available to check pipe temperature. If temperature of pipe exceeds 80F, the test pressure must be reduced in accordance with the formula found in 12.4.1 and Table #2 and Table #3.

12.5.5 Buried test sections shall be tested for a minimum of 8 hours. Above ground test sections will be tested for a minimum 4 hours.

12.6 Test Medium

12.6.1 The test medium shall be water, air, inert gas or other medium applicable to the service – that is:

- Maximum test medium temperature is 120 Deg F or manufacturer rating;
- Compatible with the material of which the pipe is constructed;
- Relatively free of sedimentary materials;
- Nonflammable, except that as applicable;
- Water containing corrosive chemicals and detergents shall not be used. The water used shall not contaminate the pipe through deposition or corrosion. The Company may specify water filtration to maintain relative freedom from sedimentary materials.

12.7 Fill and Initial Expansion

12.7.1 Fill the pipeline with test medium and allow time for the test section to equalize to a common temperature, then pressurize to the test pressure. To compensate for pressure-drop during the test, the initial test pressure should be near maximum.

12.7.2 The recommended slow fill-rate Q, in gpm, is based on the pipe inside diameter D, in inches, and an axial filling velocity of less than 10-feet per min calculated as follows:

$$\dot{Q}_{gpm} = 0.402\, D^2_{inches}$$

A firm urethane foam pig or swab, pushed by the fill water, may be used to assist in air removal, especially where the pipeline undulates and air pockets may be trapped.

12.7.3 Allowance for make-up water during the expansion phase can be determined from the below table

ALLOWANCE FOR EXPANSION UNDER TEST PRESSURE

NOMINAL PIPE SIZE[1]	U.S. GALS/100 FT. OF PIPE[2]			NOMINAL PIPE SIZE[1]	U.S. GALS/100 FT. OF PIPE[2]		
	1 HOUR	2 HOURS	3 HOURS		1 HOUR	2 HOURS	3 HOURS
2"	0.08	0.12	0.15	20"	2.80	5.50	8.00
3"	0.10	0.15	0.25	22"	3.50	7.00	10.50
4"	0.13	0.25	0.40	24"	4.50	8.90	13.30
5"	0.21	0.41	0.63	28"	5.50	11.10	16.80
6"	0.30	0.60	0.90	30"	6.20	12.60	19.10
8"	0.50	1.00	1.50	32"	7.00	14.30	21.50
10"	0.75	1.30	2.10	36"	9.00	18.00	27.00
12"	1.10	2.30	3.40	42"	12.00	24.00	36.00
14"	1.40	2.80	4.20	48"	15.00	27.00	43.00
16"	1.70	3.30	5.00	54"	18.00	30.00	50.00
18"	2.20	4.30	6.50	—	—	—	—

[1]mm=0.03937, [2]multiply by 11.53 to convert to liters/100 meters of pipe.

13.0 ✓Special Procedures – Pneumatic and Gas Testing

- ✓Any test exceeding the above the 200,000,000 ft-lbs would require VP approval and risk mitigation plan.
- Pneumatic and gas testing are not allowed for hazardous liquid pipelines.
- Stored energy calculation and limitations are applicable for all facility piping and above ground pipeline pneumatic testing. For underground pipeline testing, please consult with Pipeline Integrity for stored energy calculation requirement.

13.1 Test Plan

PM and CONTRACTOR shall devise a written test plan that is in accordance to this Special Procedure of the Testing Specification, with the drawings, sections, and testing requirements provided prior to testing. A meeting between the COMPANY's inspector and the CONTRACTOR supervisor shall be scheduled to review the testing specification(s) and CONTRACTORS test plan. The test plan shall include, but not be limited to the following information:

- Location of safety equipment and personnel;
- Emergency Reaction Plan and standby attendee sign-in log;
- Essential Personnel Roster and replacements back-ups;
- Essential personnel are considered to be those deemed absolutely necessary to perform the testing accurately and safely. At least one safety person shall be included in this group to constantly monitor for signs or symptoms of oxygen deficiency;
- Cleaning and testing schedule in reference to the provided, numbered test sections;
- Location of test manifolds, test media supply source, vents;
- Regulation, recording, metering, and data acquisition equipment (vendor and model number and calibration certificates);
- Pneumatic supply conditions;
- Identification of the test pipe segment with isolation points;
- Central Gather Point during venting or Emergency (Rally Point);

- Equipment isolation plan;
- A documented pre-test inspection of the facility shall be performed. This inspection shall at a minimum be performed by and include the following:
  - The PM and an Operations Representative of the COMPANY shall review all documents relating to the materials used in the fabrication of the facility subject to test to validate that the materials installed are designed to sustain the maximum test pressures;
  - The Contractor, COMPANY Inspector, and an Operations Representative of the Company shall perform a physical preparedness or walk-through of the facility, including and not limited to validating torque integrity of connections, alignment of fittings, and of materials installed that the facility is physically prepared for test according to this Standard and the Contractors written Test Plan.

13.2 Safety

Refer to Appendix A for Safety Guidelines

13.3 Pneumatic Pre-Test

13.3.1 Filling with Test Media

- The fill rate shall be controlled to ensure the test medium is added at a temperature close to the ambient or piping temperature, as indicated above, to prevent the gas from expanding too quickly and liquefying.

13.3.2 Pressure gauges and venting devices

- Pressure gauges shall be compatible with the maximum test pressure and have graduations of five (5) psi.
- All vents shall be installed vertically with an isolation ball valve and throttling plug valve and bleed valve between them.
- Weld-o-lets larger than two (2) inches are prohibited.
- Vent valves shall be one pressure class above the test sections design pressure. For example, a test section that was design for ANSI 600 pressure class would need ANSI 900 vent Valves. This is to ensure that maximum seat pressures are not exceeded.

13.3.3 Hoses, valves, and connections

- Minimum working pressure ratings for all flexible hoses shall be 5000 psig with a minimum of the greater of 10,000 psig burst pressure or twice the rated working pressure. Use appropriate valves and connections in reference to the pressure.

13.3.4 COMPANY approved soap/bubbling solution

13.3.5 Dead-weight testers

- Pressure range shall be compatible with the maximum test pressure and have a sensitivity of one-half (0.5) psi.

13.3.6 Pressure and Temperature Recorders (Per API RP-1110)

- Two-pen, 24-hour clock chart recorders that are compatible with the maximum test pressure, have five (5) psi graduations, a temperature range of 0 to 150 degrees F with 1-degree F graduations and remote temperature sensing bulbs.
- Pressure recorders shall be calibrated with the dead weight tester before each test.
- A calibrated thermometer shall be positioned at the test point for ambient temperature monitoring. A temperature chart recorder may also be used instead of a thermometer. Temperature recorder will be calibrated before each test with a certified thermometer.

13.3.7 Whereas testing with water provides some cleaning/ rinsing during drainage, test media will provide minimal debris removal, especially on large diameter pipe, therefore all piping shall be thoroughly cleaned during construction and prior to testing.

13.3.8 The test can be conducted with the filter separator elements inside. A benefit of doing this is that the filter closure will only need to be opened once.

13.3.9 Check sealing surfaces and O-rings on quick opening closures and blow-offs. Remove all threaded pipe connections, including valve body drain plugs, to carefully cleaned, tape (Teflon), replace, and tighten.

13.3.10 Any valves shall be partially open (1/4 open). Do not test against a fully open or fully closed valve. Ensure that valves have been greased, stroked, and have had the packing tightened.

13.3.11 Torque all flange bolts hydraulically in conformance with gasket manufacturer's recommendations.

13.3.12 Over pressure protection shall be provided on each test section. The OPP device shall be furnished by the media supplier. The maximum pressure set point shall be determined by the lesser of 80 % SMYS (in accordance with DOT) or the maximum flange / valve rating.

13.3.13 All valves in line of the pressure test shall be set to 1/4 open to prevent testing up against the valve seat. This includes any valve that is set to Normally Closed (NC), but does not include vent valves that have a seat pressure rating higher than the test section test pressure.

13.4 Leak Test

The test section shall be isolated from any equipment not included in the test (scrubbers, Compressors, pumps, etc.), all valves are to be set to 1/4 open and all blinds and instruments installed. Dead weight readings shall be taken at 15 minutes intervals to verify no leakage.

13.4.1 Air Leak Test (optional)

To prevent low pressure leakage of test media, each test section can be leak tested with 100 psig of compressed air prior to performing any tests. Use approved soap bubble solution to check for any leaks.

13.4.2 Test Media Leak Test

Purge the section with test media for 5 minutes and then pressurize to 100 psig and hold for 15 minutes. Check for any leaks and safely tighten any fittings or threaded piping and tubing connections. Increase pressure in 200 psig increments followed by a 15-minute hold period with a corresponding leak check until 30 % of the minimum test pressure is reached. Conduct a thorough leak check before proceeding to the pressure test.

13.5 Pneumatic Pressure Test

13.5.1 Prior to increasing pressure above the final leak test pressure, all pipe flanges shall be cleaned and sealed with a vapor sealing tape. A hole in the tape with an over-sealing piece of tape should be left on each flange for later insertion of a gas monitoring probe.

13.5.2 ✓ To perform the pneumatic pressure test, increase the pressure from the test media leak test in increments of the lesser of 20% of the minimum test pressure or 350 psig. After each increase, hold while checking for leaks and monitoring for pressure loss. Leak checks at flange locations shall be conducted using gas monitoring probes inserted into the flanged cavity. Holes in the tape shall be sealed when probe is not inserted. Refer to paragraph 10.2.12 if any leaks occur.

13.5.3 When the test pressure reaches the lesser of 50% of minimum test pressure or 1000 psig, discontinue the checks at the potential leak points and evacuate anyone not involved with the test operation out of the test area until the test is complete.

13.5.4 When the test pressure (adjusted for elevation) is reached, shut in the test section for one hour:

- Record the deadweight readings every ten minutes during this hour;

- Do not re-pressure the test during this hour;
- Pressure can be bled off during this hour so the maximum pressure (adjusted for elevation) is not exceeded;
- ✓If the pressure drops below the minimum during this hour, repair the leaks and begin the hour long test again until the pressure holds between the limits:
  - If a leak is discovered while the piping is under pressure, that section shall be isolated via the closest possible isolation valves on both sides of the leak as long as the leaking section pressure does not exceed the seat pressure rating of the valve. If necessary, the CONTRACTOR can lower the pressure upstream of the isolation valve in order to isolate the leaking section. The leaking section shall be depressurized to atmosphere and repaired. If the leaking section cannot be isolated, the entire test section must be blown down. During any blow down or bleed off with nitrogen used as the media, the atmosphere shall be monitored for safety.

13.5.5 SAFE WORKING DISTANCE CALCULATIONS

The following information is for reference only. Refer to Appendix C for charts to help in selecting the right safe working distance for a specific project's specifications.

13.6 ✓Natural Gas Pressure Test

13.6.1 If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium:

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS. If 20% SMYS is not required for the gas test, then a leak survey is not required.

13.6.2 To perform a natural gas test on a line below 30% SMYS, increase the pressure to MAOP at approximately 25psig/min. The pressure will then be held at MAOP for 30 minutes. During the MAOP hold, initiate 13.6.1. Once 30 minute window is accomplished the pressure will be increased at approximately 5psig/min with a 1 minute hold every 5 minute until test pressure is reached. After Test pressure is reached the line will need to accomplish a 1 hour pressure hold.

13.6.3 For Natural Gas Pressure test recording refer to 13.5.4 Pneumatic Pressure Test.

✓**13.6.4** Maximum hoop stress (percentage of SMYS) allowed during test is 80% for Class 1 and 30% for Class 2,3 and 4.

13.6.5 SAFE WORKING DISTANCE CALCULATIONS

The following information is for reference only. Refer to Appendix C for charts to help in selecting the right safe working distance for a specific project's specifications.

14.0 Records – Documentation and Reporting

14.1 Requirements

14.1.1 This section contains documentation / reporting requirements for pressure tests for pipelines to operate at or above 100 psig.

14.1.2 Copies of all correspondence with environmental regulatory agencies and all laboratory reports regarding discharge of hydrostatic test waters shall be forwarded to the Project Champion in charge and compiled for the Job Books.

14.1.3 The DOT requirements state that each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under 192.505, 192.507 and 195.310. The record must contain at least the following information:

Certification Papers: Certification of Calibration for deadweights, pressure recorders, and temperature recorders used for the test shall be furnished to the Company's Testing Inspector prior to testing. The certification papers shall include each device's serial number;

Pressure Test Report: The Field Pressure and Test Report shall be completed detailing the date/time and activities for completing the testing operation. The report shall be signed after successful completion of the test by the Contractor's Testing Supervisor and the Company's Testing Inspector. The report will also include the name of the Company, name of person responsible for making the test, name of the test company, minimum test pressure, test medium used, description of the facility tested and test apparatus and temperature of the test medium or pipe during the test period;

Pressure Test Fill Log: The Test Section Fill Log should supplement the test report and include volumes and pressure required to complete the fill operations;

Pressure Test Log: The Test Section Data and Log should supplement the test report. Items such as deadweight pressure, ground or ambient temperature, and on-going activities such as bleeding or packing should be noted;

Pressure-Volume Chart: The Pressure-Volume Data and Pressure-Volume Chart are drawn during the pressurizing operation. Beginning at approximately 80% of maximum test pressure, the Pressure-Volume Chart is developed by plotting pressure as determined by the deadweights versus volume as determined by the stroke counter, or meter on the pressure pump. Yield plot where applicable;

Profile Sketch: A Test Section Plan and Profile sketch for pipelines only, is required for establishing test section pressures. Facility name, pipe or test section number and name. Begin test point station footage and end test point station footage;

Pipeline Failure Report: The Pressure Test Failure Report shall be prepared should a leak occur in any test section;

Pressure Chart: The pressure chart shall be signed after successful completion of the test by the Contractor's Testing Supervisor present during the test, and then presented to the Company's Testing Inspector for signature witnessing;

Temperature Chart: The pipe and ambient temperature charts shall be signed after successful completion of the test by the Contractor's Testing Supervisor present during the test and then presented to the Company's Testing Inspector for signature witnessing;

Caliper Survey Report: A Caliper Survey Report shall be completed detailing the time and activities for completing the caliper surveys. The report shall include a summary review/analysis of all findings and/or actions resulting from the caliper pig survey.

TABLE 7.1 Pressure Test Documentation Required

Record	Form Number	Required for Mainline or Lateral Line Test	Required for Prefabricated Sections and Components	Required for Ancillary Test
Pressure Test Report	PT-01	X	X	X
Pressure Test Deadweight Log	PT-02	X	X	X
Pressure / Volume Data	PT-03	X	X	X
Pressure Test Failure Report	PT-04	X	X	X
Test Inspector's Summary Report	PT-05	X	X	X
Pressure Test Calculation Sheet (head, including elevations)	✓PT-106	X	X	X
Yield Plot Graph (Not required for **lengths less than 1000** feet)		X		
Pressure Recorder Charts		X	X	X
Temperature Recorder Charts		X	X	
Pressure-Temperature Graph		X		
Instrument Calibration Certification Sheets		X	X	X
Temperature Chart – Pipe and Ground Temperatures			X	
Sketch of Piping as Tested, Showing Location of Test Headers and All Welds			X	X
Sketch of Piping as Installed			X	X
Alignment Drawings or Maps/Elevation Profiles		X		

14.1.4 Originals of all documents shall be sent to the EnLink Representative for acceptance. Test documents shall be retained for the life of the facility.

14.1.5 The completed pressure test forms for each facility tested serve as permanent historical records; therefore, it is mandatory that all required forms be filled out neatly, completely and accurately. Forms shall be completed in the field by the test engineer or technician at the time the test is performed, except when instructions specify otherwise.

14.1.6 Company pressure test forms should be used to the extent practical. The test contractor's forms may be used if approved by Company's representative and they are equivalent to the Company's forms and are completed in accordance with instructions for the equivalent Company form.

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14.1.7 All required test forms and pressure and temperature charts shall be submitted with the as-built data to the Pipeline Integrity Department.

14.2 Pressure Tests Greater than 30% SMYS

14.2.1 The records specified in Table 7.1 are required at the completion of each test, whether the test is successful or not.

14.3 Pressure Tests less than 30% SMYS

14.3.1 The following test documentation shall be required at the completion of each test. The completed test documents shall be sent to the Project Champion:

- A comprehensive test summary. This summary shall include pipe diameters, wall thicknesses, grades, and weld numbers. (Secondary Pressure Test Report);
- An accurate log of ambient pipe or test medium temperature and elapsed time. (Pressure Test Log.);
- A continuously recorded pressure chart for the test period;
- A continuously recorded temperature chart of the pipe and ground temperatures for the duration of the test period for all buried tests;
- A sketch of the piping as tested showing the location of the test headers and location of all welds;
- A sketch of the piping as installed (if applicable).

15.0 Revisions or Waivers

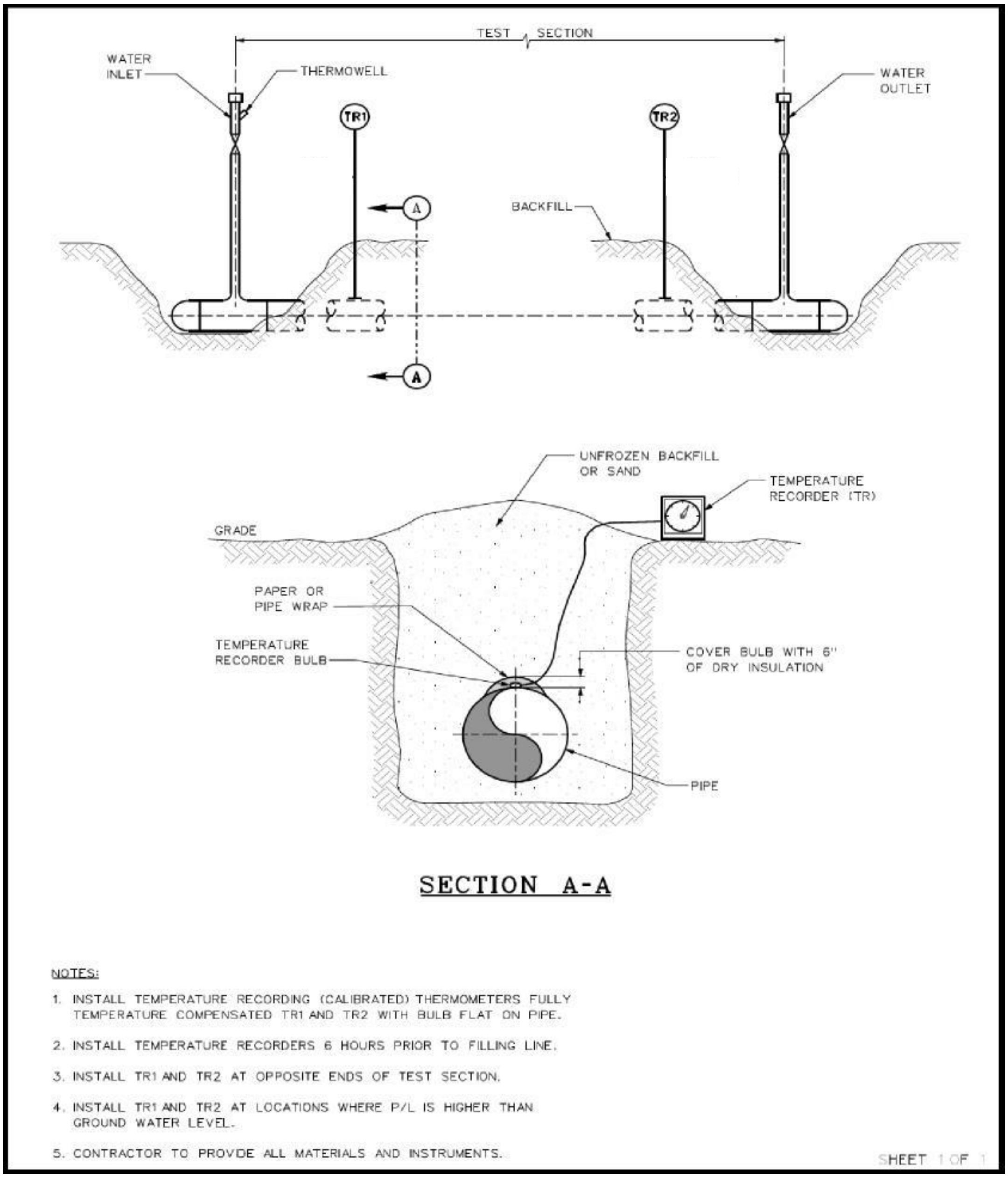
15.1 **Minor Revisions** - to this document may be performed by the plan manager without a committee approval.

15.2 **Waivers -** A waiver is a site-specific request. Any user of this document requesting a waiver of procedure from this specification requires a written request submitted to the Director of Pipeline Integrity and the Director of Engineering. Unanimous approval is required for a waiver. An approved waiver will be issued for attachment to the project test documents/file.

15.3 **Major Revisions –** to this document require Pipeline Integrity and Engineering review and approval. Requests are to be issued to the plan manager (Pipeline Integrity).

16.0 DRAWINGS

✓STANDARD PRESSURE TEST DRAWINGS



17.0 Appendix A – Safety Guidelines

17.1 Activity Description

- This document provides basic safety guidelines for the safety of all personnel and the general public during pressure (e.g., hydrostatic, pneumatic) testing operations.
- Plan and implement each pressure-testing event in a manner that mitigates unnecessary exposure to procedural hazards.
- All pressure tests must be conducted with due regard for the safety of life and property.
- All personnel have, and should use, "Stop Work" authority whenever there is concern for safety during pressure testing operations.
  - Contract personnel are required to attend daily safety meeting prior to working on this site and follow EnLink Safety Standards. With regards to an unsafe act or situation, any personnel involved in the operations have “Stop Work” authority, but only the EnLink Representative can give an "ALL START". No activities will be undertaken until the communications between the various locations has been established and is in full working order. Any accidents or incidents, including near misses, will require a total "Stop Work" with a post review of the situation before any activity can resume.
- This document is not meant to supersede or replace regulatory requirements, nor is it intended to be all inclusive of the applicable regulatory requirements. It is intended to be supportive and complimentary to such requirements.

17.2 Hazard Assessment

- Hazard assessments are performed to identify and mitigate perceived and actual environmental and operational hazards.
- A Job or Test Plan, including procedures and controls related to safety, is prepared prior to conducting pressure testing.
- Hazard assessments are performed at the beginning of each shift.
- Review and update hazard assessments when:
  - Each new task is begun;
  - There is a change in how a task is performed;
  - Changes in site or environmental conditions occur;
  - A specific need or concern is identified (i.e., as needed to ensure the safety of personnel or property).

17.3 Roles and Responsibilities

17.3.1 Management Responsibilities (includes all personnel with a supervisory role)

- Empower all personnel with the authority to “Stop Work” whenever hazardous conditions or potentially hazardous conditions are identified.
- Provide for and require that signs, barricades or other protective barriers are placed in a manner and at a distance sufficient to demarcate a safe zone to protect personnel and the public from unanticipated pressure release or equipment failure.
- Provide for and require the installation of devices that mark the limits of the exclusion zone.
- Keep unauthorized personnel out of the test area.

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- Provide for and require that equipment and materials are arranged to give unobstructed access/egress during testing and in the event of an emergency.
- Establish lines of communication between the Owner/Facility, Contractor, and local authorities.
- Provide for and require the use of reliable transportation and communication systems during all aspects of the testing event.
- Prohibiting major pipeline work not directly associated with the test operations around the pipeline sections being tested. While the pipeline facilities are being pressurized and during the test all personnel not required for direct operations (check for leaks, tighten gaskets, check valve status, operating pumps, recording data, etc.) shall be restricted from the area where the pipeline is being tested

17.3.2 Health & Safety (H&S) Responsibilities, when necessary

- A Health and Safety Professional is involved with performing the hazard assessment.
- Provide technical support for interpretation of pressure testing safety guidelines.
- Evaluate the effectiveness of the job-specific safety plan (or equivalent).
- Immediately stop and correct any safety related non-compliant activities.

17.3.3 Employee Responsibilities

- Do not enter or otherwise be present at a pressure-testing event unless you are part of the testing team.
- Personnel performing the test should approach the pressured line only in the performance of their duties. Where possible, personnel should use safety barriers for protection from the pressurized line and position the testing equipment in such a manner so as to minimize potential hazards.
- Review safety requirements of the site-specific test plan (see Section 15.4.6).
- Do not work over or near where pressure testing is being conducted.
- Wear the PPE as appropriate for the task being performed.
- Report any non-compliant H&S activities to a Supervisor.

17.4 Hazard Mitigation

17.4.1 General

- Suspend a test when the testing personnel (including but not limited to: contractor, contractor's agents) or equipment are not working in a safe manner.
- Consider the forces that would be present if any portion of the system failed while filling, under test, depressurizing or dewatering. Also consider potential for water hammer, potential for leakage of isolation valves, variable system pressures, potential for fill and dewatering pig velocity changes and other site specific conditions.
- When performing pneumatic tests, the piping shall be inspected to determine if the inside surfaces are contaminated with a combustible or flammable material (e.g., iron oxide, condensate). If found, remove such materials prior to air testing.
- Never tamper with or tighten any fittings (i.e., connections, bolts, hoses) while component is under any pressure.
- Never tighten connections that are under pressure. If a leak develops, you must depressurize to a safe level and then re-tighten.

- Wear hearing protection (which may include double hearing protection) that is adequate to reduce the noise below 80 decibels.
- The pressure recorders and deadweight gauge shall be located at a safe distance least 100 feet from the facility being tested.
- Contractor shall check unrestrained and slip coupled water fill lines. Restrain and anchor any connecting pressure hoses to prevent whipping after a hose failure.
- Special work permits are required for some plant areas, such as confined spaces; such permits usually are valid only for 8-hour shift and may require a standby worker outside the confined space at all times. Work permits to be obtained from the safety department prior to commencement of work.
- The LO/TO (LockOut/TagOut) process will be implemented by both company and contractor for all phases of the pressure test plan until confirmation that all work is completed and all affected party is ready to remove their isolation device.
- All equipment and skids shall be completely isolated from the section that is being tested. Details and/or strategy for accommodating this shall be in the Test Plan and discussed with the COMPANY inspector prior to any testing.

  Note: Paddle Blinds (ASME Blanks) are acceptable provided that they have the appropriate certifications, permanent marking and are manufactured in accordance with API 590 for ASME 816.5 and/or MSS-SP 44 pipe flanges. The Chief Inspector from each site may deny the use the paddles blinds if sufficient manufacturing documentation to verify the integrity of the paddle blinds is not provided.
- All vent valves, drain valves, and blow-down valves shall be locked and tagged with a warning device, so they are not opened during the test. Power gas actuated valves shall have the power gas supply disconnected or the power gas valve locked, closed, and any reservoir tanks depressurized. Electrically actuated valves shall have the power de-energized and locked out at the disconnect switch or at power distribution panel. In addition, all equipment shall be completely isolated.

17.4.2 General Worksite Safety

- Incorporate general worksite safety precautions and procedures, as applicable.
- Verify that test equipment and materials are rated to withstand the test pressures:
  - Verify that all supply lines and hose connections are secure with retaining devices before and during the test;
  - Visually inspect and ensure soundness and proper installation and valve positioning of all equipment used.
- Adequate lighting shall be available throughout testing operations.
- Safety equipment and supplies should be readily available and should include, but are not limited to:
  - Emergency spill kit;
  - Fire extinguisher;
  - Ladders;
  - Mobile light plants;
  - Whip checks;
  - Warning signs and barricades.
- Install mats or utilize secured ladders for access to test header valves. If using mat bridges across the excavation, handrails must be installed if elevated 6' above a lower level.
- Restrain or otherwise secure fill and discharge lines and/or hoses.
- Verify the pressure ratings of hoses, fittings, gaskets, and other manifold materials.
- Verify pressure rating of facility being tested.

17.4.3 Signage

- During pressure testing events, distinct warning signs, such as DANGER – HIGH PRESSURE TESTING IN PROGRESS must be posted at the test site and additional locations identified in the job specific safety plan.
- When testing in a populated area, an extensive public relations campaign (e.g., warning signs, barricade tape, strobe lights, and/or security guards) may be required to inform and protect the public from hazards associated with testing activities.

17.4.4 Exclusion Zone

- Precautions should be taken to see that persons not directly engaged in the testing operations remain out of the test area during the test period.
- A minimum distance of 100 feet shall be maintained between facilities that are being tested and the personnel conducting the test. The safe distance may be increased and the temperature probe, manifold and recorders may have to be set back further than 100 feet due to potential projectiles or extreme volume/pressure. Refer to Appendix C for safe working distance calculations.
- Restrict access to the immediate area involving the pressure test (i.e., test shelter, manifolds, pressure pumps, instruments, etc.) to only those persons actively engaged in the testing operation.

17.4.5 Notification

- Residents within close proximity of the facility being tested, and state and local enforcement agencies, if applicable, shall be advised by the Owner/Operator of the testing program and kept informed of the progress, as necessary.

17.4.6 Safety Planning / Site-Specific Test Plan

- Develop and deploy a site-specific test plan including descriptions of safety procedures and requirements.
- Before attempting any test, the Testing Supervisor will review the test specifications and procedures with the Test Inspector, Chief Inspector, and any other relevant personnel to be certain that all equipment is adequate and duties are organized and understood.
- Inform all personnel of assignments, responsibilities, and test requirements.
- Precautions associated with potential weather extremes should be considered and addressed in the site-specific test plan.

17.4.7 Pre-Test Checks and Inspections

- Prior to commencing testing operations, the Company Representative and /or Contractor shall inspect test heads to confirm all components are in good condition and meet working pressure requirements.
- Confirm that the following conditions are checked prior to testing:
  - There are no unrestrained or Victaulic (or equivalent) coupled fill lines;
  - Fill lines are able to contain initial water pack pressure;
  - Manifolds and other facilities are properly installed and will be adequately protected from damage in the event that violent failures or water surges occur;
  - Methods of isolating facilities being tested from test equipment and pumps are adequate;
  - Dewatering discharge lines are properly restrained, cribbed or anchored.
- All temporary butt welds subject to test pressure shall be radiographed prior to the start of the test. All new fillet welds on test manifolds shall be non-destructively tested using magnetic particle inspection (MPI) or dye penetrant.

17.5 Pressure Testing Safety Issues & Mitigation Recommendations

17.5.1 Test Manifold Construction

- A welded connection is recommended as the first connection to the test manifold.
- Prior to commencing hydrostatic testing operations, the Company Representative and /or Contractor shall inspect test heads to confirm all components are in good condition and meet working pressure requirements. This will include an inspection and test of heads / manifolds to ensure that no components (e.g., gaskets, O-rings, fittings, valves) will leak or cause loss of test water and that the components conform to specified safety requirements.
- If the 1st connection to the manifold is screwed, the following should be performed after each test:
  - Break apart the manifold equipment;
  - Reassemble the manifold with new equipment;
  - Inspect/test the equipment to confirm all pieces are structurally sound and functioning properly.
- High-pressure pipe and fittings shall be used for connection of the pressure pump, manifolds, and test equipment.
- If the testing manifold contains a longitudinal seam, the test equipment shall be located on the side opposite the seam, if possible.
- Inspect the make-up of all screwed connections.
- Material certifications should be confirmed as appropriate for use in pressure testing operations.
- Vent valves shall be installed and opened at the appropriate time when stored energy can be isolated and/or trapped between two points such as valves, skillets, etc.
- ✓ When using a pressure relief valve (pop-off valve), it should be set to a pressure above maximum test pressure; This pressure will be determined by Pipeline Integrity. This will ensure that the pipeline and testing equipment will not exceed its maximum pressure ratings.
- During pneumatic tests, a regulator shall be installed in line to protect testing equipment and the facility being tested.

17.5.2 Depressurizing / Dewatering

- All temporary fill and dewater piping should be connected with welded/screwed joints.
- Verify the length and integrity of welded/screwed connections prior to depressurizing.
- Properly de-pressurize connecting lines before attempting to seal or break joint components.
- When bleeding the pressure from a section of the line, use extreme caution, especially when deflectors such as ells are used. Slowly bleed pressure following a test.
- Confirm that the diversion of water and/or gas will follow a safe pathway (e.g., use of 90° or 45° angles).
- Always verify that complete depressurization has occurred through the use of pressure gauges and visible checks.
- The atmosphere shall be monitored for safety during any blow down, bleed off or depressurization.
- During the initial planning stage of a de-watering operation, an analysis of the existing and temporary piping system should be performed to identify the pressure associated with fluids and other forces that could adversely affect the integrity of the pipeline or the stability of the drainage and its components.
- Securely support and tie down dewatering lines at the discharge end to prevent uncontrolled movement during dewatering.
- The following guidelines should be followed in de-watering activities:
  - **Anchor the de-watering lines**. It is accepted industry practice to adequately anchor or secure de-watering piping to prevent movement and separation of the piping. Establish effective

anchoring systems based on expected forces and ensure that the systems are used during de-watering projects.

- **Ensure condition of couplings and parts**. All couplings and parts of the de-watering system need to be properly selected for their application. The associated piping which the couplings connect is a significant variable in the entire mechanical piping system. The couplings are manufactured in a controlled environment, and variations in the quality of the couplings should be limited. Ensure that couplings are within manufacturer's tolerances and free of damage that may result in connection failure.

- Notify all personnel that the area is all clear.

17.5.3 Testing Using Nitrogen

- Nitrogen testing or Gaseous medium testing shall only be performed after an Engineering or Pipeline Integrity approval is granted for the stress level and maximum test pressures of the facilities to be tested. All personnel and operating facilities shall be isolated from the test area.
- The Nitrogen quality shall be a minimum of 92% pure. Nitrogen should be treated as a hazardous substance. As a gas, nitrogen naturally displaces oxygen molecules in the atmosphere and is therefore known as an asphyxiate gas. Nitrogen has the same molecular weight as air. It is important to monitor all personnel in and around the area for signs of oxygen deficiency. Oxygen levels below 19 % are considered to be not fit tor respiration. Atmospheric Oxygen in the test area shall be continuously monitored with Oxygen analyzers.
- Atmospheric monitoring will start from the time the nitrogen supply rig is connected to the facility to be tested and ready to run until all piping has been depressurized and evacuated of nitrogen, and the COMPANY inspector has determined that the atmosphere is suitable to return to work.
- Any meter reading that displays an oxygen level below 19% shall result in all personnel being evacuated from the area until the cause of the oxygen displacement can be isolated and contained. This includes all buildings and any other enclosed area(s).
- The nitrogen supply rig shall have a check valve to prevent backflow of the nitrogen into the supply equipment. The rig shall also have a double block and bleed arrangement to prevent leakage into the test section. Double block and bleed can be accomplished by using a valve on the test section's fill point.
- For venting, the preferred method is to have the Nitrogen supplier manage all venting activities. The Nitrogen supplier shall provide a venting plan. If a vent not furnished by the Nitrogen supplier is used, ensure that the vent has an inline ball valve and plug valve with a bleed valve between them. The ball valve shall be wide open, and the plug valve shall be used for throttling. If the plug valve ices up, then the ball valve can be closed, and the plug valve replaced or deiced.
- The Nitrogen shall be released slowly into the atmosphere in order to prevent the gas from expanding too quickly causing it to cool and become denser than air, thus settling to the ground instead of dispersing to the atmosphere.
- During testing, only essential personnel shall be on site in accordance with *CFR 49 Part 192.505,* all buildings Intended for human habitation within 300 feet of test section shall be evacuated. In addition, a perimeter of 300 feet shall be established and roped off around the testing section(s). If the 300 feet perimeter is incapable of being roped off because of areas subject to potential public use or access (roads, cemeteries, etc.) notify the appropriate public officials of the testing plans. Work with those officials to determine if restrictions to the public access or use can be enforced during the test period. If restrictions can be enforced work with the public officials to get the requirements enforced. In all cases install highly visible warning signs along the finalized perimeter to indicate that high-pressure Nitrogen testing is in progress and that unauthorized personnel are prohibited from entering the site. (Refer to site specific aerial view drawings with evacuation radii shown around testing site). *Note:* some *evacuation radii* may *exceed 300* feet.
- If a leak is discovered while the piping is under pressure, that section shall be isolated via the closest possible isolation valves on both sides of the leak as long as the leaking section pressure does not exceed the seat pressure rating of the valve. If necessary, the CONTRACTOR can lower

the pressure upstream of the isolation valve in order to isolate the leaking section. The leaking section shall be depressurized to atmosphere and repaired. If the leaking section cannot be isolated, the entire test section must be blown down. During any blow down or bleed off, the atmosphere shall be monitored for safely.

17.6 REFERENCES

- Current versions of the reference automatically supersede the reference listed below.

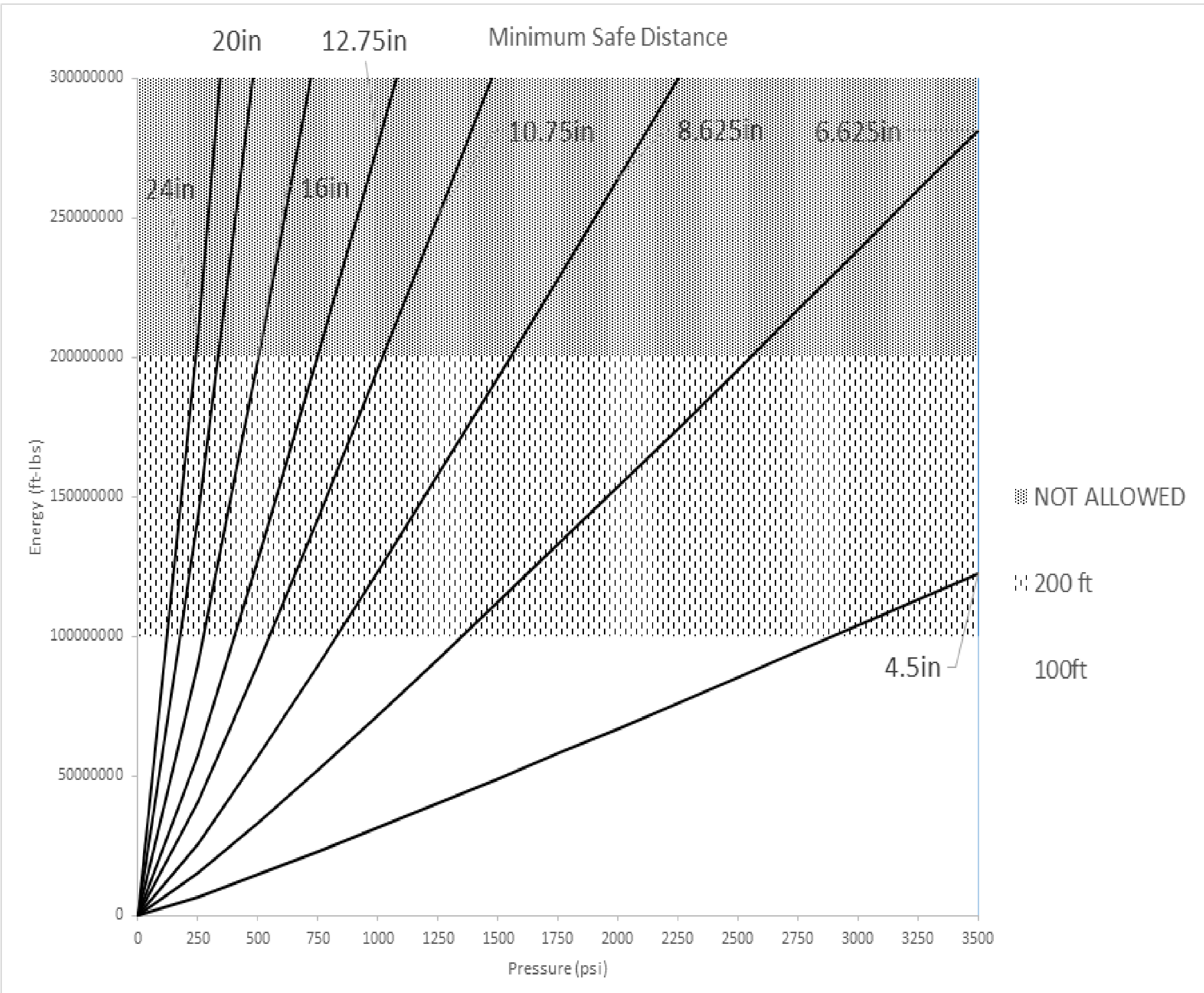
17.6.1 Occupational Safety and Health Administration (OSHA)

- Hazards Associated with De-Watering Pipe Lines, Safety and Health Bulletin SH 1B 06-21- 2004 / Advisory Bulletin ADB-04-01.

18.0 Appendix B - Revision History

Section	Date	Summary of Revisions
All	07/07/2016	Complete Revision and formatting changes
All	07/07/2016	Reviewed revisions with Committee, made recommended changes and forwarded document to Engineering for their approval.
All	07/07/2016	Added Process piping testing standard and Safe distance guidelines
All	08/25/16	Updated Coast guard pressure testing guidelines
12.0	1/10/2018	Added new Section 12 for poly-pipe testing procedures.
All	02/05/2018	Reviewed with group and made recommended changes. Sent to Prasanna for Committee approval
All	5/22/20018	Final review completed by Committee.
	3/26/2020	Final review completed by Committee. For list of detailed revisions, see DOT Team.

Appendix C – Safe Working Distance



NOTE: This chart applies to pneumatic testing distances ≤ 0.25 miles.

For distances > 0.25 miles use the formula provided below

Stored Energy Calculation

$$E = 360 \times P_{at} \times V \left[1 - (P_a/P_{at})^{0.286}\right]$$

and

$$TNT = \frac{E}{1488617} \quad \text{(lbs)}$$

Where E is the stored energy, ft-lbs
P_{at} is the absolute test pressure psia
P_a is absolute atmospheric pressure, 14.7 psia
V is the total volume under test pressure, ft^3

Safe Working Distance R Calculations

R = 100 ft for E < 100,000,000 ft-lbs
R = 200 ft for 100,000,000 < E $\leq$ 200,000,000 ft-lbs

The maximum calculated Stored Energy E of any vessel or piping system being pneumatically tested should not be greater than 200,000,000 ft-lb. Any test exceeding this limit would require VP of Engineering and Pipeline Integrity approval upon successful Risk evaluation consideration per ASME PCC-2 Article 5.1, Mandatory Appendix III and IV

Note: The stored energy value of 200,000,000 ft-lb is equivalent to an explosive energy of 127 lb of TNT

Typical Safe Distance R, Examples

Diameter	WT	Length, mi	Vol, ft3	Pressure, psi	Energy E, ft-lbs	Safe distance R, ft
4.5	0.188	0.1	49	500	5,789,753	100
4.5	0.188	0.25	122	1000	31,388,489	100
4.5	0.188	0.5	245	1500	98,014,799	100
4.5	0.188	1	490	400	44,964,026	100
6.625	0.188	0.1	112	500	13,293,636	100
6.625	0.188	0.25	281	1000	72,069,937	100
6.625	0.188	0.5	562	1500	225,048,121	NOT ALLOWED
6.625	0.188	1	1124	2000	615,637,342	NOT ALLOWED
8.625	0.219	0.1	193	500	22,817,724	100
8.625	0.219	0.25	482	1000	123,703,695	200
8.625	0.219	0.5	965	1500	386,281,512	NOT ALLOWED
8.625	0.219	1	1929	2000	1,056,704,327	NOT ALLOWED
10.75	0.219	0.1	306	500	36,199,998	100
10.75	0.219	0.25	765	1000	196,254,174	200
10.75	0.219	0.5	1530	1500	612,830,188	NOT ALLOWED
10.75	0.219	1	3061	2000	1,676,446,559	NOT ALLOWED
12.75	0.25	0.1	432	500	51,085,179	100
12.75	0.25	0.25	1080	1000	276,952,487	NOT ALLOWED
12.75	0.25	0.5	2160	1500	864,821,582	NOT ALLOWED
12.75	0.25	1	4319	2000	2,365,789,405	NOT ALLOWED
16	0.344	0.1	675	500	79,815,379	100
16	0.344	0.25	1687	1000	432,710,002	NOT ALLOWED
16	0.344	0.5	3374	1500	1,351,195,476	NOT ALLOWED
16	0.344	1	6748	2000	3,696,304,542	NOT ALLOWED
20	0.375	0.1	1067	500	126,149,114	200
20	0.375	0.25	2667	1000	683,903,081	NOT ALLOWED
20	0.375	0.5	5333	1500	2,135,579,824	NOT ALLOWED
20	0.375	1	10666	2000	5,842,051,387	NOT ALLOWED
24	0.375	0.1	1556	500	184,021,537	200
24	0.375	0.25	3890	1000	997,651,838	NOT ALLOWED
24	0.375	0.5	7780	1500	3,115,302,732	NOT ALLOWED
24	0.375	1	15559	2000	8,522,162,666	NOT ALLOWED

20.0 Appendix D – U.S Coast Guard Pipeline Testing guide

I. <u>JURISDICTION FOR MARINE TRANSPORTATION RELATED PIPELINE AT FACILITIES HANDLING OIL AND HAZARDOUS MATERIAL IN BULK</u>

Under a 1971 Memorandum of Understanding (MOU) between the Department of Transportation (DOT) and the Environmental Protection Agency (EPA), implementing Section 311(j) (1) (c) of the Federal Water Pollution Control Act, responsibility for marine transportation related facilities (MTR) was delegated to the Coast Guard. The Coast Guard is required to ensure testing is conducted by the facility along the entire marine transfer pipe system. These tests can either be conducted by facility personnel or a third-party entity. The goal of our pipeline testing policy is to identify and eliminate pollution risks from transfer piping. Coast Guard's policy on the extent of pipeline testing is as follows.

A. For MTR co-located with non-transportation related facilities protected by Spill Prevention Control and Countermeasure (SPCC) Plans required by the EPA:

Oil transfer piping systems will be tested from the dock loading arm or manifold of the Coast Guard inspected MTR up to the first valve encountered after the pipe enters the SPCC area required under 40 CFR 112.7(c).

If the EPA expands a facility's SPCC containment area, then the extent of pipeline testing monitored by the Coast Guard should be adjusted accordingly.

<u>NOTE</u>: The areas controlled by SPCC Plans provide pollution prevention for transfer piping located inside those areas. The EPA has not yet established a similar pollution prevention program for hazardous liquid storage facilities. Currently, many bulk liquid facilities handling both oil and hazardous materials are already afforded adequate protection form hazardous material pollution by virtue of an existing SPCC Plan. However, some bulk hazardous liquid MTR may not be protected by an SPCC Plan, or the SPCC Plan may not prevent pollution from certain types of bulk liquid hazardous materials transferred at the facility.

B. For MTR co-located with non-transportation related facilities <u>not</u> protected by SPCC Plans required by the US EPA:

Piping systems will be tested from the dock loading arm or manifold of the Coast Guard inspected marine transportation related facility up to the first valve encountered after the pipe enters the secondary containment around the bulk storage tank required in 40 CFR 112.7 (e) (2).

If conformance with this policy is not economically or physically practical for a facility without SPCC containment, the facility can submit an application for alternative testing to Commandant (G-MEP-1), via the Captain Of The Port COTP, per 33 CFR 154.108.

II. <u>STATIC LIQUID TESTING REQUIREMENTS FOR MARINE TRANSPORTATION RELATED PIPELINE HANDLING OIL AND HAZARDOUS MATERIAL IN BULK</u>

The static liquid pressure test is required for marine transportation related pipelines handling oil and hazardous material in bulk to ensure their integrity and safety. It is a gross test that provides general information of the pipelines susceptibility to leakage and its overall strength. The following guidelines contain minimum requirements for conducting the static liquid test. Refer to 33 CFR 156.170 for other testing requirements.

The static liquid test is normally performed using water. However, other test mediums can be used without requesting an alternative from the COTP.

REQUIREMENTS FOR THE STATIC LIQUID TEST

(1) Test pressure and frequency

A. 33 CFR 156.170 requires that transfer pipeline be tested annually by the facility at 1½ times the Maximum Allowable Working Pressure (MAWP). The MAWP is the designed working pressure of the pipe. Unlike transfer hoses there is no established minimum MAWP for transfer pipeline. The operating pressure (i.e. the upper pressure at which the facility decides to limit their operations) may be substituted for the MAWP if the facility operator can demonstrate to the COTP's satisfaction that mechanical safeguards, such as relief valves or pump controls, are in place to limit pump pressure to a value below the MAWP.

B. At no time during the static liquid test may any part of the piping system be subjected to a stress greater that 90 percent of its yield strength at test temperature.

C. The test pressure must not exceed the maximum rated pressure of any component in the system.

(2) Test medium

A. If the liquid is flammable, its flash point shall be at least 49°c (120°F).

B. The test medium must be compatible with the cargo handled and the piping material.

C. The temperature of the test medium must be compatible with the normal temperatures of the products transferred under the given ambient conditions.

D. Consideration should be given to the toxicity of the liquid, its potential for pollution if spilled, and the safety of personnel in the vicinity.

(3) Test criteria

A. For pipe that can be visually examined, the test pressure shall be maintained for a minimum of 10 minutes and held for such additional time as may be necessary to conduct the examination for leakage.

B. For pipe that is buried or insulated and cannot be visually examined, the pressure shall be maintained for 1 hour.

C. Insure all items (i.e. valves, pumps, etc.) that should not be subjected to the test pressure have been disconnected or isolated by blanking or other suitable means.

D. If the testing medium in the system is subject to thermal expansion during the test, provisions shall be made for immediate safe relief of excess pressure. Effects of temperature changes shall be taken into account when interpretations are made of recorded test pressures.

E. Immediately after completion of the static liquid test, it is important in cold weather that the lines, valves, and fittings be drained completely of liquid prone to freezing to avoid damage to the pipeline.

(4) Acceptance criteria

A. The pipe and all joint sections must maintain the test pressure for the duration of the test without damage or permanent distortion.

B. No leakage is allowed during the static leak test. For pipe that can be visually examined, leakage should be physically checked.

C. Should a leak occur during the test, the line section or component part shall be repaired or replaced to the satisfaction of the COTP and re-tested.

ALTERNATIVE TESTING FOR MTR RELATED PIPELINE AT FACILITIES HANDLING OIL AND HAZARDOUS MATERIAL IN BULK

The COTP may consider and approve alternative procedures, methods, or equipment standards to be used by the facility operator under 33 CFR 156.107. All testing methods, other than a static liquid test, shall be considered an alternative. Criteria have been established for evaluating the need for an alternative testing method. If it is determined that a testing alternative is appropriate then it may be approved by the COTP, without further review, if the plan for using that method is consistent with this policy. All other requests should be forwarded the Commandant (G-MEP) for review with a recommendation from the COTP.

All alternatives for pipeline testing must offer an equivalent level of safety and protection from pollution to substitute to the required static liquid test. Alternatives should not be approved if testing is for initial installation or following major alterations to the system.

Alternatives should only be approved when compliance with static liquid test requirements would be economically or physically impractical. Alternatives have been approved when:

- the length of transfer system makes the costs of conducting the test and/or disposing of contaminated liquid excessive;
- the product medium is reactive with water and testing would risk harm to personnel and property; or
- exclusive lines used to transfer hazardous materials would be contaminated by the test medium.

Once it has been determined that an alternative testing procedure may be warranted, the following information should be considered in evaluating the request.

1. The age of the piping and dimensions of the system.
2. The commodities transferred and the system’s operations.
3. The history of the system including the system’s compliance performance and past discharges and releases.
4. Access to transfer system: whether system is buried, elevated, insulted, etc.
5. The presence of any relief valves in the system and their routine maintenance schedule.
6. Proximity to environmentally or economically sensitive or hazardous areas.
7. The date of the last static liquid test.
8. The system Maximum Allowable Working Pressure (MAWP), system operating pressure, and relief valve settings.

<u>NOTE</u>: Specific procedures should be included in the Facility Operations Manual. Alternatives can be withdrawn at any time if the COTP believes that safety and pollution prevention requirements are not adequately met.

PNEUMATIC PRESSURE TESTING ALTERNATIVE FOR TRANSFER PIPELINES

Procedures for conducting an alternative testing method for pneumatic pressure testing have been established and should be referenced by the COTP in evaluating such requests.

Unlike the static liquid pressure test, pneumatic pressure testing involves the compression of a gas. This compressed gas may constitute an enormous amount of stored energy which, in the event of a failure, releases suddenly with tremendous force. Special precautions to ensure the safety of personnel and property must be taken whenever a pneumatic pressure test is conducted.

The pneumatic test can be an acceptable alternative for testing pipeline facilities provided the following minimum safety precautions are taken:

(1) Test pressure and duration

A. **IF OPERATING PRESSURE > 25% MAWP** (DESIGN PRESSURE OF PIPE)

For pipe that can be visually examined, the pneumatic test pressure must be maintained at 1.25 times the MAWP for a minimum of 10 minutes and then reduced to 700 kpa (100 psi) or the operating pressure (ex. relief valve setting), whichever is less for such additional time as may be necessary to conduct the examination for leaks.

For pipe that cannot be visually examined, the pneumatic test pressure must be maintained at 1.25 times the MAWP for 10 minutes then followed by a reduced pressure leak test equivalent to not less than 1.1 times the MAWP for not less than 1 hour.

B. **IF OPERATING PRESSURE < 25% MAWP** (DESIGN PRESSURE OF PIPE)

For pipe that can be visually examined, the pneumatic test pressure must be maintained at 700 kpa (100psi) or .25 times the MAWP, whichever is less for a minimum of 10 minutes and for such additional time as may be necessary to conduct the examination for leakage.

For pipe that cannot be visually examined, the pneumatic test pressure must be maintained at 700 kpa (100 psi) for .25 times the MAWP, whichever is less, for a minimum of 1 hour.

(2) Test medium

The gas used as test fluid, if not dry air, shall be non-flammable, non-toxic and compatible with any cargo residue in the pipe material. The temperature of the gas must be compatible with the pipe material.

(3) Other considerations

A. For pipe that can be visually examined, the test equipment must be examined before pressure is applied to ensure that it is tight and that all items that should not be subjected to the test pressure have been disconnected or isolated by valves or other suitable means.

B. The pressure in the system must gradually be increased to not more than one-half of the test pressure after which the pressure is increased in steps of approximately one tenth of the test pressure until the required test pressure has been reached.

C. A safety zone, in accordance with local code, should be established around the pipe and should allow only essential personnel to enter the zone for purposes of conducting the test or examining the pipe for leaks.

D. If the testing medium in the system is subject to thermal expansion during the test, provisions shall be made for the immediate safe relief of excess pressure. Effects of temperature changes shall be taken into account when interpretations are made of recorded test pressures.

(4) Acceptance criteria

A. The pipe must maintain the test pressure for the duration of the test without damage or permanent distortion.

B. No leakage is allowed during the leak test. For pipe that can be visually examined, leakage should be checked by the use of a reliable method such as with a liquid soap solution.

C. Should a leak occur during the test, the line section or component part shall be repaired or replaced and re-tested.

HAZARDOUS MATERIALS: Pipelines must be purged of hazardous material products before testing to the extent that a material failure or leakage during the test will not create a hazard.

NOTE: A professional engineer may certify the results of tests that meets Coast Guard pneumatic testing requirements.

III. TESTING REQUIREMENTS FOR TRANSFER HOSES

The hose that runs between the facility's manifold and the vessel's deck manifold is separate and distinct from the transfer pipe system. The following guidelines contain minimum requirements for testing transfer hoses. These tests are to be done annually by the facility. Refer to 33 CFR 156.170 for other testing requirements.

Alternative testing methods are not normally necessary since the hose can be removed for testing. Any alternative, other than that pre-established by this policy for testing transfer hoses should be referred to G-MEP with a recommendation from the COTP.

The static liquid test is normally performed using water. However, other test mediums can be used without requesting an alternative from the COTP.

REQUIREMENTS FOR TESTING HOSES USED UNDER PRESSURE

(1) Test pressure

Hoses used under pressure must be inspected annually at 1½ the Maximum Allowable Working Pressure (MAWP), but not less than 1550 kPa (@225 psi). This figure represents 1½ times the minimum MAWP of 1040 kPa (@150 psi), required for facility hose assemblies under 33 CFR 154.500.

Note: At no time should the hose be subjected to a stress greater than 90% the yield strength at test temperature.

(2) Test medium

A. If the liquid is flammable, its flash point shall be at least 49°c (120°f).

B. The test medium must be compatible with the cargoes handled and transfer hose tube as recommended by the hose manufacturer.

C. The temperature of the test medium must be compatible with the normal temperatures of the products transferred under the given ambient conditions.

D. Consideration should be given to the toxicity of the liquid, its potential for pollution if spilled, and the safety of personnel in the vicinity.

(3) Test duration

Pressure shall be continuously maintained for a minimum time of 10 minutes and held for such time as may be necessary to conduct the examination for leakage.

(4) Acceptance criteria

A. The hose must maintain the test pressure for the duration of the test without damage or permanent distortion.

B. No leakage is allowed during the test.

ALTERNATIVE TESTING METHOD FOR HOSES USED EXCLUSIVELY IN GRAVITY TRANSFERS

Alternative testing methods are not normally necessary since the hose can be removed for testing. Any alternative, other than that established by this policy for testing transfer hoses should be referred to G-MEP with a recommendation from the COTP.

Where transfers are conducted by a gravity method, an alternative testing pressure to 33 CFR 154.500 (b) can be used for the hose that runs between the facility's manifold and the vessel's deck manifold if the hose is permanently attached to the facility. For the purpose of the test, a MAWP determined by an operating pressure less that the 150 psi Maximum Allowable Working Pressure (MAWP) is acceptable provided the following conditions are met:

(1) The hose is labeled "GRAVITY ONLY".

(2) The hose is maintained at a fixed operating pressure (ex. relief valve setting of the piping).

(3) The hose is tested annually at 1.5 times the maximum operating pressure.

(4) The material condition of the hose is inspected annually.

(5) The alternative is only granted for those hoses used to transfer product from a facility to a vessel where no pumps are connected during the transfer.

(6) If the components that comprise the transfer system are changed, the alternative is rescinded, and a new request must be made.

(7) All other requirements for testing pressure hoses apply.

21.0 ✓Appendix E – GAS PIPELINE UPRATE PROCEDURE

21.1 Purpose

The following is a procedure for confirming MAOP utilizing uprating techniques for segment(s) of a pipeline.

21.2 Roles and Responsibilities

Position	Responsibility
Operations	• Will provide the criteria for establishing a new MAOP which is higher than the established MAOP. • Is responsible to see that the uprating procedure is followed and properly documented.
Engineering/Construction	• Will establish the new MAOP and provide a written plan for each pipeline segment to be uprated, which will include all requirements contained in this uprating procedure.
Engineering/Regulatory	• Will insure that the proper checks and verifications have been completed in accordance with 49 CFR 192.

21.3 Procedures

21.3.1 INTRODUCTION:

Prior to any pressure increase utilizing uprating techniques for confirming an MAOP, the Company shall perform the following phased work:

PHASE I: PRELIMINARY

1. Review the design, pipe grade, pipeline components, operating and maintenance history, construction AFE files, and facility files to determine if each segment meets the requirement for safe operation at proposed MAOP. *[192.555(b)(1)]*

2. The proposed MAOP confirmation shall not exceed the maximum MAOP that would be allowed under Part 192 for a new segment of pipeline constructed of the same materials in the same class locations. *[192.553(d)]*

3. Determine the % SMYS of the pipeline at proposed MAOP.

4. Review the class location for each pipeline segment.

5. Make any repairs, replacements, or alterations to each segment that are found and determined to be necessary for safe operation at proposed MAOP. *[192.555(b)(2)]*

6. Determine the highest pressure the pipeline actually operated at within the last five years prior to July 1, 1970 (or applicable date defined by Part 192.619), or was previously tested to a pressure compliant to the code for a new line for the proposed MAOP.

7. Prepare a valve procedure to increase pressure incrementally to proposed MAOP and to maintain incremental increases for the required duration. After all preliminary steps indicated in Phase I have been performed and it has been determined that the pressure increase meets the requirements for safe operation at the proposed MAOP, the Company may proceed to Phase II.

PHASE II: REVIEW AND SCHEDULE

1. Review the valve procedure developed in Phase I with Pipeline Control and field personnel involved in the MAOP Confirmation process.

2. Review the Emergency Action Plan with operating personnel performing the MAOP Confirmation procedure.

3. Verify that each field system operator has a copy of the Emergency Action Plan.

4. Check leak detection equipment that will be utilized for patrolling in Class 3 locations.

5. Check all Company radios and cell phones.

6. Locate and prepare calibrated test gauge.

PHASE III: INCREMENTAL PRESSURE INCREASE

1. Install calibrated test gauge at the appropriate location(s).

2. Determine the starting pressure by choosing the lowest of either the highest pressure the pipeline facility experienced in the last five years or the current operating pressure the day of the proposed incremental pressure increases.

3. Determine the number of incremental pressure increases by using one of the following techniques that produces the fewest number of increments: *[192.555(e)]*

a) 10% of the starting pressure determined in Phase III, Item 2 above.

b) 25% of the total pressure increase, starting with the pressure determined in Phase III, Item 2 above.

4. Perform a patrol and leak survey across each pipeline segment to be confirmed prior to increasing pressure if no such survey has been conducted within the previous 12 months.

5. Implement the valve procedure to increase the pressure to the first incremental pressure increase determined in Phase III, Item 3. Record and log time and pressure prior to and after the patrolling of each pipeline segment as required in this procedure:

- Pipeline sections in Class 3 locations shall be patrolled with leak detection equipment. Pipeline sections other than Class 3 locations may be patrolled without leak detection equipment.
- Incremental pressure increases must be held as near constant as practical during the patrol while checking for leaks or failures. *[192.553(a)(1)]*

6. Each leak detected or found must be repaired before a further incremental pressure increases are made. *[192.553(a)(2)]*

7. Each consecutive incremental pressure increase shall be logged and patrolled as per Phase III, Item 5, until the number of incremental increases determined in Phase III, Item 3, is complete.

8. Upon completion of the final incremental increase and patrol resulting in no leaks or failure, the pipeline system shall be returned to normal service. All gauges and associated test equipment installed as per Phase III, Item 1, shall be removed.

9. All recorded information, pressure readings and details shall be collected, noting station footage start point and station footage end point of the segment(s) confirmed or uprated by the test contractor (if utilized) and company representative, signed and dated, as valid, and submitted to the project engineer.

PHASE IV: DOCUMENTATION AND RECORDS

1. All documentation and records associated with this MAOP confirmation utilizing uprating techniques shall be filed in each pipeline segment facility file for the life of the facility. *[192.553(b)]*

21.4 REQUIREMENT

Any time the maximum allowable operating pressure (MAOP) on any Company pipeline is to be increased, it must be performed according to a written uprating plan which meets all requirements of this uprating procedure. The uprating shall be performed as outlined in this procedure. *[192.553(c)]*

21.4.1 General Requirements (Reference §192.553)

- **Pressure increase** - When the operating pressure is increased by required increments, the pressure must be increased gradually at a rate that can be controlled and in accordance with the following:
  - After each incremental increase the pressure will be held constant while the entire pipeline segment is checked for leaks. *[192.553(a)(1)]*
  - Each potentially hazardous leak must be repaired before further increase in pressure is made. *[192.553(a)(2)]*

- **Written Plan -** A plan will be written for each pipeline segment to be uprated which will include all the requirements contained herein. *[192.553(c)]*

- **Limitations on increase of the MAOP.**
  - The highest MAOP that can be established by the uprating procedure is that pressure which is permitted in § 192.619 and must not exceed the maximum. *[192.553(d)]*

  - **Design Formula -** The maximum allowable operating pressure (MAOP) must not exceed the maximum design pressure as calculated by the following design formula:

$$P = \frac{2St}{D} * F * E * T \quad (\text{§ } 192.105)$$

Where :

P =	Maximum design pressure in PSIG
S =	Specified minimum yield strength of pipe (SMYS) is PSI as per §192.107
D =	Nominal outside diameter of pipe in inches
t =	Nominal wall thickness of pipe in inches
F =	Design factor for class location as per § 192.111
E =	Longitudinal joint factor as per § 192.113
T =	Temperature de rating factor as per § 192.115

Example:

16” OD, 0.203” WT, X52, ERW, 70 Deg f, Cl 1

$$P = \frac{2*52000*0.203}{16.00} * 0.72 * 1.0 * 1.0$$

$$P = 1319.5 * 0.72 * 1.0 * 1.0$$

P = 950.04 (*rounded to the lowest whole number*)

- **Determination of "% of SMYS" -** The "% of SMYS" shall be calculated by the following formula:

$$\% \text{ SMYS} = \frac{50 * Pp * D}{St}$$

Where:

Pp = Proposed New MAOP

Example:

$$\% \text{ SMYS} = \frac{50 * 920 * 16.00}{52000 * 0.203}$$

$$\% \text{ SMYS} = 69.72\%$$

- If the "% of SMYS" is greater than or equal to 30%, the uprating must be carried out according to § 192.555. If the "% of SMYS" is less than 30%, the uprating must be carried out per § 192.557.

21.4.2 Uprating steel pipelines to a pressure equal to 30% SMYS or higher *(Reference § 192.555)*

- A pipeline segment operating at 30% SMYS or higher cannot be operated above the established MAOP of that segment unless that segment is uprated in accordance with this procedure.
- Before increasing the operating pressure above the established MAOP the following requirements must be met:
  - Review the design, operating and maintenance history of the pipeline segment to determine if the segment meets the requirements for a safe operation at the higher MAOP. *[192.555(b)(1)]*
  - Make any repairs, replacements or alterations in this segment of pipeline that are necessary for a safe operation at the higher pressure. *[192.555(b)(2)]*
- Pipeline segments that comply with the above requirements can be uprated to a higher MAOP, but not higher than allowed by §192.619. The uprate shall be in accordance with one of the following, however, under no circumstance may the MAOP exceed that allowed for a new pipeline in the same location: *[192.555(c)]*

- If the pipeline was constructed before September 12, 1970, the MAOP may be increased to one of the following:
  - The highest actual operating pressure that the pipeline was subjected between July 1, 1965 and July 1, 1970 divided by the appropriate class location factor in Table 212.1 below.
  - The highest test pressure that the pipeline was subjected to divided by the appropriate class location factor in Table 212.1 below.

TABLE 212.1 CLASS LOCATION FACTOR	
CLASS LOCATION	**FACTOR**
1	**1.1**
2	**1.25**
3	**1.4**
4	**1.4**

- Any pipeline that is unable to be uprated in accordance with 1) above shall meet at least one of the following:
  - The pipeline is successfully tested to the pressure required for a new pipeline of the same material and in the same location, or *[192.555(d)(1)]*
  - If a pipeline in a Class 1 location has not previously been tested, the pipeline can be uprated to a maximum of 80% of the pressure allowed for a new line of the same design and in the same location if, *[192.555(d)(2)]*
    - It is not feasible to test, and
    - It is determined that the new MAOP is consistent with the condition of the pipeline and design requirements of Part 192.

- Any time a pipeline is uprated without a re-test in accordance with test requirements in 49 CFR 192, the increase in pressure must be made in increments equal to: *[192.555(e)]*
  - 10 percent of the pressure before uprating; or
  - 25 percent of the total pressure increase;

- whichever requires the fewer number of increments.

21.4.3 Uprating steel pipelines to a Pressure of less than 30 percent SMYS *(Reference § 192.557)*

- A pipeline segment operating at less than 30% SMYS cannot be operated at pressures above the established MAOP of that segment unless that pipeline segment is uprated in accordance with this uprating procedure. *[192.557(a)(1)]*
- Before increasing the operating pressure above the previously established MAOP the following requirements must be met:
  - Review the design, operating and maintenance history of the pipeline segment. *[192.557(b)(1)]*
  - Conduct a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except leaks that are determined not to be potentially hazardous need not be repaired, if they are monitored during pressure increase and they do not become potentially hazardous. *[192.557(b)(2)]*
  - Make repairs, replacements, or alterations in the pipeline segment that are necessary a for safe operation at the higher pressure. *[192.557(b)(3)]*
  - Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings to prevent failure of these pipe joints, if the offset, bend, or dead end is exposed by excavation. *[192.557(b)(4)]*
  - Isolate the pipeline segment in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure. *[192.557(b)(5)]*
- After complying with the above the increase in pressure to the new MAOP must be made in the following increments:
  - 10 psig; or
  - 25 percent of the total pressure increase;
  - whichever requires the fewer number of increments. *[192.557(c)]*

21.5 SCHEMATIC DRAWING

- A schematic drawing of the facility to be uprated is to be included and is to become a part of the permanent record.
- The schematic should include:
  - construction dates,

- size, wall thickness and grade of pipe,
- laterals, side connections & other appurtenances.

21.6 EMERGENCY PROCEDURES

The appropriate Pipeline Operations management is to ensure that there are adequate materials, equipment, and personnel to undertake emergency procedures in the event of line failure.

21.7 INSTRUCTION OF PERSONNEL

A conference shall be held with all involved personnel prior to the uprating operation. The uprating procedure shall be reviewed and all personnel shall be instructed regarding their specific duties.

21.8 SYSTEM ISOLATION

It shall be the responsibility of the appropriate Pipeline Operations management to isolate adjacent piping from the system to be uprated and to ensure that adequate pressure can be maintained in adjacent systems.

21.9 MONITORING OF PRESSURE

- A dead weight tester and pressure recorder shall be installed on the system to be uprated.
- A gauge, which has been calibrated for this uprating operation, shall be installed in adjacent facilities of a lower pressure and shall be monitored during the uprating operation.

21.10 RECORDS

Each required investigation, description of work performed, written uprating plan and each pressure test will be documented and retained for the life of the uprated pipeline segment.

APPENDIX A (Example)

PIPELINE REVIEW FOR UPRATING									
UPRATE SEGMENT STATION FOOTAGE	FROM:	See Appendix C				TO:	See Appendix C		
DIAMETER (od):	D	16.00”							
WALL THICKNESS (nominal):	t	0.203”							
PIPE SPECIFICATION / SMYS:	S	52000							
LONDITUDIONAL JOINT FACTOR	E	1.0							
TEMPERATURE DERATING FACTOR	T	1.0							
SEAM TYPE (ERW, seamless, spiral, etc):	-	ERW							
EXTERNAL COATING:	-	TGF-2							
DATE OF COMMISSION TEST:	-	06/27/1966							
COMMISSION HYDROSTATIC TEST (psig)	-	1050 PSIG							
ARE ORIGINAL MILL RECORDS AVALIABLE:	-	YES							
CURRENT MAOP (psig):	Pc	792 PSIG							
PROPOSED NEW MAOP (psig):	Pp	**840 PSIG**							
PROPOSED INCREASE (psig)	Pi	48 PSIG							
MINIMUM ANSI RATING:	-	400							
CLASS LOCATION(s) of UPRATE: Check Box(s)	F	X	CL 1		CL 2		CL 3		CL 4

(If multiple pipe data exist in a common segment of uprate, utilize the segment data having the lowest design pressure)

PIPE DESIGN CALCULATION: (highest MAOP that can be established by this uprating procedure)

$$P = \frac{2St}{D} * F * E * T$$

P = 950.04 PSIG (round down to lowest whole number) = 950.00 PSIG

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DETERMINE of % SMYS (=/> 30% SMYS , utilize 49 CFR192.555 or <30% SMYS, utilize 49 CFR 192.557)

$$\% \text{ SMYS} = \frac{50 * Pp * D}{St}$$

$$\% \text{ SMYS} = 69.72\%$$

UPRATE INCRIMENT PRESSURE: (10% of the pressure before uprating)

Increment PSIG =	Pc * 10%
Increment PSIG =	**48.0** PSIG @ 1 INCREMENT

APPENDIX B (Example)

FEASIBILITY TO UPRATE:						List anomalies, defects, safety related conditions, incidents
CLASS LOCATION(s) STUDY:	Check Box		YES		NO	NONE
HISTORY OF LEAKS/RUPTURES:	Check Box		YES		NO	NONE
SURFACE PATROL CURRENT:	Check Box		YES		NO	NONE
HISTORY OF 3RD PARTY DAMAGE OCCURANCES	Check Box		YES		NO	NONE
CP HISTORICALLY > -850 Mv	Check Box		YES		NO	NONE
CP PRESENTLY > -850 Mv	Check Box		YES		NO	NONE
HISTORY OF INTERNAL CORROSION	Check Box		YES		NO	NONE
HISTORY OF EXTERNAL CORROSION	Check Box		YES		NO	NONE
HAS PIPELINE BEEN IN-LINE-INSPECTED:	Check Box		YES		NO	NONE
HAS PIPELINE BEEN DIRECT ASSESSED:	Check Box		YES		NO	NONE
UPRATE DIAGRAMS PREPARED	Check Box		YES		NO	NONE
OTHER	Check Box		YES		NO	NONE

REMARKS:

Review of pipeline, alignment drawings, construction records, maintenance records of the pipeline to be uprated found the following results:

-
-
-
-

Pre-uprate assessments performed on the pipeline found the following results:

-
-
-
-

Based on the above and attached, the uprating of the described pipeline to the proposed MAOP would be safe and consistent with 49 CFR 192 applicable codes.

Director Operations	Date	Director Pipeline Integrity	Date

APPENDIX C (Example)

UPRATE DIAGRAM

Segment Uprate: **From** **000 psig** **To:** **000 psig**

LEGEND	
	CL I
	CL II
	CL III
	HCA

Corrosion Control Manual

This document applies to EnLink employees when working for or acting on behalf of EnLink Midstream Operating, LP or any of its subsidiaries and /or joint ventures.

01/13/2022

DATE OF CURRENT REVIEW

Version 2.0

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SCOPE

1. PURPOSE

This manual is a training and reference tool for corrosion control. It is designed to provide clear and simple explanations of:

- General Procedures
- Annual Surveys
- Close Interval Surveys
- Cathodic Protection Systems
- Coatings
- Internal Corrosion
- Interference Testing
- Contract Specifications

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Code of Professional Ethics

Anyone performing corrosion control activities is expected to abide by the following guidelines:

Whereas:

- The control of corrosion on all our facilities is critical to the safety of the public.
- The control of corrosion is necessary to maximize resources, reduce economic loss, and protect the environment.
- Corrosion is a continuing process, and its mitigation requires constant vigilance for the life of the facility.
- The control of the many problems associated with corrosion can only be found through continual association and cooperation with peers in the corrosion profession.
- The quality of our work reflects on the entire profession of corrosion control.

Therefore I:

- Agree to first consider the safety and welfare of the general public, as well as the environment, in all my corrosion control work.
- Agree to be diligent and responsible to all corrosion control work that lies within my area of competence.
- Agree to pursue my work with honesty, integrity, and courtesy, ever mindful of the best interest of the public, my employer, and fellow workers.
- Agree not to represent myself to be proficient or make recommendations in areas of corrosion control work in which I am not qualified by knowledge or experience.
- Agree to treat as confidential my knowledge of the business affairs and/or technical processes of my employer, customers, or clients when their interest so require.
- Agree to inform my employer of any business affiliations, interests, and/or connections that might influence my judgment.
- Agree to uphold, foster, and contribute to the achievement of all objectives and standards of EnLink Midstream.

SECTION 1 - General Procedures

Introduction

This section describes the general procedures for performing various corrosion control tasks.

CORR-001: Multimeter P/S Potential Measurements

Scope

Structure-to-Electrolyte Potential Measurements (called *pipe-to-soil* or *pipe-to-water* when the structure is a pipe, *casing-to-soil* when structure is a casing, *tank-to-soil* when the structure is a tank, etc.) are necessary to determine the level of cathodic protection of Company underground/submerged structures.

Only high impedance multimeters (greater than 100 Mega Ohms) will be used to take pipe-to-soil readings.

Meters used for structure-to-electrolyte potential measurements must be calibrated to or checked against a NIST traceable standard at least once every two years.

Procedure

1. Ensure the meter is in working order by checking the batteries, switches, binding terminals, etc.
2. If using a copper/copper sulfate reference electrode, ensure the electrode is clean and contains an uncontaminated copper sulfate solution (*see procedure CORR - 005: Maintaining Reference* Electrodes).
3. Ensure there is continuity between the meter test leads.
4. Locate the corrosion test station or test location on the structure to be surveyed.
5. Place the reference electrode in contact with the earth as close as possible to the structure to be surveyed (directly over the structure). If the earth is extremely dry, either dig a hole

Note

DO NOT place the reference electrode in or on:

- ***Contaminated soil; soil contaminated with grease, oil, or distillate.***
- ***High resistance contacts; ice, snow, or frozen ground, concrete, or asphalt.***

THIS MAY YIELD AN ERRONEOUS MEASUREMENT!

to find soil with more moisture content or add potable water at the contact point to reduce contact resistivity.

6. Connect the meter to the structure and half-cell using a consistent polarity convention.
7. Set the meter on the appropriate DC scale, then read the potential. If necessary, adjust the meter scale.
    - Ensure that the sign of the reading is correct based on the polarity of the connection. If not, further investigation is necessary.
    - Record the potential on the appropriate company form.
8. If measuring the "instant off" P/S potential, use an approved meter capable of reading the instant off potential and record on the appropriate company form.

Polarity Convention

P/S potentials are usually measured by connecting the meter negative terminal to the pipe and the positive terminal to the reference electrode, which is in contact with the pipe electrolyte (see **Figure 1**). With this connection, the meter will indicate that the reference electrode is positive with respect to the pipe. Since the reference electrode has a positive value with respect to the pipe, the pipe voltage is negative with respect to the reference electrode.

- **A positive value on the meter indicates a negative P/S potential and is documented as a "-XXXX' value.**
- **A negative value on the meter indicates a positive P/S potential and is documented as a "+XXXX' value.**

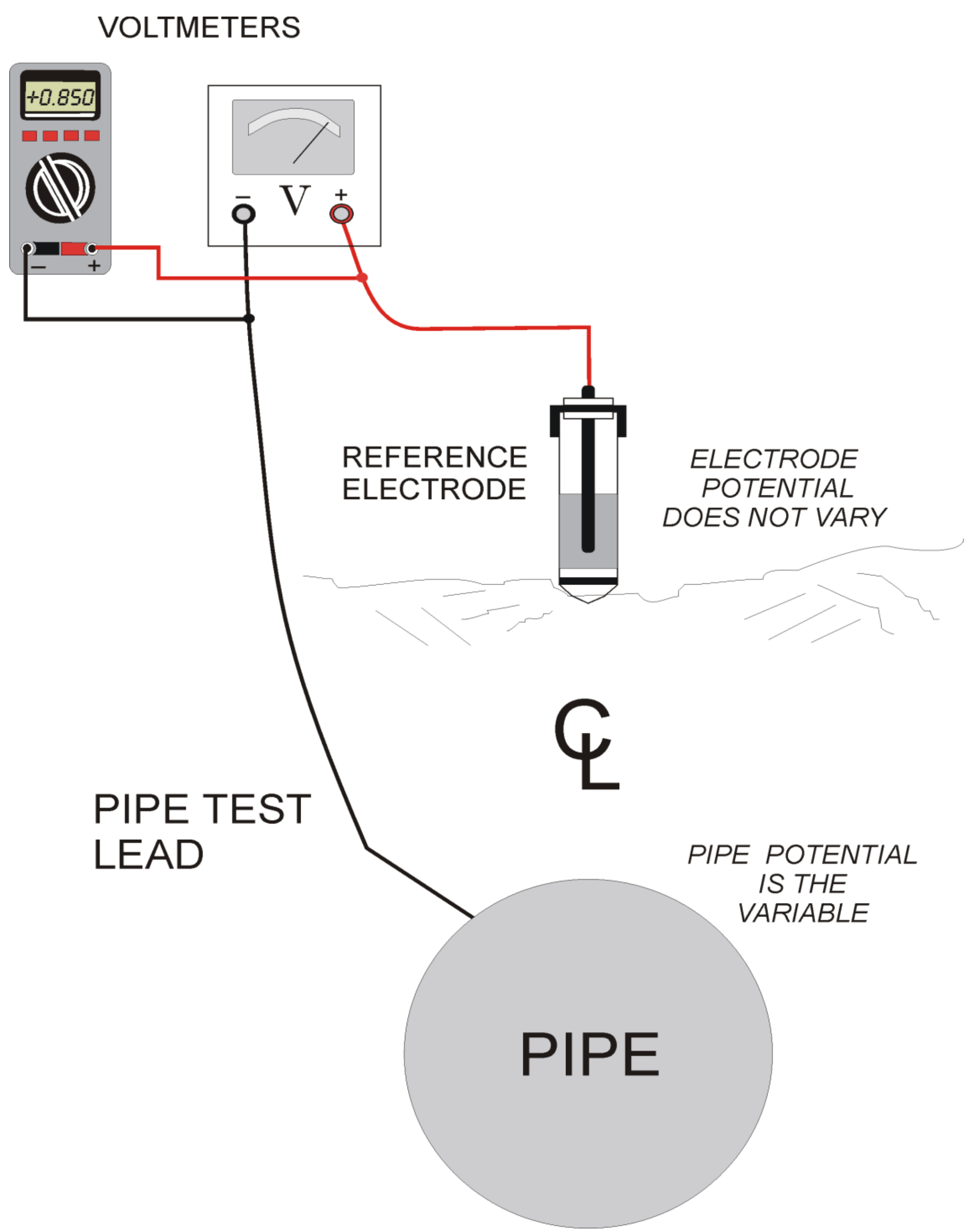

Figure 1: Polarity Convention

P/S potential measurements are sometimes made with the reference electrode connected to the meter negative terminal and the pipeline connected to the positive terminal (see **Figure 2**).

- **A negative value on the meter indicates a negative P/S potential.**
- **A positive value on the meter indicates a positive potential.**

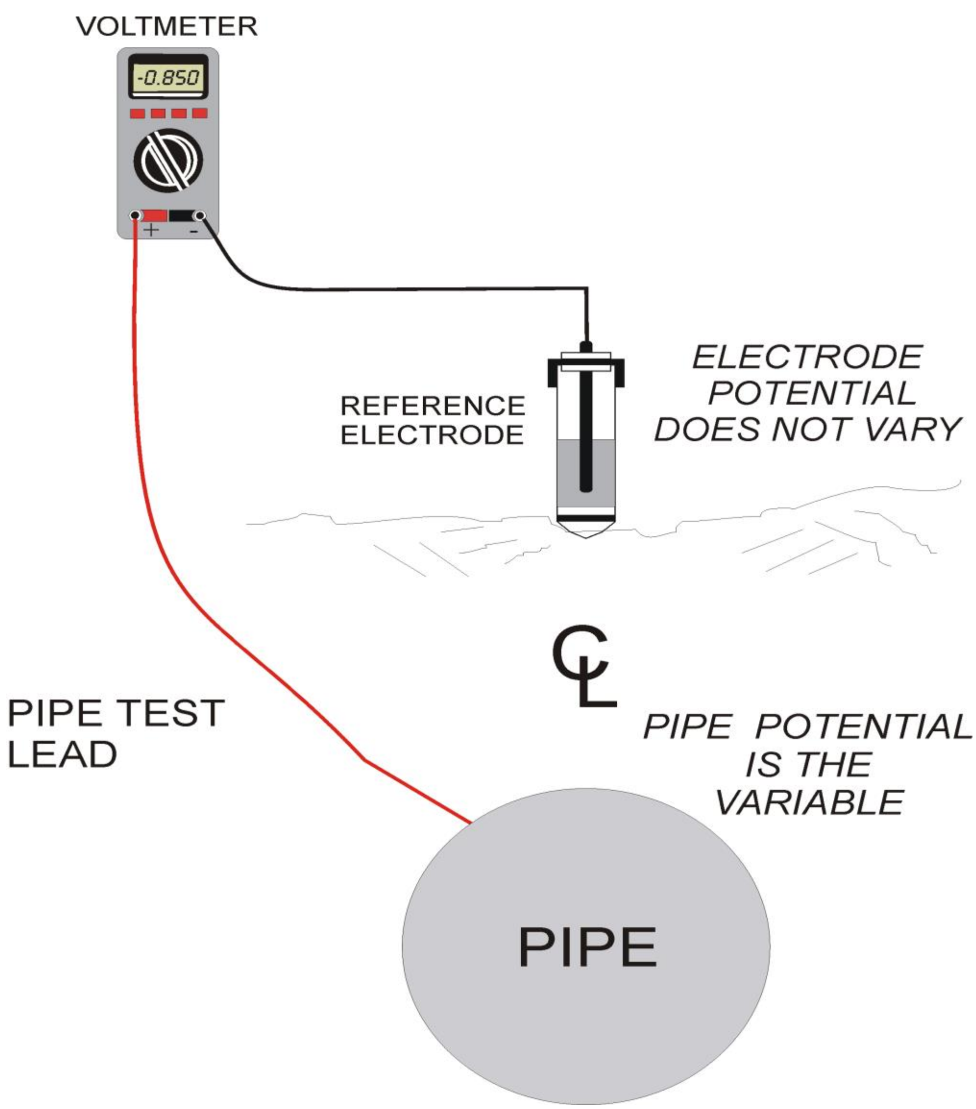

Figure 2: Reference Electrode Connected to Meter Negative Terminal and the Pipeline Connected to Positive Terminal

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Temperature effects on reference electrode

To compare a measured structure-to-electrolyte potential to an industry potential criterion, the measured potential should be corrected for temperature if the reference used for the measurement is not 25C or 77F. The following equation can be used for this purpose:

$$E_{str/ref\ @25^\circ C} = E_{str/ref\ @T} + k_t\ (T - 25^\circ C) \qquad [1\text{-}11b]$$

where:

$E_{str/ref\ @25^\circ C}$ = structure-to-electrolyte potential at 25°C

$E_{str/ref\ @T}$ = structure-to-electrolyte potential at a temperature T

k_t = temperature coefficient

For a measured potential of -865mVcse and a reference electrode temperature of 45°C the potential corrected to 25°C would be;

$$\begin{aligned} E_{str/cse\ @\ 25C} &= -865\text{mVcse} + \{(0.9\text{mV}/^\circ\text{C}) \cdot (45^\circ\text{C} - 25^\circ\text{C})\} \\ &= -865\text{mVcse} + \{(0.9\text{mV}/^\circ\text{C}) \cdot (20^\circ\text{C})\} \\ &= -865\text{mVcse} + 18\text{mV} = -847\text{mVcse} \end{aligned}$$

An equivalent version of the equation in terms of Fahrenheit will be:

$$\mathbf{E_{str/\ CSE@77F} = E_{str/\ CSE@T} + 0.5\ (T - 77F)}$$

Note: T is in degrees Fahrenheit.

CORR-002: Electrical Isolation at Flanges/Connections

Scope

Insulating flanges and connections are used to electrically isolate company structures from other structures such as customer's piping or electronic measurement devices, or bare lines from coated lines so Company cathodic protection currents can be applied correctly. Their function is paramount in controlling cathodic protection currents and must be monitored and maintained to ensure their proper operation. The following procedures can be used in conjunction with or in lieu of using a radio frequency (RF) isolation tester.

Isolation Testing Procedure

1. Remove any bond wires, arc dissipation devices, and zinc grounding cells from the insulated connection before checking the connection to eliminate parallel current paths.
2. Check the voltage difference from Company protected pipe to other pipe by following one of the two methods below:
   - Connect a voltmeter across the insulated flange/connection and read the voltage directly.
   - Read the p/s potential on both sides of the insulated connection with the half-cell in the same position for both readings, and subtract the readings to obtain the voltage difference.
3. If the voltage difference is greater than 100 mV CSE, the insulator is effective. If the voltage difference is less than 100 mV CSE, additional testing may be necessary to ensure the effectiveness of the insulator.
4. A radio frequency insulator checker may be used to determine the effectiveness of the insulator.

Inspection

Visually inspect the flange for potential trouble spots:

1. Visually inspect the insulating washers for cracks, missing pieces, or missing washers.
2. Check for foreign material between the flanges.
3. Visually inspect the bolt insulating tubes for cracks, missing pieces, or missing tubes.
4. Visually inspect flanges and bolts for signs of arc burns. Arc burns may indicate ineffective arc dissipation devices, a lightning hazard, or a potential AC hazard.

Troubleshooting

If a flange is found to be shorted:

1. Perform a visual inspection.
2. Trace out all gauge lines, tubing, etc. for a potential electrical path around the isolation flange, and check any in-line isolation devices for proper operation using the radio frequency insulator checker.
3. Use the radio frequency insulator checker per manufacturer's instructions to test each bolt for isolation.
4. If the cause of the short cannot be located by the aforementioned methods, a faulty insulating gasket may be the cause. To repair, the joint will have to be disassembled.
5. After the short is located and repaired, re-inspect to ensure the corrective action was successful.

Typical mitigation bond setup

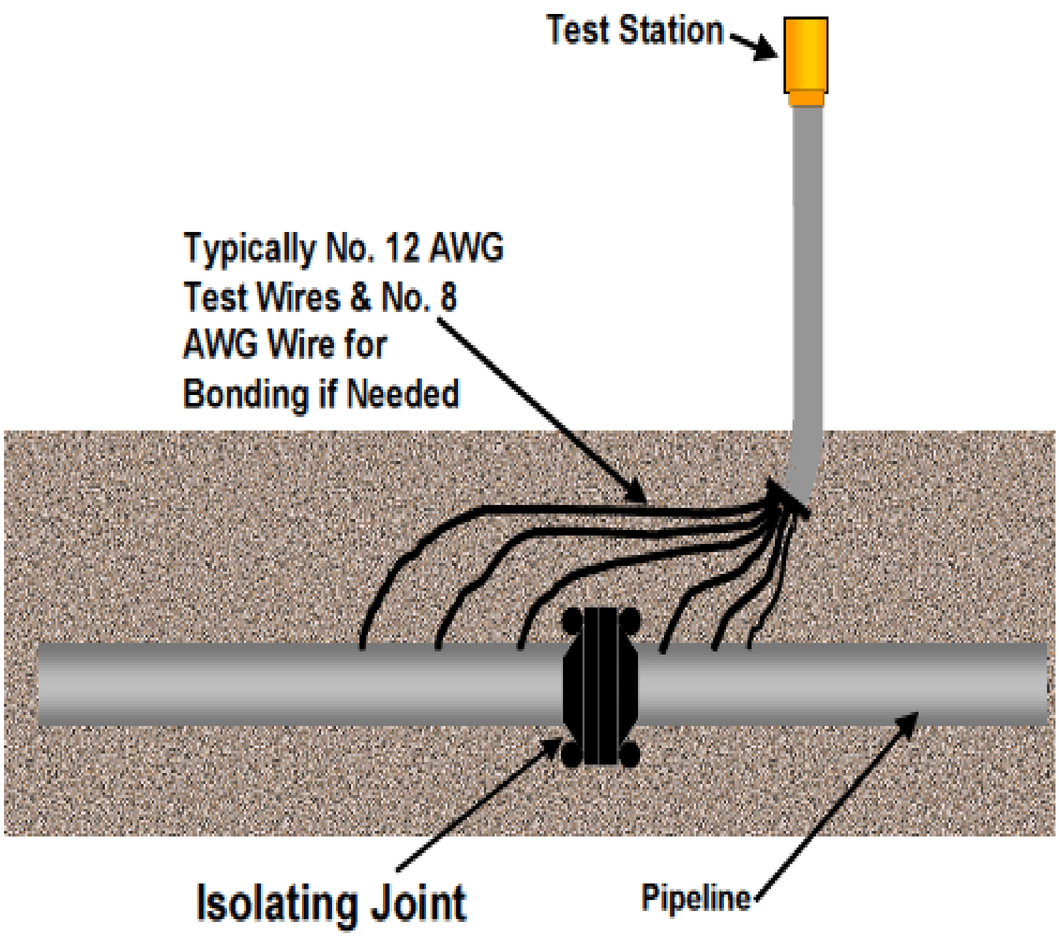

Figure 8.10 Isolation Joint Test Station Mitigation Bond

CORR-003: Testing for Shorted Casings and Valve Boxes

Scope

Cased crossings are meant to provide structural and mechanical protection to the carrier pipe. Federal Code requires pipeline operators to have a methodology for checking the electrical isolation at cased crossings and reacting to a shorted casing. The following procedures can also be used to check for shorted valve boxes.

Procedure Using Potentials and Current Drain

1. Locate the appropriate corrosion test stations.
2. Place the reference electrode in contact with the earth over the carrier pipe approximately one to three feet from the end of the casing.

Note

The casing vent location is not necessarily at the end of the casing. Verify location of the end of the casing if any doubt exists.

3. Measure the P/S potential of the carrier pipe and the casing in accordance with procedure CORR - 001: Multimeter P/S Potential Measurements and record the readings on the appropriate company form.
4. If the voltage difference measurement is in doubt when using the reference electrode, the meter may be connected directly between the carrier pipe and casing; then the voltage difference; casing-to-pipe potential may be directly read from the meter.
5. If the difference in potential between the carrier pipe and casing is greater than or equal to 100 mV CSE, the casing is considered electrically isolated from the carrier pipe and no further testing is required. Report the casing as *clear*.
   - If the difference in potential is less than 100 mV CSE, de-energize any impressed current rectifiers within ½ mile of the cased crossing and perform test again.
   - If the difference in potential is still less than 100 mV CSE, further testing using the deliberate short test is required.

Procedure Using a Deliberate Short

1. Hook the meter up to take a pipe-to-soil potential reading.
2. Deliberately short the casing to the carrier pipe using a heavy jumper cable with pressure clamps.
3. Calculate the difference (□) in P/S potential with and without the short.
   - If the change in potentials caused by the deliberate short is equal to or greater than 30 mV CSE, the casing is considered electrically isolated or *clear*.
   - If the change in the P/S potentials is less than 30 mV CSE, further testing is required using the Panhandle Eastern test incorporating either Procedure 4 or 5 below, depending on current and potential needs.

Note

Coated casings may cause difficulty in interpretation of data.

Procedure Using Universal Casing Meter

1. De-energize any impressed current rectifiers within ½ mile of the cased crossing.
2. Check instrument batteries. Turn METER SELECT to BATT. Display should read 12 volts. If not, change batteries.
3. Connect test leads as instructed in meter instructions (see **Figure 3**).
    - Lead wire from casing test lead to instrument CASING + and CASING terminals.
    - Lead wire from pipeline test lead to instrument PIPELINE terminal.
    - Lead wire from reference electrode to instrument HALFCELL terminal. Place reference electrode over the centerline of the carrier pipe 1 to 3 feet from the end of the casing.
    - At least #8 cable from temporary ground bed to instrument TEMPORARY STRUCTURE terminal.

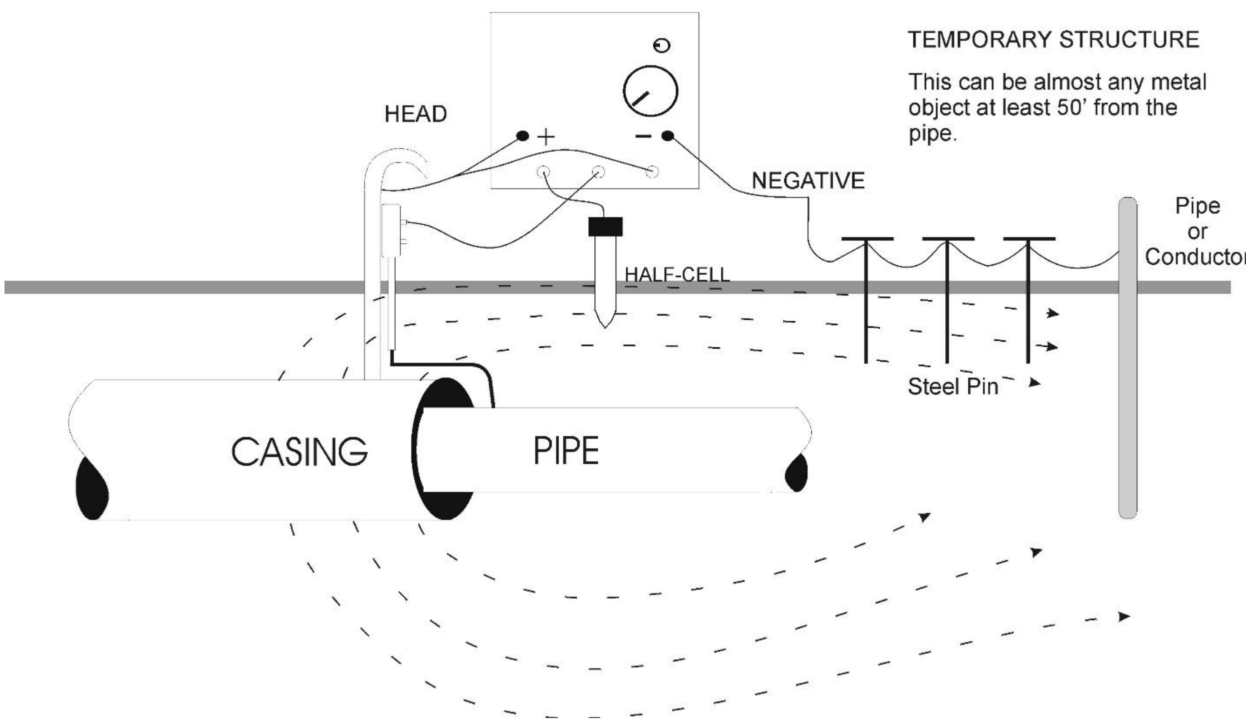

Figure 3: Universal Casing Meter Test Lead Connections

4. With power OFF, read AMPS, P/S, C/S with METER SELECT, noting polarity. Amps should be zero (0) and P/S should be greater than or equal to C/S.
5. Put CURRENT ADJUST at zero. Switch power to ON and take AMPS, P/S and C/S readings within 3 seconds. Note polarity.
6. Turn power OFF. Check P/S and C/S to see that they fall back to within 10 mV CSE of original reading.
7. Rotate CURRENT ADJUST to new position and repeat readings in step 4.

Note

The current output must increase a minimum of 10% above the previous current output for each set of readings. If this cannot be achieved, either provide an additional power source for this test or go to the Panhandle Eastern test procedure.

8. Take 5 sets of readings.

Note

Do not exceed 10 amps of current during the test.

Casing-to-pipe contact resistance can be determined for each set of readings using the following formula:

$$\Delta R = \frac{[(\frac{P}{S_1}) - (\frac{P}{S})] - [(\frac{C}{S_1}) - (\frac{C}{S})]}{AMPS}$$

Where:	R	=	Resistance in ohms
	P/S_1	=	Initial P/S reading
	C/S_1	=	Initial C/S reading
	P/S	=	Subsequent readings
	C/S	=	Subsequent readings

9. Determine the resistance.
   - If the averaged resistance is greater than 0.08 ohms, the casing can be considered "clear" and no further testing is required.
   - If the averaged resistance is equal to or less than 0.08 ohms, the casing and carrier pipe are shorted.

Procedure Using Panhandle Eastern Test

1. Establish a test setup and temporary ground bed using a culvert, guard rail, probe rods, or any metallic structure in contact with the earth and at least 50 feet from the pipeline/casing installation as shown in **Figure 4**.

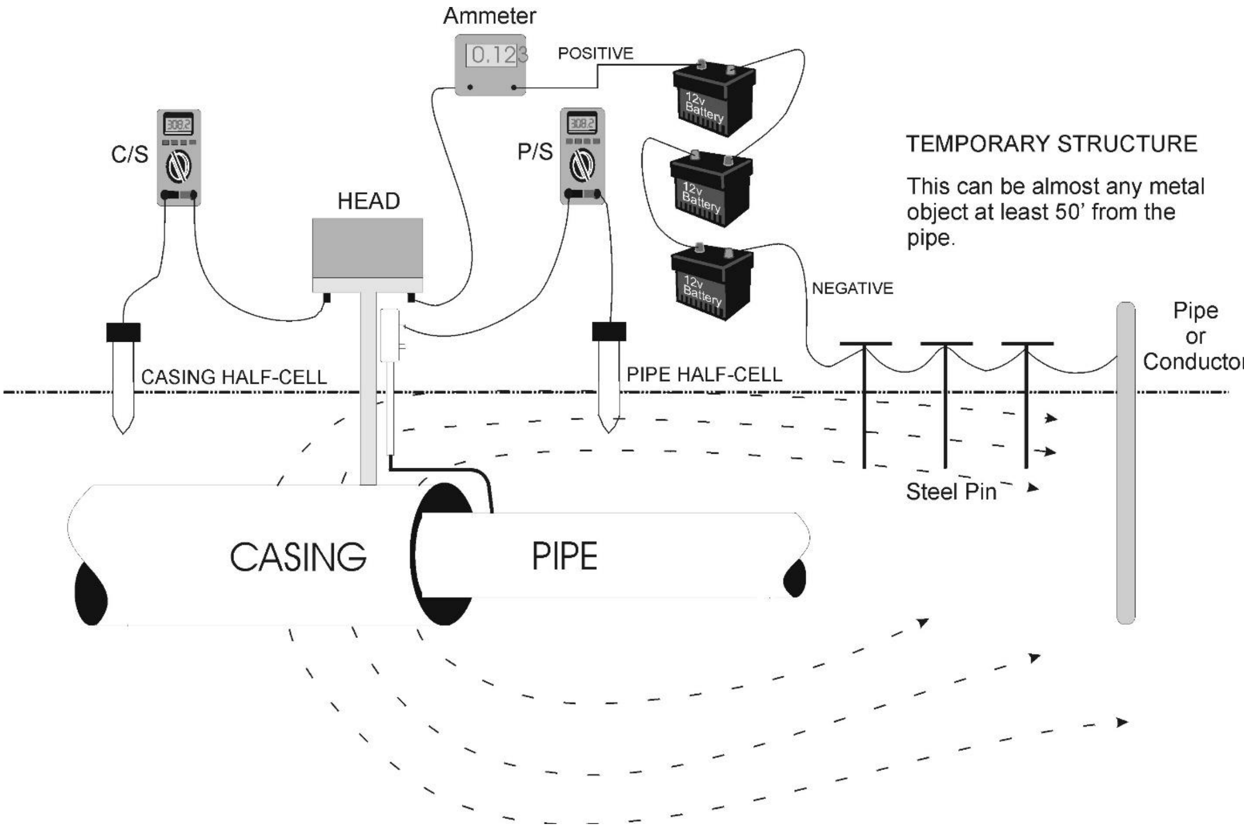

Figure 4: Test Setup and Temporary Ground Bed

2. De-energize any impressed current rectifiers within ½ mile of the cased crossing.
3. Connect the positive terminal of a variable DC power source to the casing.
4. Connect the negative terminal of the power source to the temporary ground bed.
5. Energize the DC power source and wait at least two (2) minutes or until the P/S potentials stabilize.
6. Using an approved Multimeter, measure and record the potentials of the casing and carrier pipe, and record the amount of current applied from the DC power source.

7. Repeat steps 5 and 6 using at least 10% increments of increased current. A minimum of five (5) different values of test current should be applied.

- **Indication of isolation:** The casing potential will shift in a positive direction. The carrier pipe will either remain near its normal potential, shift in the negative direction, or shift in the positive direction to a lesser degree than the casing.
- **Indication of a short:** Both casing and carrier pipe potentials will shift in the positive direction and there will be a minimum voltage difference between the carrier pipe and casing.

8. If the status of the casing is still in doubt after the above testing, calculate the "resistance" between the casing and carrier pipe as follows:

$$\Delta R = \frac{[(\frac{P}{S_O}) - (\frac{P}{S_1})] - [(\frac{C}{S_O}) - (\frac{C}{S_1})]}{I}$$

Where: ΔR = resistance change in ohms

(Negative values are possible)

P/S_O = P/S potential in volts of carrier pipe w/o current applied

P/S_1 = P/S potential in volts of carrier pipe w/current applied

C/S_O = P/S potential in volts of casing w/o current applied

C/S_1 = P/S potential in volts of casing with current applied

I = Current applied in amps

9. Determine the resistance change.

- If the averaged resistance change is greater than 0.08 ohms, the casing can be considered *clear* and no further testing is required.
- If the averaged resistance change is equal to or less than 0.08 ohms, the casing and carrier pipe are shorted.

Documentation

A copy of the test data on the appropriate Company form should be filed in the PCS file.

- ✓If the casing is shown as newly shorted by the Panhandle Eastern test, and an attempt to clear the short has not been made, the casing should be reported as a deficiency and entered into the appropriate work management system.
- If the casing has previously shown as shorted by the Panhandle Eastern test, and the difference between the pipe-to-soil and casing-to-soil potentials remains the same or decreases, then subsequent testing of the pipe-to-soil potentials is *not* necessary, and the casing should be indicated as *shorted*.
- If the casing has previously shown as *clear* by the Panhandle Eastern test, and the difference between the pipe-to-soil and casing-to-soil potentials remains the same or increases, then subsequent testing of the pipe-to-soil potentials is *not* necessary, and the casing should be indicated as *clear*.

✓Attempt to Clear a Shorted Casing

Any attempt to clear a shorted casing will be done according to a written procedure specific to the pipeline involved and adhering to Company safety standards and Integrity/Engineering protocols. An attempt to clear a shorted casing while in-service shall be made if it is practical and can be safely accomplished. If an in-service attempt to clear a shorted casing is not successful, the shorted casing may have to be cleared during a scheduled shutdown.

If the attempt to clear the shorted condition is unsuccessful it is recommended the below examples be evaluated for consideration, also in regard to Pipeline Polarized potentials, one should provide additional “CP” current to the casing in the event the pipeline does not meet an acceptable criterion. This approach does not apply to coated casings.

PHMSA would expect the Company, at a minimum, to clear any shorts that are practical to clear such as:

- through the excavation of both ends of the casing, performing inspections, re-centering the carrier pipe inside the casing pipe, and removing or repairing materials that may cause the short such as: metallic shorts and damaged casing insulator spacers at the casing end points and any electrolytes between the casing and pipeline.

If after attempting to clear the short, it is determined impractical to achieve electrical isolation, the Company must take other preventive measures to mitigate corrosion of the pipeline inside the casing and to maintain safety.

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The following are examples of other preventive methods that may be used when isolation measures to clear the short are impractical, if it's determined they will minimize corrosion of the pipeline inside the casing:

1. Filling "high dielectric fill or corrosion inhibiting materials" between the casing/carrier pipe that can demonstrate will minimize corrosion of the carrier pipe and monitoring of the dielectric fill or corrosion inhibiting materials at a minimum in accordance with the timing and during the patrolling and leakage surveys required in §§ 192.705(b) and 192.706;
2. Monitoring corrosion with in-line inspection (ILI) tools that have demonstrated that they can properly detect and assess corrosion over the shorted locations and including concentrated pinhole corrosion areas along the carrier pipe. When assessing the shorted locations, the operator must use the proper application of ILI tool tolerance, class location safety factor in determining the safe operating pressure for any shorted corrosion area, and corrosion growth rate, and at intervals that meet either § 192.939 or at a more often reassessment interval if required based upon corrosion growth rate. If the shorted casing masks a proper inline inspection tool assessment, this would not be an applicable method;
3. Utilizing leak detection monitoring and intervals in combination with items 1 or 2 above, if leak monitoring can maintain safety based upon parameters such as assessments of risk and the consequences to the public. The risk assessment must be based upon the pipeline MAOP, diameter, operating stress levels, odorization of the gas, usage of remote or automatic closure valves for isolation, the pipeline material properties, whether the pipeline would only leak at operating pressures, and that leak detection monitoring (periodic or ongoing) would reduce the impact of an in-service leak to safety;
4. Implementing remedial measures to maintain the carrier pipe MAOP based upon suitable remaining strength calculation methods (§ 192.933(d)(1)(i)) and using the class location design factor (§ 192.111) of the pipeline whether it is in a high consequence area or non-high consequence area for any assessment findings, and whether through findings in conducting Items 1, 2, or 3 above or other findings; or
5. Applying for a special permit in accordance with § 191.341 that is applicable to the pipeline operating, safety, and environmental conditions.

CORR-004: Attaching Cathodic Protection Conductors (Such as Test Leads)

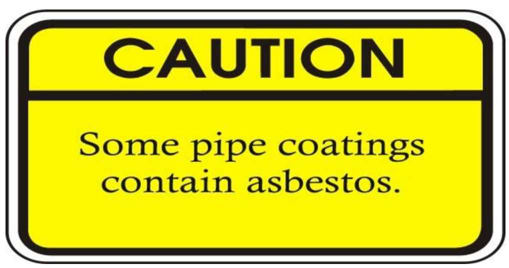
Scope

Acceptable methods to make CP test lead electrical connections are thermite welding, silver soldering, and pin brazing.

- For pipe having nominal wall thickness of less than 0.150", silver soldering shall be used. Thermite welding may be used on pipe having nominal wall thickness of less than 0.150".
- For pipe having nominal wall thickness of 0.150" or greater, connections may be made by silver soldering, thermite welding, or pin braising.

Procedure for Thermite Welding

Before installing test leads, follow all company safety procedures regarding PPE, hot work permits, excavation, and other applicable safety standards.



The Company has established a written Asbestos Control Program to control potential exposures to asbestos containing materials (ACM) in its facilities. An asbestos survey must be conducted at each facility to identify ACM. Employees performing maintenance activities that can potentially disturb ACM must meet the minimum requirements set forth in the Asbestos Management Policy. Abatement activities may also require notification of proper regulatory agencies.

Before contractor begins work, Company personnel will inform contractor of any potential asbestos hazards associated with the job.

Asbestos products will not be purchased unless non-ACM products are available.

Only trained personnel should remove ACM products.

ACM found at Company facilities can include transit siding/roofing, gaskets, floor and ceiling tile, window caulking, and pipe coating.

No eating, drinking, smoking, or chewing in any contaminated work areas.

Avoid contact/inhalation with ACM material by the use of protective clothing such as gloves, coveralls, rubber boots, respirators, and eye protection.

Thoroughly washing exposed skin areas, which may have been exposed to ACM before eating, drinking, smoking, or chewing.

1. Determine pipe nominal wall thickness.
2. Remove pipe coating in an area 3” to 4” square at a point of attachment and file the pipe to a bright, clean surface. Do not perform thermite weld on existing seam or weld, or in heat-affected zone. Do not perform thermite weld near (within 6 inches) of previous thermite weld.
3. If nominal wall is less than 0.150”, use an ultrasonic thickness gauge to test the pipe thickness.
4. Strip the wire or cable insulation back about 1½” or sufficient to slip on an adapter sleeve or fit completely in the thermite weld mold.

Note

Adapter sleeves are not necessary for wires larger than #6 (6AWG).

5. If a wire larger than #4 (4AWG) is used on pressure piping, strip the insulation on the wire far enough back to separate the strands by at least 6 inches into groups according to the following table:

Conductor	Total #	Strands per	Total #
2	7	3 or 4	2
1/0	19	6 or 7	3
2/0	19	5 or 6	4
3/0	19	5 or 6	4

4/0	19	3 or 4	5

6. If necessary, use the crimping tool to attach an adapter sleeve to the bare end of the wire or cable.
7. All surfaces and cable ends must be clean and dry prior to welding.
8. Check to ensure the wire or cable end fits in the thermite weld mold properly.
9. Prepare the weld material in the mold:
   - Place a disk in the mold.
   - Pour the weld metal charge on top of the disk.
   - Distribute the remaining flash material over the weld metal charge.

WARNING!

Never use a weld metal charge larger than 15 grams.

10. Close the thermite weld mold lid and use the handle to hold the charged mold in place over the wire or cable to be attached.
11. Check the wire or cable to verify correct positioning.
12. Position yourself upwind and to the side of the lid opening.
13. Use a flint igniter to ignite the flash material on top of the weld metal charge.
14. Hold the mold in place and steady until combustion is complete.
15. After combustion is complete, remove the mold from the weld and use a file, knife, etc. to clean out any slag left in the mold.
16. Allow the weld to cool for 1-2 minutes.
17. Use a hammer and wire brush to remove all slag from the weld area.
18. Visually inspect the weld for any indications of poor fusion.
19. Test the fusion of the weld by gently striking the side of the weld with a hammer or gently pulling the wire or cable.
20. Coat the weld area with one of the following company approved coating materials:

- Two-part epoxy
- Wax
- Mastic filled thermite weld caps
- Other coatings approved by Pipeline Integrity

21. Always coat the wire from the weld back to sound insulation.

Note

If a thermite weld does not appear sound or breaks when tested, cut the wire or cable from the weld and make a new weld at least 6 inches away. File and coat broken weld.

Procedure for Soldering

Before installing test leads, follow all company safety procedures regarding PPE, hot work permits, excavation, and other applicable safety standards:

1. Remove pipe coating in an area 3" to 4" square at a point of attachment and file the pipe to a bright, clean surface.
2. Strip the wire or cable insulation back approximately 3" to provide sufficient bonding surface area.
3. Use only 2% silver/98% tin solder material (e.g., Eutec 157-1/8" silver solder, Welco 5 or All-State 430) with the appropriate flux (e.g., Eutector 157, Welco 5 or Duzall).
4. Stir flux thoroughly and apply a thin coat to the areas to be soldered.
5. "Tee in" the pipe and conductor to be soldered.

6. Heat the pipe and melt a solder puddle sufficient in size to attach approximately 3” of the conductor to the pipe.

Note

Do not heat the pipe more than is necessary to puddle the solder. Excess heat is detrimental to the pipe and soldering process.

7. Position approximately 3” of the “tinned” conductor in the solder puddle and hold steady until the solder cools and sets.
8. Test for adequate bond strength by lightly tapping the connection with a hammer.
9. Neutralize the acid flux with a base solution (mixture of baking soda and water to make a watery paste is acceptable). Apply the base solution to the area wetted by the flux and then rinse with clean water to remove the solution.
10. Clean, let dry and coat the connection with a company approved coating material as stated in *Procedure for Thermite Welding* step 20 above.

Procedure for Pin Brazing

Before installing test leads, follow all Company safety procedures regarding PPE, hot work permits, excavation, and other applicable safety standards.

1. Determine pipe nominal wall thickness.
2. Remove pipe coating in an area 3” to 4” square at a point of attachment and file the pipe to a bright, clean surface.
3. Use an ultrasonic thickness tester to test the pipe thickness.
4. Grind the brazing area until clean.
5. Attach the earthing device on the rail, which is to be brazed first. If required, grind the rail clean to ensure good contact.
6. Load the gun with brazing pin and ferrule.
7. Hold the rail bond against the brazing area.
8. Place the brazing pin in the cable lughole.

Note

Follow instructions on correct placement of the brazing pin.

9. Press the gun to hold the ferrule tight against the cable lug.

Note

Ensure full contact around the entire ferrule.

10. Hold the gun firmly and close the circuit by pulling the trigger. Keep the trigger depressed for the duration of the arc.
11. After 1.5-2.5 seconds, depending on the thickness of the fuse wire, the fuse wire will melt and the pin shoots forward.
12. Hold the gun in place for a second or two while the braze freezes.
13. Remove the gun and depress the ejector or expel the remaining fuse wire.
14. Break off the shank of the brazing pin and the braze is completed.
15. Test for adequate bond strength by lightly tapping the connection with a hammer.
16. Clean and coat the connection with a company approved coating material as stated in *Procedure for Thermite Welding* step 20 above.

CORR-005: Maintaining Reference Electrodes

Scope

Reference electrodes are used in the process of measuring P/S potentials. The one most commonly used is the copper/copper sulfate ($Cu/CuSO_4$) electrode or “half-cell.” It consists of a high purity copper rod surrounded by a saturated solution of copper sulfate and enclosed in a protective case. Contact between the copper sulfate solution and soil or water is made by means of a porous plug at the bottom end of the electrode. The reference electrode must be maintained to ensure that correct potentials are measured.

Another type is the Silver/Silver Chloride (Ag/AgCl) reference electrode. The silver/silver electrode can be used in lieu of the copper/copper sulfate electrode to obtain p/w (pipe-to-water) or s/w (structure-to-water) potentials offshore or in brackish water to prevent chloride contamination of the reference cell. The silver/silver chloride electrode must be used when taking potentials in water depths of 200 feet or greater.

Procedure for Initial Use (Copper Sulfate)

WARNING!

Copper sulfate is toxic and corrosive. Wear appropriate PPE when handling copper sulfate. Used copper sulfate solution should be disposed in accordance with environmental procedures.

1. Remove plastic cap and copper rod assembly.
2. If copper rod is corroded, clean it using the following method:
3. Clean the rod with new non-metallic sandpaper and rinse any residue off using distilled water.
4. With copper sulfate crystals in the bottom of the tube fill electrode tube to near the top with distilled water.

Note

When the electrode is expected to be used in sub-freezing conditions, remove the crystals and fill with Electrode Anti-Freeze solution. Do not use an anti-freeze solution in warm weather since it will adversely affect readings.

5. Replace the copper rod assembly and tighten the plastic cap firmly to effectively seal the tube.
6. Shake the electrode until a saturated solution is obtained. The solution should be blue in color and must have some excess copper sulfate crystals visible in the tube.
7. If no crystals can be seen:
   - Reopen the tube.
   - Add a few copper sulfate crystals to the solution.
   - Close the tube and tighten the plastic cap firmly.
   - Shake the tube and check for crystals.
8. Repeat process until crystals are evident.
9. Allow at least 5 minutes for the porous plug to saturate before using electrode for the first time.

Procedure for Checking for Contamination (Copper Sulfate)

1. A reference electrode check should be performed, at a minimum, before starting each survey. This constitutes taking a potential reading with a minimum of two half-cells (one half-cell, unused in field conditions, and the field half-cell) placed in a non-conductive container of water or wet sand, or placed in firm contact with each other. A difference in readings between them of five (5) mV CSE or greater requires either the cleaning or replacement of the field half-cell.
2. Temperature variations will make the half-cell read more negative as the temperature increases or less negative as the temperature decreases. The variation is approximately 0.5 mV CSE per degree F change.

3. Temperature variations will affect the quantity of copper salts that can be dissolved in a saturated solution. As the temperature increases the quantity of salts that can be dissolved increases. Each order of magnitude change in concentration equals approximately a 20 mV CSE potential shift.
4. Light will affect the photosensitive copper salts. The half-cells should be constructed of a non-transparent material or if a clear window is present to observe solution levels, the window should be covered with a non-transparent material.

Procedure for Initial Use (Silver Chloride)

1. Immerse the complete electrode into electrolyte, seawater.
2. When lowering the reference electrode into the seawater, avoid immersing the electrode through a film of oil, which could coat the electrode element and cause abnormal readings.
3. Allow the potential measurement to stabilize over a five to ten minute period. This time is necessary if the Ag/Cl element is dry before immersion.
4. Position the reference electrode as close as possible to the structure (minimize IR drop).

Maintenance and Storage of Ag/AgCl Reference Electrode

1. Rinse or brush away any foreign deposits with distilled water. If grease or oil is encountered, clean with a mild detergent and rinse with distilled water.
2. To ensure quick response time and fast potential stabilization, the Ag/AgCl element should be moist.
3. If electrode is being used daily, soak Ag rod assembly in the storage tube filled with local seawater.
4. If electrode will not be used for an extended period of time, disassemble and wash with distilled water. Before returning to service, prepare as for new electrode. Allow electrode to stabilize for five or ten minutes before recording readings.

Ag/AgCl/Sea Water - Cu/$CuSO_4$	
ELECTRODE @ 25° C CU/$CUSO_4$	**SEAWATER 20 OHM-CM**
Cu/$CuSO_4$ Saturated	0.850 V
Ag/AgCl	0.800 V

CORR-006: Reading Shunts

Scope

Shunts are in-line devices used to measure current in bond wires and anode junction boxes, calibrate ammeters in rectifiers, etc. Shunts are available in various types and sizes depending on use and current range. Shunts used in CP measurements are usually based on a maximum 50-millivolt drop across the known resistance. A voltage difference measured across a given resistance is used to determine the current flow in a wire or cable using Ohm's Law.

Procedure

1. Determine shunt resistance. This may be written on the shunt directly, such as .001, .01 etc. or calculated from the voltage and amp range stamped on the shunt, such as 50 mV CSE and 5 amps, 50 mV CSE and 10 amps, etc.
2. Using Ohm's Law calculate the shunt resistance if not known.

   E = IR or R = E/I

   Example: 50 mV CSE – 5 amp shunt

$$\mathbf{R = \frac{50\ mV}{5\ amps} = \frac{.05\ V}{5\ amps} = .01\ ohms}$$

3. Read the voltage across the shunt (see **Figure 5**). Connect meter leads to proper connection points and note polarity.

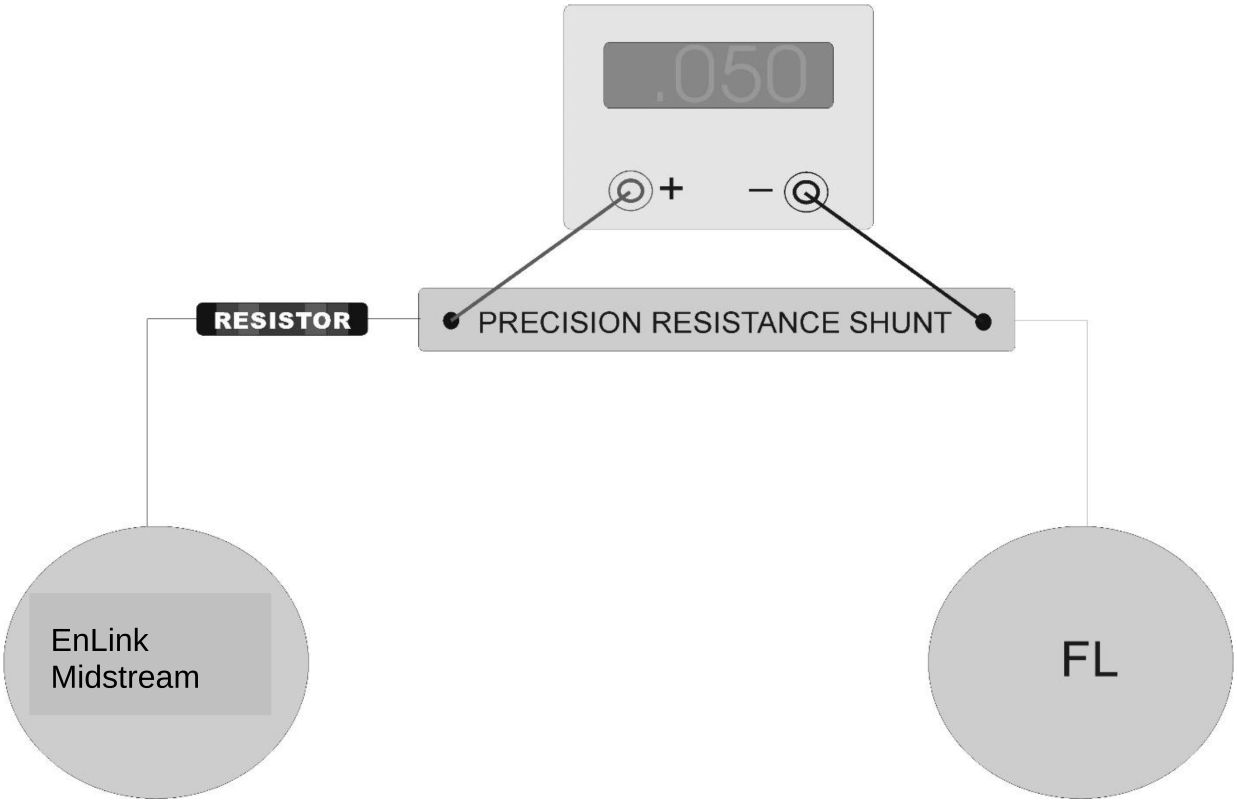


Figure 5: Read Voltage Across Shunt

4. Using Ohm's Law, calculate the current flow and determine the direction of current flow in the shunt:

I = E/R

Example: (0.050 volts or 50 mV CSE reading across shunt; note polarity of reading)

I = 50 mV CSE / .01 ohms

= .05 V / .01 ohms

= 5 amps (flowing from + to -)

In the above example, 5 amps of current is flowing through the shunt from the EnLink Midstream pipeline to the foreign pipeline.

Shunt Factors Procedure

A shunt factor from the following table may be used to calculate the current flowing through a shunt.

1. Read the voltage across (refer to Figure 5 above). Connect meter leads to the proper points and note polarity.
2. Determine the shunt factor by finding the shunt size in the table below. The shunt size may be written on the shunt. If the shunt resistance is written on the shunt, such as .001, .01, etc., then use the table to determine a factor for that resistance.
3. Multiply the reading by the shunt factor. Pay special attention to decimal points.

mV	Amps	Resistance	Factor
50	1	.05	.02
50	2	.025	.04
50	3	.017	.06
50	4	.0125	.08
50	5	.01	.1
50	10	.005	.2
50	15	.003	.3
50	20	.004	.4
50	25	.002	.5
50	30	.0017	.6
50	50	.001	1
50	60	.0008	1.2
50	75	.0007	1.5
50	100	.0005	2

Example: Shunt size is 10amps/50mV CSE. Reading is -41mV CSE.

-41 x .2 = 8.2 amps

8.2 amps are flowing from the foreign structure to the EnLink Midstream structure.

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CORR-007: Color Coding/Installing Wiring

Scope

EnLink test leads on company facilities are normally made using black insulated wire, and foreign facilities using white insulated wire.

EnLink Midstream Color-Coding

LOCATION/AREA	COLOR
Casings (Railroad and Highway):	
• Pipe	Black
• Casing	White
CP Coupon Test Station:	
• CC Technologies Test Stations	
▸ Pipe	Black
▸ Cathodically protected coupon	Black
▸ Native Coupon	White
• Cott Test Stations	
▸ Pipe	Orange
▸ Coupon	White
• OR AS DESIGNATED BY MANUFACTURER	
Underground Insulating Flange Test Stations:	
• Ownership Change	
▸ EnLink Facility	Black
▸ Foreign Company	White
Meter Station – Foreign Company:	
• Meter Station	Black
• Foreign Company	White

CORR-008: Making Electrical Splices

Scope

Splices are used to connect sections of wire/cable or multiple wires/cables at a connection. It is imperative that the splice be of excellent quality to prevent a future failure in the splice. This is especially true in the positive circuit of an impressed current rectifier system.

Procedure (Manual Splice)

1. Shut power sources off.
2. Clean any foreign debris from each end of wire/cable back about 1 to 2 feet.
3. Strip insulation back on each end only far enough for crimp or split-bolt to fit.
   - Be careful not to cut or nick copper strands.
   - Use only copper split-bolts or sleeves. Use correct size connectors.
4. Clean wire/cable strands with wire brush.

Note

If deposits on copper strands appear to go back under the wire/cable insulation or the insulation appears to be ballooned, cut more cable off to get to good wire/cable.

5. Use emery cloth to shine copper strands and “roughen up” insulation back about 6 to 10 inches on each wire/cable.
6. Wipe wire/cable with a clean rag to clean off any cleaning debris.
7. Make connection using the correct size connector and test connection for strength.
8. Using Scotchfill insulating putty or mastic, fill all voids, cover all sharp edges, and taper the putty onto the wire/cable insulation for about 3 inches.

9. Using rubber electrical tape, cover all insulating putty plus another 3 inches of wire/cable insulation with two tape passes.
10. Using Scotch 88 electrical tape or equivalent, cover all rubber tape plus another 3 inches of wire/cable insulation with 4 tape passes. Keep the tape tight and overlap tape by 1/3.
11. For more secure insulation, such as splices on positive anode cables through areas of moisture, steps 8 and 9 can be repeated.
12. Flood the tape splice with Scotchkote and let dry before backfilling.

Procedure (Epoxy Splice Kit)

1. Shut down all power sources.
2. Clean any foreign debris from each end of wire/cable back about 1 to 2 feet.
3. Strip insulation back on each end only far enough for crimp or split-bolt to fit.
   - Be careful not to cut or nick copper strands.
   - Use only copper split-bolts or sleeves. Use correct size connectors.
4. Clean wire/cable strands with wire brush.

Note

If deposits on copper strands appear to go back under the wire/cable insulation or the insulation appears to be ballooned, cut more cable off to get to good wire/cable.

5. Use emery cloth to shine copper strands and "roughen up" insulation back about 6 to 10 inches on each wire/cable.
6. Wipe wire/cable with a clean rag to clean off any cleaning debris.
7. Make connection using the correct size connector and test connection for strength.
8. Use only splice kits approved by Operations Corrosion Control personnel.
9. Follow manufacturer's specifications to install splice kit.
10. Allow sufficient time for epoxy to cure before backfilling connection.

CORR-009: Surface Potential Surveys

Scope

A *surface potential* survey is a type of cell-to-cell survey that is used to detect areas of active corrosion on sections of underground structures.

Procedure

1. Locate the centerline of the pipeline using a pipe/cable locator and place marker flags every 100 feet over the section to be surveyed.
2. Set-up the equipment.
3. The chaining equipment must have a spacing between the reference electrodes of twenty (20) feet. Smaller spacing may be used if approved by operations corrosion control personnel.
4. Mount one reference electrode on each of the two chaining equipment poles.
5. Mount the Multimeter on the back pole.
6. Connect one test lead between the meter negative terminal and the back pole reference electrode.
7. Connect the other test lead between the meter positive terminal and the front pole reference electrode.
8. Place the pole-mounted reference electrodes in contact with each other by touching the porous plugs together or by placing them in a cup of tap water.
9. If the potential difference between the two is greater than 5 mV CSE, the electrodes should be thoroughly cleaned following procedure *CORR - 005: Maintaining Reference* Electrodes.
10. If the potential difference between the two is 5 mV CSE or less, the electrodes are considered balanced, and the equipment is ready for use.
11. The front pole reference electrode should be placed in contact with the earth directly above the pipeline at the point corresponding to the beginning of the survey.
12. The back pole reference electrode should be placed in contact with the earth directly above the pipeline at a point twenty (20) feet along the pipeline.
13. Record the potential reading on the appropriate company form, including the polarity.
14. Shift the two electrodes up the pipeline twenty (20) feet ensuring the back pole electrode is now placed in the same spot as the front pole electrode before the shift.

15. Record the potential reading including the polarity and compare this reading with the prior reading.
16. If the polarity has changed from positive to negative and the potential has shifted at least six (6) mV CSE, an anodic area or reversal is near.
17. To locate a reversal:
    a. Leave the back pole reference electrode in contact with the earth at its present location.
    b. Move the front pole toward the back pole approximately 2 ½ feet and place in contact with the earth directly over the pipeline.
    c. While watching the potential reading, continue to move the front pole towards the back pole until the reading becomes zero.

Note

As a zero reading is approached, it may be necessary to reduce the 2-½ foot interval.

    d. The location of the front pole when the zero reading is observed corresponds to the reversal location.
    e. Record the station number corresponding to the reversal location on the appropriate company form.

Note

Station numbers corresponding to reversals should be recorded on the line associated with the last positive reading.

18. Place the back pole reference electrode in contact with the earth at the reversal location. The front and back pole electrodes should now be side by side.

19. Measure the left- and right-side drain potentials at the reversal:
    a. Leave the back pole reference electrode in contact with the earth at the reversal location.
    b. Place the front pole reference electrode in contact with the earth at the location approximately five (5) feet to the right of and perpendicular to the pipeline.
    c. Record the right-side drain potential and polarity on the appropriate form.
    d. Repeat steps 19.b and 19.c for the left-side drain potential.

Note

If this is the first surface potential survey to be run on the survey area, a soil resistivity reading should be taken at all reversal locations determined to be "hot-spots" and recorded on the appropriate form. Soil type (sand, clay, rock, swampy, etc.) should also be noted where the resistivities are required.

20. When locating a reversal as in step 17, if the front pole has been moved all the way back to the back pole and the zero has not been located, there may be two overlapping voltage gradient fields present. To locate the two reversals:
    a. Continue to relocate the front pole reference electrode toward and past the back pole until the zero is found.

Note

When the front pole reference electrode is placed behind the back pole reference electrode, the meter polarity WILL reverse.

    b. Measure the side drain potentials as in step 19 at the zero location and at the location corresponding to the lowest negative reading found in the original twenty (20) foot spacing while looking for the zero. These locations correspond to the two reversals.

21. All reversals evaluated to be “hot-spots” should be marked by driving a wooden stake into the earth directly over the pipeline at the reversal location. Write the station number on the stake.
22. Reversals evaluated as not being “hot-spots” do not have to be marked with a wooden stake.
23. Note the location of any fence, creek, ditch, house, tower, and road centerline on the appropriate form.
24. Continue the survey by repeating steps 14 through 20 until the survey is complete.
25. Evaluate the data per the following guidelines:

GUIDELINES

Large Reversals

A *large reversal* may be defined as "a reversal of 100 mV CSE or greater." A *small reversal* is defined as "being less than 100 mV CSE." A *large side drain*, whether positive or negative, may be defined as "being 60 mV CSE or larger." *Small side drains* are defined as "being less than 60 mV CSE."

REVERSAL	LEFT SIDE DRAIN	RIGHT SIDE DRAIN	INDICATION
Large	Large +	Large +	Hot-Spot
Large	Large -	Large -	Hot-Spot
Large	Large +	Large -	Sacrificial Anode
Large	Large -	Large +	Sacrificial Anode
Large	Large +	Small +	Sacrificial Anode
Large	Small +	Large +	Sacrificial Anode
Large	Large +	Small -	Sacrificial Anode
Large	Small -	Large +	Sacrificial Anode
Large	Large -	Small +	Sacrificial Anode
Large	Small +	Large -	Sacrificial Anode
Large	Large -	Small -	Hot-Spot
Large	Small -	Large -	Hot-Spot
Large	Small +	Small +	Hot-Spot
Large	Small -	Small -	Hot-Spot
Large	Small +	Small -	Hot-Spot
Large	Small -	Small +	Hot-Spot

GUIDELINES

Small Reversals

A *large reversal* may be defined as “a reversal of 100 mV CSE or greater.” A *small reversal* is defined as “being less than 100 mV CSE.” A *large side drain*, whether positive or negative, may be defined as “being 60 mV CSE or larger.” *Small side drains* are defined as “being less than 60 mV CSE.”

REVERSAL	LEFT SIDE DRAIN	RIGHT SIDE DRAIN	INDICATION
Small	Large +	Large +	Hot-Spot or Sacrificial
Small	Large -	Large -	Hot-Spot
Small	Large +	Large -	Sacrificial Anode
Small	Large -	Large +	Sacrificial Anode
Small	Large +	Small +	Sacrificial Anode
Small	Small +	Large +	Sacrificial Anode
Small	Large +	Small -	Sacrificial Anode
Small	Small -	Large +	Sacrificial Anode
Small	Large -	Small +	Sacrificial Anode
Small	Small +	Large -	Sacrificial Anode
Small	Large -	Small -	Hot-Spot
Small	Small -	Large -	Hot-Spot
Small	Small +	Small +	Hot-Spot
Small	Small -	Small -	Hot-Spot
Small	Small +	Small -	Hot-Spot
Small	Small -	Small +	Hot-Spot

CORR-010: Pipeline Current Testing

Scope

Measurement of pipeline currents is beneficial in investigating interference problems and determining current flow from long line corrosion cells and cathodic protection installations. Current flow in pipelines has traditionally been measured by amp clamps installed around exposed pipelines or through the installation of voltage drop test stations.

This procedure deals with voltage drop test stations where test leads are attached at a given distance on a pipeline and through pipe resistance and voltage drop, the current in the pipeline is calculated.

Procedure

Two test leads are installed on a pipeline at a predetermined distance from each other (span).

This span can be obtained from pipeline steel resistivity charts for a known resistance, such as the one below based on R = (16.061 x 18 microhm-cm)/W.

Size	Wall	Weight /	Resistance /		Size	Wall	Weight /	Resistance /
2 3/8	0.109	2.64	0.00010959		8 5/8	0.352	31.1	0.0000093
	0.154	3.65	0.00007914		10 3/4	0.203	22.87	0.00001264
	0.167	3.94	0.00007341			0.25	28.04	0.00001031
	0.218	5.02	0.00005757			0.365	40.48	0.00000714
2 7/8	0.125	3.67	0.00007875		12 3/4	0.203	27.2	0.00001063
	0.187	5.37	0.00005385			0.25	33.38	0.00000866
	0.276	7.66	0.00003774			0.375	49.56	0.00000583
3 ½	0.125	4.51	0.00006416		14	0.205	30.2	0.00000957
	0.25	8.68	0.00003332			0.21	30.93	0.00000935
	0.3	10.25	0.0000282			0.375	54.57	0.0000053
4	0.128	5.29	0.00005462		16	0.25	42.05	0.00000687
	0.237	9.52	0.00003035			0.375	62.58	0.00000462
	0.25	10.01	0.00002887			0.401	66.81	0.00000433
	0.318	12.5	0.00002312		18	0.25	47.39	0.0000061
4 ½	0.128	5.98	0.00004837			0.31	58.57	0.00000494
	0.337	14.98	0.00001929			0.437	81.97	0.00000353
5 ½	0.134	7.68	0.00003765		20	0.312	65.6	0.00000441
	0.25	14.02	0.00002062			0.375	78.6	0.00000368
	0.361	19.81	0.00001459			0.562	116.67	0.00000248
6	0.14	8.76	0.000033		24	0.312	78.93	0.00000366
	0.25	15.35	0.00001883			0.375	94.62	0.00000306
	0.359	21.63	0.00001337			0.562	140.68	0.00000206
6 5/8	0.144	9.97	0.000029		26	0.231	63.57	0.00000455
	0.28	18.97	0.00001524			0.281	77.18	0.00000375

Size	Wall	Weight /	Resistance /		Size	Wall	Weight /	Resistance /
	0.375	25.03	0.00001155			0.291	79.9	0.00000362
	0.188	12.92	0.00002237			0.303	83.16	0.00000348
8	0.158	13.23	0.00002185			0.311	85.33	0.00000339
	0.25	20.69	0.00001397			0.375	102.63	0.00000282
	0.375	30.54	0.00000947		30	0.324	102.69	0.00000282
8 5/8	0.165	14.91	0.00001939			0.334	105.82	0.00000273
	0.203	18.26	0.00001583		31	0.324	106.15	0.00000272
	0.271	24.18	0.00001196			0.334	109.39	0.00000264

Pipe Size, Inch	(W) Weigh per Foot, lb.	(R) Resistance of One Foot of Pipe, Ohms x 10^{-6}
2	3.65	79.2
4	10.8	26.8
6	19.0	15.2
8	28.6	10.1
10	40.5	7.13
12	49.6	5.82
14	54.6	5.29
16	62.6	4.61
18	70.6	4.09
20	78.6	3.68
22	86.6	3.34
24	94.6	3.06
26	102.6	2.82
28	110.6	2.62
30	118.7	2.44
32	126.6	2.28
34	134.6	2.15
36	142.6	2.03

A rule of thumb estimate for span length is to multiply the pipe weight in pounds/foot times 4. This will give the span length in feet required to achieve a .001-ohm resistance.

The two voltage drop test leads can be installed, then two additional (calibration) test leads are installed permanently or temporarily at a point 5 pipe diameters outside the voltage drop test leads. A known current is applied to the calibration test leads and the voltage is measured across the voltage drop test leads. Using Ohm's Law, the span resistance can be calculated.

1. Attach the positive (red) lead from a Multimeter to the upstream test lead and the negative (black) lead to the downstream test lead (see Figure 6).

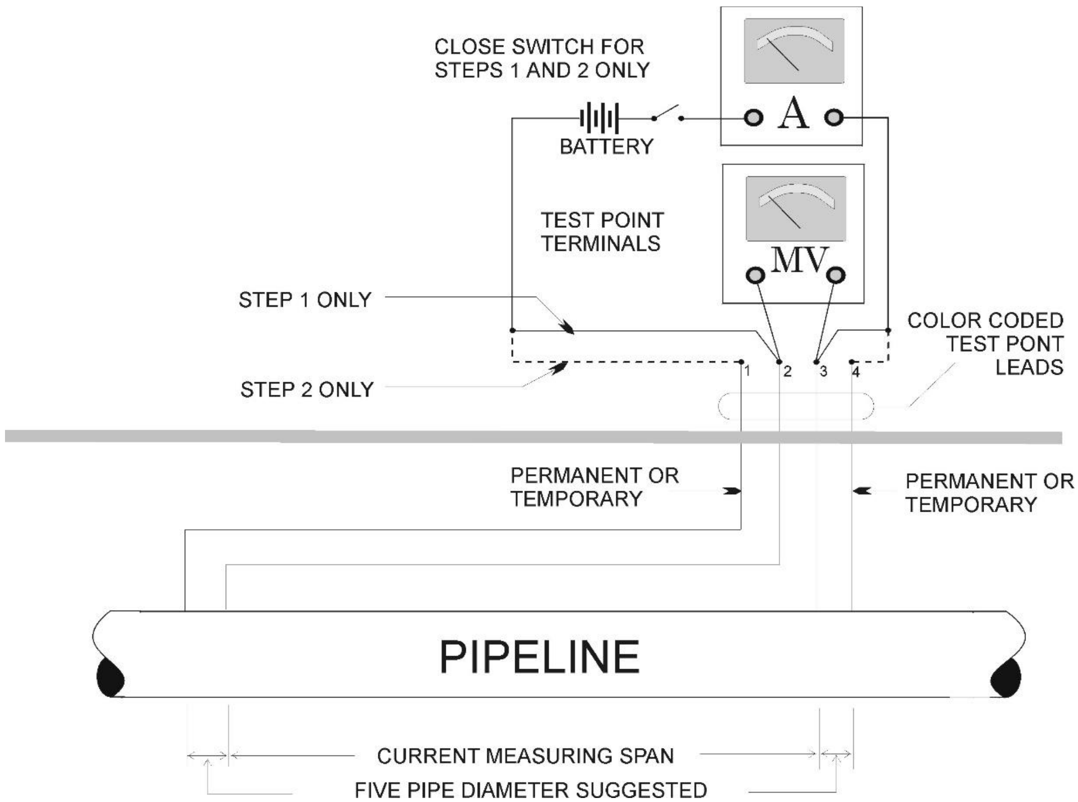

Figure 6: Pipeline Current Testing Test Lead Connections

2. Measure the voltage drop across the span while noting the sign.
3. Determine current flow following the procedure for reading shunts.
   - If the reading was positive, then current flow in the pipeline is from upstream to downstream.
   - If negative, it was the other way.

CORR-011: Current Requirement Testing

Scope

At times in corrosion control, it may be necessary to determine the amount of current, which will be required to cathodically protect a structure, and also to qualify a structure's coating condition. Current requirement testing involves using a temporary or existing ground bed, an interrupter in series with a DC power source, and taking before and after P/S potential readings at various stations along the structure being interrupted.

Procedure

1. Conduct an initial P/S potential survey along the structure being surveyed and record on the appropriate form.
2. Set up a temporary ground bed such as a metal fence, metal sign posts, and driven pins with a DC power source.

Note

Using a minimum of #12 AWG gauge wire connect the positive (+) terminal of the power source to the ground bed and the negative (-) to the structure.

Note

The temporary ground bed may be set up either remote or close to the structure, depending on the circumstances. A remote ground bed is defined as one located approximately 300–600 feet perpendicular to the structure. A close ground bed is located near the structure.

3. Insert a current interrupter and ammeter in series with either wire from the power source. Set the interruption cycle at approximately 20 seconds ON and 5 seconds OFF. Record the test current on the appropriate form.

Note

Test current will usually be restricted by the temporary CP installation circuit resistance.

4. Read and record P/S potentials (ON and OFF) on the appropriate form at the same locations previously surveyed for initial potentials.
5. At each test location calculate the difference between the ON and OFF reading. This will be the amount of potential shift at each test location.
6. Calculate the value of □V_{reg1} using the following formula:

$$\square V_{reg1} = A - B$$

Where: A = Desired CP level

B = OFF reading at the lowest potential shift

Example: Readings in millivolts

Milepost	ON	OFF	□V_g
MP 1.1	-1000	-700	300
MP 1.2	-950	***-800***	***150***
MP 1.3	-1100	**-600**	**500**

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7. Calculate the amount of CP current required to achieve a minimum of –850 millivolts at the lowest potential test location. Use the following formula:

$$I_A = \left(\frac{\Delta V_{reg1}}{\Delta V_{g1}}\right) I_T$$

Where:	I_A	=	Current required to achieve desired CP level, amps
	ΔV_{reg1}	=	Desired CP level, mV CSE
	ΔV_{g1}	=	Lowest potential shift, mV CSE
	I_T	=	Test current, amps

From example ***data*** and using 5 amps as test current:

$$IA = \left(\frac{850 - 800}{150}\right) 5 = 1.7$$

8. Calculate the value of ΔV_{reg2} using the following formula:

$$\Delta V_{reg2} = A - C$$

Where:	A	=	Desired CP level
	C	=	Lowest OFF reading

9. Verify that this calculated current requirement will be enough to raise the lowest OFF reading to the desired CP level by using the following formula:

$$I_A = \left(\frac{\Delta V_{reg2}}{\Delta V_{g2}}\right) I_T$$

Where:	I_A	=	Current required to achieve desired CP level, amps
	ΔV_{reg2}	=	Desired CP level, mV CSE
	ΔV_{g2}	=	Potential shift in mV CSE, at the lowest OFF reading
	I_T	=	Test current, amps

From example **data** and using 5 amps as test current:

$$I_A = \left(\frac{850 - 600}{500}\right) 5 = 2.5$$

10. Compare the results of both calculations. The current requirement is the larger of the two.
11. Determine the soil resistivity of the proposed ground bed site.

CORR-012: Installation and Monitoring of Cathodic Protection Coupon Test Stations

Scope

Cathodic Protection Coupon Test Stations are used on facilities that are sensitive to changes in cathodic protection current, in areas that may appear marginally protected, on facilities that parallel HVAC facilities, on facilities that are protected by sacrificial anodes, and in areas with unusual current gradients. They should *not* be located near galvanic anodes or by other current sources, such as impressed current anode beds.

Installation

It is important to maintain the same soil conditions around the coupon as are around the pipe because the coupon is supposed to simulate a holiday in the pipe wall with approximately the same surface area as that of the coupon. When the coupon is placed in the bottom of the ditch, the soil that was removed from the bottom should go back first so the coupon will see the same type of soil as the pipe. However, if the bottom of the ditch is rock, replace it with a finer soil. It is more important to get good soil/coupon contact.

1. Dig or Pot hole (6" diameter minimum) to within one foot of the pipe and level with the bottom of the pipe.
2. Separate the bottom two to three feet of soil from the rest. This will be used as bedding around the coupon and will be the first of the backfill. The idea being to put the soil back in the hole in the same order it came out.
3. Use 1/8" to 1/4" wire fabric to sift enough of the bottom soil to fill the hole to about six inches to one foot above the coupon. Save back about a pint of the sifted soil for the dip tube.
4. The test lead wires should be attached to either:
    - Test lead on the existing test station
    - A nearby riser connected to the pipeline
    - The pipeline with a #15 exothermic weld

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5. Remove any protective wrap from the coupon and set the test station in position with the coupon at the bottom of the hole near the pipe.
6. Pour two to three gallons of water in the bottom of the hole around the coupon and add the sifted soil.
7. Tamp the soil, then back fill the hole tamping about every two feet.
8. Pour about one pint of water down the inside of the test station, or dip tube if using a Cott station.
9. Slowly pour about half a pint of a 50/50 mixture of washed playground sand and sifted soil into the dip tube, and gently tamp with wooden dowel.
10. Disconnect the coupon from the pipe. If using a Cott station, **pull the Bond** Plug out of the pipe and coupon terminals in the Big Fink so that the coupon is **NOT** connected to the pipe. If using a CC Technologies station, turn the switch to the **Coupon OFF** position. It is important to let the coupon freely corrode for a specified time (usually six months) before connecting it to the pipe.

Monitoring

Some coupons will be selected to validate the monitoring program. For those, refer to *Validation Monitoring Procedure* on page 56.

First Read

1. Check to see that the bond plug is still disconnected.
2. Measure the soil resistivity at pipeline depth using the Wenner four-pin method.
3. Read the native potential of the coupon. Take two readings: One with the half-cell inside the dip tube, and one with the half-cell outside the dip tube next to the test station.
4. Read the potential of the pipe. Take two readings: One with the half-cell inside the dip tube, and one with the half-cell outside the dip tube next to the test station.
5. Connect the coupon to the pipe with the bond plug.
6. Read the potential again. This will be a mixed potential of the pipe and the coupon. Take two readings: One with the half-cell inside the dip tube, and one with the half-cell outside the dip tube next to the test station.
7. Measure the current flow between the pipe and the coupon utilizing an appropriate shunt.

RECORD THE POLARITY

+ FOR CURRENT **FLOW TO COUPON**

- FOR CURRENT **FLOW TO PIPE**

Subsequent Reads

1. Place the half-cell in the dip tube and measure the pipe-to-soil potential.
2. Measure the instant off by disconnecting the bond plug and recording the second display after the interruption (disconnection). The meter will start flashing, changing displays as the potential drops; try to catch the second one. If the meter display is too fast, record the first potential you can get within one second of interruption.
3. Allow the coupon to depolarize for at least 10 minutes and record the depolarized reading.

Validation Monitoring Procedure

The purpose of the IR Drop test station is to provide as close to an IR drop free potential as possible on a structure without having to interrupt rectifiers or other power sources. However, it will be necessary to interrupt the cathodic protection on these structures for a test period in order to validate the coupon data. More data than normal for this period will be required. Readings should be taken at **quarterly intervals**.

Eight potentials will be taken at each test station while the cathodic protection power sources are in an interrupted cycle. Interrupters should be set to give you the minimum time necessary to get an instant off. Two to three seconds off in a thirty-second cycle will be more than enough time to get the OFF reading with minimal depolarization of the pipeline.

1. With the copper/copper sulfate half-cell directly over the pipe:
   - Pipe-to-Soil ON
   - Pipe-to-Soil Instant OFF
   - Coupon-to-Soil ON
   - Coupon-to-Soil Instant OFF

2. With the copper/copper sulfate half-cell inside the test station plastic conduit:
    - Pipe-to-Soil ON
    - Pipe-to-Soil Instant OFF
    - Coupon-to-Soil ON
    - Coupon-to-Soil Instant OFF

Current Flow To/From the Coupon

Replace the jumper with a Cott shunt[1] and measure the current flow and direction between the pipe and the coupon.

Soil Resistivity

Since soil resistivity changes during the year, this will need to be measured during each test. The Wenner Four Pin method should be used. Measure to approximately pipeline/coupon depth.

pH

Measure the pH of the soil at the surface with an antimony half-cell, both outside the plastic conduit and inside.

[1] An ammeter may have to be connected between the pipe and the coupon instead of using a shunt since the current flow should be very small.

Typical Coupon Test Stations

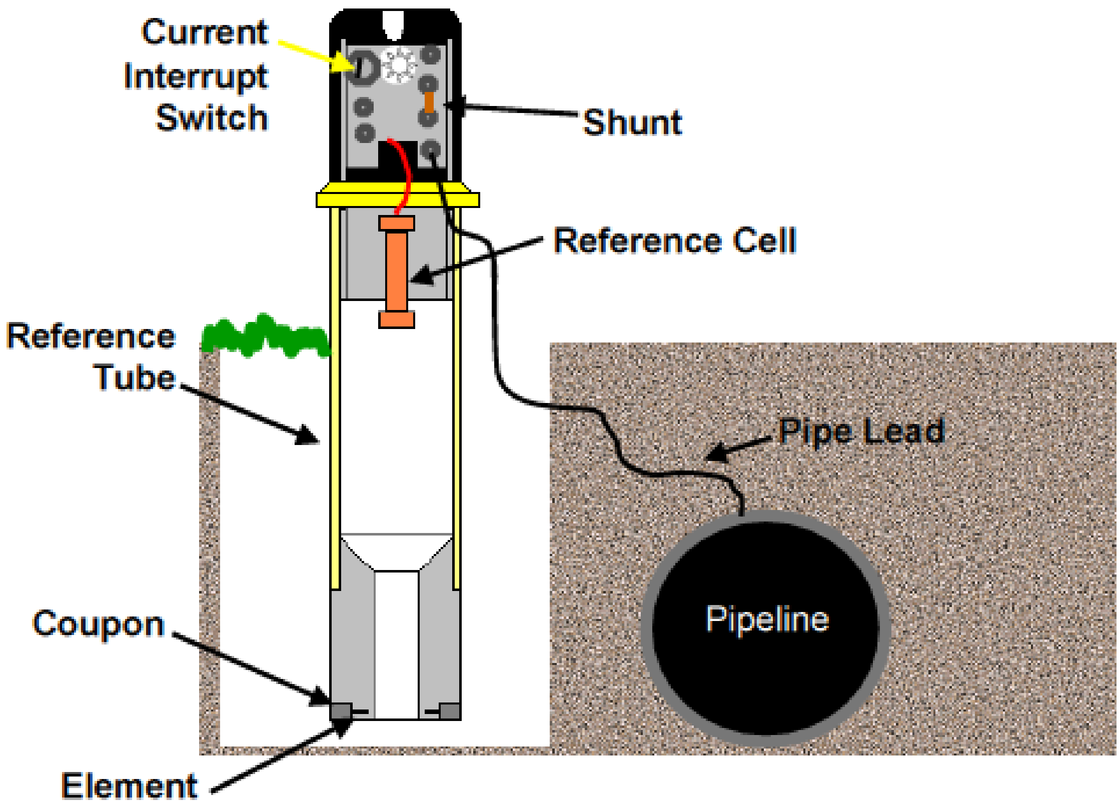


Figure 8.11 Typical Coupon Test Station

CORR-013: Conducting E-LOG-I Current Requirement Tests on Well Casings

Scope

To provide a standard method for conducting E-Log-I current requirement tests on well casings.

Data Gathering

1. Size and depth of each casing string.
2. Top of cement.
3. Electrical isolation.
4. Location of other impressed current systems in the vicinity of the well to be tested.

Procedure

Set Up

1. Install a temporary ground bed a minimum of 100 feet from the wellhead.
2. Connect the temporary ground bed to the positive terminal of a rectifier or other DC power source capable of 20 amp output, minimum #10 wire.
3. Connect the negative terminal of the DC power supply to the wellhead through a carbon pile resistor or some other current controlling device. Ensure no electrical isolation is between the negative connection and the well casing.
4. Insert a 0.01-ohm shunt into the circuit. Current drain will be measured by noting the voltage drop across the shunt. A digital voltmeter having a minimum impedance of 10 megohm shall be used.
5. Casing potentials will be measured with reference to a remote electrode a minimum of 500 feet from the wellhead and as far as possible from other underground metallic structures.

Conducting the Test

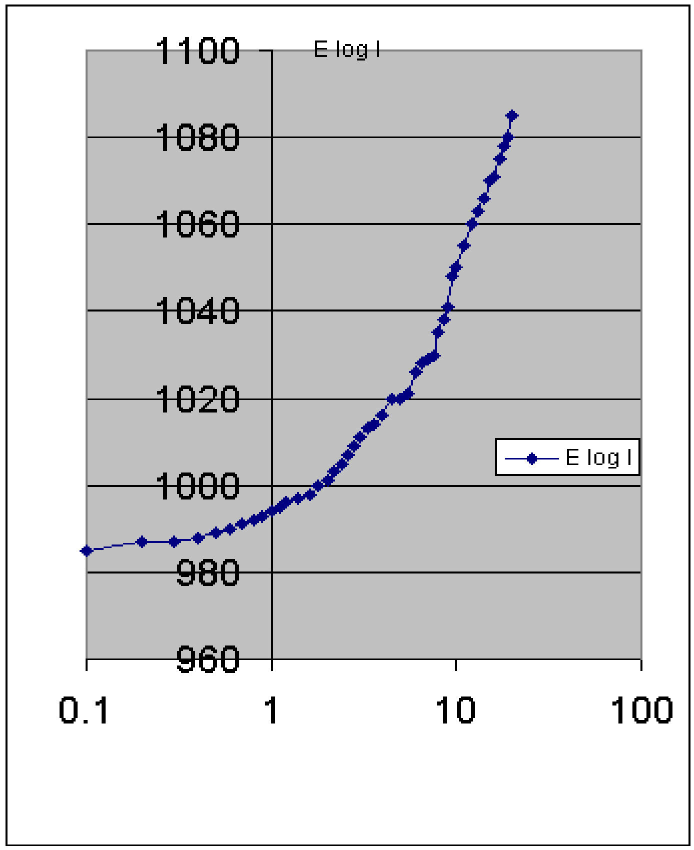
1. Apply 100 mA to the structure.
2. After the current has been applied for four minutes, interrupt the power and measure an "instant off" potential to the remote reference.
3. Repeat the four-minute on/instant-off cycle by increasing the current output in the steps shown in the example below. These are the maximum number of measurements that may be required. After gaining experience on typical wells in a field, the number of measurements may be reduced.

Interpreting the Results

1. Construct a polarization curve by plotting the data collected on the semi logarithmic paper.
2. The polarization curve should become linear after the test current reaches a certain point. Draw a line tangent to this part of the graph (Tafel portion) extending toward the left side of the graph.
3. Several interpretations are commonly used. The most common interpretation is that where the tangent to the Tafel slope breaks away from the data, the current at the break-away point is considered the required current to achieve complete protection.

Semi-logarithmic graph form

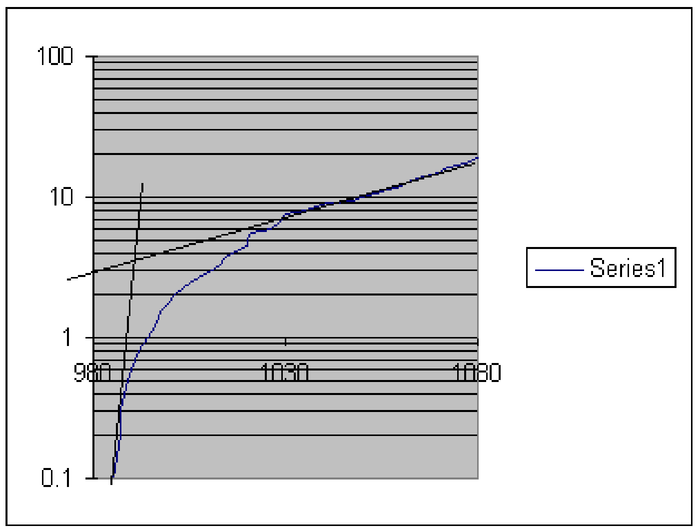
0	984		6.5	1028
0.1	985		7	1029
0.2	987		7.5	1030
0.3	987		8	1035
0.4	988		8.5	1038
0.5	989		9	1041
0.6	990		9.5	1048
0.7	991		10	1050
0.8	992		11	1055
0.9	993		12	1060
1	994		13	1063
1.1	995		14	1066
1.2	996		15	1070
1.4	997		16	1071
1.6	998		17	1075
1.8	1000		18	1078
2	1001		19	1080
2.2	1003		20	1085
2.4	1005			
2.6	1007			
2.8	1009			
3	1011			
3.3	1013			
3.6	1014			
4	1016			
4.5	1020			
5	1020			
5.5	1021			
6	1026			



✓ - denotes update

Return to TOC

985	0.1		1020	5
987	0.2		1021	5.5
987	0.3		1026	6
988	0.4		1028	6.5
989	0.5		1029	7
990	0.6		1030	7.5
991	0.7		1035	8
992	0.8		1038	8.5
993	0.9		1041	9
994	1		1048	9.5
995	1.1		1050	10
996	1.2		1055	11
997	1.4		1060	12
998	1.6		1063	13
1000	1.8		1066	14
1001	2		1070	15
1003	2.2		1071	16
1005	2.4		1075	17
1007	2.6		1078	18
1009	2.8		1080	19
1011	3		1085	20
1013	3.3			
1014	3.6			
1016	4			
1020	4.5			



CORR-014: Storage Well Cathodic Protection Profile

Purpose

This procedure is intended to eliminate factors that can cause erroneous readings while preparing and logging a well. The logging contractor shall follow this procedure and give the Company a checklist to document that all steps were completed. It is the responsibility of the Company to supply the contractor all pertinent data concerning the well, and to prepare the well for logging, including making sure the well is properly insulated.

Criteria

Pre-Run Instrument Check

1. Voltmeter warm-up - 30 minute minimum.
2. Zero meter using heavy jumper cables connected between contacts on the tool.
3. While tool is shorted, read and record circuit resistance.
4. Meter accuracy; connect calibrated voltage source between contacts, read, and record potential.
5. Record potential difference of calibration voltage source, per latest certification of source.
6. Verify that the well is properly insulated and there is only one path for electrical current.

Re-Run Tool Check

1. Test all insulating devices.
2. Check to ensure that contacts are adjusted for the proper size.
3. Inspect condition of contact points.
4. Bottom contact points connected to positive terminal on meter.

During the run:

- Readings must be stable and voltage, current, and resistance readings must be recorded.
- Should a reading need to be repeated; the reading shall be taken before proceeding to the next interval.

Post-Run Check

1. Repeat steps 2, 3, and 4 of the Pre-Run Instrument Check.
2. Furnish Company with a completed checklist.

Information

General Information

1. Description of the well being logged, including depth, location, pressure, etc.
2. The name of the reference well.
3. Potential difference between the well being logged and the reference well.
4. Casing size, weight, grade, and bottom hole temperature.
5. Remarks and changes occurring during logging, and any information deemed important by the Company representative.

Graph Information

1. Plot of potential difference vs. depth.
2. Plot of current density/sq. ft. vs. depth.
3. Plot of projected annual metal loss vs. depth.

Table Information

1. Potential difference reads.
2. Current, and current density/sq. ft.
3. Direction of current flow (up of down hole).
4. Status (Anodic or Cathodic).
5. Circuit resistance (3 factor in ohms cm^2).
6. Time the reading was taken.

The Company reserves the right to repeat any given reading while the tool is in the well. Also, to have any check repeated and questionable contact points replaced.

The intent of this procedure is to enable the contractor, as well as the Company, to perform logging in a more efficient manner.

CORR-015: Compressor Station Maximum Allowable Operating Temperature

Scope

All company facilities will be operated in a manner that allows the maximum allowable gas temperature necessary to protect the coating systems from degradation not to be exceeded (see coating manual for maximum allowable temperatures).

Provisions must be made to take and record out gas temperatures at each compressor station. At stations with multiple lines and some gas cooling, the gas temperature must be taken on each line as it leaves the station yard.

The gas temperature at production and/or supply interconnects will normally be documented either electronically or manually

No compressor station shall be operated routinely without gas temperature higher than its specified maximum allowable operating temperature. When operating conditions cause the gas temperature to approach within approximately 3°F of the maximum allowable temperature, Gas Control should be notified to allow system flow changes to be made, if possible.

Buried piping located between gas compressor engines and gas cooling towers will be evaluated on a site specific basis to determine proper operating temperatures.

If operating conditions result in the maximum allowable gas temperature being exceeded, Gas Control should be immediately notified so that action can be taken to reduce the out gas temperature.

Pipeline Integrity shall be notified anytime the maximum allowable operating temperature of any facility is exceeded.

CORR-016: Underground Flanges (Non-Isolating)

Scope

At times, it may be necessary to bury a non-isolating flange for operational design purposes. Over time, a high resistance connection may develop, and self-interference can damage the flange and associated piping. To provide the best available technique to ensure corrosion control of the various parts, the following procedure should be used. This procedure applies to pipelines operating below 130˚F. For pipelines that operate above this temperature, contact Pipeline Integrity for procedures.

Procedure

1. Before installing the flanges to the pipeline, blast and coat the flanges with coal tar epoxy per Coating Specification UC-171 using the following guidelines:
   a. Protect flange sealing surface (raised face or ring joint) from the blast and coating material.
   b. Protect the flange welding area approximately 2 inches back from the edge from blast and coating material.
   c. Bolt holes are to be blasted and coated.
2. Install flanges on pipeline.
3. Bolt up flanges using coated nuts and bolts per EnLink Procedure Specification.
4. Abrasive blast and coat following Coating Specification UC-171 noting the following guidelines:
   a. Bare surfaces blasted to a NACE #2, “Near White” finish.
   b. Coated surfaces, including the Teflon coated nut and bolts, to be lightly blasted to roughen surface.
   c. Install two AWG #4 HMWPE or larger test lead on each side of the flange connection on the pipe body.
   d. Do not blast Trenton Guard-Wrap.
   e. Coat **all** surfaces with coal tar epoxy.
5. Pour Trenton Intercoat into gap between flanges per Trenton Corporation specifications.

6. Use Trenton Guard-Wrap as a ‘granny rag’ to work hot wax into flange gap.
   a. Guard-Wrap should be of sufficient width to cover both flange ends to the edge, but not beyond.
   b. Saturate Guard-Wrap with Intercoat for two complete wraps of the outer flange ends.
7. Bring test leads to a test station.
8. Bond together two test leads (one from each side of the flange) with a minimal resistance connection (bus bar or direct connection).

CORR-017: IR DROP CONSIDERATION

There are four common methods of ascertaining the amount and the effect of IR drop on pipe to soil readings, which are current interruption, location of the reference cell at the pipe/soil interface, IR drop coupon and the remote step-wise reading with calculations:

1) Interrupting rectifiers:

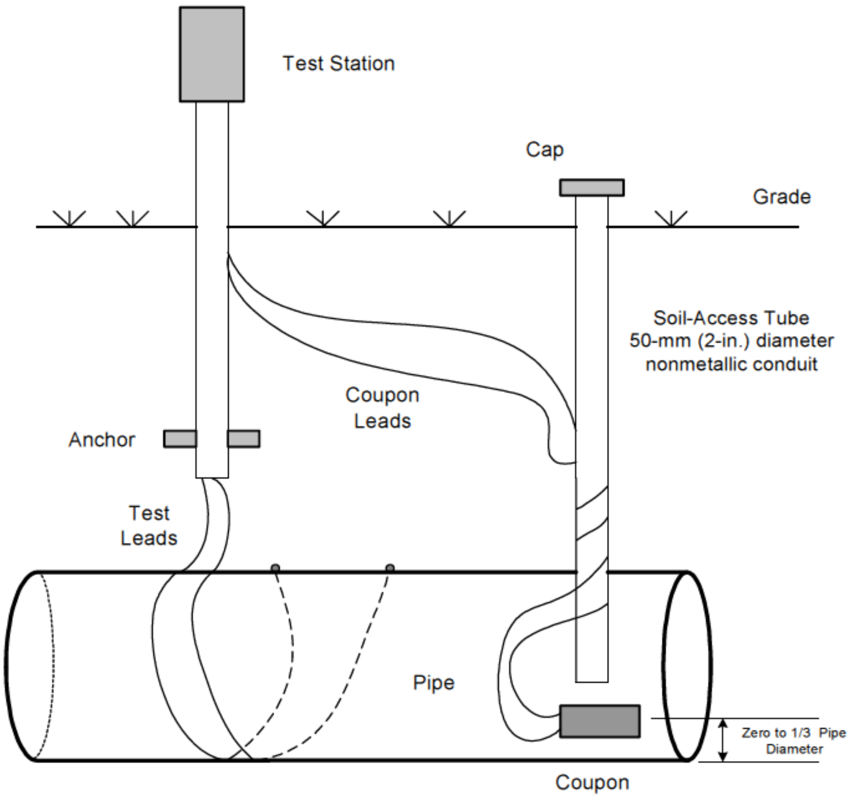
This method requires all current sources to be interrupted simultaneously and synchronization of all influencing rectifiers, bonds and galvanic anodes, and must be timed to have identical "on-off" cycles for the best and most accurate results. Remotely located galvanic anodes to the testing area probably have little or no effect on this method due to the low current output, low driving voltage and distant location.

2) Bellhole inspection

This method of correcting for IR drop is to place the reference electrode as close to the pipe/soil interface as possible without touching the pipe or pipe coating. Where to place the electrode in this type of correction for IR drop is not explained and normally the readings will vary greatly from top to side to bottom. The readings could be logged in the bellhole report inspection form.

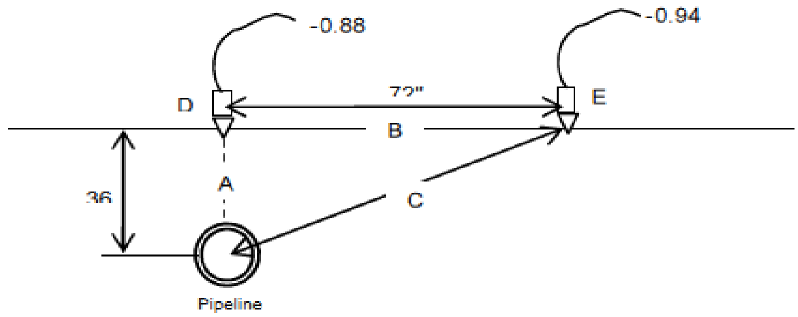
3) Coupons

This method suggests that a 2-inch diameter hole be augured to the desired depth and a plastic pipe be installed in the soil for future access. This method only corrects for the IR-drop in the soil from the top of the ground down to the location of the reference electrode and the pipe resistance is not considered. Refer the below drawing and NACE standard RP 104 – Appendix D – IR Drop coupon calculation for more information.



4) Step-wise reading

The step-wise reading requires the least field testing time and with practice, should be the easiest to perform on an extensive format or on a reoccurring basis. The easiest parameters are to use the 3' x 4' x 5' triangle as follows. With a pipe depth of 3' and a side reading at 4' remote, the hypotenuse is then equal to 5'. For deeper pipe at road crossings with a depth of 6', then a 6', 8', 10' relationship could be used. Any other pipe depth/side distance can be used, but it make the solution of the hypotenuse a little more difficult. The following Example 2 is solved both in feet and inches with -1.00 Volt over the pipe and a side reading of -1.15 Volt 4 feet away.



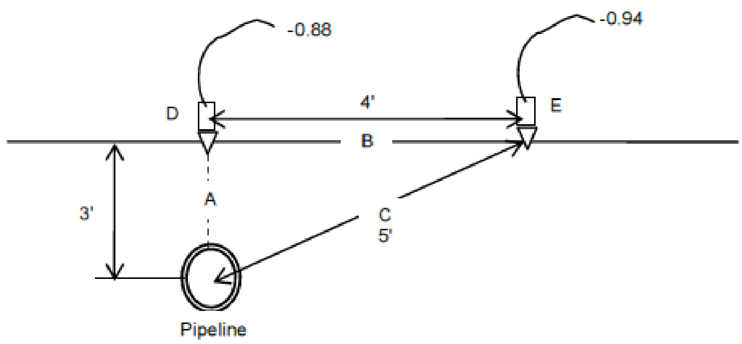
Example 2

FORMULA

TR = D - [((E - D)/(C-A)) x A]
TR = TRUE READING
A = 36"
B = 72"
C = 80.5"
D = -0.88
E = -0.94

$C = (A^2 + B^2)^{0.5}$ $C=(36^2 + 72^2)^{0.5}$
$C = (1296 + 5184)^{0.5}$
$C = (6480)^{0.5}$

C = 80.5
TR = .88 - [((0.06)/(80.5 - 36)) x 36]
TR = .88 - (.001348 x 36)
TR = .88 - .0485
TR = .832 VOLTS



FORMULA

TR = D - [(E - D)/(C-A) x A]
TR = TRUE READING
A = 3' (36")
B = 4' (48")
C = 5' (60")
D = 1.00
E = -1.15

$C = (A^2 + B^2)^{0.5}$
$C = (3^2 + 4^2)^{0.5}$
$C = (9 + 16)^{0.5}$
$C = (25)^{0.5}$
$C = 5$

TRUE READING
SOLVED IN INCHES

D = 1.00 - [(1.15-1.00) / (60 - 36) x 36]
D = 1.00 - [(.15 / 24) x 36]
D = 1.00 - [0.0065 x 36]
D = 1.00 - [.225]
D = 0.775

TRUE READING
SOLVED IN FEET

D = 1.00 - [(1.15-1.00) / (5 - 3) x 3]
D = 1.00 - [(.15 / 2) x 3]
D = 1.00 - [.075 x 3]
D = 1.00 - [.225]
D = 0.775

SECTION 2 - Annual Surveys

Introduction

The Pipeline Safety Acts resulted in the establishment of Federal minimum standards for corrosion control. Cathodic protection (CP) must be applied to pipelines and be tested each calendar year (at intervals not to exceed 15 months) to determine if CP is adequate per Title 49-CFR-Part 192 & 195 External Corrosion Control: Monitoring.

These procedures define Company requirements to meet these and other regulations, as well as best practice and sound engineering judgment.

Complete documentation and proper record keeping is an integral part of Company operating procedures and compliance with regulations.

Procedure 1 - "On" Annual Surveys

Procedure 2 - "On" & "Off" Annual Surveys

Procedure 3 – Annual Drop Cell Surveys for offshore platforms

Procedure 4 – Annual Riser Pipeline Survey for offshore pipelines

Procedure 5 – Communication Tower Surveys

Procedure 6 - 100 mV surveys

Pre-Survey Requirements for "On" or "Off" Criterion

Preventative Maintenance Data (PM)

- Review PM data, if applicable, for pipeline to be surveyed from pipeline integrity personnel from last survey cycle

CIS

- Review any CIS data collected on pipeline to be surveyed since last survey

Previous CP Survey

- Have printout or electronic copy of previous year annual survey of the pipeline to be surveyed

Annual pipe-to-soil potential surveys will be conducted over all pipelines, compressor stations, meter stations, platforms and other applicable pipelines to be compliant.

Annual surveys should be completed within **thirty (30) days** of their start date in order to survey under as consistent as possible weather and soil conditions.

Any deficiencies requiring remedial action found in conducting the survey must be reported in a timely manner.

If applicable, to completely evaluate CP effectiveness, onshore Annual Surveys may be *rotated*, or surveyed during different times of the year. This will enable CP data to be evaluated as to seasonal variations.

If the applicable survey grouping is started later than 12 months from the previous completion date or the survey grouping is to be "rotated", O&M procedures **must** be considered to ensure the Annual Survey does not exceed the 15 month time frame between surveys for **each individual reading**.

Survey Grouping

A single pipe-to-soil reading at a test point only validates a single point on the pipeline system. Test points are normally put into a logical grouping to facilitate CP evaluations, allow trend analysis over a large area, and aid in the filing and documentation of the survey as required by Federal or applicable State Regulations.

Annual Pipeline Survey

This section describes how to conduct the annual pipeline survey. The steps consist of conducting the survey, analyzing the survey, documenting the survey, and maintaining the PCS annual survey database.

Conducting the Survey

The following topics explain how to conduct the survey:

- Current sources
- Pipeline contact
- Test point
- Reference electrode check
- Survey cycle
- Survey meters
- Minimum pipeline survey data requirements

Current Sources

Before conducting a survey, CP current sources that have an influence on the surveyed pipe section must be checked for proper operation.

Read and record voltage and current output for all impressed current sources. Read and record current output of bond stations, and sacrificial anodes where practical.

Pipeline Contact

Pipeline contacts are locations where contact with the pipeline can be made such as valves, spans, drips, test leads, risers, main line taps, foreign line crossings, roads, highways, and railroad crossings.

Negative lead wires of a rectifier, galvanic anode ground bed lead wires, or bond station lead wires cannot be used as pipeline contacts to obtain pipe-to-soil (P/S) potential readings. Metallic IR drops occur in these test leads due to current flowing in the wire and will introduce an error into the P/S potential reading. If a dedicated test lead has been installed at these locations, then that lead can be used as a pipeline contact.

Sufficient test points must be present to determine the adequacy of cathodic protection. The Annual Pipeline Survey may not require the use of all existing test points. The location and quantity of test points shall be determined by operations corrosion personnel.

All existing annual survey test points and data must be maintained for the life of the system unless the area corrosion technician can provide proof the station reading is no longer needed to assure adequate locations are being monitored. No test station or data collection point should be permanently removed from the database. Deactivated locations must have comments of why the location is no longer read during future annual surveys.

Test Point

This is the point over the centerline of the pipeline where the reference electrode (half-cell) must be placed to take the potential reading. A pipeline locator may be required to locate the center of the pipeline. The reference electrode must be placed over the centerline of the buried piping.

Since the test point may vary from the “pipeline contact” location, the test point location designated by milepost/station number/GPS coordinates/ Landmark is the recorded data location.

P/S potentials taken over blacktop, concrete, frozen ground, or other extremely high resistance surfaces are considered invalid due to the high IR drop that may be present and the possibility the reading indicated may be remote to the relative position of the half-cell. Half-cell contact must be made with the representative environment that surrounds the pipeline.

It may be necessary to wet the point of contact (with potable water) in areas of dry or high resistivity soils to lower the contact resistance of the half-cell to an acceptable level. In areas paved with asphalt or frozen, the high resistance cover should be removed. Where possible, a permanent access point should be installed.

Because there is an abundance of gravel at stations, it may be necessary to use a shovel and dig down to soil at some test points in order to get an accurate measurement.

Reference Electrode Check

Before conducting the survey, check the reference electrode per procedure *CORR - 005: Maintaining Reference* Electrodes.

Survey Cycle

When an interrupted survey is performed, corresponding ‘on/off’ potentials must be logged at each half-cell position to allow for IR determinations.

The normal survey interruption cycle of current sources is a 3:1 ratio for a maximum duty cycle of 20 seconds. Other survey cycles, more than the maximum must be approved by operations management.

Survey Meters

All annual surveys will be recorded electronically. The calibration of the meter must be checked before the beginning of any annual survey with a power source of a known voltage. See procedure CORR-001 in Section 1 of this manual.

Minimum Pipeline Survey Data Requirements

DC voltage and amperage outputs at all impressed current sources affecting pipeline being surveyed.

A structure-to-environment potential is defined by the computerized survey. These potentials may consist of an “On” or “Off” annual survey dependent on the procedure being utilized.

Galvanic anode ground bed current output and polarity

P/S potentials at each company and metallic foreign structure crossings.

Pipe-to-soil and casing-to-soil potentials at all casings.

Pipe-to-soil and box-to-soil potentials at all metallic valve boxes installed around the pipeline

Casing/Valve Box isolation tests if required, per company procedure CORR-003:

- If the casing/valve box-to-pipe potential is => 100 mV CSE, no further testing is needed.
- If the casing/valve box-to-pipe potential is < 100 mV CSE, the “Deliberate Short” test is to be performed. If the change in p/s during the short test is => 30 mV CSE, the casing/valve box is considered clear, and no further testing is needed.
- If the change in p/s during the short test is < 30 mV CSE, the Universal Casing Meter and/or Panhandle Eastern test(s) is to be performed.

P/S potentials, current flow, and polarity at all bonds (critical, non-critical, continuity).

A check of insulating properties of all isolation devices per company procedure

For routine checking of isolation devices use an Insulator Checker instrument or procedure. The status of the insulator should be indicated in the Insulator Status field.

- For reporting the condition of casings, valve boxes, J-tubes, etc. use procedure CORR - 003: Testing for Shorted Casings and Valve Boxes. The status of the casing, box or other structure should be indicated in the Casing Status field and the results of the testing should be indicated in the Casing/Pipe, Pipe/Soil Shift and Universal Casing Test fields, where applicable.

AC monitoring for inductive/conductive AC from High Voltage Power Lines: Exercise caution in all areas of possible inductive/conductive AC potentials while performing the following requirements. A periodic AC potential reading in each valve section to validate the existence/non-existence of inductive/ conductive AC potentials may be required. A minimum of one AC P/S per valve section, at the location of highest risk for AC potentials, should normally be taken.

AC potential readings required in areas with known AC potentials.

- AC P/S potentials at all test points.
- AC current recorded at all galvanic anode ground beds, Kirk cells, polarization cells, or other equipment installed for AC mitigation or step-touch protection.
- AC current flow at all bonds.

If a required minimum (RM) or allowable maximum (AM) monitoring scheme is established and not met during the annual survey the low readings must be reported as a deficiency. If multiple RM/AM violations occur in the same general area of the pipeline, the influencing current sources should be inspected for proper current outputs.

Test points for new facilities are to be added to the survey.

Normally during the annual surveys, an atmospheric survey will be performed on all exposed pipe and all aboveground facilities, within the specified times frames.

Analyzing the Survey

All P/S potentials will be evaluated per procedure to the criteria limits to the pipeline being surveyed.

If applicable, P/S potential readings will be evaluated with regard to required minimums (RM) and/or allowable maximums (AM) set for test point.

All survey test points not read on the survey will be listed as a deficiency.

A trend analysis will be performed on all data for a minimum of three (3) years to evaluate any change in the level of protection. Any substantial change in the trend will be evaluated as to cause and its projected effect.

All known galvanic anode outputs will be evaluated.

All bond currents (critical, non-critical, continuity) will be evaluated.

Any reading showing a substantial change will be investigated to determine its cause and evaluated to determine its projected effect.

All isolation devices will be evaluated for adequate insulating qualities.

Rectifier(s) and/or any other cathodic protection current sources will be evaluated for required output.

All P/S potentials at foreign crossings will be evaluated for interference conditions. Any substantial change at the crossing will be evaluated to determine cause and projected effect. If interference is suspected, the crossing should be listed as a deficiency and an interference test scheduled.

All casings, supports, and valve boxes will be evaluated for isolation. Testing of suspected shorts may be scheduled at a later time. Any required testing must be performed before the survey is submitted or listed as a deficiency.

AC potentials will be evaluated to determine magnitude and cause. AC potentials above 15 VAC are a potential safety concern, will be listed as deficiencies, and will have prompt remediation if necessary.

If AC potentials are found above 15 VAC on a bond, the bond should not be broken to read open-circuit voltages. The reading should be listed as a deficiency and read after appropriate mitigation measures have been taken.

All unexplained indications of current pick-up or discharge will be evaluated to determine cause.

Documenting the Survey

When the Annual Survey of a pipeline, chart, and/or segment has been completed, the data must be entered into the appropriate database and analyzed. Any deficiencies must be reported and documented per company O&M procedures.

Maintaining the Annual Survey Database

All pipeline facilities should be set up in the appropriate computerized Database. Facilities should be located in the proper hierarchy. Each reading location should be entered under the proper segment and tab. Reading locations include test stations, rectifiers, bonds and critical bonds, ground beds, towers, offshore pipelines, and piles.

All test points should use the actual milepost/station number/ landmark for half-cell placement. Mile post/station numbers can be corrected. During the Annual Survey when a feature such as a test point or rectifier is found to be incorrectly designated, change it to the correct value. Remember, mileposts are calculated from station numbers, not the other way around! Anytime a milepost or station number is changed, a reason must be entered in to the *Description* field of the database for the test point.

Quite often the casing vent is not directly above the end of the casing. The vent may be "dog-legged" or extended - either back over the casing, away from the end of the casing, or to the side of the casing. Every casing should have documentation as to the exact location of the vent. Add this information to the *Description* field in *PCS* and include in the notes for the close-interval survey.

The casing readings are to be taken over the pipeline one to three feet from the end of the casing. This may not be at the vent pipe.

The required readings for each reading location should be made active.

The appropriate criterion must be selected prior to the annual survey whether it is Procedure 1 the "On" potential or Procedure 2 the "Off" potential.

The appropriate limits should be established for each reading. These are listed in Exhibit 1 at the end of this section.

Corrections, deletions, or additions can be made in the *Description* section. The *Description* section is intended to give information to the person making the survey, not to the person(s) reading the resulting printout. The standard corrosion abbreviations found in Exhibit 2 should be used in this section.

For many test points, special instructions are necessary for the person conducting the survey to know how to find the test points. This is true for test points on Company pipelines but is especially for test points on foreign lines. Include these special instructions in the appropriate database field. The *Description* field is currently displayed on all reports.

The *Comment* field is useful to denote events or conditions for that year's Annual Survey. This section should not supplement the Route File. Comments should be associated with a particular reading or year's survey. General comments should be put in the *Description* field.

Atmospheric locations, meter stations, and compressor stations must be entered and maintained using PCS.

Data from retired or abandoned facilities MUST NOT be deleted. Approved methods for making data inactive or archiving data must be used. There are numerous circumstances that may require deleting an individual data set from a database. This might be the removal of a sales station and its associated piping, destruction of a test lead when land is converted from pasture to cultivation or housing, removal of a casing or removal of a foreign line. The data containing the information is not to be deleted but must be converted to an inactive test point. This will maintain the test point's history and assist in documentation. A large group of points can be moved to another section of the hierarchy and made inactive. The data for a reference point or group of points cannot be deleted from the database or deactivated from the database without approval. Test points can then be deactivated with approval from area corrosion technician.

✓The PCS database server will be used for certain EnLink corrosion control data. Individual corrosion technicians are responsible to upload any corrosion data as soon as practical after surveys are completed. Other data and reports are saved on a shared drive on the EnLink network.

Required Minimum (RM) Control Points

The following is a procedure for monitoring irregularities (dips, changes in profile, peaks, etc.) found during annual survey. The procedure correlates the minimum (or maximum) pipe-to-soil potential at a remote site on an annual survey reading at a test station. This provides a “flag” that can identify possible low potential areas remote from reading sites when conducting the annual survey. If a limit is broken, the remote site can then be surveyed to ensure compliance with criteria.

Per Company-defined monitoring procedures, remote irregularities revealed by the annual survey can be monitored remotely from an established test point by assigning a RM to that test point. These will be listed on the Tabulation of Irregularities and attached to the applicable annual survey.

Irregularities should be listed in the *Description* field of the Annual Survey. The calculated RM should be set as the lower limit of the P/S “On” or “Off” field in the Data Point Definition. The lower limit of the RM cannot be set lower than the established criteria.

The controlling test point may have an allowable maximum (AM) assigned. The irregularity should be listed in the *Description* field of the Annual Survey and noted as AM. The calculated AM should be set as the upper limit of the P/S “On” or “Off” field in the Data Point Definition.

Should a situation arise when a test point has both a RM and an AM assigned, then list (in the *Description* field) both remote locations. To identify them it is suggested that, in order to fit both items into the field, the remote location associated with the RM carry the prefix RM. In like manner, the remote locations associated with the AM should be given the prefix AM. Naturally, the lower limit (RM) and upper limit (AM) should be entered for that test point.

Exhibit 1: Limits for Test Points

DESCRIPTION	UPPE	LOWER	REMARKS
On P/S	-2500	-850	Set to these values or to the required RM/AM value. ✓ON potentials over -2500 mV CSE will be justified by the field corrosion personnel. (ex: consideration should be given to de-energize nearby foreign current sources)
Polarized P/S Potential	-1260	-850	Set to these values or to the required RM/AM value
Casing-to-Soil (C/S)	-850	-500	✓Nearby current source may cause > -850 in upper limit
Casing-to-Pipe (C/P)	-2500	-30	
Casing Short Test (CT)	-2500	-30	
Casing test with meter	-100	-0.08	
Box-to-Soil (B/S)	-850	-500	
Box-to-Pipe (B/P)	-2500	-30	
Box short test (BT)	-2500	-30	
Box test with meter (in ohms)	100	0.08	
Rectifier DC volts			Upper = Unit Maximum Rated Output
Rectifier DC amps			Upper = Unit Maximum Rated Output,
Foreign Structure P/S	2500	850	
Foreign Crossing Bond I			
Bond I (Company to Company)			
Galvanic G/B I			
AC *P/S* Volts	15	0	
AC VOC	15		
AC Amps - Bond Current	10		
Communications Tower Ground	5		
Communications Tower	2500	850	
Communications Tower	2500	850	
Meter Tube/Soil	2500	100	

Note: Limits cannot be changed without management approval

✓ - denotes update

Return to TOC

Exhibit 2: Typical Corrosion Abbreviations

PREFIXES	DEFINITION
PS or P/S	Pipe-to-Soil
RM	Required Minimum
AM	Allowable Maximum
CS or C/S	Casing-to-Soil
BS or B/S	Box-to-Soil
C/P	Casing-to-Pipe
B/P	Box-to-Pipe
SL	Same Point Local
UL	Up Station Local
DL	Down Station Local
US-XXX	Up Station-XXX Ft.
DS-XXX	Down Station-XXX Ft.
SUFFIXES (Used with Rectifiers or Galvanic Ground Beds)	
V	Volts
A	Amperes
MA	Milliamperes
SUFFIXES (Used with Bond Currents)	
MA	Milliamperes
AMP	Amperes
POS	Positive Polarity
NEG	Negative Polarity
VOC	Open Circuit Voltage

Annual Compressor/Meter Station Survey

The annual Compressor Station and Meter Station surveys may be conducted using one of two survey procedures at the discretion of Operations Corrosion Personnel. Procedure 1 is for the "On" survey and procedure 2 is for the "Off" potential survey.

Procedure 1 ("On" Survey)

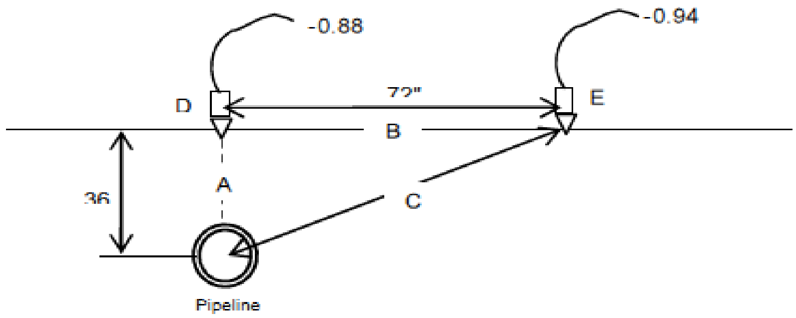
Procedure to collect an -850 mV "On" with IR drop considered, EnLink will do the following:

- Utilize pre survey procedure in Section 2 of the EnLink Corrosion Manual prior to performing an "On" survey

Calculating IR Drop

IR Drop Reading (Step-wise Reading Method):

- The step-wise reading requires the least field testing time and with practice, should be the easiest to perform on an extensive format or on a reoccurring basis. The easiest parameters are to use the 3' x 4' x 5' triangle as follows. With a pipe depth of 3' and a side reading at 4' remote, the hypotenuse is then equal to 5'. For deeper pipe at road crossings with a depth of 6', then a 6', 8', 10' relationship could be used. Any other pipe depth/side distance can be used, but it make the solution of the hypotenuse a little more difficult. The following Example 2 is solved both in feet and inches with -1.00 Volt over the pipe and a side reading of -1.15 Volt 4 feet away.
- If the pipeline is 20 feet deep of cover or more these calculations should not be used.



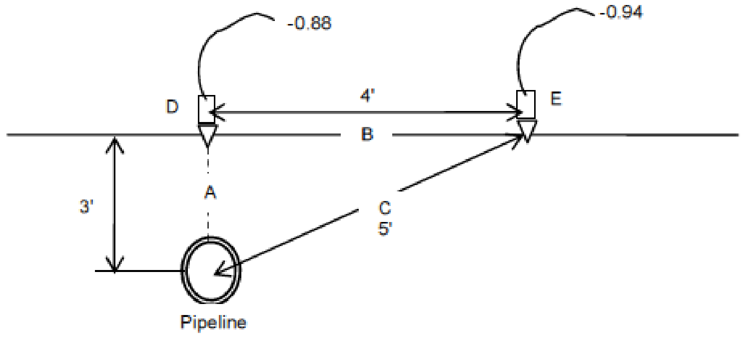
Example 2

FORMULA

TR = D - [((E - D)/(C-A)) x A]
TR = TRUE READING
A = 36"
B = 72"
C = 80.5"
D = -0.88
E = -0.94

$C = (A^2 + B^2)^{0.5}$ $C=(36^2 + 72^2)^{0.5}$
$C = (1296 + 5184)^{0.5}$
$C = (6480)^{0.5}$

C = 80.5
TR = .88 - [((0.06)/(80.5 - 36)) x 36]
TR = .88 - (.001348 x 36)
TR = .88 - .0485
TR = .832 VOLTS



FORMULA

TR = D - [(E - D)/(C-A) x A]
TR = TRUE READING
A = 3' (36")
B = 4' (48")
C = 5' (60")
D = 1.00
E = -1.15

$C = (A^2 + B^2)^{0.5}$
$C = (3^2 + 4^2)^{0.5}$
$C = (9 + 16)^{0.5}$
$C = (25)^{0.5}$
C = 5

TRUE READING SOLVED IN INCHES	TRUE READING SOLVED IN FEET
D = 1.00 - [(1.15-1.00) / (60 - 36) x 36]	D = 1.00 - [(1.15-1.00) / (5 - 3) x 3]
D = 1.00 - [(.15 / 24) x 36]	D = 1.00 - [(.15 / 2) x 3]
D = 1.00 - [0.0065 x 36]	D = 1.00 - [.075 x 3]
D = 1.00 - [.225]	D = 1.00 - [.225]
D = 0.775	D = 0.775

At least once every 3 years the calculations above must be conducted on every pipe-to-soil potential reading with the exception of metal risers, to provide proof that the “on” criterion is satisfied. The years that a calculation is not conducted; a required minimum (RM) must be established prior to the annual survey based on previous survey data. A minimum of 10% of the pipe-to-soil potentials collected annually must be calculated to prove IR drop consideration has been achieved. If a required minimum is not met at any pipe-to-soil reading a calculation must be done before proceeding with the annual survey.

New Pipeline Survey - New pipeline to be surveyed, with no previous history or existing CP records, calculations are required at all readings except where a metallic riser is the collection point.

Metallic Connects at valves and risers and interconnects, etc.

- Collect pipe-to-soil potential readings at the 3, 6, 9 and 12 position next to the riser at the soil interface. Record the lowest pipe-to-soil potential reading of the 4 positions taken and input that lowest pipe-to-soil reading into the annual survey

Soil Tubes or external corrosion coupon stations may be used to identify IR corrected readings. However, soil tubes or external coupons are not a specific requirement to meet the "On" criteria.

Document all readings into the appropriate PCS location. Establish new RM or AM, if necessary, for the next annual survey cycle.

Create a summary of the annual survey to document the discrepancies found that need to be remediated. This will include small adjustment of impressed current rectification. This summary will be kept at the location level. All remedial action(s) must be documented.

If a remediation is required to meet the minimum requirement, that remediation must be completed before the next annual survey.

Procedure #2 ("Off" Survey)

Procedure to collect an -850 mV "Off", EnLink will do the following:

Utilize pre-survey procedure in this section prior to performing an "Off" survey

Interrupt all impressed current sources that could affect the pipeline or section of pipeline to be surveyed. This does include rectifiers and critical bonds. Consideration must be given to sacrificial anodes that may affect the true "Off" potential during this survey.

✓Interruption cycle should follow the pre-procedures in this Section but should stay with the 3 to 1 cycle. A full cycle should not exceed a 20 second interruption. If a slower cycle is desired by corrosion personnel; operations management must approve the request if more than 20 second full cycle is desired. Pipeline integrity personnel must be involved in this final approval process. This approval must be completed prior to the survey being conducted.

No approval process is necessary if the cycles are 20 seconds or less:

- Survey must be a synchronous survey of all known currents interrupted.
- Record all Off and On potentials at all locations on the annual survey data sheet:
  - Must be sensitive to de-polarization during the "Off" survey collection
  - Must be sensitive to assure the interruption cycle remains synchronized

Document all readings into the appropriate PCS location. Establish new RM or AM, if necessary, for all current sources that were interrupted.

Create a summary of the interrupted annual survey to document the discrepancies found that need to be remediated. This will include small adjustment of the impressed current rectification. All remedial action(s) must be documented. This summary will be kept at the location level.

P/S Potential Limits - High tensile strength steels (Grade X-60 and higher) may require an upper P/S potential in order to prevent hydrogen embrittlement and hydrogen blistering of coatings. An ON potential more negative than -2500 mV CSE should raise a flag as an area for further investigation. The **true polarized potential** at which hydrogen is generated may be **extremely difficult** to determine in the field. Therefore, ON potentials over -2500 mV CSE will be justified by the field corrosion control personnel. The company limit is a polarized potential of -1260 mV CSE at the drain point. Polarized potentials exceeding -1260 mV CSE should be reported as deficiencies. If the close-interval survey disclosed remote area(s) where the potential is running close to this limit, then an Allowable Maximum (AM) can be setup to monitor such areas in the future.

Annual Offshore Platform Survey

Conducting the Survey

The Annual Platform Survey requires the following four inspections:

1. Structure P/S potential by drop cell method;
2. Riser inspection of coatings, clamps, isolation devices and pipeline P/S potential;
3. Splash zone inspection;
4. Structure and piping coating inspection;
5. Sub-sea inspections are required every five (5) years by BESE. This is beyond the scope of this section;
6. Structure Potential by Reference Cell Drop Method;
7. Reference Cell;
8. Copper/copper sulfate (CSE) or silver/silver chloride (SCE) reference cells may be used. SCE is preferred due to less potential for contamination. Both cell types should be weighted with non-metallic material and meet the following requirements:
    9. CSE - The half-cell must be filled with copper sulfate gel completely to the top (no air space) and equipped with a submersible adapter to prevent intrusion of seawater into the half-cell/lead cable connection. If the half-cell has transparent sides, they must be covered with tape to prevent sunlight from

entering the cell. For offshore work, this half-cell must be cleaned, recharged, and calibrated at least **twice** a day;

10. SCE - The half-cell must be permanently attached to the lead cable. This half-cell is **required** for drops over 200 feet.

Drop Cell Requirements

Measure the P/S potential on the jacket/structure supporting each offshore platform by means of a drop cell survey. The criterion for adequate CP on the jacket/structure is -850 mV CSE to a CSE reference cell. The equipment required to perform this survey include:

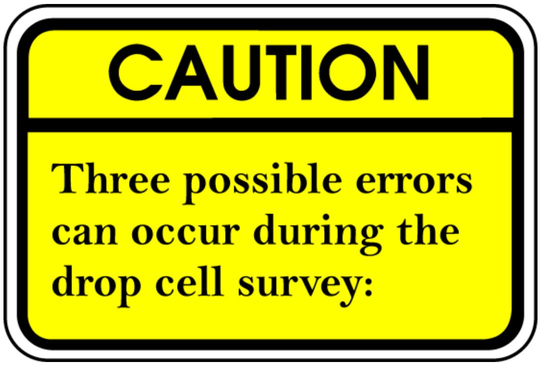
- One new or rebuilt CSE half-cell for calibration.
- Two weighted half-cells for use as drop cells equipped for offshore service.
- A minimum 200 feet of unspliced, insulated, **submerged service** CP cable on a reel. The cable must be marked at 3-foot intervals to allow accurate estimation of water depth. The copper wire and all connections must be electrically insulated to prevent contact with seawater during submersion. No splices or damage to the cable are allowed.
- A company-approved voltmeter with test leads
- A clamp and a file
- A non-metallic bucket
- A clipboard and pen

Drop Cell Survey

At least two drops, one each on opposite sides of the long axis of the platform, are required for a complete survey. More drops may be done if desired or if special circumstances require them. The drops must be inside the legs of the structure and as far apart as possible, provided safe access is available. All drops should be performed from the lowest accessible level of the platform. Walkways at the +12 foot level are preferred. Each drop should be performed as follows:

1. At the drop location, use the file to remove coating, dirt, and rust from an appropriate contact point on the structure and attach the clamp firmly to the clean metal.
2. Turn on the voltmeter and set it on the deck so that you can read it while standing. Attach the voltmeter leads to the half-cell cable and the clamp.

3. Fill the bucket with seawater and place both the calibration cell and first drop cell in the bucket.
4. Measure the potential difference between the two half-cells and record. If both half-cells are CSE and their potential differs by more than 5 mV CSE, the first drop cell may not be used. Try the second drop cell. If neither meets the 5 mV CSE requirement, clean and rebuild either one till the 5 mV CSE requirement is met. If the drop cell is SCE, leave it in the bucket for 5 minutes before placing the calibration cell in the bucket. Then record the potential difference as the "correction potential." If the drop cell is CSE, no correction potential is needed.
5. Drop the weighted half-cell into the water and record the potential just under the water. Reel out the cable quickly until the bottom is reached then carefully draw up the cell, stopping every 3 feet to record the potential reading and the depth on the clipboard. If a CSE half-cell is used, proceed as quickly as practical to minimize the chance of chloride contamination of the half-cell. There is no concern with time if a SCE half-cell is used. Be careful to avoid hitting the drop cell on any submerged members and do not allow the cable to rub against barnacles.
6. Continue until you recover the half-cell. When the half-cell is near the surface, repeat the first surface reading and record it. If the first and second surface potential readings are more than 10 mV CSE different, the half-cell has become contaminated during the drop and the survey data is invalid. Repeat the drop survey with the second drop cell using the same procedure as for the first.
7. Record the results and attach to the appropriate company form. Any single potential reading less than -850 mV CSE must be reported on the appropriate company form as a deficiency.



1. Side motion of the half-cell from seawater currents under the platform. The cell should drop vertically. Note in the report if the angle is not vertical. If the cell is carried beyond the boundary of the jacket by the current, the drop should be repositioned.
2. If the initial and final surface potential readings do not agree within 10 mV CSE when using a CSE, contamination from chloride in the seawater has most likely occurred to the copper sulfate. The half-cell should not be reused until it has been cleaned and recharged with new electrolyte.
3. If the potential reading makes a 25 mV CSE or more sudden shift during the survey, the cable most likely has been nicked, exposing the copper wire to seawater. The initial and final surface readings should also show a large difference in potential. Remove the half-cell from the cable and throw the cable away – **nicks, splices and repairs to cables are not allowed.**

Pipeline Riser Survey (Offshore)

Riser Description

A riser is any section of piping that carries product onto or off of a platform. The riser inspection must be done for each riser on the platform and consists of three components; riser isolation and potential, riser clamp inspection and riser coating inspection. In cases where a single pipeline enters the platform and then returns to the water, both the incoming and outgoing vertical portions from the outboard most flange down to the water must be considered a separate riser.

Isolation and Potential Survey Requirements

Check riser isolation by measuring the voltage difference between the riser and platform. If clean metal is unavailable, use a file to clean the paint on the riser and platform and connect one lead to each from the voltmeter and record the voltage difference. If the reading is > ± 5 mV CSE, the riser is isolated. If the reading is ≤ ± 5 mV CSE, the riser may be shorted to the platform and will need further testing during the riser drop cell survey described below. If the riser appears to be shorted, check isolation flange integrity and inspect to see if an obvious metallic path exists between the riser and the platform. This could be at pipe supports, riser guards or by contact with instrument/chemical tubing. If the location of the short is found, record the location on the appropriate company form. If the location of the short is not found, the short may be sub-sea. In that case a short investigation must be added to the scope of work for the next sub-sea inspection. All shorted risers must be identified on the appropriate company form and arrangements made to correct the short at the next opportunity.

Perform a drop cell survey similar to the one described for the platform, making sure to attach the voltmeter **positive lead to the riser** and not the platform. Further investigation is required for potentials below -900 mV CSE to a CSE reference cell with consideration for IR drop. The drop should be done outside the platform as near the riser as possible. If the riser is potentially shorted, shift the contact point for the positive lead between the riser and the platform at each depth. If the potential is identical for both contact points at each depth, the riser is shorted. If not, the riser is not shorted. Record the drop cell results on the appropriate company form. Any single CSE potential less than -900 mV CSE **must** be reported on appropriate company form as a deficiency.

Clamp Inspection

Visually inspect each riser clamp or pipe support for evidence of corrosion. Check for rust build up under clamps or rust stain on the pipe outside the clamp. Record the location and extent of all corrosion on the appropriate company form. Also, note if any clamps are located within 12 feet of the water line.

Coating Inspection

Using the guidelines in the atmospheric coating section of this manual, visually inspect the coating from the water line up to the isolation flange, paying special attention to the first 12 feet above the water. Record the location and size of any blisters, corrosion or paint failure on the appropriate company form.

Splash Zone Inspection

The splash zone of the platform includes all structural members from mean low tide (-6 feet) up to mean high tide (+12 feet). The *splash zone* is the area of highest corrosion rates and must be inspected yearly. Inspect all legs, vertical and horizontal cross members, walkways, handrails, stairways, boat bumpers, personnel access platforms, riser guards, and auxiliary piping for rust and coating condition. Report the location and extent of all rust, failed coating, dents, or gouges on the appropriate company forms. General statements such as "all support members are rusted" are acceptable if they are accurate. Also indicate location of splash zone corrosion on the platform drawing. Structural damage caused by impact from boats or barges is particularly important and should be recorded and repaired as soon as possible.

Coating Inspection

All high-pressure piping, vessels, and structural members should be inspected for atmospheric corrosion. The piping condition should be prioritized using the system given in the atmospheric coating section of this manual. The results of the survey should be recorded as required on the appropriate company form.

Submitting the Survey

The Annual Corrosion Survey of an offshore platform chart, when completed, must be entered into the appropriate corrosion database.

Communications Tower Survey

Conducting the Survey

The Communication Tower survey provides corrosion and grounding data for communications/radio towers.

Survey Requirements

Anchor-to-Soil Potentials: ON potentials are to be taken at all tower anchors. Off potentials will be taken where needed to correct for IR drop.

Tower-to-Base Soil Potentials: ON potentials are to be taken at the tower base between the ground cable and soil. Off potentials will be taken where needed to correct for IR drop.

Galvanic Anode Current: Read and record all galvanic anode currents and polarities. The location of all galvanic anodes is to be indicated on the sketch.

Impressed Anode Current: If a rectifier has been installed to protect the tower, read and record DC volts and amps and all anode current outputs.

Atmospheric Corrosion Inspection: Conduct an atmospheric corrosion survey of the anchors, guy wires and structure supports (nuts, bolts, plates, etc. whose failure could jeopardize the structure) per Atmospheric Corrosion Control section of this manual. Some towers equipped with strobe lighting will be exempt per FAA regulations from having to be painted. **Network Systems personnel will designate these towers.** This exemption does not apply to any area whose failure will jeopardize the integrity of the structure.

Building and Tower Grounding Inspection: The grounding system for the communication's building and tower can be inspected using the following procedures. Each structure will have one or more ground rods and will be electrically common with a ground wire running between them.

Without Jumper in Place: The building and tower are to be initially inspected separately and the readings recorded.

- Tower resistance to ground: Take tower-to-earth resistance at "remote earth" using the three-pin hook-up.
- Building resistance to ground: Take the building-to-earth resistance at "remote earth" using the three-pin hook-up.
- Tower-to-soil potential: Take the tower-to-soil potential at the base of the tower.
- Building ground-to-soil potential: Take the building ground-to-soil potential at the building ground system.

With Jumper in Place: Install a low resistance electrical connection (#6 or larger jumper wire) temporarily between the building and tower ground systems. The aforementioned readings are to be repeated and recorded. After the test is completed, remove the jumper wire.

Analyzing the Survey

All PS potentials are to be evaluated for being out of criteria (over or under). A trend analysis should be performed on all readings to evaluate the amount of change taking place in the values. All galvanic anode outputs will be evaluated as to required output. Rectifier outputs will be evaluated as to required outputs. All unexplained indications of current pickup or discharge will be evaluated as to cause.

The information from the building and tower grounding inspection will be evaluated. Since both grounding systems are supposed to be electrically common, no change in the values taken should be noted. If there is any change, the electronics/communications personnel responsible for the tower should be notified of a possible problem with the grounding system.

Submitting the Survey

The Annual Corrosion Survey of a Communication Tower chart, when completed, must be entered into the appropriate corrosion database.

100 mV CSE Cathodic Protection Polarization of Steel Structures

The 100 mV CSE polarization criterion may only be utilized when it is impractical to apply the negative 850 mV CSE due to interference to other structures or an effectively bare or poorly coated pipeline(s). This 100 mV CSE polarization criterion will measure the polarization decay. The procedure for verifying this criterion will be under the direction of a Corrosion Engineer or NACE Certified Cathodic Protection Specialist. The Operations Manager and/or Superintendent must provide prior writing approval to apply this criterion to a jurisdictional structure.

See Figure 3a for Polarization Decay Chart

See Figure 3b for Polarization Formation Chart

- Operations Manager and/or Superintendent must provide prior written approval to apply this criterion to a jurisdictional structure
- Validate that the Cathodic Protection (CP) is operating and in good working condition
- Sufficient time must be allowed for the structure to polarize

1. Determine the site to be evaluated. Selection of site will be based on:
   a. Structure unable to utilize the negative 850 mV CSE criterion
   b. If part of a structure is selected to use this criterion, operations must identify the beginning and ending points that meet the negative 850 mV CSE protection level. These two sites will be included in the 100 mV CSE study as well as everything in between during the evaluation process.
2. Perform an interrupted ‘On/Off’ Close Interval Survey (CIS)
   a. Use a minimum of 3 to 1 ratio of interruption
   b. Interrupt all known impressed CP affecting the site being evaluated
   c. Locate and mark all known sacrificial anodes and disconnect if necessary
   d. Locate and identify all bonds with foreign structures that may influence cathodic protection levels on the structure being evaluated

e. An oscilloscope may be required to validate if all DC current sources are being interrupted

3. Once the CIS is completed and the data is validated, turn off all current sources affecting the structure. Allow sufficient time for the structure to depolarize.
4. Chart or Monitor and record the depolarization decay at pre-established locations to quantify the depolarization curve. The supervising corrosion expert will establish actual frequency of measurements based on site specific conditions. However, sufficient time must be allowed to quantify the depolarization decay. The depolarization decay will be plotted to confirm the data. This plot must be retained for future evaluation purposes.
5. Once the polarization decay is validated to be sufficient, another CIS will be conducted with all the DC current sources remaining off. This will be the depolarized potential survey.
6. Once the data is recorded and validated for accuracy return the CP system to normal service.

The 100 mV CSE criteria shall be judged adequate, if all CP readings have met or exceed the established requirements of polarization.

If some areas of polarization do not meet the 100 mV CSE criterion, additional steps must be taken to elevate potentials to acceptable levels and then test revalidated.

Annual Monitoring once the 100 mV CSE polarization evaluation study is successful:

- A sufficient number of readings will be taken annually by qualified personnel in corrosion control methods to comply with this criterion.
- A spreadsheet or graph will be created to identify the minimum CP potential for each specific test point during annual corrosion CP survey.
- No less than two readings per mile shall be recorded unless unpractical based on the geography of the structure.
- All monitoring sites must meet or exceed the ‘On’ potential previously identified in the evaluation study.
- If one or more ‘On’ structure-to-soil potentials are below the established minimum, additional steps must be taken to elevate the CP potentials.
    - Coupons may be used to validate the “instant off” or polarized potentials
- If a potential or group of potentials cannot meet or exceed the required minimum, a remedial action must be drafted that will include the date and name of the corrosion

technician documenting the action or actions required to elevate potentials to acceptable levels. This remedial plan must also be signed by Operations Manager and/or Superintendent.

- In no case shall a structure-to-soil potential or a set of potentials be allowed to remain below the criterion for protection for more than one annual corrosion survey cycle. In the case in Louisiana this will be 90 days.
- If an external leak has occurred in or near this area of the structure utilizing the 100 mV CSE criterion, then the section must be reviewed to validate if the 100 mV CSE polarization evaluation study is still applicable. This re-evaluation must be documented.
- Every three years the data must be re-evaluated for application reasonableness and documented.
- Every 5 years this study must be repeated to validate accuracy and applicability of the 100 mV CSE criterion

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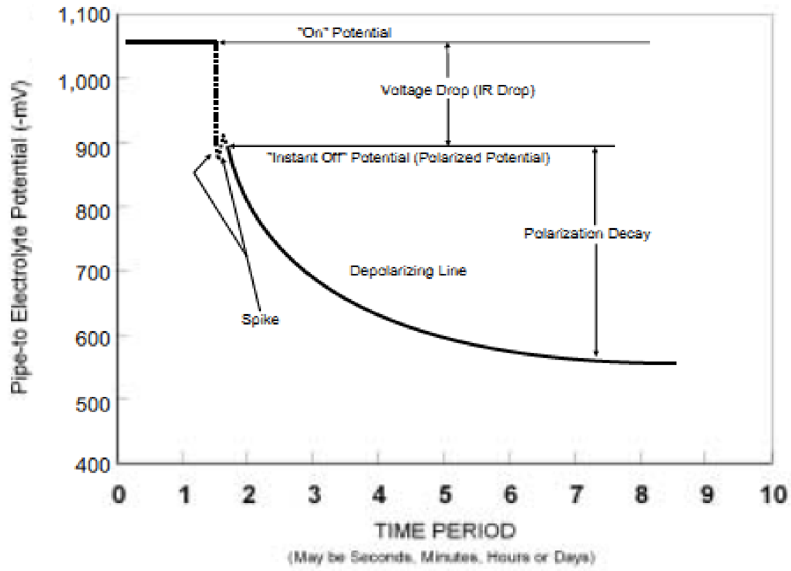

Figure 3a
Polarization Decay

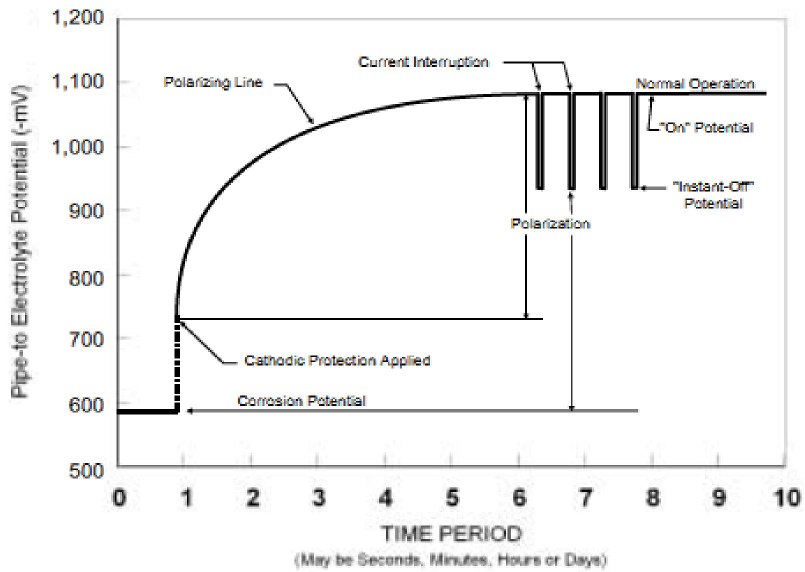

Figure 3b
Polarization Formation

FIGURE 3
Cathodic Polarization Curves

SECTION 3 - Close-Interval Surveys

Introduction

Close-interval surveys (CIS) provide enhanced information about the effectiveness of the CP installations, coating irregularities, and interference potentials. Types of close-interval surveys commonly performed using reference electrodes are:

- ON – All currents sources in operation.
- ON/OFF – All current sources interrupted.
- Telluric (2-wire) – Either On or On/Off CIS, with stationary reference cell to correct for telluric currents.
- Native – All current sources off a sufficient amount of time for effects to have disappeared. Also called a “native state” or “depolarized” survey. Native surveys are normally performed in conjunction with an On/Off survey.
- Side Drain – Either On or On/Off survey, measures net protective current to pipeline.

A close-interval survey is normally a P/S potential taken every 3 feet with the CP current sources interrupted.

Survey Requirements

Close-interval surveys using Company-approved instrumentation will be conducted on all pipelines, compressor stations, meter stations, platforms, and all other applicable facilities as determined by corrosion control personnel based on past history of survey program, system goals, and risk analysis, by business unit.

Pipeline close-interval surveys are to be conducted from a known point to a known point. To compare data with past surveys, it may be beneficial to conduct survey in full valve section increments.

New Class 3 & 4 areas are to be evaluated to determine if a close-interval survey should be conducted.

Close-interval surveys should be completed within thirty (30) days of their start date in order to survey under as consistent as possible weather and soil conditions.

Pipeline Surveys

Setting Up Notes

Before conducting a close-interval survey, survey notes should be set up to assist the surveyor in defining locations. Sources of information would be alignment sheets, previous pipeline close-interval surveys, and annual surveys. Enter the survey station number and a brief description of all features, which fall into one of the following categories:

- **Pipeline Contact** – Are locations where contact with the pipeline can be made such as valves, spans, drips, and test leads. Mileposts, engineering station numbers, meter codes, and line ID's for each contact should be provided as necessary.
- **Skip Features** – Pipeline locations where P/S potentials cannot be observed such as aerial spans or cased crossings. These are to be defined by the upstream and downstream station numbers in order to define the length of the skip.
- **Reference Points** – Permanent features along the pipeline noted, which will serve as checkpoints to keep the survey on track. The more reference points used, the better the correlation between potential reading locations and pipeline locations.
- **Crossings** – All metallic pipelines whether foreign or company which cross the surveyed pipeline.
- **Casings** – In addition, note the distance and direction of the casing vent(s) from the end(s) of the casing.
- **Bonds** – Connections with other structures through bonds must be noted whether they are considered critical, non-critical, or continuity. Current readings are required on all bonds tied to or having an influence on the line being surveyed.
- **Current Sources** – Sources of current which may have an influence on the line being surveyed. Examples are rectifiers and sacrificial anode ground beds attached to the surveyed line or to a foreign line, which crosses or parallels the surveyed line.

Conducting the Survey

The Pipeline close-interval survey is an ON/OFF (also called *instant off* or *interrupted*) survey taken at a maximum of 3-foot intervals.

Current Source Interruption

Before conducting an ON/OFF survey, all CP current sources, including foreign sources that influence the surveyed pipeline section must have interrupters installed.

Before installing an interrupter, the voltage and current output should be read on rectifiers and other impressed current sources, and current output should be read on bond stations and sacrificial anodes, where practical. A local P/S potential should be recorded at the nearest test point.

After the interrupter is installed, amps should be read to determine if the interrupter has electrically loaded the circuit down. Adjust rectifiers to compensate for the interrupter load. The local P/S should again be recorded to ensure proper operation has been maintained.

The local P/S will also be read before removing the interrupter. By comparing the initial and final p/s readings, the amount of depolarization that has occurred due to interrupting the current flows can be determined.

Pipeline Contact

Pipeline contacts are locations where contact with the pipeline can be made such as valves, spans, drips, test leads, risers, main line taps, foreign line crossings, roads, highways, and railroad crossings.

Negative lead wires of a rectifier, galvanic anode ground bed lead wires, or bond station lead wires cannot be used as pipeline contacts to obtain pipe-to-soil (P/S) potential readings. Metallic IR drops occur in these test leads due to current flowing in the wire and will introduce an error into the P/S potential reading.

Test Point

This is the point over the centerline of the pipeline where the reference electrode (half-cell) must be placed to take the potential reading. A pipeline locator is required to locate the center of the pipeline. The reference electrode must be placed over the centerline of the buried piping.

P/S potentials taken over blacktop, concrete, frozen ground, or other extremely high resistance surfaces are considered invalid due to the high IR drop that may be present and the possibility the reading indicated may be remote to the relative position of the half-cell. Half-cell contact must be made with the representative environment that surrounds the pipeline.

It may be necessary to water the point of contact with the half-cell in areas of dry or high resistivity soils to lower the contact resistance of the half-cell to an acceptable level. In areas of gravel, it may be necessary to dig down to soil in order to get an accurate measurement.

Reference Electrode Check

A reference electrode shall consist of a copper rod in a saturated copper-copper sulfate/distilled water solution. Anti-freeze or gel-type $Cu\text{-}CuSO_4$ is acceptable if approved by corrosion control. Other types of reference electrodes, such as silver-silver chloride, may be used in brackish or salt water environments, but readings must be converted to equivalent Cu-CuSO4 potentials. A reference electrode check should be performed, at a minimum, before starting each day, per company procedure CORR-005.

Survey Cycle

When an interrupted survey is performed, corresponding 'on/off' potentials must be logged at each half-cell position to allow for IR determinations. A slow cycle synchronized survey may be used with approval from operations control.

The normal survey interruption cycle of the current sources is 3 sec 'on' and 1 sec 'off' for a total duty cycle of 4 second. In some cases, an interruption cycle of 3:1 ratio may be used. Other survey cycles may be used with approval of corrosion control.

The meter recording the data must be capable of reading these cycles.

Survey Meters

All annual surveys (where practical) will be recorded electronically using a Company-approved meter. The calibration of the meter must be checked before the beginning of any annual survey with a power source of a known voltage.

Survey Types

Normal close-interval surveys are performed in ON/OFF mode. The survey data will generate a printout with two data traces. One will be the ON potential profile and the other will be the OFF potential profile.

With corrosion control approval, IR-Free (or Polarized Potential) survey methods may be performed.

In areas with fluctuating potentials, the Telluric method should be used. Slow cycle interruption of the current sources is recommended. The survey data will generate a printout with two data streams. One will be the moving (remote) potential profile and the other will be the stationary (local) potential profile.

In some instances, a Native (or Depolarized) potential survey may be performed to establish a baseline for use in determining if 100 mV CSE of polarization is present on the structure. Where native potential surveys are performed, a three-line trace will be necessary.

In rare occasions, a Side Drain survey may be conducted in areas of bare piping, non-electrically continuous or severe coating defects.

Skips

Skips are places on the pipeline where P/S potentials cannot be measured. There are two types of skips: unexplained and explained.

- *Unexplained skips* are locations where the pipeline is either inside steel casing or the piping is in the air (spans).
- *Explained skips* are all other locations where potential readings would be invalid, such as over blacktop or concrete roads. These must be noted on the appropriate form
- If the area of the pipeline covered by the road surface is of sufficient length, the area must be evaluated to determine if test holes or flush test stations are required to fully evaluate the section.

Distance Flagging

A distance flag should be entered into the data stream every 100 feet as the survey proceeds. The most common method is to pre-mark the pipeline at 100-foot intervals by using either a survey chain or by pacing off the length. A device such as a wire counter is acceptable for distance measuring during performance of the survey if proper techniques are observed.

Irregularities in the Potential Profile

The purpose of the Pipeline Close-Interval survey is to find irregularities in the potential profile.

An irregularity exists if the P/S potential drops by a specified amount within a distance of 400 feet and rises back to the general level of the potential profile within a similar distance. The specified drop will vary as the general level of the potential profile varies. The following table defines the magnitudes of typical irregularities.

GENERAL PROFILE ON POTENTIALS (-ve)	MAGNITUDE OF IRREGULARITY
2000 – 4000 mV CSE	500 mV CSE
1500 – 2000 mV CSE	300 mV CSE
1000 – 1500 mV CSE	150 MV CSE
900 – 1000 mV CSE	50 mV CSE
INSTANT OFF/POLARIZED POTENTIAL	
1200 – 1500 mV CSE	200 mV CSE
1000 – 1200 mV CSE	100 mV CSE
900 – 1000 mV CSE	50 mV CSE
870 – 900 mV CSE	20 mV CSE
100 mV CSE POLARIZATION CHANGE	
200 – 500 mV CSE	100 mV CSE
150 – 200 mV CSE	30 mV CSE
140 – 150 mV CSE	20 mV CSE
110 – 140 mV CSE	10 mV CSE

When an irregularity or low potential is encountered, the surveyor should enter a comment in the data stream. Additional readings, such as lateral potentials, waveprint(s), AC potentials, or other information should be recorded if they might indicate the cause of the irregularity. The 100 mV CSE polarization change table will be used when a Native close-interval survey and ON/OFF or Polarized survey are evaluated together.

Minimum Survey Data Requirements

As a minimum, the following information is required for the survey:

1. Minimum of 30 P/S potentials per 100 foot flags.
2. P/S potential readings are required at all pipeline contacts.
   - ON/OFF close-interval surveys require both ON and OFF potentials.
   - Polarized close-interval surveys require both ON and polarized potentials.
   - Native close-interval surveys require a native potential only.
3. Wave prints at each pipeline contact.
4. ON/OFF lateral potentials at pipeline contacts.
5. AC voltage potential readings at each pipeline contact.
6. ON/OFF near and far ground readings at pipeline contacts.
7. ON/OFF metallic IR-drop readings at each pipeline contact.
8. Influencing rectifier current and voltage outputs.
9. ON/OFF influencing sacrificial anode ground bed currents where leads are accessible.
10. ON/OFF bond currents (critical, non-critical and continuity) influencing the area being surveyed.
11. ON/OFF casing potentials at all casing vent pipes. Casing vents can be dog-legged in any direction and not represent the end of the casing. Note casing location from alignment sheet and start P/S potential readings on the casing 1-foot from the end. P/S potential readings on the pipeline should start a minimum of 1-foot from the end of the casing.
12. ON/OFF Company and foreign structure P/S potentials at all foreign crossings with test leads.
13. An engineering station and description entered for all features or reference points.
14. The upstream and downstream station numbers and descriptions of all skips.
15. ON/OFF potentials are to be recorded over all drip blow-down lines connected to and in the area of the line being surveyed. Determine if the drip blow-down lines are isolated by taking near and far ground potential readings.
16. ON/OFF potentials over all cross-over lines connected to the line being surveyed, from the line being surveyed to the next mainline.
17. ON/OFF potentials are to be taken at all isolation devices connected to the mainline at a tap, lateral or inserted in the mainline.
   - Take an ON/OFF potential on both sides of the isolation device.

- Take an ON/OFF potential across the isolation device.

Analyzing the Survey

Download survey information from the survey instrument to the PC. Then analyze the data for any area(s) in need of remedial correction or future monitoring.

Edit the data to correct information that was omitted or improperly entered during the survey. Examples are incorrect or omitted station numbers, missing reference points, etc.

If an interrupted survey was conducted, print out all wave prints for analysis. Determine if there were any transients on the piping and if they affected the potentials being collected. Ensure that all interrupters were synchronized and operating properly.

Graph the survey data for analysis. Indicate all irregularities, skips, and low potential areas on the graph. Irregularities and low potential areas will be indicated on the graph by noting their potential values and beginning and ending station plus. Skips will be noted on the graph by beginning and ending station plus.

Evaluate the near and far ground readings for differences in potential. Differences can be caused by the location the readings were taken, pipe diameter and wall thickness, distance between pipeline connection points, and amount of current flowing in the pipe. Large potential differences should be evaluated to identify isolation problems, unknown current sources, etc. Evaluate metallic IR-drop readings. The ON potential metallic IR-drop reading is indicative of the IR-drop due to current flow in the metallic circuit. The OFF potential metallic IR-drop reading in an ideal situation would be zero if no current was flowing in the metallic circuit.

AC potential readings will be evaluated as to magnitude and cause. **AC potentials above 15 VAC should be listed as deficiencies and must have prompt remediation.**

Side drains or lateral potentials will be evaluated as to direction of current flow. Current flow should be toward the pipeline. There should be no current flow towards the pipe during the off cycle when conducting interrupted survey.

All foreign crossings will be evaluated for interference. A dip in Company piping potential at a crossing will be evaluated and if necessary, assigned an **immediate priority** for correction. A positive potential on Company piping will be **immediately** corrected.

Isolation devices will be checked for proper operation.

Rectifier and other impressed current source settings will be evaluated, and new minimum current requirements will be set as required for each unit.

All unexplained indications of current pickup or discharge will be evaluated as to cause.

All P/S potential readings will be evaluated for profile irregularities, which may or may not be below criteria. These will be tabulated as part of the survey and monitoring assigned to them.

If a 100 mV CSE polarization survey has been performed, the difference between the polarized (instant off) potential and the depolarized (native) potential must be at least equal to 100 mV CSE.

On areas of the pipeline where SCC has been detected, polarized potentials in the range of -660 to -760 mV CSE should be avoided. Potentials in this range along with certain conditions can contribute to SCC and may need to be remediated.

Analyze all skip areas:

1. List all skips where the potentials cannot be observed, such as cased piping or spans. The areas (description, beginning station, ending station, reason skipped) are to be listed on the summary letter attached to the appropriate company form.
2. Skips where a potential survey is not normally performed, such as offshore, marsh, swamps, and large water crossings, are also to be listed on the summary letter. These skips should be listed as deficiencies unless prior approval is received from corrosion control.
3. Skips that do not fall into either of the aforementioned categories are to be listed on the appropriate document as a deficiency in the survey, which requires a follow-up close-interval survey before the Annual Survey is considered complete. Exceptions exist for areas of uncased paved roads (less than 51 feet wide), sidewalks, and residential driveways that meet the following criteria. These can be listed as a group on the summary letter. If they do not meet the criteria, they are to be listed as a deficiency on the appropriate company form.

   - If the potential profile is essentially level and the lowest reading at either edge of the pavement is no lower than -900 mV CSE, then no further action is required.
   - If the potential profile declines slightly (25 mV CSE drop) from the ROW line to the edge of the pavement and the reading at the edge is no lower than -950 mV CSE, then no further action is required.
   - If the potential profile declines significantly (50 mV CSE drop) from the ROW line to the edge of the pavement and the reading at the edge is no lower -1000 mV CSE, then no further action is required.
   - If the potential profile does not meet any of these criteria, then the area is to be entered on the deficiency list and efforts must be made to drill through the pavement to take P/S potentials to verify the level of CP. Corrosion Control will determine the interval between readings based on past history, current levels of protection adjacent to the skip area, and risk management.

Skips wider than 51 feet are to be evaluated as to the need to drill or install flush mounted test stations to verify the level of CP. In most cases, these areas are to be listed as deficiencies and efforts must be made to take the necessary action to obtain the readings. Corrosion Control will determine the interval between readings based on past history, current levels of protection adjacent to the skip area, and risk management.

P/S Potential Limits - High tensile strength steels (Grade X-60 and higher) may require an upper P/S potential to prevent hydrogen embrittlement and hydrogen blistering of coatings. An ON potential more negative than -2500 mV CSE should raise a flag as an area for further investigation. The true polarized potential at which hydrogen is generated may be extremely difficult to determine in the field. Therefore, ON potentials over -2500 mV CSE will be justified by the field corrosion control personnel. The company limit is a polarized potential of -1260 mV CSE at the drain point. Polarized potentials exceeding -1260 mV CSE should be reported as deficiencies. If the close-interval survey disclosed remote area(s) where the potential is running close to this limit, then an Allowable Maximum (AM) can be setup to monitor such areas in the future.

Tabulating Irregularities and Calculating Limits

General Requirements

The following is a procedure for monitoring irregularities (dips, changes in profile, and peaks) found by close-interval survey. The procedure correlates the minimum (or maximum) pipe-to-soil potential at a remote site to an annual survey reading at a test station. This provides a *flag* that can identify possible low potential areas remote from reading sites when conducting the annual survey. If a limit is broken, the remote site can then be surveyed to ensure compliance with criteria.

Per Company-defined monitoring procedures, remote irregularities revealed by the close-interval survey can be monitored remotely from an established test point by assigning a RM to that test point.

Tabulating Irregularities

Analyze the pipeline close-interval survey profile. This involves scanning the profile pages identifying the irregularities.

All P/S potentials below or above criteria will be listed in two places. First, an “Exception Table” will be generated from final survey data for each run, listing by station number all areas above and below criteria or skipped. The second listing will be on the TABULATION OF IRREGULARITIES (or on the RM Calculation form RMCalc.xls).

Emphasis should be placed on the following concepts:

- Look only for irregularities and high or low potential areas.
- An irregularity exists when the potential drop and rise occurs within the prescribed distance.
- A long slow potential drop or a long slow rise is not an irregularity. These are simply sags in the profile.
- If there is doubt or reason to treat the area as an irregularity, then call it an irregularity and list it in the notes as such.

It is not necessary to define the exact length or contour of an irregularity, only the approximate 100 feet in which the low potential occurs.

The profiles should be studied carefully in order to identify and tabulate the irregularities, skips, and low potential areas.

The pipeline contact becomes the control point. Use the control point for all calculations.

Retain the computer printout of the Tabulation of Irregularities (or on the RM Calculation form RMCalc.xls) and attach it to the Close-Interval survey. The calculated RM should be set as the lower limit of the P/S ON field in the Data Point definition in the PCS database. The lower limit of the control point will reflect the RM but cannot be set lower than the established criteria. List the beginning station number of the irregularity along with the length in the *Description* field (i.e., 100' at 237+21).

This survey format will also introduce a remote monitoring capability for a dominant remote high. P/S potentials greater than -2500 mV CSE for all grades of pipe must be justified by corrosion control (i.e., interrupted on-off close-interval P/S survey over affected area).

The controlling test point will have an allowable maximum (AM) assigned. The irregularity should be listed in the *Description* field of the Annual Survey and noted as AM. The calculated AM should be set as the upper limit of the P/S ON field in the Data Point Definition. List the beginning station number of the irregularity along with the length in the *Description* field (i.e., 100' at 237 + 21).

Should a situation arise when a test point has both a RM and an AM assigned, then list (in the *Description* field) both remote locations. To identify them, it is suggested that, in order to fit both items into the field, the remote location associated with the RM carry the prefix RM. In like manner, the remote locations associated with the AM should be given the prefix AM. Naturally, the lower limit (RM) and upper limit (AM) should be entered for that test point.

Calculating Required Minimums/Absolute Maximums

All entries on a completed TABULATION OF IRREGULARITIES can be classified into four categories.

1. **Low potential area**: Represent situations for which corrective measures must be specified and **action promptly initiated**.
2. **Skips**: Areas that must be surveyed later when conditions permit. A full valve section survey **is not considered** complete until all skips are filled in.
3. **Local Irregularities**: Areas where the low or high point of the irregularity coincides with the pipeline contact point.
4. **Remote Irregularities**: Areas where the low or high point of the irregularity is located at least 5 feet from the pipeline contact point.

Remote Irregularities can deteriorate below the required level for CP or above the maximum level which could cause hydrogen generation. These situations would be missed during the Annual Survey, where only readings observed are the local readings at the available test points. To obtain the full benefit of the close-interval survey, these remote irregularities should be monitored annually. The most accurate method would be to actually return to each remote location during each Annual Survey to actually observe potentials. However, this would be very time consuming and very costly. An alternative method has been devised based on the assumption that the potential profile is linear in movement with changes in current. For example, an increase in DC current to a pipeline which causes a 100 mV CSE shift at MP 7.31 should also show a corresponding 100 mV CSE increase at MP 8.35. However, this assumption is not absolutely true. To compensate for a certain degree of non-linearity, a specified voltage drop factor has been devised dependent on the type of survey being run.

The low value a remote irregularity can drop is:

- -900 mV CSE for an ON survey
- -870 mV CSE for an "Instant Off" survey
- -870 mV CSE for a Polarized survey
- 110 mV CSE for a Polarization Change survey

Each remote irregularity will be assigned a test point, which will serve as its 'control point' for monitoring. Rules for assigning "control points".

1. Generally, the 'pipeline contact' is used.
2. If a 'pipeline contact' is too far away from the remote irregularity or group of irregularities the words "Will Detail" will be entered on TABULATION OF IRREGULARITIES in the column headed "REMARKS." A repeat close-interval survey is to be performed on the irregularities a minimum of once every 5 years

from the date of the initial close-interval survey. These should be listed as deficiencies. It is the responsibility of local supervision and corrosion control personnel to schedule and maintain these surveys.

3. When only one remote irregularity is assigned a ‘control point’, it will be designated the dominant irregularity.
4. When more than one remote irregularity is assigned to a ‘control point’, the one with the lowest potential will be designated the dominant irregularity.
5. For each control point, calculations will be made using the actual P/S potential data to determine what minimum potential must be maintained at the ‘control point’ in order that the potential at the dominant irregularity does not violate the applicable criterion. That value then becomes the ‘required minimum’ (RM) for that ‘control point’ and will be entered on TABULATION OF IRREGULARITIES on the line with the dominant irregularity and in the column titled “REQUIRED MINIMUM”.
6. Enter on TABULATION OF IRREGULARITIES the calculated value of the RM even though it may be lower than the applicable criterion. In the appropriate Annual Survey Chart, the lower limit for the control point will be set at the minimum criteria.
7. For high strength steels (grade X-60 or higher) ‘allowable maximums’ (AM) will be calculated to prevent hydrogen generation. When P/S potentials begin running close to the acceptable upper limit (-2500 mV CSE), then an Absolute Maximum (AM) can be set-up to guard against such areas going above the limit in the future. Exceeding -2500 mV CSE on low strength steels (grade X-52 or lower) is not a concern and no calculations are necessary. However, field corrosion control personnel should evaluate the reason(s) for the high potential.
8. When TABULATION OF IRREGULARITIES is completed, with the remote monitoring set-up, the new scheme must be substituted for the old scheme in the appropriate Annual Survey Chart.
9. Only one remote monitoring scheme may be used per ‘control point’.

ON Surveys

This monitoring scheme is used when an ON close-interval survey is performed and will be monitored annually with an Annual Survey.

Calculating a RM: All RM calculations are based on -**900 mV CSE ON**. Subtract 900 mV CSE from the dominant irregularity and subtract this difference from the potential at the 'control point'. This becomes the required minimum.

Dominant Irregularity = -910 mV CSE	Control Point = -1120
RM = Control Point – (Dominant Irregularity – 900) = 1120 – (910 – 900) = 1110 mV CSE	

If the lowest potential at the lowest remote irregularity is more negative than the potential at the control point, the RM calculation is not required but the irregularity is still listed.

If the dominant irregularity has a low value between 850 and 900 mV CSE, then assign RM equal to the control point reading or perform close-interval survey over the area of the irregularity annually.

Enter "O" in the "TYPE" column on TABULATION OF IRREGULARITIES to indicate the monitoring scheme for an ON Survey was used.

Calculating an AM: All AM calculations are based on -2500 mV CSE ON. Subtract -2500 mV CSE from the high point potential and subtract this difference from the potential at the 'control point'. This becomes the allowable maximum.

High Point Potential = -2300 mV CSE	Control Point = -1120
AM = Control Point – (High Point Potential – 2500) = 1120 – (2300 – 2500) = 1320 mV CSE	

The necessary AM's will be entered on TABULATION OF IRREGULARITIES in the "REQUIRED MINIMUM" column. Insert "AM" in the "REMARKS…" column to designate that this is an allowable maximum.

ON/OFF Surveys

This monitoring scheme is used when an ON/OFF close-interval survey is performed and will be monitored annually with an Annual Survey.

Calculating RM: All **remote irregularities** use RM calculations based on -**870 mV CSE OFF**. All **local irregularities** use RM calculations based on -**850 mV CSE OFF**.

	Control Point (VM)	Remote Irregularity (VR)
ON	-1500 mV CSE	-1120 mV CSE
OFF	-910 mV CSE	-980 mV CSE
RM (Control Point) = (VM ON –(VM OFF – 850)) = (1500 – (910 – 850)) = -1440 mV CSE		
RM (Remote Irregularity) = (VM ON –(VR OFF – 870)) = (1500 – (980 – 870)) = -1490 mV CSE		

In determining the dominant irregularity, the RM for the control point is evaluated along with all remote irregularities that will be monitored from that control point. The highest calculated RM from this evaluation will be the RM assigned to the control point for monitoring during the Annual Survey.

If the dominant remote irregularity has a low value above -850 mV CSE but below -870 mV CSE, then assign a RM equal to the ON reading at the control point or perform close-interval survey over the area of the irregularity annually.

When no remote irregularities are to be monitored from a control point, the RM will be the control point calculated RM.

By using an ON/OFF monitoring scheme, all Annual Survey test points will be required to have a RM assigned and listed on TABULATION OF IRREGULARITIES.

Enter “I” in the “TYPE” column on TABULATION OF IRREGULARITIES to indicate the monitoring scheme for an ON/OFF Survey was used.

Polarized Survey

This monitoring scheme is used when a Polarized close-interval survey is performed and will be monitored annually using a polarized P/S potential at each Annual Survey test point.

Calculating RM: All **remote irregularities** use RM calculations based on -**870 mV CSE OFF.**

	Control Point (VM)	Remote Irregularity (VR)
Polarized	-910 MV CSE	-980 mV CSE
RM (Remote Irregularity) = (VM "Pol" –(VR "Pol" – 870)) = (910 –(980 – 870)) = -800 mV CSE		

In determining the dominant irregularity, the RM for the control point is evaluated along with all remote irregularities that will be monitored from that control point. The highest calculated RM from this evaluation will be the RM assigned to the 'control point' for monitoring during the Annual Survey.

When no remote irregularities are to be monitored from a 'control point', the RM need not be calculated nor are these test points listed on TABULATION OF IRREGULARITIES.

Enter "P" in the "TYPE" column on TABULATION OF IRREGULARITIES to indicate the monitoring scheme for a Polarized Survey was used.

100 mV CSE Polarization Change

This monitoring scheme is used when an area of the pipeline is being evaluated using the 100 mV CSE polarized change criteria. There are two survey methods that may be used in setting up the remote monitoring.

Method One

The Native close-interval survey and ON/OFF close-interval survey will be evaluated together to determine the change in polarization.

ON potentials taken during the Annual Survey will be used to monitor the protection levels.

Calculating RM: All **remote irregularities** use RM calculations based on **110 mV CSE** change in polarization. All **local irregularities** use RM calculations based on **100 mV CSE** change in polarization.

	Control Point (VM)	Remote Irregularity (VR)
ON	-1500 mV CSE	-1120 mV CSE
OFF	-800 mV CSE	-780 mV CSE
Native	(-) 500 mV CSE	(-) 660 mV CSE
Polarization Change	300 mV CSE	120 mV CSE
RM (Control Point)	= (VM ON – (VM “Polarized Change” – 100))	
	= (1500 – (300 – 100))	
	= -1300 mV CSE	
RM (Remote Irregularity)	= (VM ON – (VR “Polarized Change” – 110))	
	= (1500 – (120 – 110))	
	= -1490 mV CSE	

In determining the dominant irregularity, the RM for the control point is evaluated along with all remote irregularities that will be monitored from that control point. The highest calculated RM from this evaluation will be the RM assigned to the control point for monitoring during the Annual Survey.

If the dominant remote irregularity has a value of polarization change above 100 mV CSE but below 110 mV CSE, then assign a RM equal to the “on” reading at the control point or perform a close-interval survey over the area of that irregularity annually.

When no remote irregularities are to be monitored from a control point, the RM will be the control point calculated.

By using a change in polarization monitoring scheme, all Annual Survey test points will be required to have a RM assigned and listed on TABULATION OF IRREGULARITIES.

Enter “C” in the “TYPE” column on TABULATION OF IRREGULARITIES to indicate the monitoring scheme for a100 mV CSE polarization change was used.

Method Two

The Native close-interval survey and Polarized close-interval survey will be evaluated together to determine the change in polarization.

Polarized potentials taken during the Annual Survey will be used to monitor the protection levels.

Calculating RM: All **remote irregularities** use RM calculations based on **110 mV CSE** change in polarization. All **local irregularities** use RM calculations based on **100 mV CSE** change in polarization.

	Control Point (VM)	Remote Irregularity (VR)
Polarized	-800 mV CSE	-780 mV CSE
Native	(-) 500 mV CSE	(-) 660 mV CSE
Polarization Change	300 mV CSE	120 mV CSE
RM (Control Point)	= (VM “Polarized” – (VM “Polarized Change” – 100))	
	= (800 – (300 – 100))	
	= -600 mV CSE	
RM (Remote Irregularity)	= (VM “Polarized” – (VR “Polarized Change” – 110))	
	= (800 – (120 – 110))	
	= -790 mV CSE	

In determining the dominant irregularity, the RM for the ‘control point’ is evaluated along with all remote irregularities that will be monitored from that ‘control point’. The highest calculated RM from this evaluation will be the RM assigned to the ‘control point’ for monitoring during the Annual Survey.

If the dominant remote irregularity has a value of polarization change above 100 mV CSE but below 110 mV CSE, then assign a RM equal to the Polarized reading at the ‘control point’ or perform close-interval survey over the area of that irregularity annually.

✓ - denotes update Return to TOC

When no remote irregularities are to be monitored from a 'control point', the RM will be the control point calculated RM.

By using a change in polarization monitoring scheme, all Annual Survey test points will be required to have an RM assigned and listed on TABULATION OF IRREGULARITIES.

Enter "C" in the "TYPE" column on TABULATION OF IRREGULARITIES to indicate the monitoring scheme for a 100 mV CSE polarization change was used.

Submitting the Survey

When the close-interval survey has been completed, the remote monitoring scheme has been established (if required) and the appropriate PCS database has been adjusted to reflect the new monitoring scheme (if required), the survey must be forwarded to corrosion control.

The close-interval survey remote monitoring information may be added to the Annual Survey prior to the next Annual Survey due date.

ALL ON, OFF, polarized and native potentials taken at Annual Survey test points during the close-interval survey must be entered in the Annual Survey database.

ALL voltage and current readings taken at Annual Survey test points must be entered in the Annual Survey database.

List each of the following deficiencies individually:

- All areas where applicable criteria were violated.
- All locations where the installation or repair of a test lead is necessary.
- All areas where interference testing is necessary.
- Skips requiring explanation and a follow-up re-survey at a later date.
- Uncased paved roads (less than 51 feet wide) and/or several short, paved areas such as sidewalks and residential driveways that did not meet the criteria.
- Each point of X-60 or greater pipe that is above maximum criteria.

Clearly identify each and every area or point of deficiency by providing the following:

- Milepost (calculated from beginning station number)
- Beginning and ending survey station numbers
- Length of low potential area or identification as a local
- Lowest or highest value of P/S potential recorded
- Features such as I-20, Penn Central RR, MLV 55-3, Hwy 92, etc.

Cause of Deficiency: For each item listed, provide a brief evaluation of the possible cause of the deficiency.

Recommended Corrective Measures: A corrective measure must be included for each and every listing in the deficiency statement.

- If an individual corrective action is intended to correct several deficiencies, then it needs to be listed only once, but must be clear which deficiencies are corrected.
- Corrective measures can include maintenance functions such as repair coating, clear shorted casing, install test lead(s), replace faulty insulators, etc. They can include operational functions such as conduct an interference test, perform a Follow-up survey, etc. They will also include items requiring a construction order (CO).
- Corrective measures for X-60 or greater pipe can include installing bias, lowering rectifier output, relocating ground beds, etc.

Areas of Class 3 & 4 Area Survey: If this close-interval survey performed some needed Class 3 or 4 area survey, list these areas here.

Follow-up Survey Accomplished: Clearly identify each previously listed deficiency for which follow-up was accomplished by the survey being submitted. Each listing should provide the following:

1. Milepost as carried on the original deficiency list.
2. Beginning and ending survey station numbers.
3. Date First Reported - use the earliest date if the deficiency has been reported repeatedly.
4. Type of survey on which first reported (i.e., Annual Survey, Close-Interval survey, Atmospheric Survey, Follow-up Survey, etc.)
5. Date corrective measure completed.
6. Lowest or highest (if broken AM is being resurveyed) P/S potential observed on this survey.
7. Remarks if still deficient – Provide a description

Follow-Up Resurvey

A follow-up close-interval re-survey is used to verify that deficiencies have been corrected. All CP deficiencies revealed by any survey must have a follow-up close-interval resurvey performed following completion of all corrective measures for that survey, and within 12 months of the discovery of the deficiency.

Deficiencies can be classified into four categories:

1. Low Potential Areas
2. Repair Areas - Areas such as a temporary repair, installation of a manifold, leak repair, anomaly dig site, recoating, or pipe replacement.
3. RM/AM Limit Not Met or Exceeded – If not checked during the Annual Survey, the irregularity needs to be surveyed.
4. Skip Areas from close-interval survey – Skips from close-interval surveys where the survey was interrupted across areas that could have been surveyed.

Conducting the Survey

Where applicable, pipeline close-interval survey procedures apply to the follow-up close-interval re-survey. Procedures requiring special consideration are:

- The area covered by a follow-up close-interval re-survey must cover at a minimum the full length of the listed deficiency. Anytime the station numbers of the follow-up close-interval resurvey differ from the station numbers of the original deficiency the reason must be given.
- Any area where the remedial corrective measure performed could change the IR drop an ON/OFF resurvey is required.
- All coating repair areas require an ON/OFF resurvey. Coating repair changes the IR drop.
- Any area where the current density to the piping has been changed by removing CP current requires an ON/OFF resurvey over the area influenced.

RM or AM resurveys require the same survey that was performed when the monitoring limits were originally established. The local control point P/S potential should also be taken at the same time to allow for the new calculation of RM or AM, if required.

Areas skipped during a close-interval survey require an ON/OFF resurvey.

Areas with parallel impressed or galvanic anodes installed on the pipeline may be scheduled for ON/OFF resurvey by corrosion control if the effective operation of the ground bed cannot be confirmed by other means.

A remote irregularity or group of irregularities with no assigned control point may be scheduled for ON/OFF resurvey by corrosion control if the effectiveness of cathodic protection at that location cannot be confirmed by other means.

Submitting the Survey

1. Submit all data and documentation with appropriate company form.
2. Indicate reason(s) for resurvey:
   - Repair area
   - RM/AM limit not met or exceeded
   - Skip area
   - Low potential areas
3. Indicate the survey date and the low P/S potential originally found.
4. Indicate the type of survey the deficiency was found
5. Scheduled re-survey area
6. Distributed anodes
7. Remote irregularity
8. List resurvey area(s):
   - If the resurvey was on the pipeline, indicate the valve section and milepost. The milepost is based on the upstream station plus of the area resurveyed.
   - For the pipeline, enter the upstream station plus for the resurvey area. For a compressor station, enter the beginning east or west coordinate.
   - For the pipeline, enter the downstream station plus for the resurvey area. For a compressor station, enter the beginning north or south coordinate.
9. Enter length of the resurvey area.
10. Enter the lowest value of P/S potential observed on the resurvey. If an AM resurvey is involved, enter the highest P/S potential observed and make a notation of RM in the feature description.
11. Enter a description of the resurvey area.
12. Cause of Deficiency: If the criterion was not met, enter the suggested cause of deficiency.
13. Corrective Measure: A recommended corrective measure must be included for areas that did not meet the criteria.
14. Close remedial actions in a work management system.

Telluric Survey

Setting Up Notes

The setting up of the notes prior to conducting the Telluric close-interval survey is the same as described under *Pipeline Surveys* on page 99.

Conducting the Survey

The survey is basically conducted in the same manner as described under *Conducting the Survey* on page 99. There are a few basic differences as follows.

Instrument

The survey instrument must have the Telluric Survey Program loaded instead of the normal close-interval survey Program.

Current Source Interruption

It is recommended that a slow cycle interruption of the influencing rectifiers be done for the stray current and Telluric areas where possible. This will allow for better interpretation of the survey data.

Pipeline Connection

At each "pipeline contact," the negative terminal of the survey instrument will be connected to the piping through a reel of wire. The survey instrument having two separate positive terminals will have one terminal connected to a second wire reel with a reference cell attached. This reference cell will remain at the pipeline connection as the reference potential for the survey. The second positive terminal will connect to two-reference cells bridled together.

Survey Cycle

The survey cycle will be determined by the amount of Telluric current in the area. Normally it will be a slower cycle than normally used. In some extreme cases, Telluric activity may be of such magnitude and frequency during a slow cycle ON/OFF survey that if will prevent accurate data from being collected and interpreted. In this case, an ON survey may be required with permission from corrosion control.

Analyzing the Survey

The final survey data will generate a printout with two data streams. One data stream being the moving or remote potential profile and the other the stationary or local potential profile.

The survey is analyzed in the same manner as the *Analyzing the Survey* on page 105.

When an irregularity is encountered in the moving potential profile, the stationary potential profile will also be evaluated at the same point.

If the stationary potential profile also decreased at this point, then the drop in potential profile can be attributed to a Telluric current and not to an actual drop in the CP level on the pipeline.

If the stationary potential profile remains stable at this point, then the drop in the moving potential profile can be attributed to an actual drop in the CP level on the pipeline. In this case the irregularity in the profile is addressed in the same manner as on the Pipeline close-interval survey.

Tabulation of Irregularities

The TABULATION OF IRREGULARITIES is performed in the same manner as for a Pipeline close-interval survey (see *Tabulating Irregularities* on page 107).

Submitting the Survey

The survey is submitted in the same manner as a Pipeline close-interval survey.

Native Surveys

Setting Up Notes

The setting up of the notes before conducting the Native close-interval survey is the same as described under *Setting Up Notes* on page 99 of this section.

Conducting the Survey

The survey is normally used to establish the baseline for determining the difference between the “instant off” or depolarized survey and the native potential. This difference is used to evaluate if 100 mV CSE of polarization is present on the pipeline.

The survey is basically conducted in the same manner as described under *Conducting the Survey* on page 99 of this section. There are a few basic differences as follows.

Current Source Interruption

Before conducting a Native close-interval survey, all current sources that have an influence on the section of pipeline being surveyed are shut off for the duration of the survey.

Monitor the P/S potential over time to determine when the pipeline has become fully depolarized. The time necessary for full depolarization will vary from area to area.

Survey Cycle

There will be no cycle for a Native close-interval survey – all current sources are shut off.

Distance Flagging

It is critical that the distance flagging is accurate. A Native close-interval survey and a separate ON/OFF or Polarized close-interval survey are normally conducted over the same pipeline area to be evaluated together. **The distance flags must be at the same locations for both surveys to accurately tie the potential readings together or the survey may be invalid.**

Minimum Information Required

ON potentials and currents are not recorded due to the current sources being off.

The remaining information as indicated under "Survey Requirements" at the end of *Conducting the Survey* in this section.

It is critical that as many reference points as possible be entered in the data stream in order to match the native survey to the ON/OFF survey.

Normally an ON/OFF or Polarized close-interval survey will be compared to the Native close-interval survey.

Analyzing the Survey

Download the survey information from the survey instrument to the PC, then analyze the data for any area(s) in need of remedial correction or future monitoring.

Edit the data to correct information that was omitted or improperly entered during the survey. Examples are station numbers incorrectly entered or omitted, reference points not entered, or in need of additional information.

Print out all wave prints for analysis. These will be analyzed to determine if there were any transients on the pipeline and if they affected the potentials recorded.

Graph the survey data for analysis.

Evaluate near and far ground readings for differences in potential. Some of the difference will depend on where the readings were taken; pipe OD, pipe weight, distance between pipeline connection points, and amount of current flowing in the pipe. Large potential differences will need to be evaluated to be sure that isolation problems or unknown current sources are not the cause.

Evaluate metallic IR-drop readings. The OFF potential metallic IR-drop reading in an ideal situation would be zero if no current was flowing in the metallic circuit.

Evaluate AC potential readings as to magnitude and cause. **AC potentials above 15 VAC should be listed as deficiencies and must have prompt remediation.**

Evaluate all unexplained indications of current pickup or discharge as to cause.

When evaluating the Native close-interval survey in conjunction with an ON/OFF or Polarized close-interval survey to determine if 100 mV CSE polarization is present, two areas that must be evaluated are:

- The difference between the polarized (OFF) potential and the depolarized (Native) potential must be at least equal to 100 mV CSE.
- On areas of the pipeline where SCC has been detected, polarized potentials in the range of -660 to -760 mV CSE should be avoided. This range of potential, along with other conditions, can contribute SCC.

Tabulation of Irregularities

The TABULATION OF IRREGULARITIES is performed in the same manner as for a Pipeline close-interval survey.

Setting Up Remote Monitoring (RM and AM)

Monitoring is set-up as indicated under “Pipeline close-interval survey.”

Submitting the Survey

The survey is submitted in the same manner as a “Pipeline close-interval survey.”

SECTION 4 - Cathodic Protection Systems

Introduction

The Natural Gas Pipeline Safety Act resulted in the issuing of requirements for corrosion control. Cathodic protection (CP) must be designed, installed, operated, and maintained by or under the direction of a person qualified by experience and training in pipeline corrosion control methods per "Title 49-CFR-Part 192/ 195."

Company standards are to cathodically protect buried or submerged pipelines and piping in compressor, regulator, meter stations, and other related facilities. Exceptions to these standards must be approved by corrosion control.

This section defines the design and selection, installation, operation and maintenance, and required forms to ensure consistent application of cathodic protection systems.

All new construction will have a properly designed cathodic protection system installed and in operation as soon after construction as possible but no later than one year from completion of construction. A temporary system may be necessary, depending on the length of time between burial and expected completion of the permanent cathodic protection system.

References noted in the CP systems section are:

1. Title 49-CFR-Part 192/ 195
2. O&M Manual Section 9 in Gas and Section 11 in Liquid
3. NACE RP-0492-99: Metallurgical and Inspection Requirements for Offshore Pipeline Bracelet Anodes
4. NACE RP-0572-95: Design, Installation, Operation and Maintenance of Impressed Current Deep Ground Beds

Design and Selection

Qualifications

All corrosion control design, materials, and installation procedures must be approved by Corrosion Control before installation.

The design and installation of all cathodic protection systems including impressed current systems, galvanic anode systems, and offshore pipeline bracelets must be carried out by personnel qualified by Company operator qualification programs in pipeline corrosion control methods.

Design Considerations

The total cathodic protection system design will consider the following:

- Hazardous conditions such as combustible gases and induced AC that may prevail at the proposed site.
- Material specifications should conform to the latest applicable codes.
- Minimization of interference current on neighboring structures.
- Be as secure as possible from outside disturbances or damage.
- Provide adequate monitoring facilities.
- The effect of polarization on coatings and metallurgical compositions susceptible to hydrogen over voltage or embrittlement.
- The presence of amphoteric metals.
- All designs are to follow the latest applicable NEC codes.

Cathodic protection system types are either impressed current or sacrificial. Considerations that influence the type system selected are:

- Magnitude of current required.
- Stray current sources.
- CP systems on adjacent structures.
- Availability of power.
- Physical space requirements, proximity of foreign structures (within ½ mile), right-of-way easements, surface conditions, presence of streets and buildings, river crossings, ancient cultural resources, environmentally sensitive areas, etc.
- Future development of the ROW and extensions of the pipeline.
- Cost of installation, operation, and maintenance.
- Electrical resistivity of the environment.
- Geological information

Available records should be reviewed, and tests conducted to ensure adequate and economical designs. Typical sources of design information are:

- Review piping system route maps, construction records, material specifications, coatings, crossings, spans, isolation points, and electrical bonds.
- Review existing and proposed cathodic protection systems for possible interference problems, environmental concerns, neighboring under-ground

structures, accessibility, power sources, foreign crossings, or historical performance of previous designs.

Perform appropriate field surveys such as current requirements, soil resistivity, continuity, electrical isolation, coating resistance, leak history, foreign current sources, changes to original designs, and maintenance and operating records.

Design Calculations

Impressed Current Systems-Onshore Facilities

When designing onshore facilities impressed current CP systems, the design guidelines described below must be met.

General Considerations

- Electrical resistivity of the environment.
- Determine ground bed current requirement from calculated or test methods.
- The design current requirement shall be sufficient to provide 150% of the current requirement at the expected CP circuit resistance. This becomes the minimum rated DC current output on the rectifier.
- Normal design life for an impressed current ground bed is 20 years. Determine number of anodes necessary to meet this anode life.
- Calculate or measure anode ground bed circuit resistance.
- Calculate minimum rectifier voltage using design current requirement and circuit resistance. This is the voltage required to maintain the design current output at the initial ground bed circuit resistance.
- Determine the rectifier rated DC voltage output by increasing the minimum rectifier voltage to allow for an anticipated increase in circuit resistance. Consult Corrosion Control for assistance.

New Construction Current Requirement Calculation Method

At least 0.5 percent (0.5%) of the new piping external surface will normally be assumed to be bare.

Current requirements will be based on a minimum of two (2) ma of current for each square foot of bare pipe. For example:

40,000 feet of 12.750 inch externally coated pipe

Current required (amps) = (Pipe Length (ft) x Pipe Diameter (in)/12 x PI) x (0.5% Bare) x (2 ma/sq. ft) x (0.001 amp/ma)

Current required (amps) = (40,000 x 12.75/12 x 3.1416) x (.005) x (2) x (.001) = 1.34

Corrosion Control may vary these requirements based on expected construction and operating parameters.

Existing or New Facility Current Requirement Test Method

Follow *CORR-011: Current Requirement* Testing.

Galvanic Anode Systems-Offshore Facilities

When designing offshore facilities galvanic anode systems, the design guidelines described below must be met.

General Considerations

Conditions such as water salinity, depth and temperature will dictate when magnesium, zinc or aluminum anodes are used. Magnesium anodes are typically not used in salt water environments.

Normal design life for a galvanic anode system is 40 years.

The ability of the anodes to survive the pipe laying operation must be considered during anode design.

Both conventional and spool lay procedures must be considered for all CP designs.

Current Requirement - Calculation Method

At least 0.5 percent (0.5%) of the new piping external surface must be assumed to be bare. This is based on 0.5% bare for the first third of the design life, 1% bare for the second third and 2% for the last third.

Current requirements will be based on a minimum of five (5) ma of current for each square foot of bare pipe.

Example: 40, 000 feet of 12.750 inch externally coated pipe.

Current required (amps) = (Pipe Length (ft) x Pipe Diameter (in)/12 x PI) x (0.5% Bare) x (5 ma/sq. ft) x (0.001 amp/ma)

Current required (amps) = (40,000 x 12.75/12 x 3.1416) x (.005) x (5) x (.001) = 3.34

Galvanic Anode Systems-Onshore Facilities

When designing onshore facilities galvanic anode ground beds, the design guidelines described below must be met.

General Considerations

Typically, only zinc or magnesium anodes may be used. Galvanic anode lead wires should be 10 feet of AWG #12 or larger stranded copper wire and terminate in an above ground test station to allow for monitoring and current interruption. There are situations where larger diameter wire will need to be used, such as in AC mitigation or anode cables longer than 10 feet where IR drop will need to be calculated.

A separate test lead to the pipeline should be installed and terminated in a test station. A shunt should be installed between the anode/anode bed and the pipeline connection for anode current measurements.

The anodes should be placed at least three (3) feet from the pipe and at pipeline depth or lower. Normal design life for a galvanic anode ground bed is 15 years.

Wire leads should be attached to the pipeline by a single #15 thermite welding charge, pin brazing, or silver soldering.

Current Requirement - Calculation Method

At least 0.5 percent (0.5%) of the new piping external surface will normally be assumed to be bare.

Current requirements will be based on a minimum of two (2) mA of current for each square foot of bare pipe.

Example: 40, 000 feet of 12.750 inch externally coated pipe.

Current required (amps) = (Pipe Length (ft) x Pipe Diameter (in)/12 x PI) x (0.5% Bare) x (2 mA/sq. ft) x (0.001 amp/mA)

Current required (amps) = (40,000 x 12.75/12 x 3.1416) x (.005) x (2) x (.001) = 1.34

Note: For old pipe use 2% bare in the calculations.

Rectifiers

All rectifiers used on Company systems shall meet the requirements designated on the latest version of the specification guidelines. The vendor will supply the rectifier according to the completed specification with a copy going to the location file.

When installing rectifiers, the following requirements must be met:

- The installation and wiring of all rectifiers shall comply with the manufacturer's recommendations and all applicable requirements of the National Electrical Code and local electrical utility.
- Rectifier must be installed in a manner to minimize the possibility of vandalism or damage.
- Rectifier must have a disconnect switch in the external AC circuit.
- Rectifier case must be properly grounded. The preferred method to attach a wire to the ground rod is by thermite weld.
- Rectifier DC cable connections must be mechanically secure and electrically conductive. Negative and positive DC cables should be properly sized but no smaller than AWG #2.
- Ensure DC cables are installed and marked with the correct polarity.
- DC cables will generally be installed splice free. If splices are required, they must be installed to ensure a complete seal from the electrolyte. During handling and installation, avoid damage to cable insulation.
- A rectifier installed to protect more than one structure requires the negative cable be split so separate current measurements can be obtained for each structure.
- During installation, a separate test lead from each structure for taking potential measurements must be installed.
- If solar panel arrays are used, they should be designed to withstand winds up to 125 MPH.
- Thermo-electric and DC engine generators may require a reverse current device to prevent galvanic action between the anode ground bed and the pipe.
- A CP unit record may be placed inside the rectifier.

Operations Management may require that a security-locking device (NUT) be installed on either the positive or negative lug inside the rectifier case so the rectifier leads cannot be easily reversed.

After installation, complete the appropriate inspection report. After completing the proper Company in-service/removal documentation, including the appropriate diagrams, drawings, material lists, and rectifier inspection report, send copies to the location files.

Impressed Current Ground Beds

Typically, any of four types of impressed current ground beds may be used as the situation warrants (deep hole, parallel, distributive, or conventional beds).

Anodes will be made of graphite, high silicon cast iron, mixed metal oxide, platinum, soluble iron, or polymeric.

Anode selection will consider the expected electrolyte composition.

Selection and design with scrap iron should consider confining formations to prevent migration of the resultant corrosion products.

Ground bed performance can be improved by using high carbon backfill.

Deep Well Ground Beds

Advantages

- Require less ROW.
- Produce lower potential gradient fields on nearby protected structures.
- Give better current distribution in complicated ROWs.
- Affected less by seasonal changes in temperature and rainfall.

Disadvantages

- Replacing or repairing is more difficult.
- Obtaining accurate current demand information and performance testing is more difficult.
- Ventilation is required to avoid gas blockage of the anodes.
- Anode backfill material is difficult to compact.
- May pose aquifer contamination problems.

Installation Criteria

- Corrosion Control must approve all deep well ground bed designs.
- Seal the top of the well to prevent surface run off from entering the ground bed (per State Regulations).
- Surface casings, when used, must be externally sealed to prevent water entry (per State Regulations).
- Vent pipe must be installed from the bottom of the anode backfill material to the surface, terminating aboveground and designed to prevent entrance of surface waters.
- Design and install ground bed in a manner to avoid intermixing of underground aquifers (per State Regulations).
- All anode lead wires must be sized, insulated with HMWPE unless conditions warrant the use of dual-extrusion cable such as Permarad, Halar or Kynar and properly installed to protect the wire and insulation integrity so they can perform as designed.
- Each anode will have its own lead wire.

Parallel Ground Beds

Advantages

- Can be used in very high resistance soils.
- Uses minimal ROW.
- Large amounts of current can be applied to small sections of the pipeline.
- May limit interference in congested ROWs with other metallic structures.

Disadvantages

- Does not distribute current over large areas of the pipeline.
- Produces high potential gradients near the pipe, which can complicate potential surveys.

Installation Criteria

- Corrosion Control must approve all parallel ground bed designs.

- Size anode header cable so that all anodes receive sufficient current to meet their design output.
- Location of parallel ground beds should be clearly marked to prevent any excavation damage.
- All anode lead wires must be sized, insulated with extruded HMWPE and properly installed to protect the wire and insulation integrity so they can perform as designed.

Distributed Ground Beds

Advantages

- Distributes current to complex geometries and areas prone to electrical shielding.
- Reduces the possibility of interference problems.
- Allows precise matching of current demand with current output.

Disadvantages

- Each anode has it's own unique area to cover, thus the loss of a single anode can be significant.
- Installation requires more excavation for anode lead wires.
- More susceptible to excavation damage if accurate anode locations are not recorded.
- Since the anodes produce a potential gradient over a wide area, pipe potentials are more difficult to interpret.

Installation Criteria

- Corrosion Control must approve all distributed ground bed designs.
- Size anode header cable so that all anodes receive sufficient current to meet their design output.
- Drawings of exact anode locations and lead wires should be kept to assist with surveys and excavations.
- Mark location of each anode to help prevent excavation damage.

- All anode lead wires must be sized, insulated with extruded HMWPE, and properly installed to protect the wire and insulation integrity so they can perform as designed.

Conventional Ground Beds

Advantages

- Provides good current distribution in low resistivity soils.
- Since the anodes produce less potential gradients around the pipe, potential surveys are easier to evaluate.

Disadvantages

- Requires more ROW for installation.
- Are prone to create interference problems in congested ROWs with other metallic structures.

Installation Criteria

- Corrosion Control must approve all conventional ground bed designs.
- Size anode header cable so that all anode receive sufficient current to meet their design output.
- Location of conventional ground beds should be clearly marked to prevent excavation damage.
- All anode lead wires must be sized, insulated with extruded HMWPE, and properly installed to protect the wire and insulation integrity so they can perform as designed.
- Corrosion Control must approve all distributed ground bed designs.
- Size anode header cable so that all anodes receive sufficient current to meet their design output.
- Drawings of exact anode locations and lead wires should be kept to assist with surveys and excavations.
- Mark location of each anode to help prevent excavation damage.

- All anode lead wires must be sized, insulated with extruded HMWPE, and properly installed to protect the wire and insulation integrity so they can perform as designed.

Galvanic Ground Beds

Advantages

- Require little or no maintenance during their effective life.
- When designed and installed properly they are more reliable than impressed current systems.
- Requires no external power source.
- A way to provide small amounts of current at localized areas.
- Can be used inside vessels.
- Can be used for AC grounding.
- Used onshore to solve localized potential problems.

Disadvantages

- Have a limited current capacity.
- Driving potential is low.
- Consumption rate depends on current density.
- When installed with impressed current, the galvanic anode may be in pick-up (the impressed current may protect the galvanic anode).
- Current output will be very low in high resistance soil.

Offshore Installation Criteria

Offshore piping less than 10 inches OD without a concrete coating require two- piece, semi-cylindrical anode bracelets. For concrete-coated piping, segmented anodes should be used.

Offshore piping more than 10 inches OD may use segmented or semi-cylindrical anode bracelets.

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All pipeline anode bracelets must be inspected during manufacture according to the provisions of NACE International RP-0492-99 “Metallurgical and Inspection Requirements for Offshore Pipeline Bracelet Anodes.”

Corrosion Control must provide detailed inspection and design recommendations if the use of aluminum anodes is required for offshore applications

Electrical connection integrity between the anode and pipeline must be checked during the pipe laying operation. A system employing a reference electrode to detect the potential gradient around each anode as it is deployed is preferred.

Careful design is required when using magnesium alloys in offshore or marsh environments.

Construction of Cathodic Protection Systems

Cathodic protection ground bed installation is a project involving budgeting, design, authorization for expenditure, acquiring easements, environmental approvals, ordering materials, scheduling the installation, performing the installation and, finally, documenting with reports and sketches.

If special circumstances or local requirements require the steps depicted in this section be modified, contact Corrosion Control for recommendations.

Right-of-way easements should be initiated as soon as possible to ensure the project will proceed in a timely manner.

Installation

Only materials approved by Corrosion Control will be installed.

Inspect all materials before installation to ensure material specifications have been met and no damage has occurred.

Anodes are to be:

- Checked to ensure the lead wire is the correct length, securely attached, electrically continuous with the anode, protected from damage during installation, and has sufficient slack to eliminate strain.
- Checked to ensure the connection seal is not damaged.
- Run straight and centered in the hole and be properly supported.
- Replaced, if damaged.

All construction work will be performed according to construction drawings and specifications. Any deviations must be approved by the Company inspector and must be shown on as-built drawings.

Anode backfill will be checked to ensure it is free of foreign material, meets specification, and well-compacted on installation to be as free from voids as possible.

Packaged galvanic anodes are to be kept dry during storage, must have waterproof packaging removed before installation, and back-filled with compacted native soil.

Cable and test lead attachments to pipelines and/or structures will follow procedure

CORR-008: Making Electrical Splices of this manual.

During commissioning of the CP installation, the DC circuit will be checked to ensure the positive cable is connected to the ground bed and the negative cable is connected to the structure.

A Company employee, qualified in corrosion control activities, must inspect and approve each step of the installation process to enforce Company standards and verify compliance.

Only qualified Company personnel may energize a rectifier.

Documentation

Upon completion of the installation, the following must be completed and submitted to the local files:

- List of materials used.
- Rectifier inspection form.
- Design drawings and/or sketches will be prepared to designate the overall layout of the piping to be protected and location of significant items.
- Test stations
- Electrical bonds
- Isolation devices
- Neighboring buried or submerged metallic structures

Layout drawings will be prepared for each impressed current CP installation showing the details and location of the components with respect to the protected structure(s) and to physical landmarks. These drawings will include ROW information. A list of necessary permits will be included in the design.

The locations of galvanic anodes will be recorded on drawings in tabular form with anode type, weight, spacing, depth, and backfill information.

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Operations and Maintenance

Monitoring

Cathodic protection systems are an important and regulated component in Company corrosion control program; therefore, careful maintenance of these systems is essential to maintaining structural integrity and regulatory compliance.

✓Rectifier readings shall be documented on the CP unit record and a minimum of one year's readings maintained at the rectifier, unless remote monitoring is utilized. All records not maintained at the rectifier will be filed at the local field location for the life of the protected structure. In addition to routine monitoring, the following shall be documented:

- Adjustments
- Unit maintenance
- Power outages/repairs
- Ground bed maintenance/addition
- Unit shut down for interruption, rehab or native surveys
- Anytime interrupter is installed and removed

Rectifier readings shall be entered into the PCS database.

Each rectifier should have a LOWER LIMIT SET indicating the minimum DC current output necessary to maintain effective CP. The lower limit will be set in the appropriate company corrosion database for each rectifier based on Annual and Detail Survey history. If only Annual Survey data is available, set the rectifier lower limit at 85% of the normal operating current output.

The Lower Limit will be documented on the CP unit record and entered into PCS as the lower current limit for the unit. When the lower limit is broken, the unit is to be investigated to determine if remedial action is required. If remedial action is required, refer to O&M Manual.

If a unit's current output is raised or lowered, the lower current limit is to be reset accordingly.

Rectifier Inspections

✓After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months

✓Rectifier and ground bed inspections are recommended and after installing a new rectifier, installing a new or partial replacement ground bed, and making rectifier repairs.

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✓The ground bed inspections are normally performed during the rectifier inspections.

✓Rectifier inspections determine the condition of the ground bed and rectifier. During these inspections, any regular maintenance should be done to maintain rectifier operation. Only manufacturer approved, or equivalent replacement parts should be used. Document all rectifier inspections on the appropriate company monitoring form and on the CP unit record.

✓Inspections completed shall be documented on the CP unit record. The inspection will consist of:

- AC potential of the rectifier case
- P/S potential at the closest test point to the ground bed
- Calibrate the rectifier meters
- Read the shunt for the amperage meter reading
- Read across the positive and negative leads for the voltage meter reading

Test with the positive lead of the rectifier connected to the ground rod when the rectifier is on. If the DC amperage does not increase, check the ground rod connection to make sure there is not a high resistance contact or no contact.

If the rectifier has multiple negative leads, or multiple positive leads, a current reading should be recorded for each lead.

If the lower limit is broken an appropriate inspection form is required.

Damage

Damage to rectifiers is normally caused by lightning strikes, power surges, third party damage, or improper operation. Rectifiers subject to frequent lightning or vandalism should receive precautionary treatment such as relocation or special isolation equipment.

When a rectifier operates within 10% of it's maximum rated output, consideration should be given to reducing ground bed resistance or installing a larger rectifier.

When a rectifier receives repetitive lightening damage, the following steps should be taken:

1. Test ground rod resistance. If ground rod-to-earth resistance is greater than 5 ohms, install a lower resistance grounding system. One method is to install a grounding grid in a triangle position and ensure all grounds are connected to prevent a ground loop. The ground rods spacing are equal to the length of the ground rod plus one (1) foot. If 10-foot ground rods are used, the spacing will

be 11 feet between each ground rod. It is recommended to connect the solid ground wire to each ground rod by cad-welding.

2. Surge protection can be used to decrease the number of outages. Ensure that all manufacturers' instructions are followed when installing a surge protector. One recommended surge protector is *The IT Protector*:

- AC protector is connected to the disconnect circuit breaker (Parts # ORN 1-s 120/240 AC).
- DC protector is connected to the negative pipeline lead and the positive ground bed lead (Parts # HP 125 VDC for 125 Volt DC or less output or HP 350 VDC for up to 350 Volts DC output).

For rectifiers located at the end of a power line where damage is caused by AC surges only, an AC surge protector should be placed at the AC disconnect breaker. Do not use the standard procedure that both the AC and DC sides need attention without troubleshooting first.

Impressed Current Ground Bed Inspections

Ground bed inspections are required annually by measuring and documenting the outputs of the anodes and supplying additional information about the condition of the ground bed on the appropriate Company form. Ground bed inspections are also required after:

- Installing a new ground bed
- Installing a partial replacement of anodes
- After repairing a broken header cable
- Output of the impressed current system breaks the lower limit

Impressed current ground bed failure is usually a result of:

- Broken or damaged anode leads or header cable,
- Physically damaged or broken anodes,
- Consumed anodes
- Exceeding anode output

Troubleshooting CP ground beds is accomplished with a multi-combination meter for reading AC/DC voltages and current, a pipe/cable locator, wire jumpers and leads, wire reel, and a soil resistivity meter.

Individual anodes in a distributed or parallel ground bed system must be replaced if they result in the loss of protection in the immediate area of the anode.

Galvanic Ground Bed Replacement

Replace galvanic anode ground beds when potential surveys indicate inadequate cathodic protection. Since galvanic anode output decreases rapidly at the end of their effective life, they need to be monitored annually to ensure they will be replaced as soon as possible after failure. A precision shunt should be installed between the pipeline and anode/anode bed in order to read the current output.

Rectifier Output Adjustment

Base rectifier output adjustments on actual potential survey data not preset current requirements. The following should be considered before making any adjustments:

- Soil moisture and time of year when potential survey was done.
- Never exceed the rated output of the anodes.
- Resistors may be added to individual anode circuits to balance the ground bed output and keep anodes below their maximum rating.
- When the situation requires the rectifier to be operated above 90% of its maximum rated output, plan immediately for additional ground beds or the installation of a larger unit.
- Never operate a rectifier above its maximum rated output.
- Each rectifier should have a Lower Limit set indicating the minimum DC current output necessary to maintain effective CP. When the current output cannot be maintained without exceeding the rectifier capacity, ground bed maintenance must be started as soon as possible.

Determining Monitoring Frequency of Impressed Current Cathodic Protection Current Sources

Cathodic protection impressed current source monitoring frequencies more frequent than required by regulation will be determined by rectifier risk analysis on an individual basis.

Any failures to rectifiers or other cathodic protection current sources will be recorded on the rectifier unit log.

Any rectifier or other cathodic protection current source which has failed in the previous twelve months, according to the cathodic protection current source unit log, will be monitored on an increased basis, and may require corrective action, as illustrated in the following table:

Number of Failures in Previous 12 Month Period	Minimum Monitoring Frequency*	Corrective Action
0 or 1	Six times per year, not to exceed 2½ months	As needed to maintain minimum required current
2	Twelve times per year, not to exceed 45 days	Corrosion Control will evaluate need for corrective action.
3 or greater	Twenty-six times per year, not to exceed 21 days	Corrective action is mandatory

Cathodic protection current sources and critical bonds deemed to require additional monitoring frequency based on risk are excluded from the above analysis and will be monitored per the frequency established by Corrosion Control.

✓*The table above need not apply to remotely monitored currents sources as the sources are continually monitored. Alarmed events such as (AC Power fail alarm, Low Amperage alarm, and Not Reporting alarm) notifications are sent via e-mail notification to responsible technician when such event occurs.

SECTION 5 - Coatings

Introduction

The Natural Gas Pipeline Safety Act "DOT-Title 49-Subchapter D-Part 192-Subpart 461 – External corrosion control: Protective coating and Part 195" states that each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must:

- Be applied to a properly prepared surface,
- Be designed to mitigate any type of corrosion of the buried or submerged pipeline,
- Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture,
- Be sufficiently ductile to resist cracking,
- Have sufficient strength to resist damage due to handling and soil stress,
- Have properties compatible with any supplemental cathodic protection,
- Each external protective coating, which is an electrically insulating type, must also have low moisture adsorption and high electrical resistance.
- Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
- Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
- If coated pipe is installed by boring, driving, or other similar methods, precautions must be taken to minimize damage to the coating during installation.

The Natural Gas Pipeline Safety Act "DOT-Title 49-Subchapter D-Part 192-Subpart 479 – General and Part 195" states that all above ground piping and all structures installed to support above ground piping, which are exposed to the atmosphere shall be thoroughly cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion.

The coating system and/or jacketing material selection and application shall be in accordance with all Company specifications.

Monitoring Guidelines

Regulations

The Natural Gas Pipeline Safety Act "DOT-Title 49-Subchapter D-Part 192-Subpart 481 – Monitoring and Part 195" reads as follows:

> "…Each operator shall, at intervals not exceeding 3 years for onshore pipelines not to exceed 39 months and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, re-evaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion."

EnLink Midstream maintains surveillance of all facilities exposed to the atmosphere whether they are pipelines, supports, or offshore platforms.

Surveillance

Atmospheric corrosion inspections will be conducted according to the following:

1. Offshore facilities are to be inspected and documented on an annual basis not to exceed 15 months.
2. Onshore facilities are to be inspected and documented at intervals not exceeding 3 years and not to exceed 39months. As part of the company continuing surveillance program, any area observed as a Grade 4 whether or not it is time for the 3-year documented survey is to be documented as a deficiency and reported per O&M remedial procedures.
3. All inspections are reported on the appropriate company atmospheric survey form.
4. Inspections may include, but are not limited to, the following:

Compressor Stations	Aerial Crossings
Processing Plants	Spans
Offshore Platforms	Drips
Marsh Valve Platforms	Launchers
Meter Stations	Receivers
Valve Settings	Communication Towers

Valve Operating Platforms	Water Towers
Scrubbers	Water Tanks

Cable-supported overhead pipeline bridges will be evaluated according to the following procedure:

Atmospheric Inspection:

All cable-supported overhead pipeline bridges will have an atmospheric inspection performed on them according to the onshore facilities inspection frequency shown in #2 under "Surveillance" above.

1. Company employees can perform the atmospheric inspection. No Company employees are to walk or climb on the overhead structures or piping unless approved safety precautions, equipment and access are available and used per company safety standards. Observations for atmospheric corrosion can be made from ground level using binoculars or other such devices. If areas on the structures are observed that warrant a closer inspection, a contract inspection company can be used.
2. Contract inspection companies who have demonstrated expertise in inspecting cable supported overhead pipeline crossings can perform the atmospheric inspection, according to company safety and atmospheric inspection standards.
3. The atmospheric inspection frequency for each cabled pipeline crossing is to be entered into a work management system.

Integrity Inspection:

All cable supported overhead pipeline bridges will have a structure integrity inspection performed on them once every 6 years.

1. A contract inspection company with demonstrated expertise in making such inspections may be used.
2. The structure integrity inspection frequency for each cabled pipeline crossing is to be entered into a work management system.
3. During a structure integrity inspection, the qualified contract inspection company should also perform the atmospheric inspection at the same time.

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Deficiencies: Any deficiencies found by these inspections will be monitored and corrected according to O&M procedures.

Documentation

A Company atmospheric survey is to be completed and documented on the appropriate company form or entered in the company PCS database. If any area of above ground piping that is not normally accessible is exposed for any reason, the area will be inspected and documented on the appropriate inspection form. These areas include but are not limited to tie down clamps, piping through building walls, and jacketed piping.

Prioritizing

Coating Assessment

EnLink Midstream uses the following grading system to assess atmospheric corrosion on coating systems. Assessment guidelines must be used to address areas of special concerns.

Grade 1 – EXCELLENT PROTECTION

- Paint in excellent to good condition
- Good bond
- Like new condition

Grade 2 – MODERATE PROTECTION

- Coating chalking
- Areas of rust bleed from external sources
- Poor condition cosmetically
- Coating conditions fair to poor overall

Grade 3 – MARGINAL PROTECTION

- Coating system has failed
- Disbonded areas
- Bare areas – surface rust only
- Rust and scale present
- No measurable wall loss
- Coating on riser does not extend above grade
- Will need attention in the near future (budget item)

Grade 4 – NO PROTECTION

- Needs attention
- Active Corrosion (Measurable wall loss, pitting, etc.)
- KAPA or ASME B31G must be performed on pitted areas greater than 10% wall loss and results documented

Assessment Guidelines

Atmospheric corrosion must be evaluated by a qualified employee. All risers for critical piping will have an atmospheric coating inspection performed on them. This inspection will evaluate the coating at the ground to piping interface for evidence of coating failure, shielding, or corrosion. Proper evaluation may require an area around the riser to be excavated to allow effective inspection the portion of the riser located above ground is also to be inspected to ensure the underground coating extends above ground level. Areas with evidence of coating failure or corrosion at the pipe-to-ground interface will receive a Grade 4 rating. Normally, remedial action will require the re-coating of the riser from the beginning of good coating below grade to above grade with an approved underground coating per the company coating specifications.

Grade 4 items that pass KAPA or ASME B31G will require remediation within 18 months from the date of detection. Grade 4 items failing KAPA or ASME B31G will require repair according to O&M procedure. In some cases, Grade 4 items can be scheduled for correction over an extended period based on sound company engineering practices.

Tie-down clamps are not required to be removed for the sole purpose of inspection based on some repetitive time frame. Each clamp should be visually inspected per the assessment requirements and rated accordingly. The evaluator should rate a clamp a Grade 4 if a problem is thought to exist based on observation of rust bleed, scale, or other indications of corrosion, or if corrosion could occur without those indications being observed.

Piping resting on a pier without a dielectric pad between should be scheduled for installation of a dielectric pad. This should be done on a priority basis over a period of time. In some cases, where the fit between the pipe and pier is so tight, the pier may be scheduled to be rebuilt with chock blocks under the piping.

Piping through walls and floors should be evaluated the same as clamps. If the area between the pipe and wall or floor is too small for visual examination, the evaluator should rate the pipe a Grade 4 if a problem is thought to exist based on observation of rust bleed, scale, or other indications of corrosion, or if corrosion could occur without those indications being observed. The opening should then be enlarged so that the pipe can be inspected. This can be scheduled over a set time frame.

Piping under thermal or noise abatement insulation must be evaluated for corrosion. This may be accomplished by removing the jacketing in selected critical areas until a minimal risk level is determined. Another way is to remove all the jacketing and evaluate the total jacketed system.

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Coating Repair

Coating System Identification

It is acceptable to repair the topcoat if the other coats are in good condition and do not exhibit any signs of corrosion, flaking, or disbondment. The top and intermediate coats may be repaired if the primer exhibits no sign of corrosion. Good practice dictates that the area to be repaired should be roughened up using sandpaper or abrasive blast to promote adhesion to the surrounding coating.

Before removing an existing coating, a sample should be tested for lead unless it has been previously determined to be lead-free. If lead is found, it must be removed, contained, and disposed of according to Company requirements.

The existing coating system must first be identified before being repaired to ensure that the new coating system is compatible. An example of incompatible coatings is top coating an existing inorganic zinc coating with an alkyd. The chemical reaction that takes place will saponify the alkyd, turning it into jelly.

New coatings on the market may not be compatible with existing coatings due to changes made in formulations to meet health and environment requirements. It may be necessary to apply a test patch of the new coating over the existing coating to determine if they are compatible. If the existing coating becomes soft or there is a loss of adhesion, it is not compatible and should not be used. A situation like this may require that the existing coating be removed in order to re-coat.

Factors to consider in determining the type of repair coating to be used are:

- Compatibility of the repair coating to the existing coating
- Surface preparation
- Operating temperature of the pipeline
- Application temperature
- Environmental conditions

The Company Coating Specification Manual contains approved coatings that have been tested for use according to the environment in which it will be exposed.

Surface Preparation

Surface preparation recommended by the Company must be followed to optimize coating performance. All oil, grease, dirt, and other contaminates must be removed before coating application. Improper surface preparation accounts for 80% of all coating failures. Industry standards used to describe surface preparation have been published by NACE

International, Steel Structures Painting Council (SSPC), and Swedish Pictorial Standards. Visual descriptions of some surface preparations are described as follows:

- NACE No. 1, SSPC 5 and Sa-3 (White Metal Blast)

  All rust, scale, and paint are removed to expose a clean white metal, which has a uniform gray-white appearance. Streaks and stains of rust or other contaminants are not allowed.

- NACE No. 2, SSPC 10 and Sa-2 (Near White Metal Blast)

  This provides a surface about 95% as clean as a white metal blast. Light shadows and streaks are allowed.

- NACE No. 3, SSPC 6 and Sa-3 (Commercial Blast)

  This provides a surface about 2/3 of a white metal blast. Very slight residues of rust and paint in the form of staining are allowed.

- NACE No. 4, SSPC 7 and Sa-1 (Brush Off Blast)

  Loose deposits of rust, scale, and paint are removed. Tightly adhered deposits are permitted to remain.

- SSPC-SP 2 (Hand Tool Cleaning)

  Same as a brush off blast except hand tools are used.

- SSPC –SP 11 (Power Tool Cleaning to Bare Metal)

  All surfaces shall be free of visible oil, grease, dirt, dust, rust, scale, paint, oxides, corrosion products, and other foreign matter. Slight residues of rust and paint may be left in the bottom of pits if the original surface is pitted. The surface profile shall not be less than 1 mill (25 microns).

Visual standards are available, and all personnel involved in surface preparation must have a set.

Hand and power tool cleaning are used where localized small areas of surface preparation are required or in areas where blast cleaning would be detrimental to operating equipment.

Blast cleaning is used when large areas are to be prepared and a certain degree of cleanliness is specified.

Fusion bonded epoxy powder, liquid epoxy, and coal-tar epoxy require abrasive blasting.

Anchor Pattern

The life of a coating system depends on surface preparation and adhesion to the substrate. There are two types of adhesion: molecular, where the coating must come into intimate contact with the metal substrate, and mechanical, which depends on the shape and depth of surface irregularities. Any interference from moisture, dirt, scale, or rust will prevent close contact and decrease both types of adhesion.

Abrasives should be tested for oil and grease by placing abrasives in a bottle, adding water and mixing. Examine the water layer for oil and grease and if contaminates are present, reject the abrasive. Bulk abrasives must be tested to ensure that they meet Company coating specifications for size of particles and purity (cleanliness).

Studies have shown that coating over abrasive blasted steel has lasted up to three times as long as wire brushed steel. Various abrasives can be selected to produce varying degrees of anchor patterns. Some common ones are:

Black Beauty BB-50, BB-240, G-40 steel grit	2	mil profile
Black Beauty BB-400, G-40 steel grit	2.5	mil profile
Black Beauty BB-40, BB-25, G-25 steel grit	3-4	mil profile

Once the abrasive has been selected and substrate blasted, the anchor pattern will be checked for required depth. There are many different methods for determining the anchor profile, but the easiest is Testex Press-O-Film replica tape. The procedure is:

1. Ensure the surface is free of loose dirt and dust and is below 130ºF.
2. Adjust the gauge to zero with the anvils touching.
3. Remove the backing paper from the tape and measure the film thickness at the center with the gauge. The thickness less 2 mils is the maximum surface profile the tape can measure. If the measurement is outside the expected anchor pattern depth range, a different tape must be used.
4. Place the adhesive side of the film on the steel surface and rub a burnishing tool with a round end over the central window. Continue to rub until the circular area darkens uniformly.
5. Remove the tape and measure with the gauge. The surface profile is the reading less 2 mils.

Application

The Company Coating Specification Manual contains application methods for all approved coating systems. Common methods are conventional air spray, airless spray, plural component, brush, rollers, and flood coating. The application of fusion-bonded epoxy

(FBE) is a special case where the powder is fluidized and either flocked or sprayed on a hot surface.

When applying coatings, some common points to take note of are:

1. When an air compressor is used, check the air for moisture and oil/grease contaminates by placing a white rag over the hose end while air is being discharged. If the rag shows moisture or oil/grease, replace the compressor filters.
2. The surface must be free of all contaminates that may have deposited since the abrasive blasting process.
3. **Do not apply coating when the surface temperature is less than 5ºF (2ºC) above the dew point.** The procedure for checking the dew point is covered in the Coating Specification Manual.
4. Check the substrate temperature to make sure the manufacturers recommended minimum or maximum application is not exceeded.
5. Abrade the existing coating to provide adhesion for the new coating (minimum NACE #4).
6. Apply the coating and allow it to cure according to manufacturer or Company specifications.
7. Immediately after application, check wet film thickness in 2 or 3 locations with a wet film thickness gauge. To determine dry film thickness, see *Wet and Dry Film Calculations* on page 154 in this section.

Store coatings according to manufacturer recommendations before use. Pay special attention to the temperature of the storage area. The storage room should be kept locked and only qualified personnel should be authorized to remove coating and thinner. Turn the coating containers over once each month to help keep the pigment from settling. Note the expiration date on all coatings and use them before expiration. If this cannot be done, return to the manufacturer before expiration.

Coating material should be thoroughly mixed and agitated at select intervals to keep the material completely homogeneous. Gallon containers should be mixed by hand frequently to keep the material mixed. Small mechanical mixers and shakers are available for use in mixing 5-gallon containers. Applicators that use drums may order them with built-in mixers, which can be connected to a hand crank or a motor. When a drum is used for brush painting, it should be kept under nitrogen and continuous mixing via propeller-type mixers inserted in the drum and driven by electric or air motors. **Electric motors should be explosion proof**.

To ensure each coat is applied to the recommended coverage and thickness, only qualified personnel will thin coating material according to manufacturers' specifications. If the material becomes too thin, adequate thickness cannot be met without applying extra coats or the material will run and sag. The manufacturers' recommended thinner must be used to ensure it is compatible. If incompatible thinner is used, resin in the coating material may come out of solution and ruin the material. In most cases, coating material should be initially applied in the "as received" condition to determine the ease of application, flow and leveling characteristics, film build, running, and sagging tendencies.

Modern spray equipment is capable of atomizing most paints, so thinning might not be required. See *Wet and Dry Film Calculations* on page 154 in this section to determine the effects of thinning on determining wet film requirements.

Inspection

Inspection must occur after the steel surface has been cleaned before being coated and after coating. **No steel is to be coated before it is inspected.**

Check the cleaned surface after the initial cleaning and after any stripe coating before applying the primer coat for the following:

- Moisture and oil/grease on the surface
- Dirt, soil, or chalk marks that are visible to the eye
- Flash rust
- Rust and mill scale
- Residue from the cleaning operation
- Check substrate temperature and record
- Check profile depth
- Check existing coating for abraded surfaces

After coating application, check for:

- Wet film thickness
- Dry film thickness
- Completeness of coverage especially on hard to reach surfaces
- Correct coating material used
- Mark runs, sags, brush marks, etc. for elimination
- Visually check coating for poor quality or orange peel appearance
- Check for blisters, pores, crazing, cracking, etc.

If any of these requirements are not met, the job is to be rejected and corrected at the applicator's expense.

The coating must be allowed to cure to manufacturers' specifications prior to backfilling.

Inspection Tools

Sling Psychrometer

Consists of two identical tube thermometers, one of which is covered with a wick or sock saturated with water. The covered thermometer is called the *wet bulb* and the other is the *dry bulb*. Rapidly whirl the sling psychrometer for 20 seconds, then take the wet bulb reading. Repeat this cycle until the wet bulb temperature stabilizes – three consecutive readings are the same. Read and record the wet and dry bulb temperatures. Use these readings and the psychrometric chart to determine the relative humidity and dew point.

Wet Film Gauge

A notched gauge that is firmly pressed into the wet film perpendicular to the substrate and withdrawn. The wet film depth is considered to be between the last wetted step and the next higher dry one.

Testex Press-O-Film

A tape that measures the peak to trough depth of the anchor pattern.

SSPC Visual Standards for Abrasive Blast

Pictorial abrasive blast samples used to compare substrate cleanliness.

NACE Visual Standards for Abrasive Blast

Metal abrasive blast samples encased in plastic used to compare substrate cleanliness.

Surface Thermometers

An instrument with a bimetallic sensing element shielded from drafts and two magnets on the sensing side for attachment to ferrous substrates.

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Dry Film Thickness Gauge

A magnetic pull-off gauge from manufacturers such as Mikrotest, Positest, Elcometer, and Pencil. Electronic gauges are also available. Calibrate the gauge before, during, and after each use. Calibration blocks similar to those supplied by the National Institute of Standards and Technology **must** be used to verify calibration.

30X Illuminated Inspection Microscope

Use to examine coatings for defects, contaminants in the anchor pattern, etc.

Holiday Detector

Used to detect holidays in coatings. Voltage used is determined by the coating being inspected. In the absence of a specification for the detector voltage, a rule of thumb of 100 V per mil can be used.

Procedures for using these tools can be found in the Coating Specification Manual.

Record Keeping and Forms

Records of coating applications should be kept and include information on location, coating system used, manufacturer, coating specification, date, surface preparation, application method, weather conditions, dry film thickness of each coat and inspection remarks.

Wet and Dry Film Calculations

Coating Thickness

Coating thickness can be measured directly after application while the film is still wet or later after it has dried. Wet film thickness measurements serve as an aid in evaluating coating application coverage required to obtain specified dry film thickness. The dry film to wet film ratio is based on the percentage of solids by volume in the coating being used. This information is available on manufacturer data sheets.

The basic formula is:

dry film thickness divided by % solids by volume = wet film thickness

Example: A coating specification calls for a dry film thickness of 5–6 mils. The coating material has 30% solids by volume. What range of wet film thickness will most likely dry down to the desired dry film thickness?

Answer: Since high and low values have been stipulated, both will be calculated.

Low = Dry / % Solids = Wet = 5 mils / 0.30 = 16.7 mils

High = Dry / % Solids = Wet = 6 mils / 0.30 = 20.0 mils

Since wet film thickness is not a very accurate indicator, the wet film thickness can be estimated over a range. In this case, 17 to 20 mils should cover the specification.

If the coating material is thinned, this must be taken into consideration. Thinning increases the total volume without increasing the amount of solids. The formula with thinner added:

Dry film thickness x (1 + % thinner by volume) divided by % solids by volume = wet film thickness.

Example: A coating specification calls for a dry film thickness of 3–4 mils. The coating material has 35% solids by volume. The coating was thinned by adding one pint of solvent per gallon of coating material. What range of wet film thickness will most likely dry down to the desired dry film thickness?

Answer: Since high and low values have been stipulated, both will be calculated. Also, one pint is 12.5% of a gallon or 0.125 gallons.

$$\text{Low} = \frac{\text{Dry x } (1 + \%\text{Thinner})}{\%\text{Solids}} = \text{Wet} = \frac{3\text{ milsx}(1 + 0.125)}{0.35} = 9.6\text{ mils}$$

$$\text{High} = \text{Dry x } \frac{(1 + \%\text{ Thinner})}{\%\text{ Solids}} = \text{Wet} = \frac{4\text{ mils x }(1 + 0.125)}{0.35} = 12.9\text{ mils}$$

Again, since wet film thickness is not a very accurate indicator, the wet film thickness can be estimated over a range. In this case 10 to 13 mils should cover the specification.

To read a wet film gauge, first the teeth of the gauge should be placed against the coated surface perpendicular to the plane of the surface. **Do not smear or produce any sideways motion when withdrawing the gauge**. As an example, if the tooth marked 4 is wet and the next higher number tooth is dry the wet film is between 4 and 5 mils thick. If 5 mils wet film was the required thickness, the applicator needs to be instructed to apply a thicker wet film.

Safety

The Company has a continuous and enforced safety program. **Before any coating application, the Safety and Health Handbook will be reviewed**. All personnel must be aware of potential hazards and the appropriate safety measures available. Disregard of any safety measure increases the potential danger that an accident will occur or creates a situation where health might be impaired due to excessive exposure. Material Safety Data Sheets (MSDS) for the coatings being used are available and should be reviewed prior to the coating job.

Coating Evaluation Tests

The selection of a coating system and application shall be in accordance with Company specifications. The Company evaluates and approves coating systems to obtain materials suitable for diverse field environments that will perform well and provide a long service life. The tests evaluate and analyze manufacturers coating systems against each other in identical laboratory environments.

The following accelerated tests are performed in the Company Coating Laboratory on external pipe coatings:

- **Salt Fog:** Determines how well a coating will resist a severe chloride environment. This is in accordance with ASTM-B117 where the cabinet temperature is 95ºF and the salt solution is 5%.
- **Accelerated Weathering:** Determines how well a coating will resist to some extent atmospheric weathering conditions which show how well a coating will retain gloss before chalking. Coating samples are subjected to cycles of UV "B" wavelengths for 20 hours and humidity for 4 hours for a total of 1,000 hours. The samples are evaluated every 100 hours using a glossmeter.
- **Abrasion Resistance**: Determines the abrasive resistance of a coating using a Taber Abraser. The results are recorded in milligrams of coating loss.
- **Impact Resistance:** Determines how well a coating will resist hard hits due to handling, shipping and installation. Readings are recorded in inch pounds of force from a Gardner Impact Tester with a 5/8" diameter impact head.
- **Immersions:** Determines the chemical resistance of a coating under different solutions, which may be present in the atmosphere. Five solutions currently used are distilled water, 5% caustic (sodium hydroxide), 1% acid (nitric acid), 5% sodium chloride and a hard water solution (saturated magnesium sulfate and calcium carbonated). The samples are immersed for 90 days then checked for film softening, disbondment, blistering, and any other unusual phenomenon.
- **Splash Zone:** Simulates offshore wave action. Samples are placed in racks located in a tank containing 5% sodium chloride solution. A motor-driven paddle simulates wave action for 90 days, then the samples are evaluated below the water line, at the waterline and above the waterline.

- **Cathodic Disbondment:** Determines, to some extent, the resistance of a coating to undercut and disbond. A 1/8" holiday is intentionally drilled in the holiday free sample, then the sample is placed in a 3% sodium chloride electrolytic solution. A platinum wire anode is placed in the solution with 3 volts DC impressed on the sample. After 90 days, the sample is evaluated for disbondment.
- **Flexibility:** Determines the coating flexibility by bending the sample to a degree anticipated in the field. A Carver Press is used to bend the samples to the equivalent of a maximum field bend at temperatures of 75^o, 32^o, and 0^{o}F.

SECTION 6 - Internal Corrosion Control

Introduction

EnLink Midstream pipelines normally transport "non-corrosive" commodities. Corrosion Control will designate when a commodity stream in a section of piping is "corrosive." Corrosion Control will make the final determination on whether a particular pipeline section is transporting a corrosive commodity or is no longer transporting a corrosive commodity. A corrosive commodity is defined as a combination of gas, LPG, water, and/or other contaminants occurring at operating conditions that may result in significant metal loss of the pipe or component wall.

Gas and liquid quality standards are set, in part, to minimize internal corrosion. However, pipeline commodity corrosivity cannot be determined from these standards alone. Industry experience has shown that water and corrosive impurities can unintentionally enter the pipeline due to operational upsets or slowly accumulate in low spots despite commodity quality monitoring that shows adherence to quality standards. In addition, a commodity that does not meet these standards is not necessarily corrosive. Identification of a corrosive commodity in a pipeline is achieved by analysis of operating conditions, commodity impurity content, monitoring data, mitigation schemes, and/or other considerations.

See EnLink Internal Corrosion Guide for further procedures to identify, mitigate and prevent internal corrosion in hazardous liquid and natural gas pipelines.

Responsibilities

The Area Manager is responsible for ensuring that qualified personnel perform the required procedures.

Commodity Quality Standards

If operational upsets occur or commodity quality waivers are granted, Area corrosion technicians will be contacted and provided with conditions associated with these upsets or waivers.

Corrosive Commodity Streams

Corrosive Constituents

Because of the complex nature and interaction between constituents that makeup gas (i.e., O_2, CO_2, H_2S, etc.), liquids (i.e., pH, chloride, bacteria, etc.) and LPG products, changes of these impurities being transported in the pipeline may affect whether a corrosive condition exists. Therefore, gas, liquids, LPG and operating conditions must be monitored and evaluated on an individual basis in order to accurately assess the effects of their presence and/or absence in the pipeline.

Scheduling

Routine monitoring shall be performed by the frequency schedule deemed by area corrosion technicians.

Sampling

An effective internal corrosion-monitoring program includes sampling and analysis of liquid, gas, and solid materials.

Liquid Sampling

A liquid sample, when available, shall be collected when a gas or LPG pipeline, vessel, meter tube, or tank is opened for maintenance, removal, or inspection.

A liquid sample, when available, shall be collected during pigging operations at pig receivers. When pig runs are made on internally coated lines, check the samples for evidence of coating debris. If a sample is not taken, this shall also be documented, and a reason given.

Selecting and Preparing Sampling Locations

Sampling points shall be chosen carefully to enhance the detection of water and/or solids in the line. Sampling locations may include:

- Pig Launchers/Receivers
- Drips (Pipeline, Meter Station, Compressor Station, etc.)
- Dead Ends (isolated sections of pipe with no flow)
- Vessel/Header Drain Lines
- Tanks
- Liquid Recovery Vessels (Slug Catchers, Separators, and Scrubbers)
- Meter Tubes

- Side streams and sample loops
- Low areas, sags, river crossings, etc.

Sample pots may be added to each sample valve as needed to provide at least 8-ounce samples. Sample pots and accessories should be a suitable corrosion resistant alloy or holiday-free, internally coated carbon steel. A double valve arrangement is recommended with one valve on top and one on bottom of the pot. When liquids are collected the upper valve should be completely open then the bottom valve should be slowly opened to collect the sample in a safe manner. The upper valve can be used to isolate the sample pot from the line especially if the bottom valve fails.

Sample Analysis

Compositional analysis is normally performed on the aqueous phase of a liquid sample. Since aqueous liquid samples undergo both qualitative and quantitative changes with time while being held in any sample container, the sample collected shall be analyzed on-site without delay by one or more of the tests listed below:

- Bacteria Cultures
- pH
- Total Alkalinity
- Temperature
- Dissolved hydrogen sulfide
- Other tests as specified

All sampling information can be reported in the PCS database or other any other documentation that may be provided by third parties.

Commodity Sampling

Commodity composition values obtained from a sample point at one location may be considered representative of the commodity stream at any other location in the pipeline section provided no additional commodity sources are present between the two locations.

Data included in a commodity composition analysis for corrosion purposes may include the following measurements:

- CO_2
- O_2

Additional data collected or measured on-site may include temperature, pressure, H_2S and water content. Factors affecting these properties should be considered when determining how well one sample point represents other locations. Commodity composition and physical measurements shall be recorded in the PGAS database for natural gas and into the Flo-Cal System for hazardous liquids.

Solid Sampling

A solid sample, when available, shall be collected from a pig receiver, equipment bottom, or open pipe, in order to perform the following procedure:

Samples collected should be analyzed on-site without delay when one or more of the tests listed below are to be performed.

- Bacteria culturing or fixation
- Other tests as specified

All sampling information can be reported in the PCS database on the Compositional On-Site Measurement Form and/or the Bacteria Form.

Shipping of Samples for Laboratory Analysis

All samples should be packaged and shipped in accordance with the shipper's requirements. All samples should be coordinated through the appropriate laboratory.

Coupons and Probes

Corrosion coupons can be used to monitor the corrosivity of an environment and evaluate the effectiveness of mitigation measures. Corrosion Control will determine coupon locations for both weight loss and SEM coupons.

Electronic probes can also be used to monitor the corrosivity of an environment and evaluate the effectiveness of mitigation measures.

Mitigation

If a commodity is determined to be corrosive, Pipeline Integrity can assist an internal corrosion mitigation technique. Mitigation techniques include but are not limited to chemical treatment (e.g., corrosion inhibitors, biocides), gas dehydration, cleaning pigs, line sweeping (increased velocities), internal coatings, facilities design and maintenance, materials selection, and cathodic protection.

Chemical Treatment

Selection of treatment chemical and method of application will be determined by Corrosion technicians and based on review of monitoring data and operational parameters. Chemical treatment injection systems shall be maintained and inspected. Monthly equipment inspections shall be recorded in the PCS database on the Chemical Continuous Form, batch or slug treatment information shall be recorded on the Chemical Batch Form.

Pigging

Corrosion control will specify pigging requirements including frequencies for each pipeline in the site-specific plans. While pigging operations are performed for a number of reasons they can also serve as a means to collect samples from the pipeline to monitor internal corrosion. All pigging operations shall be monitored for corrosion concerns, and all pertinent data shall be recorded in the PCS database.

Inspection

If the internal surface of any equipment is exposed and available for visual inspection, it shall be examined by qualified personnel to determine if corrosion has occurred. All pressure piping that is opened for any reason shall be inspected for internal corrosion, including areas accessible during pigging operations and recorded on the Bellhole Report.

Internal corrosion investigations shall include one or more of the following:

- Intelligent pigging (magnetic flux leakage or ultrasonic)
- Ultrasonic thickness
- Visual inspection done by checking the inside of the pipe both longitudinally and circumferentially
- Camera inspections
- X-ray
- Analyzing samples
- Other approved methods

SECTION 7 - Interference

Introduction

This section describes the rationale, definitions, and procedures that shall be followed to comply with the Code of Federal Regulations, Title 49-Subchapter D-Part 192-Subpart 473(b) and part 195 which reads:

> *Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.*

This regulation requires that the design of cathodic protection systems take into consideration existing underground metallic structures and the mitigation of possible interference currents.

This regulation does *not* require the Company to provide cathodic protection for new foreign structures that encroach into the Company's existing potential gradient field or existing metallic structures. It is the foreign company's responsibility when their cathodic protection systems fail or where the foreign company chooses not to provide protection for their facilities.

Bonds

A courtesy bond may be established to a foreign structure to mitigate stray current interference until the owner installs or repairs their cathodic protection system. The foreign operator shall be informed that this is a courtesy bond and that it shall only be maintained temporarily. These courtesy bonds shall be monitored to determine the foreign operator's progress. Courtesy bonds may be disconnected after notification if the foreign company has not abided by the courtesy bond agreement. EnLink deems, if necessary, the bonds be replaced.

A Current Exchange Agreement may be established only by agreement of both companies. A Current Exchange Agreement is a negotiated current bond that provides a benefit to one or both parties and is in effect only as long as both parties are in agreement. This type of bond requires a formal legal agreement signed by representatives of both companies. Either party may end it with 30-day notification.

If a bond is lost for any reason, it must be reinstalled as soon as possible (normally as soon as it is detected). The qualified corrosion person responsible for the area should maintain a supply (amount depends on number and type of bonds in their area of responsibility) of bond material (nichrome wire of various resistance's per foot), shunts, or various resistors.

Return to TOC

A critical or non-critical bond requires an interference test any time the normal conditions at the crossing substantially change.

No bond is to be installed or removed without an Interference Test being conducted and documented unless, EnLink corrosion technicians deems it's not required.

A *critical bond* is one which the loss of would have a detrimental effect on company facilities. A *non-critical bond* is one which the loss of would have a detrimental effect on the foreign facility. A *continuity bond* is one that bonds company systems together.

A precision resistance shunt should be installed in a bond test station to allow the current to be read without unhooking the bond or the bond current should be read with a clamp on ammeter. When a bond is disconnected to allow an ammeter to be inserted to read the current, the circuit conditions will change (polarize/depolarize) from their normal state. If a precision shunt is not installed and the current is to be read with an ammeter, the following procedure should be used to keep the circuit conditions changes to a minimum:

1. Hook the ammeter up across the terminals to the bonded structures first.
2. Disconnect the metallic connection between the structures.
3. Take the current reading.
4. Connect the structures.
5. Disconnect the ammeter.

Test Facilities

Interference test facilities should be installed and maintained at underground metallic crossing.

If a condition exists at a site such that a test facility cannot be maintained, tests may be performed by taking shunted readings.

Additional interference tests sites include:

- Meter stations with insulating devices between Company structures and foreign structures.
- Where pipelines run parallel in high resistivity soils and encounter an area of relatively low resistivity soils.
- Areas where above ground metallic structures have electrolyte contact, such as power and telephone systems, grounding systems, fences, etc.

Interference test facilities shall include two wires for each structure, one for current and one for potential measurements.

- The preferred color for wires on Company structure is black.

- The preferred color for wires on the foreign structure is white.

The color of the test wires identified by structure shall be recorded on the appropriate company report and in the test station (or bond box) when the facilities are installed.

Wire connections to underground metallic structures shall be made by thermite welding, pin brazing, or silver soldering. The connection shall be tested for mechanical strength and electrical continuity. All connections shall be coated with an approved coating system.

A copy of all interference test performed will be compiled and maintained in the cathodic protection database PCS. These test locations include points where the Company's pipeline system intersects with foreign metallic structures and other interference test stations. This includes steel pipelines, cast iron pipe, cables with metallic shielding, grounding systems, telephone cables, electric cables, and other metallic structures. A list of foreign line crossings, including metallic, above ground, and below ground facilities will be maintained in the appropriate company databases.

Attachments to, probe bar contact to, and excavation of foreign structures are at the discretion of the foreign structure owner and shall not be made by Company personnel. Probe bar contacts to Company structures for interference testing are not allowed unless the area is immediately excavated to repair coating damage.

Monitoring

All identified interference test stations shall be evaluated during annual or close interval surveys and the status shall be recorded in the cathodic protection database. Any unexplained indications of current pickup or discharge will be evaluated as to cause.

Anytime company personnel become aware of a foreign company altering their cathodic protection levels, it is the responsibility of qualified field corrosion personnel to check all company structures that could be affected by the change.

Where interference is suspected a joint interference test shall be scheduled within 30 days of discovery and testing should be completed as soon as the owner(s) representatives are available.

If indications of severe interference are discovered that might pose an immediate hazard to the Company structure or effect an area where public safety is a concern, Corrosion Control will be contacted for input.

Severe interference may require immediate installation of temporary corrective measures until definitive testing and remediation is completed.

Any area where company readings indicated a **positive potential** is to be immediately corrected in the shortest period possible.

Written documentation of all requests for interference testing and responses shall be maintained. Written documentation may be by letter or email and should contain the following information:

- Location of the area of concern
- Contact name
- Request for an exchange of cathodic protection operating history.

If the ownership of a foreign structure cannot be readily determined, then a reasonable effort shall be made to ascertain the ownership, especially if testing determines that the company's cathodic protection could be affecting the foreign structure.

If joint testing or installation of test leads is requested and the owner of the foreign structure does not respond in a timely manner, a registered letter will be sent. The registered letter should contain the same information as above:

- Location of the area of concern
- Contact name
- Request for an exchange of cathodic protection operating history.

The registered letter should be kept for the life of the system. If there is no response, the company will proceed as deemed necessary.

Possible interference indications can be many and varied.

Routine interference / stray current evaluations are done by comparing several "On" structure to $CuCuSO_4$ potentials.

There is not a potential or millivolt variation that indicates possible interference.

The mixing of IR at most interference test stations will result in some variation in potentials. This is not necessarily an indication of corrosion due to ionic current discharging from one of the structures.

Stray current discharge from an unprotected metallic structure can occur at relatively small potential variations.

At the line crossing, measure potentials over the crossing and both directions going away from the crossing.

Potentials from both structures should be measured.

An indication that interference may be occurring is markedly lower potentials at the crossing on one of the structures with the potentials returning to normal as you proceed away from the crossing.

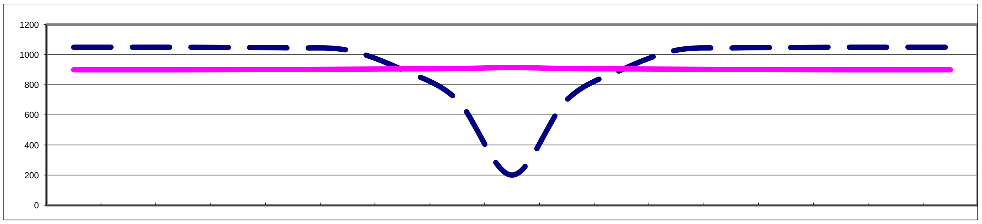
Potentials on the second structure may show a slight increase at the crossing, diminishing in both directions away from the crossing.

Potentials that are slightly lower at the crossing and slowly increase moving away from the crossing normally do not indicate interference.

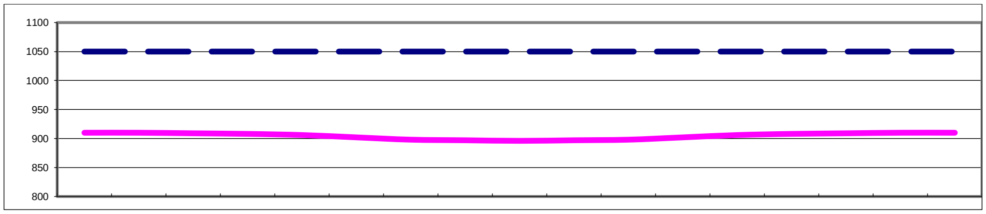
On potentials that are depressed below the normal solution potential of steel in the particular soil in the area may indicate severe interference conditions.

Stray current corrosion of unprotected structures may be indicated if a relatively small potential indication is noted; however, the same profile would normally be seen.

A plot of the potentials indicating interference might look similar to this:



A plot of the potentials not indicating interference might look similar to this:



The definitive indication of interference or stray current is net current loss at the crossing. Current loss can be measured with current spans, clamp on meters, or inductive current measuring instruments.

Potential measurements at risers many times are lower than away from the riser. This may not indicate interference but be due to less IR being included in the reading. It also may indicate coating failure on the riser.

Cycling of current sources will usually shift potentials in one direction or the other. This may or may not indicate interference or stray current corrosion.

On a freely corroding structure (without cathodic protection), shifts in potential may be difficult to interpret.

Precautions

The source of the interference or stray current may not be the cause. For example, where a pipeline crossing that has exhibited normal protection on both pipelines but suddenly has a depressed potential on one and testing confirms a current discharge may be caused by:

- The failure of a ground bed or reduction in the protective current on the second structure; or
- Grounding of the second structure to the AC ground system; or
- Construction of a third structure that provides a new path for current flow, or
- Installation of a bond to a third party, etc.
- A bond installed to correct an ionic current discharge may cause additional problems.
- AC interference on one structure will flow through the bond to the other structure.
- New interference sites may result away from the bond.
- Current distribution of existing cathodic systems will be reduced.

Interference Testing

Potential Shift Testing Procedure

1. Record the normal operating parameters of the associated cathodic protection stations on the affected structures.
2. With all cathodic protection stations on, conduct and document a close interval P/S potential survey of all lines to locate the point of maximum potential depression. A maximum of 3-foot intervals is generally adequate.
3. Interrupt all cathodic protection station(s) individually until the source cathodic protection station(s) is/are identified.
4. At point of maximum depression, record ON and OFF P/S potentials on all structures.
5. Return source cathodic protection station(s) back to normal operation
6. Interrupt cathodic protection station(s) on structure with the depressed potential.
7. Record ON and OFF P/S potentials on all structures.
8. Return cathodic protection station(s) to normal operation.
9. Determine desired P/S potential value.

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10. Select and install appropriate mitigation methods, then re-test.
11. If bond is installed, record ON and OFF P/S potentials on all lines with mitigation installed.
12. If bond is installed, record bond current and polarity.
13. Profile all lines at a maximum of 3-foot intervals and record the ON and OFF potentials with the bond installed.
14. Allow the structure polarization to stabilize (usually 1-3 months), then re-profile the ON potentials all structures to ensure the depressed potential has been corrected.

Future testing and monitoring should include checks to ensure the associated cathodic protection stations are being maintained at the level established during the initial test.

Net Current Loss Procedure

1. Record the normal operating parameters of the associated cathodic protection stations on the affected structures.
2. With all cathodic protection stations on, conduct and document a close interval P/S potential survey of all lines to locate the point of maximum potential depression. A maximum of 3-foot intervals is generally adequate.
3. Interrupt all cathodic protection station(s) individually until the source cathodic protection station(s) is/are identified.
4. At point of maximum depression, record ON and OFF P/S potentials on all structures.
5. Return source cathodic protection station(s) back to normal operation
6. Install current span(s) on depressed structure and calculate or measure resistance.
7. Measure and record IR drop in the current span(s) with all rectifiers on.
8. Interrupt the source rectifier and record the interrupted IR.
9. Calculate the change in IR and convert to net current loss.
10. Alternate current measuring techniques may be used to determine net current loss.
11. Select and install appropriate mitigation methods, then re-test.
12. If bond is installed, record profile all lines at a maximum of 3-foot intervals and record the ON and OFF potentials with the bond installed.
13. Allow the structure polarization to stabilize (usually 1 to 3 months), then re-profile the on potentials all structures to ensure the depressed potential has been corrected.

Future testing and monitoring should include checks to ensure the associated cathodic protection stations are being maintained at the level established during the initial test.

Section 7A: Interference Mitigation from impressed current Cathodic Protection systems

There are various ways to mitigate interference. No one way will work all the time in all situations. There may be cases where several remediation methods may be needed at the same time.

Precaution:

Before any mitigation activity can begin, conduct mutual interference tests where the output of the suspected source is cyclically interrupted and field measurements are taken in the presence of representatives of the interfering and interfered-with companies involved. Interference issues may often be reported through local electrolysis committees, especially where there may be more than one interfered-with party. Presuming a need for mitigation is determined, the mutually acceptable mitigation technique(s) depend on the location and severity of the interference, on the cathodic protection operational preferences of each party, and on the relative capital and maintenance costs of the mitigation options.

Mitigation Methods:

- **The interfering source of current can be shut off, relocated, or removed**
- **Install electrical isolating fittings in the interfered-with (foreign) structure.**
- **Bury a metallic shield (electrolytic shield) parallel to the interfered-with structure at the stray current pick-up zone.**

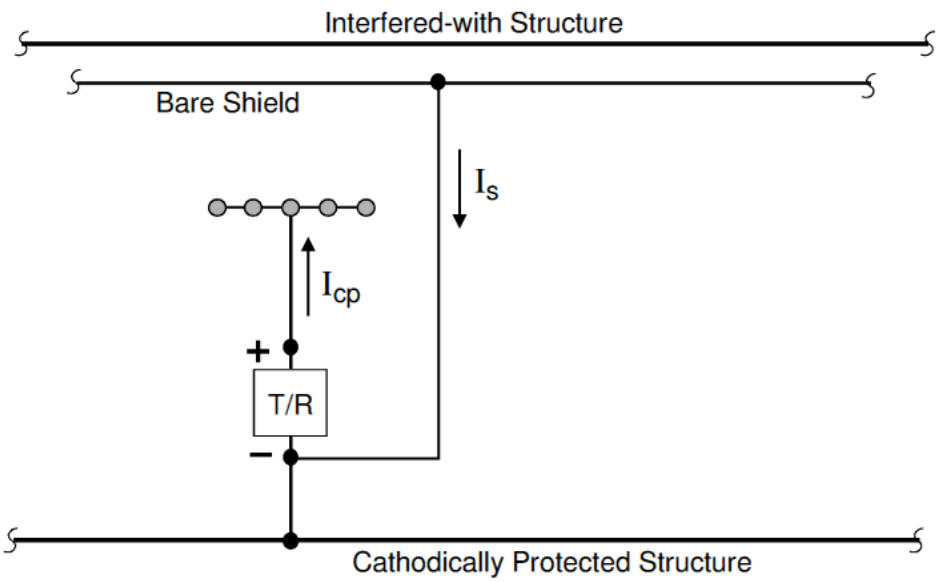

Figure: Using a Buried Metallic Cable or Pipe as a Shield to Reduce Stray Current Interference

- **Install additional cathodic protection at current discharge locations on the interfered-with structure.**

  A galvanic anode current drain, in some cases, can be used to reduce the amount of current flowing through a metallic bond. Magnesium anodes are normally used due to their higher open circuit potential. The number, type, and size of anodes used depends on the soil resistivity, length of area with the potentials depressed, and expected life of the anodes. Anodes are normally installed by the line with the more negative P/S potential. Two test leads to each structure and the leads from the galvanic anodes are to be run to the same test station

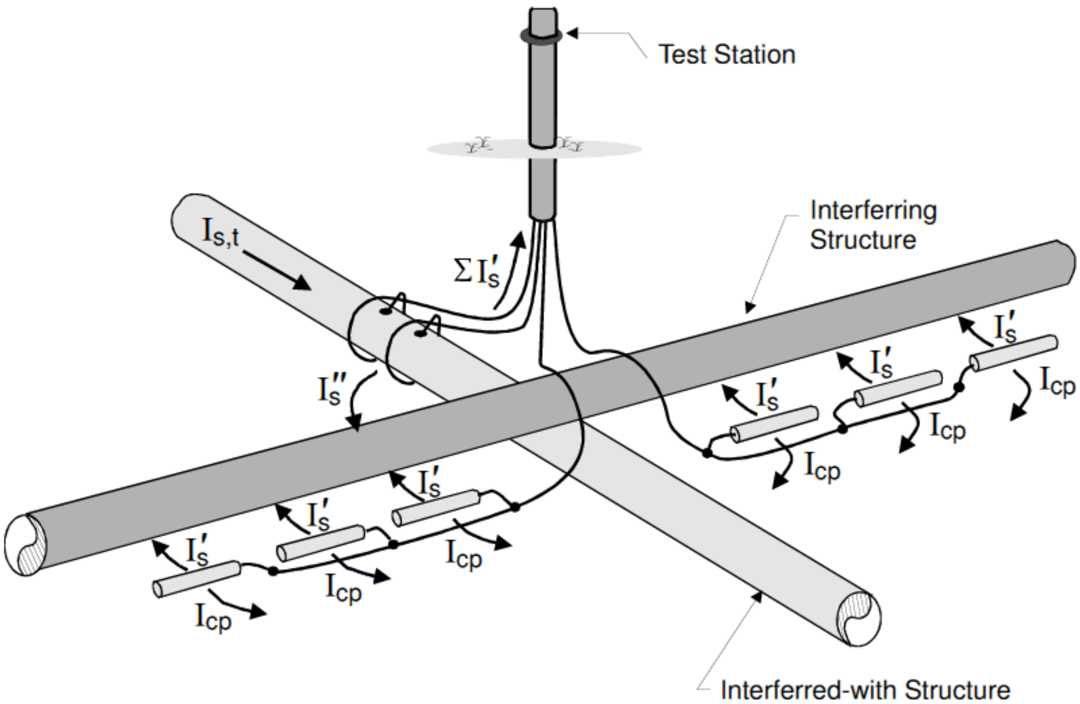

Figure: Interference Mitigation using Galvanic Anodes at Stray current Discharge Location

- **A forced drainage bond (using a rectifier and ground bed to mitigation interference) can be installed.**
- **Install a reverse current switch**
- **Install a (metallic or resistance) bond between the interfered-with and interfering structure.**

  If a resistance controlled metallic bond is needed, insert the bond and adjust bond resistance to obtain the desired potential. Bonds should never be installed unless the field corrosion control personnel are aware of what the effect of the loss/gain of current will have on the Company structure and foreign structure not only at the crossing, but in an area both sides of the crossing. The installation of the bond creating a loss of cathodic protection current to the interfering structure can affect the pipeline lines protection level many miles U/S and D/S of the crossing

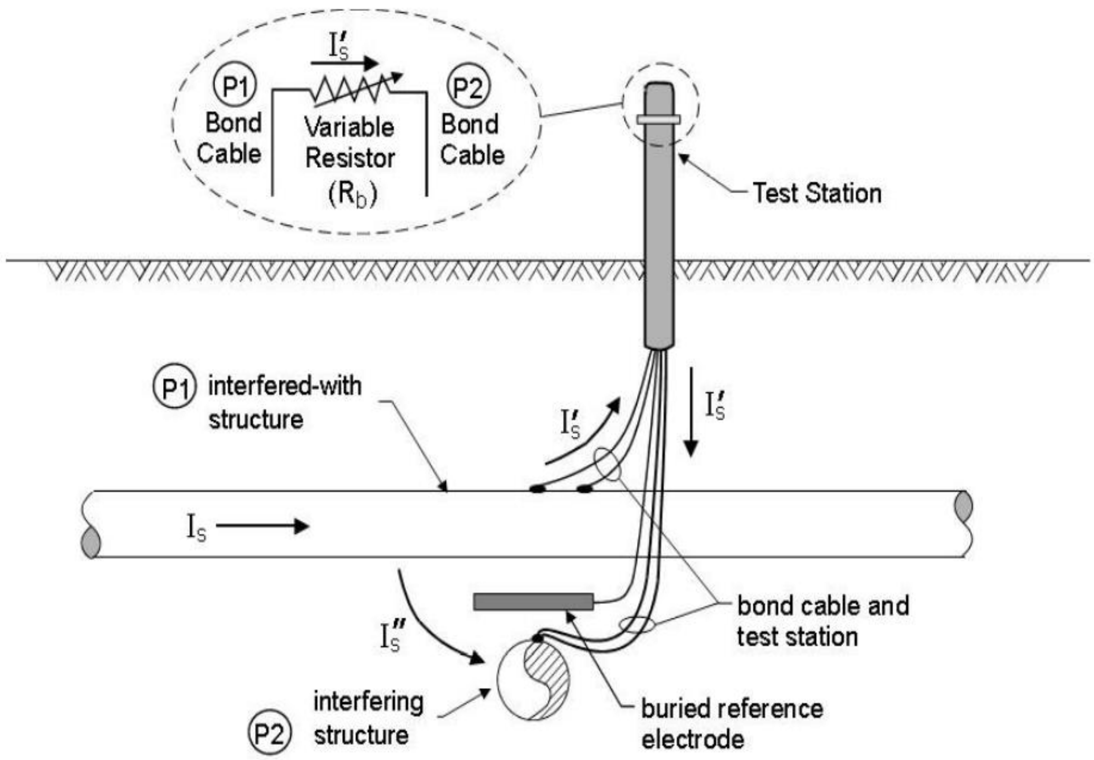

Figure: Interference Mitigation Using a Resistance Bond

- **Apply a coating to the interfered-with structure in the area of stray current Pickup or to the interfering structure where it picks up the returning stray current**

There are times when the amount of bond current required to mitigate an interference problem causes the potential of one of the structures to drop below an acceptable criteria level. One of the methods to correct this situation is to re-coat the structures in the area of interference. This will raise the amount of resistance in the bond circuit and reduce, if not eliminate, the bond current requirements. When re-coating occurs, care must be taken. If only one structure is to be re-coated, it will normally be the structure causing the interference. Re-coating just the structured being interfered may result in acceleration in wall loss at any coating holiday

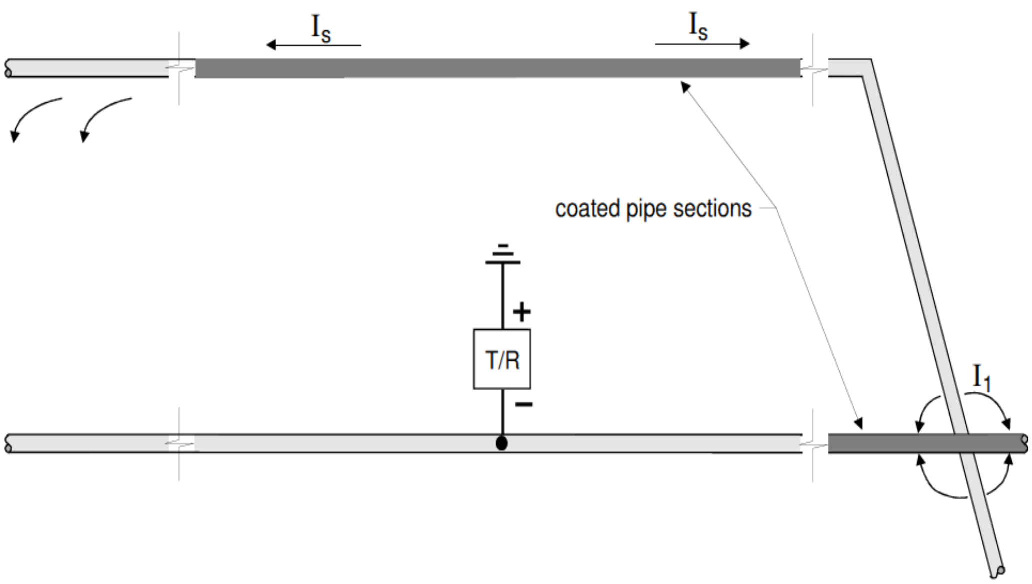

Figure: Use of a Dielectric Coating to Mitigate Interference

SECTION 7B: Interference Mitigation from AC power lines

A jointly shared right-of-way (ROW) between alternating current (AC) power systems and pipelines can lead to a transfer of energy from the AC power system to the pipeline system.

This transfer of energy, or coupling, may take the form of AC voltage and current on the pipeline system. The amount of energy (AC voltage and current) transferred will depend on a number of factors, most notably the geometric configurations of the AC power system and the pipeline system, as well as the AC power system "loading" or current carrying condition, and any unbalanced AC power system load conditions resulting in current flow in the earth. The coupling can take place as any one, or a combination of the following types.

Resistive Coupling or Conductive Coupling Due to Faults

Since the AC power system has a grounded neutral, any unbalanced load conditions in the AC power system, due to phase-to-phase, or phase-to-ground faults or lightning strikes to the AC power system itself, can result in current flow in the earth, the shared electrolyte of both the AC power system and the pipeline. Some part of this current flow can be expected to be carried by the pipeline.

On high-voltage power lines, faults are most likely to occur as the result of lightning, which can ionize the air in the vicinity of an insulator. Faults can also occur as the result of high winds, failure of the power line structures or insulators, or accidental contacts between the power line and other structures, such as, cranes, and other construction equipment.

Under fault conditions, the current leaving the power line will return to its source using all paths available to it, including power line shield wires, the earth, and metallic structures in the earth such as pipelines. The amount of current transferred to a pipeline is dependent on the relative impedances of all parallel paths available to the fault current. It is also function of the separation distance between the faulted structure and the pipeline, the available fault current, the impedance of the faulted structure to ground, and the impedance of the pipeline to ground.

Fault current is conducted to the pipeline through its coating. The better the coating quality (i.e., the fewer the holidays) and higher the coating's dielectric strength (i.e., breakdown voltage), the lower the current transfer to the pipeline.

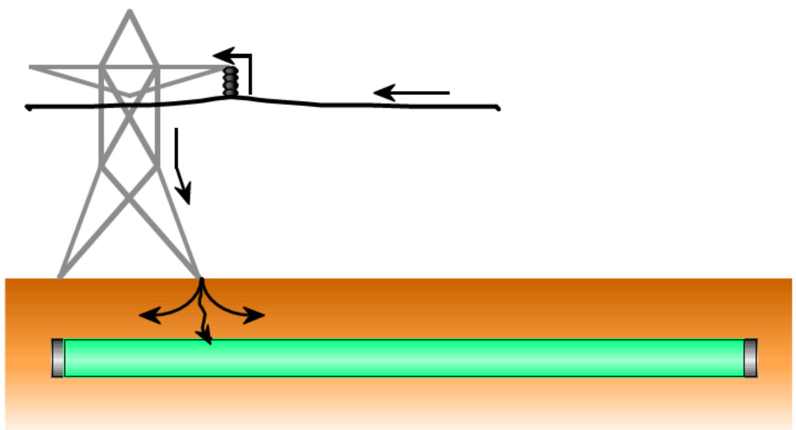

Figure: Conductive Coupling During Line-to-Ground Fault Conditions

The high pipeline voltages resulting from conductive coupling represent a safety hazard in cases where test leads and pipeline appurtenances are accessible. Electric shocks can be painful and can result in the loss of muscular control at body currents of less than 50mA. Ventricular fibrillation may occur at body currents of greater than 50mA and certainly occurs at body currents of greater than 100 mA.

In general, "touch voltage" is defined as the potential difference between a grounded metallic structure and a point on the earth's surface separated by a distance equal to the normal maximum horizontal reach (approximately 3 ft). "Step voltage" is the potential difference between two points on the earth's surface separated by a distance of one pace (approximately 3ft) in the direction of maximum potential gradient.

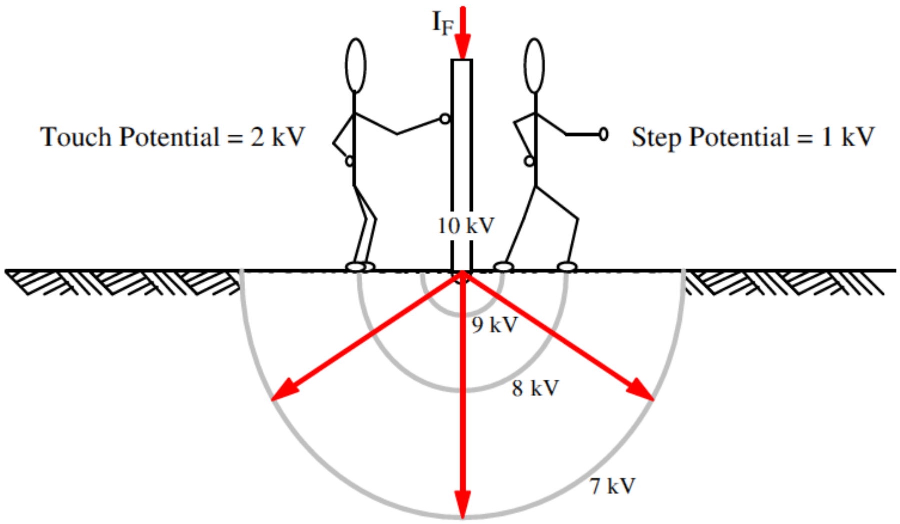

Figure: Example of Touch and Step Voltages at an Energized Grounded Structure

The most effective means of preventing arcs during fault conditions is to maintain a safe separation distance between the power line structures and the pipeline. Minimum separation distances are usually specified by both the power company and the pipeline company; however, safe separation distances specifically to prevent arcing must either be calculated or determined by Sunde equations for the distance r (m) over which an arc could occur, based on soil resistivity p (Ωm) and fault current magnitude I_f (kA)

$$r = 0.08\sqrt{I_f \cdot \rho} \quad (\rho \leq 100\,\Omega\text{-m}); \quad r = 0.047\sqrt{I_f \cdot \rho} \quad (\rho \geq 1000\,\Omega\text{-m})$$

When the probability of a fault is much higher than normal (e.g., electrical storms, ice storms, high winds), it is common sense to avoid activities involving pipe contact (e.g., CP surveys, CP installations, pipeline maintenance) to minimize the chance of an electrical shock.

The maximum transient (short term) current I_B a human body can tolerate depends on shock duration t_S (seconds) and body weight and is calculated as follows

$$I_B = \frac{0.157}{\sqrt{t_S}} \quad \text{(for a 70 kg body)} \qquad I_B = \frac{0.116}{\sqrt{t_S}} \quad \text{(for a 50 kg body)}$$

$$V_{step_{70}} = (1000 + 6\rho)\frac{0.157}{\sqrt{t_S}} \qquad V_{step_{50}} = (1000 + 6\rho)\frac{0.116}{\sqrt{t_S}}$$

$$V_{touch_{70}} = (1000 + 1.5\rho)\frac{0.157}{\sqrt{t_S}} \qquad V_{touch_{50}} = (1000 + 1.5\rho)\frac{0.116}{\sqrt{t_S}}$$

Addition of a thin layer of high resistivity surface material, such as crushed stone (3000 Ωm), can significantly increase this contact resistance.

The touch voltage to which a person is exposed during a fault can also be minimized by installing a gradient control loop around the pipeline appurtenance and connecting it to the pipe. This loop is generally installed at a depth of between 12 inches and 20 inches and extends approximately 40 inches beyond the perimeter of the appurtenance. The loop (typically Zinc ribbon) raises the voltage of the earth during a fault and minimizes the voltage difference between a hand touching the pipeline and the feet.

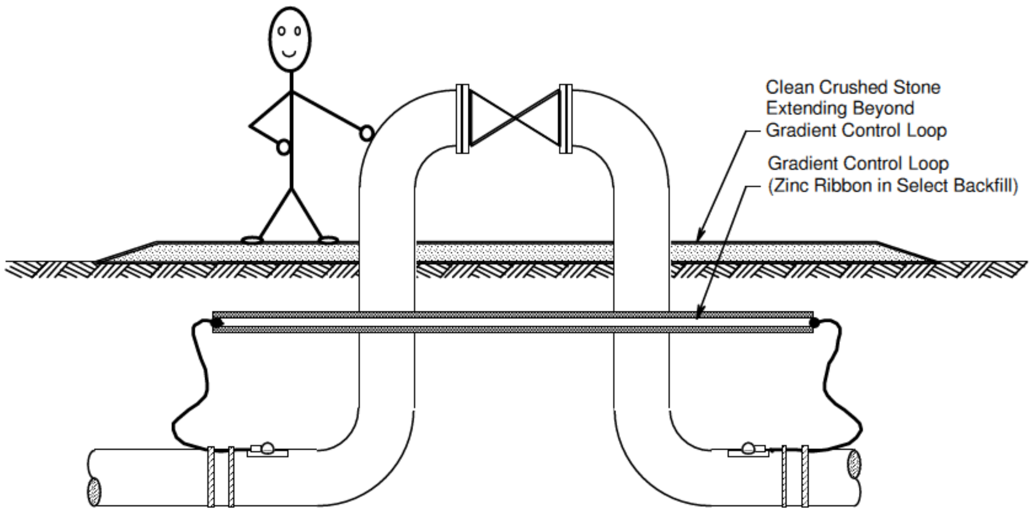

Figure: Mitigation of Hazardous Touch Potentials at Aboveground Appurtenance

Gradient control mats (GCM) are used to limit step and touch potentials due to induced power frequency voltages as well as those voltages associated with lightning strikes to the pipeline structure or adjacent AC power system structures. These galvanized mats are most often "decoupled" or "isolated" from the cathodically protected pipeline structure utilizing DCI/ACC devices such that the existing pipeline CP system is unaffected. The GCM is equipped with its own, independent galvanic type CP system to ensure maximum life of the mat material in contact with the electrolyte.

Electrostatic (Capacitive) Coupling

With electrostatic coupling, energy is transferred through the electrical capacitance that exists between the power line and the pipeline. Any two conductors separated by a dielectric material can be considered a capacitor. Capacitance is a measure of the ability to store electrical charge between two conductors relative to the voltage between the conductors. Capacitance is proportional to the area of the conductors but is inversely proportional to the separation between the conductors

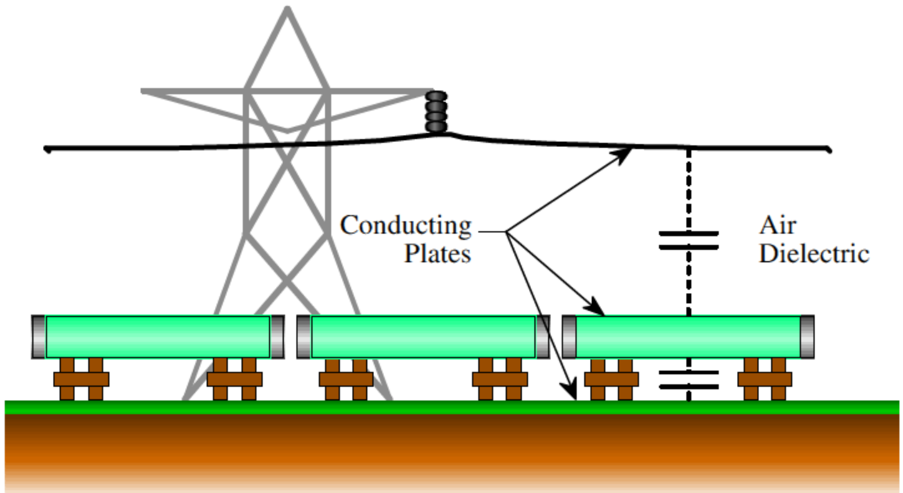

Figure: Pipeline During Construction Represented as a Capacitive Voltage Divider

Although electrostatic coupling cannot generally produce enough body current to create an electrical shock hazard, it can result in nuisance voltages that produce a sensation similar to a shock from static electricity.

While the pipeline is up on skids and well insulated from ground, electrostatic voltages can be easily mitigated by connecting the pipeline to earth, even through a very high resistance ground connection, as long as the ground connection has a much lower resistance than the pipe-to-earth capacitive reactance

Electromagnetic (Inductive) Coupling

The AC current flow in the AC power system will produce an alternating magnetic field, thus inducing an AC potential and associated AC current flow on a pipeline buried or submerged within this magnetic field.

Voltages and currents are electromagnetically induced onto a pipeline in the same manner that an inductive pipe locator induces an audio signal onto a pipeline or primary winding of a transformer induces current flow through the secondary winding.

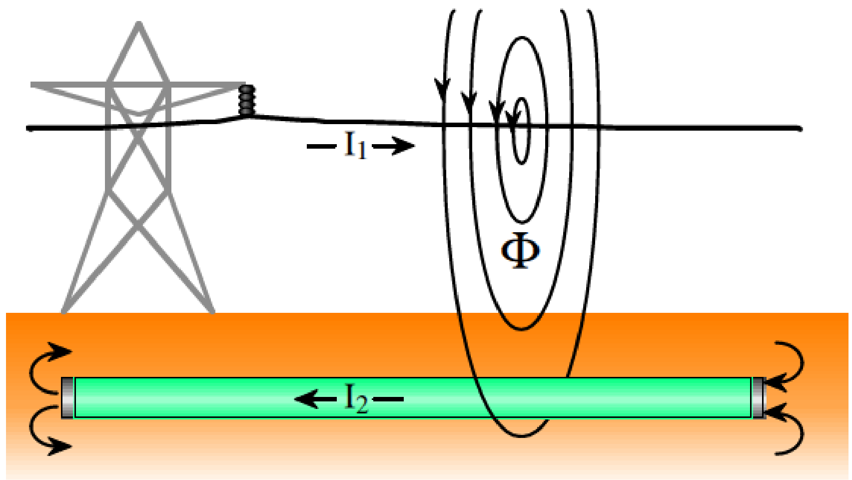

Figure: Electromagnetic Induction in a Pipeline due to an AC Power Line

✓ $i_{ac} < 30$ A/m^2 …………………No Corrosion

30 A/m^2 < i_{ac} < 100 A/m^2……Corrosion Unpredictable

$i_{ac} > 100$ A/m^2………………Corrosion Expected

The AC current density at a circular holiday is a function of the induced AC voltage on the pipeline (Vac), the soil resistivity (p), and the holiday diameter (d), and can be calculated as follows:

$$i_{ac} = \frac{8V_{ac}}{\rho \pi d}$$

i_{ac} – AC current density (A/m^2)
V_{ac} – AC Volts (V)
ρ – Soil resistivity (Ω–m)
d- holiday diameter (m)

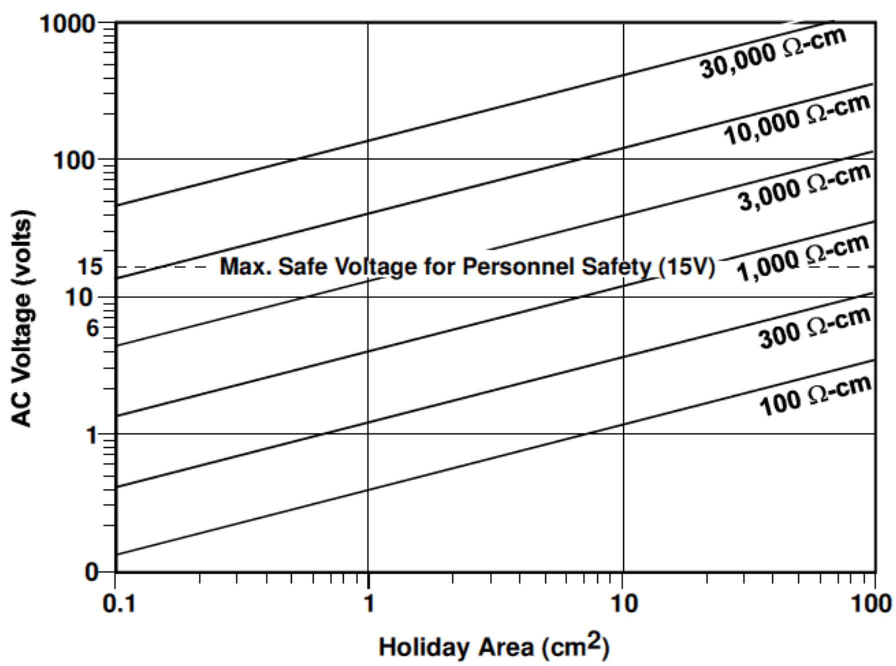

Figure: AC Voltage Required to Produce 100 A/m2 Current Density for a Variety of Holiday Sizes and Soil Resistivities

Note: The maximum allowable induced AC voltage to which a person should be exposed is 15 V

An AC current traveling along a pipeline sees greater longitudinal pipeline impedance than does a DC current and also lower shunt impedance to earth, which means that an AC signal attenuates more rapidly along a pipeline than a DC signal.

CAUTION: Electrically long pipelines subjected to electromagnetic coupling can exhibit zero voltages over much of their length provided the electromagnetic field and the electrical characteristics of the pipeline and the soil are uniform along this length.

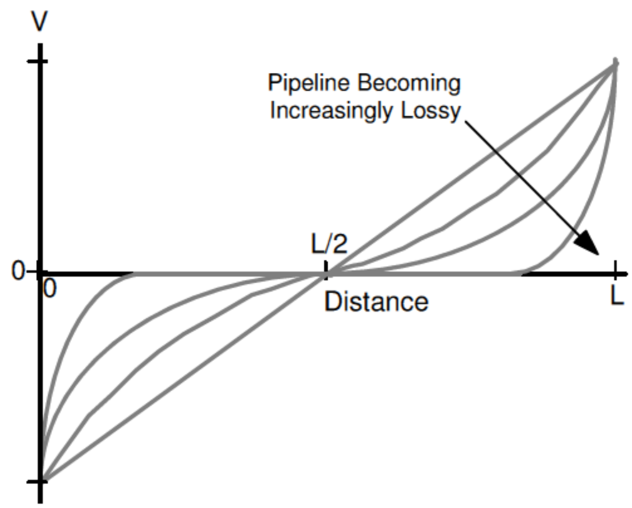

Figure: Effect of Electrical Length of Pipeline on AC Voltage Profile

To mitigate electromagnetically induced AC voltages to safe levels the pipeline must be grounded. Grounding the pipeline has the same effect as replacing a good coating with a poor coating; that is, by lowering the value of structure to ground resistance, the voltages produced by the flow of AC current from the pipeline to earth are reduced.

Ground electrodes may consist of either packaged sacrificial anodes, sacrificial anode ribbons installed in special backfill, or conventional grounding materials such as ground rods and cables. Materials that are not anodic to the pipeline, such as copper cables, would seriously affect the effectiveness of the cathodic protection system if directly connected to the pipeline. Such materials should therefore only be used if they are DC decoupled from the pipeline using a suitable device, such as a polarization cell, or a solid state DC decoupler.

SSDs or Direct Current Isolating/Alternating Current Coupling Device (DCI/ACC) devices are used to maintain dc voltage isolation between metallic structures, as is often required with cathodic protection systems, but at the same time provide for AC current conduction when specified AC voltage thresholds have been exceeded. These devices are most often used at electrical isolation locations and between gradient control mats and cathodically protected structures.

Figure: Solid State DC Decoupling Device

Ground electrodes may be evenly distributed along the pipeline, such as by installing packaged sacrificial anodes at regular intervals; however, it is often more effective to concentrate the ground electrodes at electrical discontinuities where the voltage peaks tend to occur.

The coupon test station (CTS) and zinc anode (ZA) configuration can be effective in mitigating induced AC power (voltage and current) as well as providing an AC current density measurement location on the pipeline system.

Note: Zinc anodes used in this application may sometimes form "calcite" buildup on the surface of these anodes causing decreased surface exposure area affecting the AC discharge potentials. Solid State Decouplers (SSD) would eliminate this effect. For pipelines with Casings, SSDs would be more effective. The SSDs can be connected to the casing vent pipe and test lead wires that would allow AC to drain through the casings.

SECTION 8 - Contract Specifications

Introduction

This section describes the contractor requirements, including a pre-job meeting, conducting a survey, and post-job meeting. In the last portion of this section, the types of survey, specifications, and data are described.

Contractor Requirements

The following listed items delineate specific requirements that contractors working for The Company must complete.

- Insurance – Contractor must satisfy EnLink Midstream Materials and Contract Management requirements for insurance.
- Contract – Contractor must execute necessary contracts with EnLink Midstream, which meets Materials and Contract Management requirements.
- Drug/alcohol testing – Contractor must demonstrate and document compliance with all company, Federal, State, and other applicable requirements for drug and/or alcohol testing of employees conducting safety sensitive tasks to the satisfaction of EnLink Midstream Materials and Contract Management. A list of approved contractors is maintained by Compliance Services. Only contractors on this list may bid on and perform O&M survey work.
- Training – Contractor must demonstrate and document compliance with all company, Federal, State, and other applicable requirements for training of employees conducting safety sensitive tasks to the satisfaction of EnLink Midstream Materials and Contract Management.
- Safety – Contractor must comply with all rules and standards contained within the EnLink Midstream Safety and Health handbook, including personal protection equipment (PPE):
    - Hard hat – ANSI Z89.1.1997 (Type 1 or 2 – class E hardhats)
    - Safety glasses equipped with rigid side shields meeting or exceeding ANSI Z87.1
    - Safety shoes (steel-toed shoes) meeting or exceeding ANSI Z41.1 (compression and impact ratings)
    - Fire retardant clothing (FRC), where required, meeting Federal Test Standard CS-191 (<2.0 seconds after flame and <5.0 inches char length. Consult local management to determine the need for FRC for a particular project.

- Hearing protection, in designated high noise areas (85 dBA or higher)
- Gloves (where applicable)
- Personal flotation device (PFD) where applicable
- Reporting of injuries, vehicle collisions, or any unsafe conditions
- Hold regular safety meetings, in addition to pre-job meeting
- Communicate EnLink Midstream Safety and Health handbook rules and standards to all employees participating

Pre-Job Meeting

Contractor will attend a pre-job meeting with all employees, where practical, to discuss job plans, safety rules, local contacts for emergencies including medical, company, and law enforcement phone numbers, hospital locations, etc. Contractor must be satisfied that the crew leader and all members of the crew have and know the proper procedures for dealing with emergencies such as:

- Injury;
- vehicle damage (incapacitated vehicle in remote areas);
- damage to company property;
- lost personnel (should have meeting places and times, what to do if lost);
- observing leaks or ruptures, or other potential safety-related conditions;
- angry land-owners;
- dangerous wildlife, domestic animals, or pets;
- other situations which cannot be anticipated.

Company and contractor should review specifications and scope for the project, and expectations for communication with company personnel, including presentation of field plots. Information about the system (alignment sheets, engineering station of test leads and features, line names, rectifier locations, and contact information) will be presented to the contractor.

Conducting the Survey

Field Plots

Arrangements with the company representative should be made to submit field plots on a periodic basis. Field plots should include data, all waveprints taken, and a run summary table. Field plots must be reviewed by the appropriate company personnel qualified to evaluate survey data. Surveys will be accepted or rejected based upon this evaluation. It is important to evaluate the data contemporaneous to conducting survey so that areas may be resurveyed, if required, without reinstalling equipment or re-mobilizing crews.

Communications

Arrangements should be made for communications with the crew leader and the company representative to communicate on a regular basis, and for emergency situations. If communications are impossible for a period of time (out of cell phone coverage, radio coverage) then arrangements should be made to check in on a periodic basis.

Crew Leader

The assigned crew leader is responsible for communicating with the company representative, and distributing that communication, when applicable, to all members of the survey crew. The crew leader has ultimate responsibility, as a representative of the contractor, to ensure that all members of the survey crew follow all company policies. The company reserves the right to halt all work if violations of company policy threaten the safety of contractor's or company personnel or property, or the general public.

Company Representative

The assigned company representative is responsible for communicating necessary information to the contractor regarding locations of facilities, safety information, any known hazards, and company policies. The company representative will review the field plots or send the field plots to the appropriate qualified company personnel. The company representative may also take the role of inspector, reviewing the operation of the survey crews.

Post-Job Meeting

Depending on the size of the job, the post job meeting may require everyone meeting at the office, or simply involve a discussion with the crew leader in the field, or even a phone call to say that everything has gone as planned. At the post job meeting, the data should be formally accepted by the appropriate company designee, approval for removal of interrupters should be given, and company safety policies should be reviewed to endure that no violations or reportable injuries have occurred. At this point, a contractor evaluation form may be filled out and discussed with the crew leader.

Surveys

Types of Surveys

"On" Survey

A series of pipe-to-soil potentials taken along a pipeline.

Interrupted Survey

A series of pipe-to-soil potentials taken along a pipeline, with influencing cathodic protection current sources switched using equipment designed to briefly interrupt the cathodic protection current.

Depolarized Survey

All current sources off a sufficient amount of time for effects to have disappeared. Although this is sometimes called a "native" or "native state" survey, it is actually a survey of free corrosion potentials. Depolarized surveys are normally performed immediately following an On/Off survey. Since the pipeline is allowed to depolarize to a state where corrosion sites can re-activate, this survey must be performed as expediently as possible, and the cathodic protection system must be re-energized as soon as possible.

AC Survey

A series of pipe-to-soil alternating current potentials taken along a pipeline. AC surveys may require measurement of AC step potentials, measuring the effectiveness of AC mitigation devices, and other measurements.

Close Interval Survey

A series of pipe-to-soil potentials taken along a pipeline at small intervals (usually three feet or less) directly over the structure, remote from an electrical connection to the structure, using a wire to connect to the structure.

Fast Cycle Survey

An interrupted survey where the off portion of the interruption cycle is less than one second. Both an on and an off reading are measured at each reading location.

Slow Cycle Survey

An interrupted survey where the interruption cycle is greater than one second. Either an on or an off reading are measured at each reading location. This type of survey can be either a saw tooth or synchronized survey. On a saw tooth survey potentials are not identified as on or off but are interpreted by the person analyzing the survey. The equipment for a synchronized survey identifies the data as an on, off, or transitional reading during data gathering.

DCVG (Direct Current Voltage Gradient) Survey

A cell-to-cell survey conducted with impressed current sources interrupted, using a special analog meter or software program using common field data loggers, to locate and grade coating defects.

Pearson Survey

A survey similar to DCVG that uses an AC signal to identify and grade coating defects.

Cell-to-Cell (Hot-Spot) Survey

A survey measuring the potential difference between two half-cells, usually to determine the direction o f current flow in the soil. This survey is often used on pipe that is not electrically continuous or on bare pipe in order to meet net protective current criterion.

Side Drain Survey

A cell-to-cell survey measuring the net current flow in the direction of the pipe.

Telluric (Two-Wire) Survey

A survey technique that uses a stationary half-cell to correct for telluric (earth) currents.

Pipe Location/Marking Specifications

Pipeline Marking

Pipe shall be marked directly over center of pipeline within 6 inches of the centerline of the pipe using flags or other temporary marking material. Flags shall be 100 feet distance ±2.5 feet unless other approved methods are being used for distance measurement, in which case flags used for marking the pipe location are to be 100 feet or less apart. Marking material must be adequate to be visible from the previous marker while conducting the survey.

Pipeline Location

Casing vents or pipeline markers are not sufficient for location of the pipeline. Approved radio-frequency pipeline locators or other devices must be used. In congested pipeline right-of–way, areas of deep cover, small diameter or poorly coated pipe, areas of high AC potentials, conductive location techniques, or other more accurate location techniques and equipment may be required. In the case of survey offshore, magnetic anomaly detectors or other methods can be used for pipeline location. Areas found to be improperly located, or with unacceptable distance errors, must be relocated and resurveyed.

Pipeline distance measurement - If the wire-counter method is used for distance measurement, entry must be made at 100 feet ±2.5 feet into the data stream to indicate 100 feet distance. Appropriate measures must be taken to ensure that the distance measured by the spooling wire corresponds with distance traveled along the pipeline, including staking the wire at bends in the pipe, fences, etc.

Removal of materials - All marking materials and survey wire must be removed contemporaneous to the survey, and prior to the completion of the job. Certain areas may require immediate removal of the marking materials and survey wire, such as areas of crops being harvested, areas with livestock, well-traveled areas, etc.

Survey Specifications

Survey Interval

Survey interval is to be 3 feet or less between reading locations, or a minimum of 30 reading locations per 100 feet. When conducting a fast-cycle interrupted survey, an on and an off reading must be obtained at every reading location. An approved method must be used to differentiate the on and off readings.

Electrical Connections

Connections should be made at every available aboveground contact point in order to minimize metallic IR drop. Reconnection to another contact point in a distance less than 1,000 feet is not required, under normal conditions. Connections must be made in a manner that establishes a low resistance (metal to metal) electrical connection that is mechanically sound. Survey procedures must ensure that the survey wire is electrically isolated from ground and other metallic structures (fences, etc.) traversed during the survey. Connections cannot be made at rectifier negative ties, galvanic anode leads, bonds, or other current-carrying wires. The type of connection (e.g., test lead, above ground pipe, span, MLV) should be documented in the survey header information.

Survey Wire

Connections must be made with appropriate gauge wire to minimize measurement circuit resistance. Wire should be adequately insulated to ensure isolation from the ground/electrolyte. Wire that is submerged during a survey must be tested to ensure that the insulation is adequate for electrical isolation.

Skips

Readings should not be taken in areas where the pipeline is above grade. The appropriate skip footage should be entered into the data stream, and the survey resumed where the pipeline is buried including areas where the pipeline is partially buried. Approved skips include cased crossings, areas less than 51 feet covered by asphalt or concrete, and areas where the pipe is above grade. All other areas must be surveyed, including lakes and waterways, large distances covered by asphalt or concrete, residential areas, etc. Additional equipment, such as boats, marsh buggies, drills, ladders, etc. may be required.

Broken Lead Wires

Survey runs should normally be conducted from one metallic connection to the next, in order to obtain metal IR drop measurements. During the operation of a survey it is recognized that occasionally outside forces will cause the survey wire to break, and it is impractical to attempt to find the break and repair it. In these cases, the location of the end of the survey should be clearly marked, and a station number calculated based on the distance surveyed. A survey back to that point should be conducted, and the ending stations of the two surveys should be made to match.

Survey Meters

Pipe-to-soil potentials must be measured and logged with an approved survey meter. The meter must be calibrated to an accuracy of 1 mV CSE in a range of –10 V to 10 V DC, traceable to NBS standards. The meter must have sufficient AC rejection so that AC potentials will not influence DC potential measurements. The meter shall have adequate input impedance to minimize the influence of contact resistance. The minimum input impedance of survey meters shall be 40 megohm. If a meter with less than a 40 megohm input impedance is used, tests should be made at every reconnection point showing that the error introduced is no more than 2 mV CSE. All connections should be made in a manner that establishes a low resistance (metal to metal) electrical connection that is mechanically sound. The measurement circuit must be electrically isolated from any path to ground, including the survey operator.

Half-Cells

Pipe-to-soil potentials must be measured using approved copper-copper sulfate reference half-cells. A saturated solution of copper-copper sulfate must be maintained in each half-cell. The half-cells shall be calibrated between each other at the start of each run and must match to within 5 mV CSE. All half-cells must be calibrated nightly with an uncontaminated half-cell to ensure accuracy, and each must read within 5 mV CSE of the uncontaminated half-cell. Any half-cells that do not meet this specification should be rebuilt or discarded. Offshore or marsh areas may use silver-silver chloride half-cells.

Invalid Conditions

Pipe-to-soil potentials cannot be taken through frozen ground, asphalt, concrete, cased pipe, or above ground pipe. The portion of surveys containing such potentials are invalid and must be re-surveyed.

Contact Resistance

Surveys containing excessive contact resistance that influences pipe-to-soil potential (scatter) are invalid. While a survey with no scatter is impossible in many conditions, the pipe-to-soil potentials must be discernable throughout the survey. Distances greater than 50 feet without valid potentials, or where the potentials cannot be interpreted due to scatter, will require continuous resurvey from the nearest metallic connection. Dry soil, rocky conditions, excessive vegetation, and other conditions may require watering, digging, or cutting vegetation to obtain valid pipe-to-soil potentials.

IR Correction

Interrupters

For interrupted surveys, adequate current interrupters must be installed to interrupt all influencing impressed current cathodic protection, including company and influencing foreign cathodic protection sources, bonds, and galvanic cathodic protection. Company will provide a list of required cathodic protection sources to be interrupted, including type, output, and location. Types of current sources include rectifiers powered by 120/240 single-phase AC, 240 and 480 three-phase rectifiers, constant potential controlled rectifiers, galvanic ground beds, solar powered current sources, thermo-electric units, and engine-generator sources. Rectifiers can be interrupted at the primary AC, secondary AC, or DC side. Constant potential or constant current controlled rectifiers must be interrupted at the primary AC to prevent spiking. Sufficient interrupters should be provided for spares in case of failure. Current interrupters must be capable of maintaining synchronous interruption within 10 milliseconds for the duration of the survey or resynchronized to guarantee a difference in 10 millisecond or less. Interrupters for fast cycle survey must interrupt using solid-state switches or fast relays without chatter.

Bonds

The preferred method for interrupting cathodic protection current from foreign sources through bonds is to interrupt the sources. There may be cases in which this is impractical, requiring interruption of the bond. This may require special equipment.

Interruption Cycles

Interrupters must be capable of interrupting using an approved interruption cycle. Fast cycle interruption cycle shall be 3:1 ratio.

Depolarization

Steps must be taken to prevent depolarization during the survey, including deactivating interrupters at night and when not surveying. This can be done manually or automatically with timers. Steps should be taken to ensure that interrupters on timers are active before survey resumes. Current output of rectifiers after interrupter installation should be maintained as close to the previous output as possible. This may require increasing tap settings. Increasing the rectifier output during interruption may be necessary to compensate for reduced net current during interruption.

Documentation

Voltage and current output of the rectifier should be documented on the unit record when an interrupter is installed or removed. An interrupter installation form should document pipe-to-soil potentials at the nearest test lead before interrupter installation and immediately before removal, tap settings, current and voltage output of the rectifier before and after interrupter installation, rectifier location and ID, interrupter serial number, and other information. Any changes to tap settings should be documented on the unit record, as well as an interrupter installation form.

IR Correction

Some method must be used to confirm synchronous operation of the current interrupters, and the effective operation of all interrupters, at the start of each survey run. Oscilloscopic waveprints, lateral potentials, and measurement of metal IR drop are acceptable methods. Other methods must be approved.

Metallic IR Drop

Metallic IR drop must be measured at the end of each run. Direct metal-to-metal of the IR drop or near-ground versus far-ground potentials are acceptable methods. If the metal IR drop indicates current flowing in the pipe in the off window, then the company should be contacted, and the influencing current source should be located and interrupted.

Lateral Potentials

Lateral potentials must be taken at the start of each survey run. After taking a near-ground potential, on and off potentials should be taken approximately 10feet perpendicular to the pipeline on each side. If the off lateral potentials indicate current flowing to the pipe in the off window, then the company should be contacted, and the influencing current source should be located and interrupted.

Data

Header/footer information - A minimum of information is required at the start and end of each survey run. Missing data may result in a run being rejected. See Appendix B for typical information required.

Irregularities – Additional readings should be taken at low potential sites and when readings change abruptly, including lateral potentials, waveprints, and AC potentials. Cells should be checked at the start of each run and when data appears to be affected.

Stationing - Company will provide a list of engineering stations at connection points and key physical features. Starting and ending points must match company engineering stations when provided. Key physical features should be entered into the data stream and engineering station reset to match company stationing.

Comments – Sufficient comments should be entered when conducting the survey to document survey conditions and allow for accurate relocation of irregularities. Features that could affect readings, such as soil conditions (wet, dry, rocky), vegetation, AC power lines, pipeline crossings, a list of typical physical features is included in appendix C. Features that would allow for accurate relocation include road names, aerial markers, company names of pipeline crossings, line markers, fences, etc.

Valid data – Data is determined to be valid when potentials are accurate and discernible from scatter, potentials are taken directly over the pipeline and connected to the proper metallic connection, IR drop is effectively corrected, and all components of the data are incorporated into the run. All data for a particular valve section must be taken in a 30-day period, to insure similar soil conditions and levels of protection.

Survey direction – Survey data can be collected in either the upstream or downstream direction. Plots must indicate the direction of survey and plot the data in the direction of increasing station number, regardless of the direction the survey was made.

Final Report

Data - Contractor shall provide two sets of data to the company. The data should include plots, waveprints, reports, summaries, and disks.

Plots – Plots of the pipe-to-soil potential versus engineering station, on 8 ½ x 11 landscape, with engineering station indicated every 100 feet, including separate discernible traces for on and off potential, using the same vertical scale for every run. Plots should include a criterion line for -850 mV CSE on and –850 mV CSE off. If depolarized survey is done, the plots should include the depolarized trace with the on and off traces. Comments should appear on the plots in approximately the location they were entered. Potential data is to be presented “as-taken”, without editing or averaging.

Waveprints – Printouts of all waveprints, including starting, ending, metal IR, and other waveprints should be included. A missing waveprint may result in a run being rejected.

Summaries – The report should include a cover letter summarizing the work completed, including district, lines surveyed, and engineering stations of areas surveyed. In addition, a run summary table should be provided that lists the run name, the starting and ending stations, the flagged (calculated) footage, and the difference between the company stationing and the measured footage. Contiguous runs should match in stationing head-to-tail. Any skipped features between runs should be documented on the run summary table.

Reports - Contractor to provide reports including Survey Summary, Computer Analysis and Exceptions reports for each run.

Disks – Contractor to provide data in digital format, consistent with FERA Win/CIS format. See appendix A for format requirement. 3-1/2 inch floppy disks or CD-ROM media are acceptable.

APPENDIX A - GLOSSARY

TERM	DEFINITION
Acid Producing Bacteria (APB)	Bacteria that produce small-chain fatty acids (see “Organic Acids”) as an end product of their metabolism, which may be aerobic or anaerobic and use a variety of substrates.
Aerobic	Containing or using air or oxygen.
Aerobic Bacteria	Bacteria that require oxygen for metabolism and growth.
Alkalinity	A measure of water’s ability to neutralize acids.
Anaerobic Bacteria	Bacteria able to grow without free oxygen, oxygen is toxic to many of these organisms.
Allowable Maximum (AM) Potential	The maximum potential reading at any given test point that can be measured without danger of over-protection somewhere on the line.
Amphoteric Metal	A metal that is susceptible to corrosion in both acid and alkaline environments.
Anaerobic	Free of air or oxygen.
Anions	Negatively charged ions (e.g., chloride – Cl^-, sulfate – SO_4^-, etc) that react with positively charged ion species (see “Cations”) to form salts or other compounds that can form scale deposits and/or promote corrosion. Some anions (most notably, phosphate & nitrate) are capable of forming compounds that inhibit corrosion.
Anode	The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in an external circuit, which is normally metallic. The anode is usually the electrode where corrosion occurs, and metal ions enter solution.
Anodic Polarization	The change of the electrode potential in the noble (positive) direction resulting from the flow of current between the electrode and the electrolyte.

TERM	DEFINITION
Average Pit Density	The average number of pits per square centimeter (cm^2) located on any side of an EM coupon (see "Electron Microscope Coupon") as observed through a light microscope at a magnification of 10x. This measurement may range from 0 to 99. A default value of 100 (the maximum detection value) is indicated when 100 pits/cm^2 or greater are counted.
Background Potential	In areas with a lot of buried piping, such as a compressor station yard, it may not be possible to find a remote potential. Relatively constant non-remote potentials in areas of congested piping that do not change with position are called background potentials.
Batch Treatment	Sometime known as *slug treatment*, performed by injecting corrosion inhibitor or biocide at one location or various selected points on a system. Generally used in conjunction with pigging operations. Normally works best where no free liquids are transported with the gas.
Bicarbonate (HCO_3^-) Ion	Is naturally occurring in some oilfield waters and can act as a buffer and prevent the acidity in the water from increasing (see "Alkalinity"). An important component in scale formation, which may help protect the pipe from corrosion. HCO_3^- ions do not exist when the pH drops to 4.3 or less; therefore, no alkalinity is measurable.
Biocides	An additive used to kill or control bacteria. Some biocides have inhibiting powers in certain corrosive environments. Depending on the biocide, concentration levels of 50 - 250 ppm are typical residuals found in the water phase.
Bond	A metallic path installed to provide a return path for cathodic protection current, which prevents corrosion due to interference or stray current.
Cable	One or more conductor insulated from one another.

TERM	DEFINITION
Calcium (Ca^{++}) Ion	Calcium is an “active metal” cation which is a common dissolved constituent of most waters. It represents a percentage of the total dissolved solids and is a hardness component of water. Calcium ions can combine with sulfate or carbonate ions to form insoluble compounds which may in turn form deposits. These deposits can build-up to form scales on pipe surfaces, some of which may be protective in nature. Excessive and uncontrolled formation of scale deposits can decrease the diameter of the pipe creating flow problems. Calcium also reacts with chlorides to form salts that can be corrosive.
Carbonate ($CO_3^{=}$) Ion	Naturally occurring ions in some oilfield waters that participate in the buffering of acids and in the formation of scales. However, carbonates seldom contribute appreciably to the total dissolved solids in the water. Because no carbonate alkalinity exists in acidic environments (pH < 7.0), the CO3= ion concentrations within such solutions are zero.
Carbon Dioxide (CO_2)	A colorless odorless gas that is present at varying levels in natural gas. When dissolved in soft water, CO_2 forms carbonic acid (H_2CO_3), which is corrosive to iron and steel, as indicated by the following reactions: $CO_2 + H_2O = H_2CO_3$ $Fe + H_2CO_3 = FeCO_3 + H_2$ When hard water is present, the CO_2 will form carbonates (CO_3^{2-}) and/or bicarbonates (HCO_3^-), which may actually form a protective scale in the form of salts such as calcium or magnesium carbonate and calcium bicarbonate.
Cathode	The electrode of an electrolytic cell at which reduction occurs. Electrons flow toward the cathode in the external circuit, which is normally metallic. The cathode is usually the electrode where polarization occurs, and ions are received.
Cathodic Depolarization	The removal of cathodic hydrogen, which “depolarizes” the corrosion cell and greatly increases the corrosion rate. Removal of hydrogen at the cathode is identified as the rate-limiting reaction in steel corrosion and is a mechanism theorized for bacteria (see “Sulfate Reducing Bacteria”) accelerating corrosion.

TERM	DEFINITION
Cathodic Disbondment	Coating disbondment caused by the products of a cathodic reaction.
Cathodic Polarization	The change of electrode potential in the electronegative direction resulting from the flow of current between the electrolyte and electrode.
Cathodic Protection	A technique to control the corrosion of a metal surface by making that surface the cathode of an electrochemical cell. The corrosion rate can be reduced by shifting the corrosion potential of the electrode toward a less oxidizing potential by applying an external EMF (see "Electromotive Force").
Cathodic Protection Coupon	A coupon used to determine corrosion rate and/or cathodic protection levels in a cathodically protected environment.
Cations	Positively charged ions (e.g., sodium - Na^{+}, iron – Fe^{2+} or Fe^{3+}, etc.) that react with negatively charged ion species (see "Anions") to form salts or other compounds that can form scales, deposits, and/or promote corrosion.
Cavitation	A mechanical mechanism for metal loss that can occur in pipes when liquids move at high velocities. It is the erosion of a surface due to the sudden formation and collapse of bubbles. As the bubbles collapse and the surrounding liquid surfaces meet, a great deal of kinetic energy is released. This energy may break a protective surface film on the metal and lead to the beginnings of metal loss/corrosion.
Check Reading	A reading to test an ER probe using the electronic meter's two internal references, where the difference of the two should remain constant (relative to temperature).
Chloride (Cl^{-}) Ion	A monovalent anion that is a very common dissolved constituent of most waters. Chloride typically represents the most significant percentage of the total dissolved solids in many water samples, since it is the chief component of most brines. Chlorides form salts with a variety of cations and is well known for exacerbating pitting attack in carbon and stainless steels.

TERM	DEFINITION
Close Interval Survey	A potential survey with pipe to soil readings generally taken a maximum of three feet apart.
Coating	A dielectric material applied to a structure to separate it from the environment.
Coating System	All components comprising the protective coating, the sum of which provides effective electrical isolation of the coated structure.
Company	EnLink Midstream Services, LLC
Conductivity	The ability of a substance (measured in moh-cm) to conduct an electric charge or current due to the presence of positively or negatively charged ions. Theoretically, the higher the conductivity of an electrolyte, the greater the chance for corrosion to occur.
Conductor	A material suitable for carrying an electric current. It may be bare or insulated.
Continuity Bond	An intentional metallic connection that provides electrical continuity.
Continuous Injection	A method of applying corrosion inhibitors or biocides by continuous injection of chemical. Can be used in either stratified or annular flows. Generally recommended when the free liquids are transported in the gas stream.
Conventional Ground Bed	A shallow burial ground bed using one or more anodes in one location. The anodes are usually placed in a line perpendicular to the pipeline.
Corrosion	The deterioration of a material, usually a metal, by reaction with its environment.
Corrosion Potential	(E_{corr}) The Mixed Potential of a freely corroding surface in an electrolyte, relative to a reference electrode. Also called native potential, rest potential, open circuit potential, or freely corroding potential.
Pipeline Integrity	Department responsible for all corporate pipeline integrity control programs, training and procedures.

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TERM	DEFINITION
Corrosion Rate	The rate at which corrosion progresses, expressed in mils per year (mpy), for uniform thickness changes or metal loss. A mil is 0.001 inch, or one one-thousandth of an inch. Coupon corrosion rates may help to indicate the severity of corrosion in a system, and is calculated using the known values of W = weight loss/gain (mg-milligrams), D = density of specimen material (g/cm^3 - grams per cubic centimeter), A = area of coupon specimen (in^2 - inches squared), and T = exposure time (days) by the following equation: mpy = W x 365 / D* x 16.4 x A x T *Density of carbon steel = 7.85 It is important to note that a small corrosion rate does not necessarily mean corrosion is not a problem but does suggest that general corrosion is not of concern, however, pitting may be significant.
Coupon	A small, carefully weighed and measured specimen of metal that is used to determine metal loss caused by corrosion over a specified period of time. Coupons are generally made of the same metal composition as the structure in which they are installed. Metal loss measure measurements are usually calculated in mils per year (mpy).
Courtesy Bond	A temporary bond established with a foreign structure.
Crevice (Contact) Corrosion	Localized corrosion that is similar to pitting, although, in this case, the initial crevice was already in place. It forms in crevices and similarly shielded areas where water flow is stagnated. This type of attack often begins under sediment that accumulates. Other shielded areas where it may occur are under washers and flange gaskets.
Criteria	Standards for assessment of the effectiveness of a cathodic protection system.
Critical Bond	A bond installed to mitigate interference where the damage would be caused to Company facilities if the bond fails.
Critical Insulator	An insulator that would allow potential damage to Company facilities or create a safety hazard if the insulator fails.

TERM	DEFINITION
Critical Piping	Any piping system where a failure would threaten the safety of the public or company personnel, or cause loss of service to customers.
Critical Velocity	The velocity at which erosion-corrosion begins in a pipeline.
Culture Bottles	Liquid media formulated to cultivate and quantitate different groups of bacteria (e.g., APB, SRB, etc.) found in oilfield/pipeline environments. Accurate counts of viable bacteria require that samples remain free from any outside contamination.
Current Density	Current per unit area. Important for ground bed design.
Current Exchange Agreement	Is a negotiated current bond that provides a mutual benefit to both parties and is in effect only as long as both parties are in agreement. This bond requires a formal legal agreement signed by representatives of both companies. Either party may end it with 30-day notification.
Deep Ground Bed	A ground bed in which the anodes are placed far below the earth's surface in a single vertical hole. Deep ground beds are typically considered 50 feet or deeper.
Diode	A bipolar semi-conducting device having a low resistance in one direction and a high resistance in the other.
Disbondment	The loss of adhesion between a coating and the pipe surface.
Distributed Ground Bed	A ground bed where the anodes are spread over a wide geographical area. Usually employed to protect densely routed buried piping systems, such as in compressor station yards.
Doglegged Vent	A casing vent that is bent from vertical.
Dry System	Pipelines transporting an acceptable dew point gas, which will not condense free water into the gas stream.
Electrical Isolation	The condition of being electrically separated from other metallic structures or the environment.

TERM	DEFINITION
Electrode	An electronic conductor used to establish electrical contact with an electrolyte as part of a cathodic protection circuit.
Electrolyte	A chemical substance or mixture containing ions that migrate in an electric field. Electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.
Electrolytic Shield	A non-conductive shield installed between structures to increase the effective electrical resistance between the two structures.
Electrolytically Shorted Casing	A casing with a low casing to pipe resistance due to the presence of an electrolyte in the casing/pipe annulus. Electrolytically shorted casings are not considered to be metallically shorted.
Electro-Osmotic Effect	Passage of a charged particle through a membrane under the influence of a voltage. Soil or coatings may act as the membrane.
Electromotive Force (EMF)	The work done to maintain a voltage difference while current is flowing. In galvanic CP systems the EMF is provided by the chemical energy released during consumption of the anode. In impressed current CP systems the EMF is provided by the external power supply to the rectifier. (AC, thermoelectric, photovoltaic cells, etc.)
Electron Microscope (EM) Coupon	A coupon that is generally fabricated from actual pipeline material or from metal stock that is very similar to the materials of construction, with a surface that is prepared so any mill scale is removed. Such a finish allows the coupons to be examined using optical and electron microscope methods. This analysis provides for a more detailed look at a coupon’s surface including any pitting, scaling, and/or etching. It should be noted that the information obtained from coupons are site-specific and may not be representative of the entire system.

TERM	DEFINITION
EM Coupon Maximum (Max.) Pit Depth	The depth, in microns (µm), of the deepest pit measured on a corrosion coupon. This measurement is determined using optical microscopic methods and is used in conjunction with other optical analysis data, such as maximum pit diameter, pit density, etc., to determine the type and severity of the corrosion occurring. In addition, if mitigation is necessary, this value can assist in evaluating the effectiveness of the strategy employed. When referring to a particular max. pit depth, it is important to note the coupon exposure period related to this depth. Obviously, a shorter exposure period would be attributed to a higher level of corrosion than a longer exposure period for the same pit depth. The following scale gives a general idea of how the max. depth values are classified < 50 µm low 50 - 100 µm moderate > 100 µm high
EM Coupon Maximum (Max.) Pit Diameter	This is the diameter, in millimeters (mm), of the largest pit found on a corrosion coupon or where two or more pits have merged as one. This measurement is the greatest possible diameter formed. It is determined using optical methods (i.e., light microscopy) and is used in conjunction with other optical analysis data, such as max. pit depth, pit density, etc., to help determine the type and severity of corrosion present on a coupon. In addition, if mitigation is necessary, this value can assist in evaluating the effectiveness of the strategy employed. The following scale gives a general idea of how the max. diameter values are classified < 0.5 mm low 0.5 - 0.75 mm moderate > 0.75 mm high

TERM	DEFINITION
EM Coupon Optical Severity	The categorization, on a "macro" scale, of the corrosion severity on a corrosion coupon, as observed through a light microscope at a magnification of 10x. This indicates the relative severity of corrosion by using the following scale of 0-5: 0 = No corrosion 1 = Low 2 = Moderate 3 = Moderately High 4 = High 5 = Severe
EM Coupon Optical Type	The categorization, on a "macro" scale, of the corrosion type on a corrosion coupon, as observed through a light microscope at a magnification of 10x. This indicates the type of corrosion by using the A-F scale that follows A = Isolated Pitting B = Predominately Pitting, Some Etching C = Approximately 50/50 Pitting/Etching D = Patchy Etching, Few Pits E = Uniform Etching F = No Corrosion

TERM	DEFINITION
EM Coupon Pit Type	A classification associated with the predominant pit initiation mechanism as determined using scanning electron microscopy (SEM) and standard morphological features. There are five major pit types that may be identified, and they are listed and defined as follows: MIC = Microbiologically Influenced Corrosion PM = Predominately MIC, however significant electrochemical corrosion also present PE = Predominately Electrochemical Corrosion, with evidence of MIC present EC = Electrochemical Corrosion Other = As described by the analyst in the comments (e.g., mechanical). This determination is often quite important since it generally indicates the type of chemical treatment (i.e., biocide or corrosion inhibitor) to be recommended.
EM Coupon SEM (Scanning Electron Microscope) Severity	The categorization, on a micro-scale, of corrosion severity found on an EM coupon as observed using a Scanning Electron Microscope (SEM), generally at magnifications ranging from 500x to 5000x. A scale of 0 to 5 is used and is as follows 0 = No Corrosion 1 = Low 2 = Moderate 3 = Moderately High 4 = High 5 = Severe

TERM	DEFINITION
EM Coupon SEM (Scanning Electron Microscope) Type	The categorization, on a "micro" scale, of the corrosion type on an EM coupon as observed by SEM (500x to 5000x magnification) by using the scale that follows A = Isolated Pitting B = Predominately Pitting, Some Etching C = Approximately 50/50 Pitting/Etching D = Patchy Etching, Few Pits E = Uniform Etching F = No Corrosion
EM Coupon Type	Designation of the type of EM coupon (see "Electron Microscope Coupons") used. There are three main EM coupon designations "Detection", "Evaluation", and "Keypoint". "Detection" coupons are used in untreated systems or upstream of chemical treatment to monitor the system's corrosiveness. "Evaluation" coupons are installed downstream of chemical treatment to monitor the chemical's effectiveness. "Keypoint" coupons monitor "co-mingled" liquids and/or gas provided from multiple sources/pipelines upstream, generally at the terminus of a trunk line.
End Weight	The final weight, in grams (g), of a corrosion coupon after exposing it to pipeline conditions and cleaning. This value is used with the "Start Weight" to determine weight loss (or gain). This weight difference (typically converted to milligrams, mg) is used to calculate the corrosion rate. Accuracy may vary because the weight of the coupon, after it is removed, may be affected by things other than metal corrosion. This can be due to factors such as scale remaining on the coupon after cleaning, or the removal of metal from the coupon as a result of cleaning or mechanical damage.
Energy Dispersive Spectroscopy (EDS)	Since an electron beam is used to bombard the metal surface or solid sample and X-rays are emitted with a characteristic energy, this technique is also known as EDX (Energy Dispersive X-ray) analysis. The characteristic energy peaks emitted then are used to identify individual elements on a qualitative (i.e., not quantitative) basis.

TERM	DEFINITION
Erosion	Abrasive metal loss caused by high surface velocity of the transported media, particularly when entrained solids or particulates are present. In simple erosion, corrosion makes no contribution to the metal loss. Erosion may appear as elongated pits or channels parallel to the flow direction or general metal loss at section changes bends or elbows. Damage due to erosion generally has a smooth appearance.
Erosion-Corrosion	Corrosion, which is accelerated by high surface velocity of the transported media, particularly when, entrained solids or particulates are present. In this mechanism, erosion serves to prevent protective scales or films from forming over actively corroding areas. Erosion-corrosion may occur where changes in section cause turbulence, or at bends and elbows. Erosion-corrosion is closely related to Impingement Corrosion (see glossary).
Electrical Resistance (ER) Probes	An electronic probe that can be used in systems where gas or liquids (including hydrocarbons) are present to determine metal loss over time by measuring the increase in the resistance of the electrode as its cross-sectional area is reduced by corrosion. The resistance of the electrode is then compared with the resistance of a reference electrode. A few examples of advantages to corrosion rate measurement through the use of ER probes are as follows the ability to measure the corrosion without having to see or remove the test sample, quick and continuous measurements, and the ability to detect high or low corrosion rates that would take a long time to detect using traditional weight-loss methods (i.e., coupons). If ER probes are the only method employed, the corrosion rates measured are considered significant. A disadvantage of ER probes is that this method does not indicate pitting or potential for pitting. As a result, it is generally used with a method that does (e.g., EM coupons, LPR probes, etc.). ER probes are also subject to fouling which impacts data quality.
ER Probe Current Reading	The instantaneous reading for resistance when an ER probe is polled or measured. Such readings are used to determine whether a potential internal corrosion problem exists at a location, while assessing the extent of corrosion damage on an ongoing basis.

TERM	DEFINITION
Exposure Period	The number of days a coupon is exposed to system conditions. This value is used to calculate the corrosion rate and pitting rate.
Facultative Bacteria	Microorganisms that are capable of growing with or without the presence of free oxygen in the local environment. When no oxygen is available such as in natural gas systems or in the anaerobic zone of a biofilm, facultative organisms utilize sulfates or nitrates as electron acceptors in lieu of O_2.
Flow Velocity	A calculation of the speed a gas or liquid moves through a pipe of a specific ID (internal diameter).
Forced Mitigation Bond	A powered bond designed to balance potentials such that interference currents cannot flow
Foreign Structure	Any structure that is not intended as a part of the system of interest.
Free Liquids	Liquids (hydrocarbon or water) that are not vaporized or entrained in the gas phase.
Galvanic Anode	A metal that provides protection to another metal or metals that are more noble in the series when coupled in an electrolyte because of its relative position in the galvanic series.
Galvanic Corrosion	Corrosion resulting from the coupling of two dissimilar metals in an electrolyte.
Galvanic Series	A list of metals and alloys arranged according to their relative potentials in a given environment.
Gas Flow	Stratified Flow - Low gas velocity (liquid concentration on bottom of pipe) Wave Mist – Intermediate gas velocity (liquid concentration partially entrained in the gas flow) Annular Mist – High gas velocity (liquid concentration entrained in the gas flow)

TERM	DEFINITION
Half-Cell Reference Electrode	See "Reference Electrode."
Holiday	Any discontinuity or bare spot in a coated surface.
Hydrogen Sulfide (H_2S)	A colorless, poisonous, and flammable gas that has a characteristic rotten egg odor at low concentrations. H_2S is very soluble in water and when dissolved, it behaves as a weak acid and usually causes pitting of carbon steel, depending on the type of film formed on the metal surface.
Hydroxide (OH^-) Ion	A common dissolved constituent of water that has the ability to neutralize acids and act as an anionic inhibitor. OH^- ions are also a component in a water's alkalinity; however, a hydroxide alkalinity value can only be obtained if the pH is greater than 8.3. In addition, hydroxide ions react with bicarbonate ions to form carbonate ions and water. Thus, in a liquid sample, hydroxide and bicarbonate alkalinity do not coexist.
Impressed Current	Direct current supplied by a cathodic protection system utilizing an external power source.
Impingement Corrosion	A type of internal attack that occurs when a liquid stream collides with a metal surface and breaks down protective films in very small areas. Impingement is very similar to erosion corrosion but is usually considered to be due to more direct blasting of the surface by a fluid that is often a result of turbulence surrounding small particles adhering to the metal surface. The turbulence results in greater agitation of the liquid at the metal surface in a small particular area. Solids and gas bubbles have a tendency to increase/accelerate the impingement attack, which results in pits that are characteristically elongated and undercut on the downstream end.

TERM	DEFINITION
Inhibitors	An additive used to retard undesirable chemical action in product when added in small quantity. Inhibitors have solubility characteristics, and some are pH activated. Depending on the product, concentration levels of 50 – 250 ppm are desired residuals in the appropriate liquid phase. Not all inhibitors work to inhibit corrosion at all times. A chemical that is effective in one situation, may not work well in another situation or environment. Corrosion inhibitors can be broken down into a few main groups 1) Those that work by coating the surface with many layers, forming a barrier. 2) Those that chemically react with the surface, forming a film. 3) Those that adsorb to the surface with no significant chemical reaction.
In-Line Inspection (“Smart Pigging”)	The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline, in order to locate corrosion and/or material defects.
In-situ	A Latin phrase meaning "in place." Any process that occurs in the field as opposed to the factory. Internal coating of pipe after installation is called In-situ coating.
Instant-Off Potential	The structure to soil potential immediately after all cathodic protection current is interrupted and prior to polarization decay.
Instant-On Potential	The structure to soil potential immediately after cathodic protection current is applied and prior to polarization.
Interference	Ionic current discharged through the electrolytic path from a metallic structure due to the suppression or interference with the cathodic protection system of that structure.
Interference Bond	A metallic connection designed to control electrical current between metallic systems.

TERM	DEFINITION
Intergranular Corrosion	Localized attack at and adjacent to the grain boundaries of an alloy, with relatively little corrosion of the grains. This occurs when there are dissimilarities in the activities between the grain boundaries and the grain itself, which allows electrochemical corrosion cells to form; the grain boundary becoming the anode (corrodes) because of its higher activity. The alloy disintegrates (grains fall out because there is nothing left to support them) and/or loses its strength. Intergranular corrosion can be caused by impurities at the grain boundary, enrichment of one of the alloying elements, or depletion of one of these elements in the grain-boundary areas.
IR Drop	The voltage drop across a resistance in accordance with Ohm's Law.
Iron (Fe)	Iron is a metallic cation that is a common dissolved constituent of most waters (generally in the oxidized ferrous – Fe^{3+} form) and the chief indicator of corrosion of carbon steel. In anaerobic environments such as natural gas systems, iron may also be present as the reduced ferric (Fe^{2+}) form. Dissolved iron: Generally determined in the field on untreated aqueous samples using colorimetric methods and indicates all iron species in solution. Total iron: Generally determined in the laboratory on acidized samples, which solubilizes any undissolved iron in the sample for detection of all iron present. The analysis of the iron content of a liquid is a technique used to estimate the amount of corrosion occurring in an operating system composed of carbon steel. In general, the amount of dissolved iron tends to increase with increasing corrosion rates. However, iron values are not always reliable indicators of corrosion severity or pitting due to a variety of factors, including native iron in produced waters, variations in water production volumes and/or water condensing from the gas stream, etc.
Iron Carbonate ($FeCO_3$)	A corrosion product of iron and steel. $FeCO_3$ scale deposits often form when dissolved iron in water reacts with carbonates and precipitate on metal surfaces. Iron carbonate on the external portion of the pipe is an indicator that cathodic protection is reaching that area.

TERM	DEFINITION
Iron Oxide (Fe_2O_3)	A very common corrosion product of iron and steels (i.e., “rust”). Fe_2O_3 scale deposits form when dissolved iron ions in water react with oxygen and precipitate on metal surfaces.
Iron Sulfide (FeS)	Hydrogen sulfide (H_2S) that may be present in gas or produced by bacteria can be quite corrosive. H_2S can separate into H^+ and SH^- ions in water. The SH^- ion further dissociates into $S^=$ and H^+. Sulfide ions ($S^=$) can then react with any dissolved iron present to form black iron sulfide (FeS), which is a corrosion product of iron and steel alloys and is corrosive itself.
Holiday Detection (Jeeps, or Jeeping)	A test of coating integrity using a high voltage circuit attached to a wet sponge or spring coil on a non-conductive rod.
Line Current	The direct current flowing on a pipeline.
Local Potential	A potential taken within three feet of a test station.
Long-Line Corrosion Current	Current flowing through the earth between an anodic and a cathodic area that returns along an underground metallic structure, usually occurring over a few miles to a few hundred miles of pipe.
Linear Polarization Resistance (LPR) Probe	A linear polarization resistance (LPR) probe measures corrosion rates instantaneously by utilizing an electrochemical phenomenon known as linear polarization (polarization is the retardation in the rate of an electrochemical cell).

TERM	DEFINITION
Magnesium (Mg^{++}) Ion	A very reactive, divalent metal cation which is a common dissolved constituent of most waters. It represents a percentage of the total dissolved solids, and is a major hardness component of water. The magnesium ion can combine with sulfate or carbonate ions to form insoluble compounds which may in turn form deposits. These deposits can build-up to form scales on the pipeline's inner surface, which may serve as a protective scale. However, if the formation of these deposits is excessive and uncontrolled, their build- up can decrease the diameter of the pipe, creating flow problems. Although magnesium ions have the ability to precipitate and form protective scales, at high concentrations, they can interfere with the action of some corrosion inhibitors. By reacting with certain inhibitor constituents, such as phosphate or silicate, nonprotective substances are allowed to precipitate out of solution. This not only weakens the concentration and effectiveness of the inhibitor, but it permits the formation of a nonprotective scale buildup on the pipeline's inner surface. Mg^{++} can also form salts with substances such as chlorides, which can cause corrosion.
Manganese (Mn)	Manganese is a metallic cation that has multiple oxidation states and is a common dissolved constituent of most waters, but usually at relatively low concentrations. Mn is also a constituent of carbon steel. Its presence within liquid samples may not only indicate whether corrosion of a metal is occurring within the system, but also allows the corrosion process to be followed.
Metabolism	Chemical reactions in all living organisms that are responsible for growth and survival. In many microorganisms for example, these reactions are oxidation-reduction reactions that are accompanied by a release of energy. Since microbes may act as electron donors or electron acceptors, microorganisms attached to metal surfaces are capable of producing electrochemical reactions that can drive a corrosion cell.
Methanol (CH_3OH)	Generally used as a freeze-protectant and as a carrier in corrosion inhibitors or biocides, and in dewatering pipelines following hydro testing.

TERM	DEFINITION
Microbiologically Influenced Corrosion (MIC)	Deterioration of metal due to the activity of microorganisms. Two groups of bacteria often identified in MIC of natural gas systems are Acid Producing Bacteria (APB) and Sulfate Reducing Bacteria (SRB).
Mixed Potential	A potential resulting from two or more electrochemical reactions occurring simultaneously on one metal surface.
Mole %	A calculation of the percentage of a compound or molecule. Mole% can be converted to PPM as follows: Mole% X 10,000 = ppm Mole% = (Partial Pressure X 100) / Operating Pressure
Non-Critical Bond	A bond installed to mitigate interference or stray current that would not be detrimental to company facilities if the bond fails. (Note – Non-critical bonds may be critical to the foreign operator.)
Obligate Anaerobes	Anaerobic bacteria that cannot grow in the presence of free oxygen or for which oxygen is toxic.
Organic Acids	Weak acids that are the end product of metabolism by a variety of microorganisms, which are corrosive to carbon steel and other metals. These acids are correctly classified as carboxylic acids (contain a carboxyl group, -COOH) and are also known as short-chain fatty acids.

TERM	DEFINITION
Oxygen (O_2)	A colorless, odorless gas necessary for life. Although, well known in its role in the corrosion of iron and steel when available (i.e., certain external environments), oxygen generally is not a factor in most internal corrosion of natural gas systems that are properly operated. O_2 generally will promote pitting attack since wherever there are areas with different oxygen concentrations, corrosion takes place in the lowest concentration areas (crevices, pits, etc.). This happens because the area with the most oxygen becomes the cathode and the area with the lowest oxygen concentration becomes the anode.
pH	The negative logarithm of the hydrogen-ion concentration in a substance. A pH of 7.0 is neutral. A pH lower than 7.0 is acidic, while a pH greater than 7.0 is alkaline.
PPM	Parts per million. PPM can be converted to Mole% as follows: PPM / 10,000 = Mole%
Parallel Ground Bed	A ground bed using anodes placed parallel to and not electrically remote to the structure. Parallel ground beds are used mainly in high resistance soils or to correct low potentials on bare or poorly coated lines.

TERM	DEFINITION
Partial Pressure	The pressure, in pounds per square inch atmospheric (psia), of a component gas in a pipeline or vessel. The partial pressure of a gas represents the pressure that a gas would exert on a system if it were the only gas present. The partial pressure of a gas can be computed using the following equation (assuming "standard conditions") partial pressure = [fractional mole % x total pressure] where fractional mole % = [mole % / 100] total pressure (psia) = [pressure (psig) + atmospheric pressure] For example; if a gas sample has 0.5 mole % of CO_2 and the pipeline pressure was 1,000 psig, the CO_2 partial pressure would be calculated as follows: (0.5 / 100) (1,000 + 1 atmosphere*) (0.005) (1,014.7) = 5.07 psia *1 atmosphere (sea level) = 14.7 psi
Pipe-to-Electrolyte Potential	The potential difference between the pipe metallic surface and electrolyte that is measured with reference to a standard electrode in contact with the electrolyte.
Pitting	Pitting is a form of extremely localized attack that results in holes in the metal. Such attack occurs when the metal undergoing corrosion suffers metal loss at localized areas, rather than over the entire surface. In general, a pit may be described as a cavity or hole where the surface diameter is about the same size or less than its depth.
Pit Rate	The rate of penetrations calculated using the maximum pit depth measured on a coupon. This penetration is extrapolated over a one year period and expressed in mils per year (mpy). The following equation is used to find the pitting rate mpy = <u>max. pit depth (microns) x 0.03937 (mils/micron) x 365 (days/year)</u> exposure period (days)
Planktonic Bacteria	Free-floating bacteria in the bulk fluids.

TERM	DEFINITION
Polarization	The deviation from the free corrosion potential (open circuit potential) of a metal resulting from the flow of current between the electrode and the electrolyte.
Polarized Potential	The potential across the structure / electrolyte interface that is the sum of the corrosion potential and the cathodic polarization.
Potassium (K^+) Ion	A monovalent metallic cation which is a common dissolved constituent of most waters and formation brines. As a salt, potassium can cause corrosion. However, dissolved potassium can act as a scale inhibitor and reduce corrosion.
Potentially Wet System	A pipeline transporting high dew point gas that can condense free water into the gas stream when conditions are favorable.
Pressure	The force exerted or applied over a surface, expressed in pounds per square inch gauge (psig). Pressure affects the rates of most chemical reactions, including corrosion reactions. The primary importance of pressure is its effect on dissolved gases; i.e., more gas goes into solution as the pressure is increased. This may in turn increase the corrosiveness of the solution.
Reference Electrode	A standard electrode with a potential that may be considered constant under similar conditions of measurement. (Examples saturated copper-copper sulfate, saturated calomel, and silver-silver chloride.)
Remote Potential	The potential of a structure taken outside of the current gradient surrounding the structure. Remote potentials remain nearly constant with increasing distance from the structure or current source.
Required Minimum Potential (RM)	The minimum acceptable potential at a given test point location that ensures all remote irregularities are protected.
Resistance Bond	A metallic path, where the amount of current is controlled by a permanent or adjustable resistance, installed to provide a return path for cathodic protection current thus to prevent corrosion due to interference or stray current.

TERM	DEFINITION
Reverse-Current Switch	A bond designed and constructed such that cathodic protection current can pass in only one direction.
Scaling Tendency	Describes a water's potential for scale formation (see "Stability Index"). The tendency for scaling in a system is influenced by temperature, pressure, concentration of different ions, and amount of dissolved gases. A strongly positive stability index suggests a "Potential for Scaling", while a very negative stability index predicts no scale precipitation and that there is a "Potential for Corrosion". Values in between are generally considered inconclusive with regard to scaling or corrosion.
Selective Leaching Attack	Occurs when one metal of an alloy is preferentially attacked and leached from the alloy matrix. Two common forms are dezincification and graphitization.
Sessile Bacteria	Bacteria attached to a surface.
Shielding	High resistance or non-conducting material preventing cathodic protection current from reaching the structure, or low resistance material diverting the current away from the structure to be protected.
Shorted Pipeline Casing	A casing that is in direct metallic contact with the carrier pipe.
Side Drain Survey	Measurement of the potential gradient perpendicular to the pipe to determine net current flow onto or off of the pipe.
Sodium (Na^+) Ion	A monovalent metallic cation that is a common dissolved constituent of water, brines, and scales. Sodium commonly forms salts with anions such as chloride. The addition of salts to water increases its conductivity and possibly its corrosion potential.
Specific Gravity	The ratio of the density of the liquid being tested to the density of distilled water, at a stated temperature (60^{o} F is typically used). Specific gravity of a solution can be used as an indication of the amount of salts dissolved in water. As the specific gravity increases, the density, and therefore the amount of dissolved salts, also increases.

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TERM	DEFINITION
Stability Index	An empirical expression that indicates the scaling and corrosion tendencies of water samples. The stability index provides a somewhat quantitative value for whether calcium carbonate scale will be deposited within a pipeline, as well as potential seriousness of any scaling or corrosion that might occur. In general, the more positive the stability index is, the greater the amounts of scale accumulation tendencies are for scale to be precipitated. The more negative a stability index is, the less likely scale deposition is, and the greater the potential for corrosion. The stability index is accurate when calculated using field measured pH and alkalinity.
Start Weight	This is the initial weight, in grams (g), of a corrosion coupon before exposing it to pipeline conditions (also known as Begin Weight). This value is used with the "End Weight" to determine weight loss (or gain). This weight difference (typically converted to milligrams, mg) is used to calculate the corrosion rate.
Stray Current	Ionic current that flows onto and off of an unprotected metallic structure. Corrosion will result when stray current flows from the structure to the electrolyte.
Stress Corrosion Cracking (SCC)	The cracking of a metal alloy caused by application of tensile stress in a specific corrosive chemical environment.
Sulfate ($SO_4^{=}$)	A non-metallic, anionic divalent compound that is a common dissolved constituent of most waters. $SO_4^{=}$ can combine with calcium or magnesium ions to form insoluble compounds which may in turn form deposits. These deposits can build-up to form scales on the pipeline's inner surface, which may serve as a protective scale. However, if the formations of these deposits are excessive and uncontrolled, their build up can decrease the diameter of the pipe creating flow problems. Sulfate is also important because it is reduced by sulfate reducing bacteria (SRB), to sulfide and oxygen. Sulfide can be very corrosive to steel (FeS) and may combine with certain cations [e.g., calcium (Ca^{++}), barium (Ba^{++}), strontium (Sr^{++})] to form slightly soluble precipitates.

TERM	DEFINITION
Sulfate Reducing Bacteria (SRB)	A group of anaerobic bacteria that reduce sulfate to sulfide (see “Microbiologically Influenced Corrosion”). Considered by many to be the chief causative agent of MIC due to their ability to remove hydrogen at the cathode using their hydrogenase enzymes (see “Cathodic Depolarization”).
Sulfur	A non-metallic cation that is usually found in the form of an oxoanion such as sulfate ($SO_4^{=}$).
Telluric Current	Current in the earth (or on pipelines) produced by geomagnetism.
Temperature	Temperature, in degrees Fahrenheit (^{o}F), is a measure of the heat present in a substance or its environment. Since temperature changes rapidly, it must be measured at the time of sample collection. All chemical reactions are affected by temperature either directly or as a result of its effect on reaction rates, solubility, phase change, etc. Therefore, temperature has an effect on corrosion. Some of these effects are complex; however, in general, an increase in temperature increases the corrosion rate. A rough “rule of thumb” suggests that the reaction rate doubles for every ten-degree Celsius rise in temperature. To convert degrees Celsius into Fahrenheit the formula is as follows $^{o}F = [^{o}C \times 9/5] + 32$
Total Alkalinity	Alkalinity is a measure of a liquid’s ability to neutralize acids. Total alkalinity, is the sum effect of all the major sources of alkalinity, such as carbonate ($CO_3^{=}$), bicarbonate (HCO_3^{-}), and hydroxide (OH^{-}) alkalinity. Total alkalinity measurements should be performed in the field immediately following sample collection because the value is pH-dependent and capable of changing over time. The ability of a substance to neutralize acids makes it an effective corrosion inhibitor. A high alkalinity value indicates that the water has the ability to buffer acid and may be able to form a scale precipitate. In general, as alkalinity increases, corrosiveness tends to decrease. It should be noted that no alkalinity exists in environments with a pH less than 4.3.

TERM	DEFINITION
Total Dissolved Solids (TDS)	Total dissolved solids (TDS) is the sum of all dissolved ions, both cations and anions, detected in the analysis of an aqueous liquid. This value can be used to predict a water's conductivity and whether a water is composed chiefly of brine or condensed water. This value can also be used as a check to verify the completeness of an analysis. The sum of each of the individual constituents of the sample should approximate the total dissolved solids value.
Under-Deposit Corrosion	Results when pitting occurs under a deposit on the metal surface . The deposits may be due to corrosion product precipitation, precipitation of solids from the water or microbiological activity.
Uniform Corrosion	Also referred to as "general" corrosion, uniform metal loss is the most common form of corrosion. It occurs over an entire exposed surface due to electrochemical attack. This corrosion is caused by thousands of mini-corrosion cells spread over the entire surface. The corrosion thins the metal at a relatively constant rate. It is because of this constant rate that uniform corrosion is the basis of most engineering designs. Since the rates may be predetermined as they progress in a uniform manner, equipment can be developed with those rates and conditions in mind. Uniform corrosion represents the greatest overall destruction of metal in all industries, but from an integrity standpoint, it is not as great of a concern due to the generally slow, predictable failure rates that occur due to this type of attack. Considering the coating materials, monitoring techniques, and mitigation procedures currently available, failures due to uniform corrosion should rarely ever occur in gas pipelines and other strategic infrastructure.
Voltage	An electromotive force or a difference in electrode potentials expressed in volts.
Water Dewpoint	At specified pressures and temperatures, the point where gas becomes saturated with moisture and vapor begins to condense and form free liquids. This value, measured in lb./mmscf, represents the water content of a gas sample.
Wet System	A pipeline transporting aqueous liquids.

APPENDIX B – REVISION RECORD

Section	Date	Summary of Revision(s)	Comments
All	1/10/2019	Completed first draft of new manual V1.0	Re-format of existing manual
	2/26/2019	Completed final review and approval with Corrosion Committee. For detailed list of revisions, see DOT Group. Approved version posted on EnSite.	
All	1/22/2022	Completed final review and approval with Corrosion Committee. For detailed list of revisions, see DOT Group. Approved version posted on EnSite.	Medium changes

APPENDIX C – PCS DATA PROGRAM

Purpose

This procedure is established to outline the minimum data entry requirements for Inspections applicable to corrosion control documentation to be stored in the PCS database.

Roles and Responsibilities

Position	Responsibility
Corrosion Technician	• Responsible for all electronic data entries, and maintenance for ENLINK assets.

Procedures

Maintaining the Database

- All pipeline facilities should be set up in the appropriate computerized Database (PCS). Facilities should be located in the proper hierarchy. Each reading location should be entered under the proper segment and tab. Reading locations include test stations, rectifiers, bonds and critical bonds, ground beds, towers, offshore pipelines, and piles.
- Atmospheric locations, meter stations, and compressor stations must be entered and maintained using PCS.
- Data from retired or abandoned facilities MUST NOT be deleted. Approved methods for making data inactive or archiving data must be used. There are numerous circumstances that may require deleting an individual data set from a database. This might be the removal of a sales station and its associated piping, destruction of a test lead when land is converted from pasture to cultivation or housing, removal of a casing or removal of a foreign line. The data containing the information is not to be deleted but must be converted to an inactive test point. This will maintain the test point's history and assist in documentation. A large group of points can be moved to another section of the hierarchy and made inactive. The data for a reference point or group of points cannot be deleted from the database or deactivated

from the database without approval. Test points can then be deactivated with approval from area corrosion technician.

- The PCS database server will be used for all EnLink corrosion control data. Individual corrosion technician are responsible to upload any corrosion data as soon as practical after surveys are completed.

PCS Data Field set up by Facility Type (Inspections Tab)

The below listed fields should be utilized for each facility type for documenting required inspections in accordance with 49CFR-192/195 regulations.

- **Test Points (CP test points) -** ***CPDM module***

Line Code	Test Point ID	Location Description	Latitude	Longitude	Inspection date	structure P/S	Structure IRF	AC P/S	Casing P/S	Foreign P/S	Insulator Status	Technician	Inspection Remarks
							If applicable for Criterion			If Applicable @ test point	If Applicable @ test point		

- **Rectifiers -** ***CPDM module***

Line Code	Test Point ID	Facility ID	Location Description	Latitude	Longitude	Inspection date	Rectifier Output Volts	Rectifier Output Amps	Tap Settings	Technician	Inspection Remarks

- **Bonds -** ***CPDM module***

Line Code	Test Point ID	Facility ID	Location Description	Latitude	Longitude	Critical Bond	Bond Current	Technician	Inspection Remarks

- **Atmospheric -** ***ACM module***

Line Code	Test Point ID	Location Description	Latitude	Longitude	Coating Condition	Corrosion	Technician	Inspection Remarks

- **Inhibitor/Injections - *IC module***

Line Code	Test Point ID	Location Description	Latitude	Longitude	Inspection date	mode of Injection	Target Injection Rate	Actual Injection Rate	Quantity	Quantity Units	Inhibitor type	Inhibitor Brand	Technician	Inspection Remarks

- **Coupons - *IC module***

Line Code	Test Point ID	Location Description	Latitude	Longitude	Inspection date	Install date	Total exposure	Coupon number	Coupon Corrosion rate	Technician	Inspection remarks

See below for American Innovations training workbook specifically for PCS Axis.

PCSAxis_TrainingWor
kbook_January2017 (2

Gas Integrity Management Program

This document applies to EnLink employees when working for or acting on behalf of EnLink Midstream Operating, LP or any of its subsidiaries and /or joint ventures.

JUNE 29, 2022

DATE OF CURRENT REVIEW

✓**Version 5.0**

December 17, 2004

Effective Date

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1 PROGRAM STRUCTURE AND OVERVIEW

1.1 Overview

The following Pipeline Integrity Management Program (IMP) addresses integrity management requirements as defined in 49 CFR 192, Subpart O for natural gas pipelines operated by EnLink Midstream Partners (EnLink). Except where it is noted within this document, this plan covers all transmission natural gas pipelines operated by EnLink.

The ***IMP Team*** are responsible for the IMP Manual and oversight of the Integrity Management Program. Responsibilities for specific tasks within the Integrity Management Program are outlined in each chapter.

EnLink will utilize the risk-based and prescriptive approach to integrity management. Should EnLink decide to use the performance-based approach described in 49 CFR 192.913, the processes necessary for implementation of that approach will be included as an enhancement to the IMP at a later date.

The list of EnLink pipeline assets covered by this IMP are listed in Appendix A – Gas IMP Jurisdictional Pipelines and Facilities and is updated with new listings each year.

All records and documents required in this Program will be maintained in the ***IMP Team Chairman'***s files for the life of the line segment or pipeline facility that could affect an HCA.

1.2 Program Structure

The program contains several sections, each based on guiding principles established in 49 CFR 192 that provide the foundation of the program. In conformance with EnLink formatting requirements and in order to facilitate systematic and repeatable execution of the program, each section is organized in the following format:

- Introduction
- Scope
- Responsibilities
- Procedures

The IMP Manual is aligned with the Pipeline and Hazardous Materials Safety Administration's Gas Integrity Management Inspection Protocols. The following outlines specific program sections:

IMP 1, *Program Structure and Overview*
IMP 2, *High Consequence Areas*
IMP 3, *Baseline Assessment / Reassessment Plan*
IMP 4, *Threat Identification, Data Integration, and Risk Assessment*

IMP 5, *Direct Assessment Plan*
IMP 6, *Remediation*
IMP 7, *Continual Evaluation and Assessment*
IMP 8, *Confirmatory Direct Assessment*
IMP 9, *Preventive and Mitigative Measures*
IMP 10, *Performance Measures*
IMP 11, *Record Keeping*
IMP 12, *Management of Change*
IMP 13, *Quality Assurance*
IMP 14, *Communication Plan*
IMP 15, *Submittal of Program Documents*

2 HIGH CONSEQUENCE AREAS [192.903]

2.1 Introduction

This section describes the process for identifying and documenting covered pipeline segments.

As part of its Integrity Management Program, operators must include a process for identifying high consequence areas (HCAs) using either Method 1 or Method 2, as defined in 49 CFR 192.903. The following establishes how EnLink identifies HCAs and satisfies the requirements of 49 CFR 192.903.

49 CFR 192.903 defines HCAs as: an area established by one of the methods described in paragraphs (1) or (2) as follows:

An area defined as—

(i) A Class 3 location under §192.5; or
(ii) A Class 4 location under §192.5; or
(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy.
(ii) An identified site.

2.2 Roles and Responsibilities

Position	Responsibility
IMP Team	• Manage HCA identification, data collection, and integration of data for determining covered segments relative to the IMP process. • Responsible for performing or supervising HCA point data collection, site interviews and documentation of structure data. Responsible for pipeline attribute accuracy and confirming segment(s) MAOP's. • Accountable for 5 aspects of the HCA data collection, and integration of data for determining covered segments relative to the IMP process. Review and approve HCA's, and documentation of HCA method.
IMP Engineer	Responsible for providing the specialist proposed identified site information and newly identified HCA's for field verification.

Position	Responsibility
IMP Public Awareness Coordinator	Maintains communication between EnLink, the general public and public officials.
Regional Teams and SMEs	A survey contractor that may be utilized for performing HCA point data collection, site interviews, and documentation of structure data.
GIS Department	Responsible for performing script routines to generate pipeline route class locations.

2.3 Process

2.3.1 Program Requirements [192.905(a)]

EnLink will retain documentation of the HCA Determination Method utilized for each component within a pipeline system according to Method 1 or Method 2 criteria. The method utilized will be documented for reference and subsequent calculation requirements are listed in the Baseline Assessment Plan.

Unless otherwise stated, EnLink exclusively employs Method 2 to identify high consequence areas. EnLink will utilize one or more of the various map referencing and field surveying techniques listed below to accomplish the location and measurement of an HCA as related to a transmission pipeline segment:

- Area Council of Governments database of known structures.
- Aerial photography to determine critical density of populated areas to survey.
- Aerial photography to locate known structures.
- Interview Field Operations personnel for known locations.
- Research patrol records for known locations.
- Contract Survey Company and/or EnLink Personnel.
- Area Field Operations patrol survey (GPS ground survey work) data collection structure. evaluation frequencies, specific processes, and documentation requirements established in these supporting documents.

EnLink will acquire and/or reference HCA locations according to one of the following units of measurement to account for mapping inaccuracies:

- Latitude / Longitude - decimal degrees (preferred)
  - Survey Quality GPS
  - Survey Range Finder
  - Positive line locates (probe, daylight or quality line locator)
- Pipeline stationing measurement (ft), and distance (ft) at 90 degrees to pipeline segment
  - Survey Range Finder
  - Positive line locates (probe, daylight or quality line locator)

Sites in close proximity, but outside the PIR calculated buffer extents shall be field verified to ensure accuracy of the site location relevant to the buffer. Conservative estimates of class locations will be used until the site can be verified by field personnel.

For each HCA identified, GIS systems are employed to generate system maps that document HCA pipeline segment locations.

Once identified, HCA data is entered into the GIS system. Listings of the official HCA-covered segments are maintained in the company database. In conformance with 49 CFR 192.907(a) EnLink completed its initial HCA identification for all business units prior to December 17, 2004. Historical identification records depicting HCA covered segment selections will be contained in the Integrity Management Department.

GIS route data files will be issued on an annual basis (prior to December 31st) providing current pipeline route information to the NPMS.

2.3.2 Potential Impact Radius [192.903; 192.905(a)]

In order to identify HCAs GIS calculates the potential impact radius (PIR) and employs the PIR to establish potential impact circles (PIC) along a pipeline segment.

The following methodology is typical for PIR determinations:

$$r = 0.69 \cdot d\sqrt{p}$$

Where:

r = potential impact radius (feet)

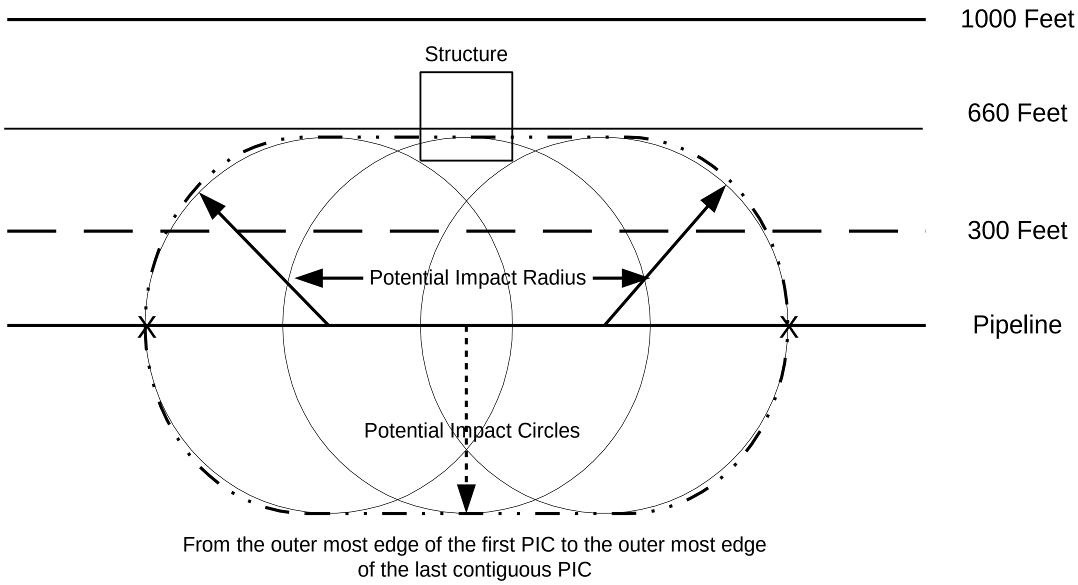
0.69 = scaling factor of lean natural gas

p = maximum allowable operating pressures (MAOP) (psi)

d = nominal diameter of pipeline (inches)

It shall be noted that when using Potential Impact Circles to identify HCAs, the HCAs include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain either an identified site or 20 or more buildings intended for human occupancy.

Figure 2.4-2



A general methodology was developed by Michael Baker Jr., Inc. June 2005 and was presented and recorded in the Department of Transportation Research and Special Programs Administration Office of Pipeline Safety. This report can be used to determine the PIR of other flammable gas mixtures and complies with ASME B31.8S, Section 3.2. The resulting formulas are summarized below.

Summary of Potential Impact Radius Formula

Product	PIR Formula
Ethylene	**R = 1.04 * (square root of (P*(D^2)))**
Hydrogen	**R = 0.47 * (square root of (P*(D^2)))**
Natural Gas (Lean)	**R = 0.69 * (square root of (P*(D^2)))**
Natural Gas (Rich)	**R = 0.73 * (square root of (P*(D^2)))**
Syngas	**R = 0.49 * (square root of (P*(D^2)))**
Nitrogen (Pickled lines)	**R = 0.05 * (square root of (P*(D^2)))**

The recommended formula for rich gas is considered appropriate for natural gas compositions for which the gross heating value is greater than 1,100 Btu/cubic foot.

2.3.3 Identified Sites [192.903; 192.905(b)]

49 CFR 192.903 defines identified sites as:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (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 roller-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 conformance with 49 CFR 192.905(b), if public officials with safety or emergency response or planning responsibilities have information available and useful regarding HCA identified sites relative to Company pipe routes, the Company will employ that information into its process to locating identified sites.

In conjunction with the Company Public Awareness Program the ***IMP Public Awareness Coordinator*** communicates Company identified HCA pipeline route locations with public officials for opportunity of these entities to provide assistance in locating any additional identified sites in the vicinity of Company pipeline segments. Public official contact lists are identified and maintained in conformance with Company Public Awareness Program in the Public Awareness Database. The ***IMP Public Awareness Coordinator*** maintains the communication to and from public officials. Annually, the Company publicly posts its HCA locations on source web sites accessible by public officials and emergency responders.

Identified sites are located and documented using the following methods:

- Company GIS digital maps
- Survey field documentation

2.3.4 Identification Using Class Locations (Method 1) [192.903; 192.905(a)]

In the event that EnLink should chose to use Method 1, the structure survey for class location and determining HCAs provides the data collection structure, evaluation frequency, specific process, and documentation requirements to complete house count and structure information updates. House counts and structure information updates, HCA determinations, and class location determinations, are updated in electronic records with HCA information. These procedures include a process for using either the class location method or the potential impact radius method of HCA segment identification.

Class locations defined in 49 CFR 192.5, are identified by EnLink personnel, and listed in the EnLink Gas Pipeline Operations and Maintenance Manual (O&M).

The Method 1 HCA Determination Method indicates that EnLink will determine and define which segments of a transmission pipeline impute a threat to people or property within a Class III or Class IV Area. This method also addresses any area outside a Class location width corridor where the PIR is greater than 660 feet and the area within a potential impact circle contains at least 20 buildings intended for human occupancy or the area within a PIC contains an identified site.

2.3.5 Identification Using Potential Impact Radius (Method 2) [192.903; 192.905(a)]

EnLink exclusively employs the PIR Method 2 to establish potential impact circles along a pipeline segment. EnLink specifies data needs and documentation requirements for PIR determinations using structure survey for class locations and HCAs.

2.3.6 Identification and Evaluation of Newly Identified HCAs, Program Requirements [192.905(c)]

Continuing surveillance activities are performed for class location and HCAs. New or changed HCA boundaries caused by changing pipeline conditions are identified and updated annually. Those changes include:

- Changes in MAOP
- Pipeline modification including pipe diameter alteration
- Change in pipeline product
- Installation of new pipe
- Change in class location / location boundary
- Pipeline reroute or a new pipeline
- Field design changes
- Identification of new construction activity
- Change in the use of existing buildings
- Corrections to erroneous pipeline center line data
- Corrections to erroneous pipeline listings (discovery of existing pipeline)

Field collected Information points (measurements and site description) will be issued to EnLink GIS department by such means as:

- E-mail
- Facsimile
- Database File Upload (preferred)

- Other methods of transfer as developed

This data will be integrated into the GIS Integrity Database System for evaluation of adjustments to HCA/class lengths. GIS evaluation includes HCA/class calculation routing and accuracy review of pipe route from the supplied survey data. This data will be issued to the ***IMP Specialist*** upon completion. All changes to an HCA/Class location require the review and approval by GIS, ***IMP Team***, and Field Operations.

Maps will be prepared annually to reflect changes of HCA areas to update the baseline assessment/reassessment plans in conformance with IMP Section 3.3.4 - New HCAs / Newly Installed Pipe / Newly Acquired Pipe**.** This data is also used by the ***IMP Specialist*** to validate the HCA changes.

In accordance with **ENLINK GIMP Procedure 101**, *Gas HCA Field Validation*, ENLINK ***IMP Specialist*** complete and return **ENLINK GIMP Form 101**, Field HCA Validation, noting any new potential HCAs not previously identified in ENLINK GIS databases.

Upon completion of could affect segment and facility identification, the ***IMP Team Chairman*** distributes the resulting tables and maps to ENLINK Personnel. **ENLINK GIMP Procedure 102**, Could Affect Segment and Facility Validation, is employed to track communication, ensure communication to field employees, and facilitate validation of results by field employees.

Could affect segment and facility results are included in Federal Gas IMP Appendix C, *Could Affect Segments and Facilities*.

3 BASELINE ASSESSMENT / REASSESSMENT PLAN [192.919]

3.1 Introduction

This section describes the process for planning and completing baseline/reassessments of covered segments.

Integrity assessments (baseline and reassessments) provide EnLink with data and information regarding the condition of the pipeline system. Information gained from assessments is employed in various integrity management elements such as; remediation related decisions and activities, subsequent risk reassessments, and the evaluation of additional preventive and mitigative measures.

EnLink's methodology for baseline assessment planning, remediating anomalous conditions, and conducting continual evaluations has been developed in conformance with 49 CFR 192.911(b) (e) and (f).

The ***IMP Engineer*** maintains a baseline assessment / reassessment schedule for each pipeline system identified in IMP Section 1 – Program Structure and Overview. The initial baseline assessment is used to prioritize integrity management plan activities by organizing data and information in a manner that facilitates threat- and risk-based decision making. Current baseline assessment/reassessment plans are maintained in the IMP database and included in the IMP appendices. The baseline assessment / reassessment plan for each pipeline contains a listing of covered segments with HCA data, identified threats, risk rank, initial assessment method and date (planned or completed), and reassessment method and date (planned). The baseline assessment plan and reassessment requirements are applicable to line pipe only.). Baseline assessment methods are selected as described in **ENLINK GIMP Procedure 103**, *Gas - Select Appropriate Assessment Tool and Vendor*.

3.2 Roles and Responsibilities

Position	Responsibility
IMP Engineer	Maintain IAP risk / reassessment spreadsheet. Responsible for selecting integrity assessment methods.
IMP Team Chairman	Approve use of other technologies for assessments. Notify appropriate agencies of usage of other technologies.
IMP Specialist	Select appropriate vendor for the assessment. Review and approve the results of an assessment.
IMP Team	Select appropriate tools based on the threat.

3.3 Process

3.3.1 Baseline Assessment Methods [192.919; 192.921]

49 CFR 192.919(b) establishes that pipeline operators must base integrity assessment methods on threats identified during the risk assessment process as applicable to ASME B31.8S – 2004, Section 6 (IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment). EnLink's assessment plan documents the type of assessment methods employed, and the rationale and justification for the selection of each assessment method. Assessment method selections are documented on **ENLINK GIMP Form 102**, Assessment Planning.

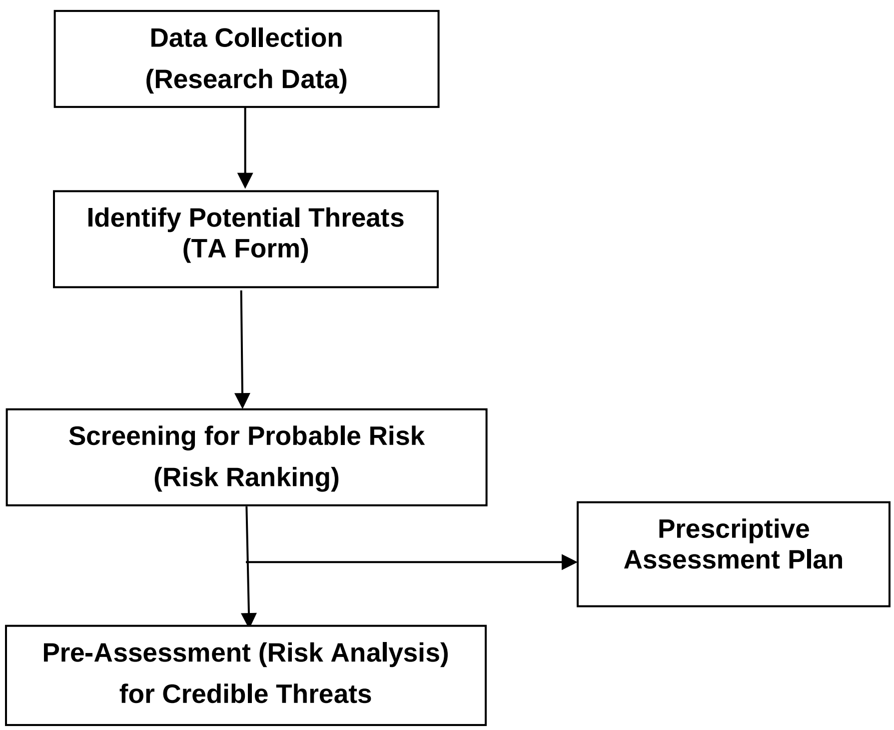
The following assessment methods are approved means of integrity assessment:

1) In-Line Inspection
2) Pressure Testing
3) Direct Assessment
4) Confirmatory Direct Assessment
5) Other technology (approved by PHMSA prior to its application). An example includes cases for low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure. The ***IMP Team Chairman*** will approve other assessment methods capable of assessing seam integrity and detecting corrosion and deformation anomalies.

The ***IMP Engineer*** gathers and integrates data to analyze risks and determine threat(s) associated with each pipeline segment according to IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment. Each segment is risk ranked on a relative scale that assigns a risk ranking from highest to lowest priority segment. The baseline assessment/reassessment plans contain the identified threats, risk rank, and prescriptive method for each covered segment.

The remaining threats (often no more than two or three) require a detailed investigation in order to quantify the contributions that they make to the failure probability. Risk Analysis is the approach that is used for this purpose. The threat assessment approach is summarized in the Figure 1 below:

Figure 1 – Threat Assessment Approach



The ***IMP Team*** employs one of the approved assessment methods to assess pipeline segment integrity. Depending on the threat(s) identified in the risk analysis process, one or more tools may be utilized to assess the integrity of a pipeline segment. ***ENLINK GIMP Procedure 103***, Gas - Select Appropriate

Assessment Tool and Vendor, provides acceptable methods for integrity assessment depending on the threats identified. The ***IMP Team*** selects assessment method(s) for addressing the specified threat(s) to determine segment integrity and document the selected method(s) on the baseline assessment/reassessment plan.

This section presents assessment options employed to determine pipeline segment integrity, and their associated requirements and procedures.

In-Line Inspection (ILI) [192.921(a)(1), 192.937(c)(1), ASME B31.8S sec. 6.2]

EnLink continually works to ensure that the types and sizes of In-Line Inspection (ILI) tools needed for evaluating pipeline segments are available at the desired scheduling intervals. All tool accuracy information is found in the contract documentation for each vendor. In-line inspection of pipelines must comply with the requirements and recommendations of API Std 1163, *Inline Inspection Systems Qualification Standard;* ANSI/ASNT ILI-PQ, *Inline Inspection Personnel Qualification and Certification;* and NACE SP0102-2010, *Inline Inspection of Pipelines.*

Validation of Assessment Results

Anomalies reported by the ILI tool vendors are used as presented. ENLINK recognizes that the reported tool tolerances are ±10% accurate 80% of the time. The tool vendor specifications sheets will be used for accurate tolerances information.

If ENLINK has had recent experience and a high level of confidence in the ILI tool results the calibration digs may be omitted but data verification studies of the ILI report will be conducted during the initial pipeline remediation phase. These studies will include comparison of predicted and found defect geometry. This information will be plotted on a unity plot, which compares actual defects to predict along with graphic representation of the specified tool accuracy and presented to the ILI vendor. This information will be used to determine if additional remediation is required or if an ILI inspection rerun is required.

Prior to the ILI projects. All necessary EnLink parties along with the ILI vendor will hold a kick-off meeting that outlines the scope of the project. Before issuing/sending ANY report, ILI vendors must first call the IMP Specialist & IMP Engineer to discuss the conditions that will be included. Refer to Appendix J in the Federal Gas IMP for ILI Reporting Criteria.

ILI Vendor Selection Guidelines

- ***IMP Specialist*** will make the selection of the appropriate ILI vendor per ***ENLINK GIMP Procedure 103***, Gas - Select Appropriate Assessment Tool and Vendor.
- The ***IMP Specialist*** will review and approve the qualification of the vendor personnel and inspection tool performance specifications prior to selection of the vendor.
- The tool specifications must include specifications that meet at minimum EnLink specifications.
- The ILI vendor's data analysis team should be headed by someone with at least five years of appropriate ILI data analysis experience and at least 80 hours of documented related training. The data analyst's qualifications should be documented in the scope of work along with any deviations from the recommended experience.
- The vendor will provide its quality control procedures to the ***IMP Specialist***.

The ***IMP Engineer*** is accountable for evaluating the general reliability of any in-line assessment method selected by looking at factors including but not limited to:

- detection sensitivity
- anomaly classification

- sizing accuracy
- location accuracy
- requirements for direct examination
- history of tool
- ability to inspect full length and full circumference of the section.
- ability to indicate the presence of multiple cause anomalies.

Digital Metal Loss Survey Tools

This tool provides detection of metal loss and certain manufacturing defects. EnLink utilizes high-resolution digital metal loss tools. Smaller diameter pipelines may provide some limitation of tool resolution due to the small space available to sensors, electronics, etc. Magnetic Flux Leakage (MFL) tools are not generally reliable for axially aligned defects.

Guided Wave Tools

Guided wave tools are a broad category of smart pigs used to detect pipeline mechanical defects such as stress corrosion cracking, manufacturing defects in the longitudinal seam weld, and other axially-oriented anomalies. These tools include modified MFL tools, elastic wave technology tools, and EMAT technology tools.

Geometry / Deformation Tools

A geometry / deformation tool is an electronic, in-line configuration caliper pig designed to provide pipeline integrity information. Specifically, these tools record indications and features such as dents, flat spots, wrinkles, ovality (out of roundness), bend radius and angle, deformation, wall thickness changes, girth welds, defect orientation, and other pipe data. This type of tool can be used to discern deformation severity and overall shape aspects of the deformation.

Hydrostatic Testing [192.921(a)(2), 192.929(b)(2), 192.937(c)(2), 192.503 through 192.517, ASME B31.8S sec. 5, Table 3, ANSI B31.1, B31.2, B31.3, B31.4, B31.8]

This standard describes the pressure testing requirements of all EnLink Midstream facilities in compliance with PHMSA Code of Federal Regulations 49 CFR Part 192 Subpart J. The intent of this document is to comply with applicable governmental regulations.

- ASME Boiler & Pressure Vessel Code, Sections I, IV & VIII
- ASTM Standards where applicable
- EnLink O&M Procedures
- EnLink Safety and Health Handbook
- EnLink Environmental Procedures
- EnLink Pressure Testing Standard

This standard shall be applicable for hydrostatic and Nitrogen (or inert Gaseous medium) testing of the following facilities:

- Buried Mainline Pipeline and Compressor or Meter Station Facilities.
- Above ground Fabricated Assemblies or pre-tested pipeline sections.
- Pressure Testing Piping Less than 30 Percent SMYS.
- Leak Testing Piping Less Than 100 psig.

The evaluation process for determination to perform pressure testing will be decided according to the ASME B31.8S Section 6.3, which details the evaluation process to determine if hydrostatic testing is an acceptable method of assessment against the specific threats identified.

Pressure testing is an accepted methodology for evaluating pipeline integrity. Pressure testing is effective for addressing time-dependent threats (external corrosion, internal corrosion and stress corrosion cracking), the construction-related threat, and the manufacturing-related threat.

Pressure testing is conducted in conformance with 192 Subpart J and ASME B31.8S Table 3 (Integrity Assessment Intervals) (Table 9-1). These pressure-testing procedures incorporate spike-testing criteria for mitigation of stress corrosion cracking consistent with ASME B31.8S Appendix A, Section A3.4.

External Corrosion Direct Assessment (ECDA) [192.919(d), 192.921(a)(3), 192.923(a) & (b)(1), 192.925, 192.931(a), 192.937(c)(3), 192.945(b), ASME B31.8S Sec. 6.4, NACE SP0502-2010

ECDA is a structured process by which underground pipeline integrity is evaluated. EnLink employs ECDA in cases where external corrosion is identified as a threat. The ECDA process integrates facility data, historical field inspections and direct examinations, physical characteristics and attributes and operational and maintenance history of a pipeline segment. ECDA is a four-step, structured, continuous improvement process that combines pre-assessment, indirect examination, direct examination, and post-assessment.

The focus of the approach is to identify locations where external corrosion defects may have formed or could form based on existing characteristics (i.e., coating faults, soil type, cathodic protection history, etc.). Other threats, such as mechanical damage and stress corrosion cracking may be detected during the ECDA process. If a threat is identified during this process that cannot be effectively mitigated, an alternative assessment method such as pressure testing, and in-line inspection is required to address that threat. The ***IMP Engineer*** or Subject Matter Experts, determine the optimal method(s).

Internal Corrosion Direct Assessment (ICDA) [192.921(a)(3), 192.923(a) & (b)(2), 192.927, 192.931(a), 192.937(c)(3), ASME B31.8S Sec. 6.4 & App. B2]

ICDA is a structured process to assess the integrity of gas transmission lines that normally carry dry gas but may experience short-term upsets of wet gas, free water, or other electrolytes. ICDA is an assessment method used to identify internal corrosion threats. EnLink's ICDA approach uses and integrates industry-accepted standards, methods, processes, and scientific modeling.

Stress Corrosion Cracking Direct Assessment (SCCDA) [192.921(a)(3), 192.929, ASME B31.8S App. A3]

SCCDA is a four-step, structured, continuous improvement process that combines pre-assessment, indirect examination, direct examination, and post-assessment to evaluate the threat of stress corrosion cracking. This assessment approach identifies locations where stress corrosion cracking defects may have formed or could form based on existing characteristics (i.e., coating faults, soil type, cathodic protection (CP) history).

Direct Examination

EnLink may utilize Direct Examination to assess exposed or bypass piping that have prior Subpart J hydrostatic tests for applicable threats. This will involve a complete removal of coating and a full visual inspection of the areas. Other equipment such as x-ray and sono-ray will be used as dictated by the applicable threats.

Other Technology [192.921(a)(4), 192.937(c)(4), 192.18]

EnLink may employ other proven technology that provides an equivalent understanding of line pipe condition. When used on a covered segment, EnLink will notify PHMSA, and appropriate state authorities, 90 days before conducting the assessment.

The ***IMP Team Chairman*** will notify the appropriate agencies having jurisdiction of EnLink pipelines listed under the Change Notification section of IMP Section 12 – Management of Change.

Integrity Assessment Tools / Method Selection Guide

If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004, Appendix A4.4 and any covered or non-covered segment in the pipeline segments with like pipe has experienced seam failure or the operating pressure has increased over the MAOP during the preceding five years, the ***IMP Team*** will assess the pipe in a method capable of determining seam integrity anomalies. This method may be an in-line inspection suitable for evaluation to manufacturing and seam type threats. A list of Pipeline Integrity Assessment Tools and a Method Selection Guide are given in the ***ENLINK GIMP Procedure 103***, Gas - Select Appropriate Assessment Tool and Vendor.

Plastic Transmission Pipelines

As stated in IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment, EnLink currently does not have plastic transmission pipe located in HCAs. In the event that a plastic transmission pipeline is identified in an HCA, EnLink will evaluate that segment with all applicable threats of a covered steel segment in conformance with this Pipeline Integrity Management Program.

When potential new threats to plastic pipe have been identified and accepted by the pipeline industry, they will be incorporated into the threat evaluation. If a threat analysis indicates that a covered segment is susceptible to failure from causes other than 3rd party damage, use of an alternative assessment method (to address the identified threat) will be justified prior to use.

3.3.2 Prioritized Schedule [192.919; 192.921(b); 192.921(d)]

EnLink's baseline assessment / reassessment plans contain the next scheduled integrity assessment by planned completion date for each covered segment. The IAPs shall be generated on an annual basis, not to exceed 15 months. The approved creation date of new HCAs is stored in the GIS database, and plan results are derived using the RIPL software. Each pipeline system's baseline assessment / reassessment plan is scheduled and developed separately based on the risk rankings which consider the potential threats and risk analysis.

High-risk segments will be prioritized for covered segments that contain low frequency electric-resistance welded (ERW) or lap welded pipe, any segment in the pipeline system with such pipe that has experienced seam failure, or that on which the operating pressure of the covered segment has increased over the maximum operating pressure experienced during the preceding five years as per B31.8S 2004.

High-risk segments will also be prioritized for covered segments that have manufacturing or construction defects (including seam defects) where 1) the operating pressure increased above the maximum operating pressure experienced during the preceding five years; 2) the MAOP increases; or 3) the stresses leading to cyclic fatigue increase.

The ***IMP Team Chairman*** has ensured that at least 50% of the covered segments beginning with the highest risk segments were assessed by December 17, 2007. The ***IMP Team Chairman*** has ensured the baseline assessment of all covered segments were completed by December 17, 2012. These records have been documented and can be found in the IAP.

An assessment on a covered segment is considered complete on the date when final field activities related to that assessment are performed, but this does not include validation digs and repair activities for in-line inspection tool runs.

Upon completion of a hydrostatic test for a covered segment, the pressure test report shall be submitted by the vendor's Project Manager. The ***IMP Specialist*** shall review and approve the results of the pressure test. Completion dates of assessments are updated on the baseline assessment / reassessment plans by the ***IMP Engineer***.

3.3.3 Use of Prior Assessments [192.921(e)]

EnLink may employ a prior integrity assessment conducted before December 17, 2002, as a baseline assessment for the covered segment if the integrity assessment meets the baseline requirements and subsequent remedial actions to address the conditions listed in 49 CFR 192.933 have been met.

Prior assessments selected for use by the ***IMP Engineer*** as baseline assessments in EnLink's original baseline assessment plan were based on the following methodology as per ASME B31.8S:

- Previous integrity assessments for each covered segment were identified.
- Threats were identified for each segment and evaluated to determine if the previous assessment was suitable for the identified threat.
- If the prior assessment was a suitable method, the assessment records were reviewed to verify correct methodology and that repairs were completed as required.
- Acceptable prior assessments were documented in the baseline assessment plan.

The ***IMP Specialist*** evaluates prior assessment and subsequent remedial actions. Documentation of prior assessments and evaluations for use is maintained by ***IMP Specialist*** for the life of the pipeline.

3.3.4 New HCAs / Newly Installed Pipe [192. 905I; 192.921(f); 192.921(g)]

Upon completion of each year's HCA identification process (IMP Section 2 – High Consequence Areas), a listing is created of covered segments that differ from covered segments previously identified. Newly installed and newly acquired pipe will be incorporated into the IAP when running the HCA buffer analysis. The ***IMP Engineer*** updates the risk model (IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment) and reviews the baseline assessment/reassessment plans on an annual basis using current covered segment information.

New covered segments identified on existing pipe or newly installed pipe will be included in the baseline assessment plan within 1 year from the date the covered segment is identified and will be scheduled to have an assessment completed within 10 years from the date the new covered segment is identified. Abandoned segments of pipe are permanently removed from the IAP, and idle segments of pipe are deferred from assessment until such time they are reactivated. Prior to reactivation, the segment will be evaluated to determine the proper assessment timing.

When new ID sites are identified by data correction, the baseline assessment will be established based on the in-service date of the ID site or within 1 year of identification. Any ID site older than 10 years will be assessed within 12 months of identification. If the ID site is less than 10 years old, then the assessment date must not exceed 11 years from the ID site in-service date.

The ***IMP Engineer*** will verify that threats to the HCAs of a pipeline were identified as required under 192.919(a) and that the assessment method used was appropriate for the threats per ASME B31.8s-2004.

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3.3.5 Consideration of Environmental and Safety Risks [192.919(e)]

A primary objective of EnLink's policies is to protect workers, members of the public, and the environment. Each integrity assessment is conducted in a manner that minimizes environmental and safety risks.

3.3.6 Plan Changes [192.911(k); ASME/ANSI B31.8S, Section 11]

Integrity projects listed in the Integrity Assessment Plan (IAP) may be impacted by a variety of issues including additional support information related to integrity threats, or updated information on physical attributes. EnLink's Management of Change procedure provides the data needs, evaluation methodology, approval process, and documentation and communication requirements for proposed changes to the IAP. It also includes documentation covering:

- Reason for change
- Authority for approving change
- Analysis of implications
- Communication of change to affected parties.
- The assessment summary is documented on the **ENLINK GIMP Form 109**, Assessment Results Review Form.

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4 THREAT IDENTIFICATION, DATA INTEGRATION, AND RISK ASSESSMENT [192.917]

4.1 Introduction

This section describes the process for identifying threats, data gathering and integration, risk assessment, and validation of risk assessments.

In conformance with 49 CFR 192.917 and ASME B31.8S, Section 4, EnLink identifies potential threats to covered (HCA) pipeline segments by gathering and integrating existing data within each pipeline segment. EnLink will use both prescriptive and/or relative risk-based assessment programs to ensure the integrity of the pipeline.

After threat identification, EnLink employs *American Innovations' RIPL©* software to conduct risk assessments (ASME B31.8S, Section 5), and considers identified threats for each covered segment taking into account SME input. The risks associated with a pipeline segment are a function of the likelihood of an event or condition that leads to a release, and the resulting consequences of that release. Risk assessment results are employed to prioritize baseline and continual assessments. Furthermore, risk assessment results are an integral component of the assessment method selection, IMP Section 3 – Baseline Assessment / Reassessment Plan, and IMP Section 7 – Continual Evaluation and Assessment. The preventive and mitigative measures selection and evaluation process, IMP Section 9 – Preventive and Mitigative Measures, also relies on information generated in the threat identification and risk assessment process.

4.2 Roles and Responsibilities

Position	Responsibility
IMP Engineer	Gather / integrate data required to input into the RIPL Model. Maintain and run RIPL Model. Develops and revises the risk algorithm. Issue P&M's in accordance to the RIPL results analysis.
IMP Team Chairman	Oversee all aspects of threat identification. Review Incident notifications immediately after they occur.
IMP Specialist	Collect data identifying potential threats. Conduct review to identify manufacturing related threats.
IMP Team	Conduct project review to determine finalized integrity project list.

4.3 Process

4.3.1 Threat Identification [192.917(a)]

EnLink employs the *RIPL©* risk-based model to determine the threats associated with pipeline segments. *RIPL©* identifies and assigns risk to known threats to pipeline integrity. During the review and validation of the *RIPL©* risk analysis output, the ***IMP Engineer*** considers the interactive natures of threats by flagging any combination of Corrosion with Third Party Damage, Outside Forces or Manufacturing Defect. These flagged areas are highlighted for further review by the ***IMP Engineer*** utilizing data from previous ILI projects and discussions with field personnel. The ***IMP Engineer*** develops and revises the risk algorithm in accordance with **ENLINK GIMP Procedure 106**, *Review Gas Risk Algorithm*.

The collection of these data sets will assist with the screening process representative of the RIPL's Threat Screening Rule. Any specific threat may be eliminated from the risk assessment provided a pipe segment contains the minimum data required and the criteria for risk assessment.

Threats are presented in categories of related failure types according to their nature and growth characteristics, and further delineated by three time-related defect types and also includes human error. In conformance with ASME B31.8S, Section 2, EnLink considers the following threats:

Time-Dependent	External Corrosion	
	Internal Corrosion	
	Stress Corrosion Cracking	
Stable	Manufacturing Related Defects	Defective pipe seam
		Defective pipe
	Welding/Fabrication Related	Defective pipe girth weld
		Defective fabrication weld
		Wrinkle bend or buckle
		Stripped threads/broken pipe/coupling failure
	Equipment	Gasket O-ring failure
		Control/relief equipment malfunction
		Seal/pump packing failure
		Miscellaneous
✓**Time-Independent**	Third Party/Mechanical Damage	Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
		Previously damaged pipe (delayed failure mode)
		Vandalism
	Incorrect Operations	Incorrect operational procedure
	Weather Related and Outside Forces	Cold weather
		Lightning
		Heavy rains or floods
		Earth movements
		Seismicity
		Geology
		Soil Stability

External or Internal Corrosion Threats [192.917(e)(5), 192.933]

Prior to risk ranking segments in *RIPL©*, the ***IMP Engineer*** reviews findings from an annual corrosion review for external and internal corrosion risk threats. Relevant findings are then incorporated into the risk analysis process through *RIPL©*.

Stress Corrosion Cracking (SCC) [192.917(a) & (e)(5), ASME B31.8S App. A3]

There are two types of stress corrosion cracking found on line pipe steels: High pH (or Classical SCC), and Near Neutral/Low pH (or Non-Classical) SCC. If SCC is discovered in a covered segment, the ***IMP Engineer*** determines if there are similar conditions (e.g., pipeline attributes) on non-covered segments and evaluates whether the risk of SCC is present. If the risk of SCC is present, the appropriate assessment process will be implemented per the Integrity Assessment Tools / Method Selection Guide in IMP 3 – Baseline Assessment / Reassessment Plan.

Manufacturing and Construction Threat (Pipe) [192.917(a) & (e)(3)]

Manufacturing and construction threats are identified utilizing *RIPL©.* These threats include, but are not limited to, the following pipe or conditions:

- Cast iron pipe
- Long seams with a history of failure
- Hard Spots
- Mechanically coupled pipe (such as unsleeved Dresser couplings)
- Acetylene girth welds where low temperatures are experienced.
- Acetylene girth welds where the pipe is exposed to movement or removal of supporting backfill.

Manufacturing and construction threats are considered mitigated for pipe that has been hydrostatically tested in conformance with 49 CFR 192 Subpart J and whose operating pressure on the covered segment has not exceeded the maximum operating pressure experienced during the five years preceding the identification of an HCA segment.

The segment is prioritized as high-risk for the baseline assessment or a subsequent assessment if any of the following changes affect the covered segment:

- Segment operating pressure increases above the maximum operating pressure experienced during the five years preceding the identification of an HCA segment.
- The segment's MAOP increases.
- The stresses leading to cyclic fatigue increase.

Pipeline attributes for those segments that are affected by the above conditions are updated by the GIS Department. For cast iron pipe, the assessment includes evaluating whether the pipe is subject to land movement or subject to support removal.

ERW or Other Seam-Type Pipe [192.917(a) & (e)(4), ASME B31.8S A4.3, A4.4]

Certain seam weld types are more likely to present a higher risk of failure. The ***IMP Engineer*** and ***IMP Specialist*** conducts a review of data to identify manufacturing threats fitting descriptions in ASME B31.8S Appendix A4.3 or A4.4. These include:

- Pipe with a joint factor less than 1.0 (such as lap welded pipe or butt-welded pipe).
- Pipe comprised of low-frequency ERW weld seams, DC-ERW weld seams, or electric flash weld seams.
- Cast iron pipe.

Pipelines covered under 917(e)(4) contain pipe listed above that has a history of failure in covered or non-covered segments, or the operating pressure on the covered segment has increased over the maximum operating pressure experienced during the five years preceding the identification of an HCA segment.

For pipeline segments covered under 917(e)(4), an assessment technology (or technologies) with proven capability of assessing seam integrity and seam corrosion anomalies is selected and the segment is prioritized as a high-risk segment for the manufacturing threat. In the event that pipe was successfully hydrostatically tested in conformance with 49 CFR 192 Subpart J, seam weld threats are considered stable.

Plastic Pipelines [192.917 (a) & (d), 192.921(h), ASME B31.8S, Sec. 4 & Sec. 5]

Currently, EnLink has no plastic transmission pipe located in a covered segment. In the event that a plastic transmission pipeline is identified in a covered segment, EnLink will evaluate that segment with all applicable threats of a covered steel segment in conformance with this Pipeline Integrity Management Program.

When potential new threats to plastic pipe have been identified and accepted by the pipeline industry, they will be incorporated into the threat evaluation. In the event that a threat analysis indicates that a covered segment is susceptible to failure from causes other than 3rd party damage, use of an alternative assessment method (to address the identified threat) will be justified prior to use.

Equipment Threat [192.917(a), ASME B31.8S Sec. 2.2]

Equipment threats are concerned with pipeline facilities other than pipe and miscellaneous pipe components (i.e., meter, regulator, and compressor stations, etc.). Equipment failure threat is managed through normal Operating and Maintenance practices. Annually, but not to exceed 15 months, the ***IMP Engineer*** will review the prior year's incident reports for leak/ruptures that were caused by equipment failure. If the equipment threat is verified and not addressed through normal O&M practices, the ***IMP Engineer*** will reevaluate the threat for the HCA impacted by the incident and issue P&M measures to operations if deemed appropriate.

Construction Threat [192.917(a) & (e)(3)]

Construction threat concerns may include welds, a wrinkle bend or buckle, stripped threads, broken pipe or couplings, or poor fusion joint joining (plastic pipe).

Construction-related threats pose an integrity issue that is often in conjunction with outside force threats. An interacting threat of outside force potentially affecting a construction threat may be active or inactive and is addressed in the algorithm. Data indicating failures due to a construction-related threat is integrated by the ***IMP Engineer*** into the RIPL© analysis. In the event that pipe was successfully hydrostatically tested in conformance with 49 CFR 192 Subpart J, construction threats are considered stable.

Third Party Damage Threat [192.917(a) & (b), 192.917(e)(1), ASME B31.8S, Sec. 2.2 and Sec.4, App. A7]

Third party damage is defined as:

- Third-party-inflicted damage with immediate failure,
- Vandalism, and
- Previously damaged pipe.

Third party damage may occur at any time and strong prevention measures may be required in areas of concern (such as heavy land use areas, farming, residential or commercial development, etc.). Field Operations personnel conduct patrols and leak surveys to detect encroachments and indications of possible third-party damage. Field Operations personnel investigate suspicious indications discovered during routine maintenance including known excavation activities documented by One-Call or other encroachment records.

Pipeline Bell Hole Inspection Reports within an HCA are routed to the ***IMP Specialist*** During the annual risk ranking process the ***IMP Engineer*** reviews the reports in HCAs for additional information including pipeline damage resulting from 3rd party activities and adds any pertinent data in GIS/PODS.

In the event that an internal inspection tool or External Corrosion Direct Assessment was used for the baseline assessment or reassessment of a covered segment, the data from these assessments is used in conjunction with data related to any encroachment or foreign line crossing to validate where indications of third-party damage exist. In the event that a threat of third party damage is identified, additional comprehensive preventive measures are evaluated in conformance with IMP Section 9 – Preventive and Mitigative Measures.

Incorrect Operations Threat [192.917(a), ASME B31.8S, Sec. 2.2]

Incorrect operation threats include incorrect operating procedures, failure to follow a procedure, or operator error while following a procedure. Additional sources of identification are as follows:

- Procedure review information
- Audit information
- Failures caused by incorrect operation
- Failures caused by operator error

EnLink investigates incidents regarding emergency reporting and investigating. If the investigation indicates that operation and maintenance are in conformance with O&M Procedures, the procedures are correct, and operating personnel are adequately qualified, no additional assessment is required. Incidents resulting from incorrect operation activities are tracked and relevant data is incorporated by the ***IMP Engineer*** in their analysis.

Weather and Outside Force Threats [192.917(a), ASME B31.8S, Sec. 2.2]

Weather and outside force threats include earth movement, heavy rains or floods, hurricanes, tornadoes, ice storms, severe cold weather, and lightning. Pipe may be susceptible to stresses at the following locations:

- Where pipe crosses a fault line.
- Where pipe traverses' steep slopes.
- Where pipe crosses water, is adjacent to water, or where the river bottom is moving.
- Where the pipeline is subject to extreme surface loads that cause settling to underlying soils.
- Where blasting is occurring near the pipeline.
- When the pipe is at or above frost line.
- Where pipeline is subject to landslides.
- Where the soil is subject to liquefactions.
- Where ground acceleration exceeds 0.2 g.
- Where facilities are prone to lightning strikes.

To identify potential threats, the key parameters that affect the significance of the threat are identified by the following data sets. These data sets will be collected by the ***IMP Specialist*** from:

- The Operation Manager/Superintendent
- Prior IM assessment results
- Performance spreadsheets derived from RIPL© risk results
- Preventative and mitigative reports

These data sets collected will be routed to the ***IMP Engineer***. The effect of these parameters is then evaluated by the ***IMP Engineer*** and combined to determine the overall significance of combined threat(s).

Cyclic Fatigue [192.917(a) & (e)(2)]

Cyclic fatigue or other loading conditions (including ground movement or suspension bridge movement) could lead to a deformation, dent, gouge, or other defect failing. Historically, metallurgical fatigue has not been a significant issue for gas pipelines. The ***IMP Engineer*** analyzes cyclic fatigue or other loading condition threats when a line has been operating in a steady-state mode and a new load on the line changes the mode of operation to a more cyclical load (e.g., daily changes in operating pressure). Other loading conditions can also be assessed on covered segments through geotechnical and geohazard studies. Cyclic fatigue or other loading conditions identified as threats are incorporated into the baseline assessment or reassessment for risk ranking.

In cases where data is insufficient to evaluate a threat, the ***IMP Engineer*** requests additional data from the appropriate source(s). The ***IMP Engineer*** and other departments may employ data from external sources such as jurisdictional agency reports (soil data, demographics, topography, etc.), and research or industry organizations. Data from an applicable source (inspection, reassessment, audits, etc.) may be applied to multiple threats and can be used to identify whether that threat exists.

4.3.2 Data Gathering and Integration [192.917(b); 192.917(e)]

To facilitate the identification of potential threats to a pipeline segment and to support the risk analysis process, EnLink gathers and integrates existing data and information pertaining to the entire pipeline that could be relevant to the covered pipeline segment. EnLink gathers and evaluates data from, the covered segment, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records, in-line inspection and remediation records, and all other conditions specific to each pipeline per ASME B31.8S. Data needs are summarized into four categories: attributes, construction, and operational and inspection data. **ENLINK GIMP Form 104**, Risk Results Validation, is employed to facilitate and document discussion with district personnel.

The Basic Data sets of collection include:

- Past leak, failure and incident history
- Corrosion control records
- Continuing surveillance records
- Patrolling records
- Maintenance history
- Internal inspection records
- All other conditions specific to each pipeline.

Additional data sets required for covered segments can be found in the IAP. The data will be gathered by the ***IMP Specialist***.

GIS Database

The GIS database stores information related to centerline drawings, pipeline construction, right-of-way, geographic locations, and other pipeline related information. It also stores data relative to HCAs including HCA boundaries, Potential Impact Radius (PIR), method used to determine the HCA, HCA type, and determination date. The GIS database supports automated mapping and facility data management and allows data synchronization across multiple and shared applications.

The ***GIS Department*** will receive pipeline data from ***Regional Teams and SMEs***. GIS data entry is limited to personnel who have modification privileges. Changes to the database are automatically tracked and systems are backed up for data recovery.

Incident Reporting Tools

An incident–tracking database stores various information related to a pipeline incident or damage. Information collected includes a brief description of the incident, pipeline system data, type of incident, and the incident cause. Data stored in the incident-tracking database is employed for determining reporting criteria and performing additional analysis on the affected segment when necessary. During the annual risk ranking process, the ***IMP Engineer*** reviews the incident-tracking database incident data on covered segments.

Incident notifications are also received by the ***IMP Team Chairman*** through EnLink's Emergency Response notification system immediately after the incident is reported.

Pipe Characteristics and Specifications

Pipe characteristics and specifications include the types of steel and pipeline components that make up a pipeline segment. This information consists of manufacture and installation dates, brand name or manufacturer, manufacturing process, seam type, and material testing records.

Pipeline steels have specific properties that affect their life of service, performance, and predicted failure mode. Various parameters such as specified minimum yield strength (SMYS), longitudinal seam type, etc. are useful when calculating failure probability. Knowledge of steel types and components is a key element in assessing future performance and inspection techniques. Pipe characteristics and specifications are attributes in the GIS database.

Pipe Coating

Knowledge of pipeline coatings is critical when assessing pipeline condition.

Holidays (coating defects and faults) are present in nearly all pipeline coatings. Cathodic protection protects the pipe surface from corroding at a holiday location where moisture may contact the pipe surface. Generic coating type and age are attributes in the GIS database.

Operating Parameters

Operating parameters include pressure (operating, MAOP, MOP, fluctuations, and hoop stress in percent of SMYS), relief valve location and settings, alarm/shutdown settings, system upsets, product type and characteristics, Pipeline Control operations, SCADA system, and delivery and receipt sites on the pipeline segment.

MAOP and MOP are attributes in the GIS database. The ***IMP Team***, ***Regional Teams and SMEs*** review operating parameters for risk reduction considerations.

One-Call Record Review

The EnLink GIS Department conducts an annual review of pipeline segments to confirm that every pipeline segment has been entered into the One-Call system database. Database revisions can be made based on need, and do not necessarily coincide with the annual review date.

High Consequence Areas (Covered Segments)

The GIS Department will complete the HCA analysis and release the official class and HCA documents with the segment boundaries and determination method no later than December 31 of each year. HCAs are identified in conformance with IMP Section 2 – High Consequence Areas.

Data Sources, Collection and Integration [192.917(b), ASME B31.8S, Sec.4]

The following data sources used for initiating and enacting EnLink's IMP. They are collected for proper data collection and are aligned into the EnLink GIS Database System for spatial linear referencing:

- Process and instrumentation drawings (P&ID)
- Pipeline alignment drawings
- Original construction inspector notes/records
- Pipeline aerial photography
- Facility drawings/maps
- As-built drawings
- Material certifications
- Survey reports/drawings
- Safety related condition reports
- Operator standards/specifications
- Industry standards/specifications
- O&M procedures
- Emergency response plans
- Inspection records
- Test reports/records
- Incident reports
- Compliance records
- Design / engineering reports
- Technical evaluations
- Manufacturer equipment data

These data requirements are collected by employing the following data gathering progression: engineering and construction records mining, mining review, and additional records review and field interviews (as necessary).

Conservative default attribute values are employed within *RIPL©* when data is not available. For each of the following items on covered segments, the data requirements support performing risk assessment are for specific considerations such as identifying severe situations requiring more or additional activities.

The absence of data being provided or available for a segment does not exclude the category of risk from evaluation. Where risk data sets are not available and not entered into the Matrix, the highest rank will be calculated within the matrix model as default, assuming a worst-case condition.

Updating of Model from Field Maintenance and Additional Data Mining

As new data is acquired from field personnel or from additional data mining in conflict with original assumption of risk, or in conflict with risk modeling output, the newly acquired data must be inputted into the risk model to correct the inaccuracies in the characterization of the risk for the segments as needed.

Integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. EnLink integrates data into the GIS spatial database that allows association of data elements with accurate locations on the pipeline and also integrates ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third-party damage.

4.3.3 Risk Assessment [192.917I]

EnLink employs the *RIPL©* risk-based model to determine the threats and potential consequences associated with covered HCA and MCA pipeline segments. The ***IMP Engineer*** generates a list of covered pipeline segments ranked by total risk for further evaluation and/or assessments and uses this information to develop baseline assessment and reassessment plans. The analysis of pipeline segments is finalized by the end of each calendar year.

The ***IMP Engineer*** is trained in operating, applying, analyzing, and evaluating the *RIPL©* modeling software. The ***IMP Engineer*** utilizes RIPL for the following objectives per ASME B31.8S – 2004 sections 5.3-5.4:

- prioritize of pipelines/segments for scheduling integrity assessments and mitigating action.
- assess the benefits derived from mitigating action.
- determine the most effective mitigation measures for the identified threats.
- assess the integrity impact from modified inspection intervals.
- assess the use of or need for alternative inspection methodologies.
- allocate resources more effectively.
- facilitate decisions to address risks along a pipeline or within a facility.

RIPL© is used for EnLink's L2 Indexing Risk Reference Model to rank pipeline threats based on a calculated score. The score is calculated by the sum of the failure likelihoods multiplied by the sum of the consequence of failure factors. The failure likelihood and consequence scores will be calculated for each pipeline segment.

Failure Likelihood Assessment

Failure Likelihood, as it relates to pipeline integrity, is the relative measure of the likelihood of the pipeline failing as a result of a design or operating condition. For the purposes of evaluating the susceptibility of pipeline segments to failure relative to one another, a failure likelihood algorithm will be used.

Within the failure likelihood algorithm, each threat is assigned a weighting that is based on its expected contribution to the overall failure susceptibility. The starting point for the assignment of weightings to each failure cause is based on industry incident statistics, but EnLink has modified the formula appropriately based on operating experience. All failure categories that are considered to materially contribute to the overall failure likelihood, along with their assigned weightings, are summarized in the following Table IMP 6-B – Failure Threats and Assigned Weightings.

Table IMP 6-B – Failure Threats and Assigned Weightings

Threat	Weighting
External Corrosion	15%
Internal Corrosion	8%
Stress Corrosion Cracking	2%
Manufacturing Defects	7%
Construction	8%
Equipment Failure	9%
3rd Party Damage	35%
Incorrect Operations	11%
Weather / Outside Forces	5%

Consequence Assessment

EnLink considers consequences when performing risk assessments of their system. The Consequence Algorithm provides a prioritized ranking of the consequences of failure based on three primary areas of concern for natural gas transmission pipeline failures. These three consequence types accounted for in the risk algorithm are safety, economic loss, and environmental loss. Table IMP 6-C – Consequence Assessment shows the weightings that are used to determine the final consequence score for a segment.

Table IMP 6-C – Consequence Assessment

Consequence	Weighting
Impact on Population	40%
Impact on Business	25%
Impact on Environment	35%

RIPL© features the data attributes used and evaluates them for risk analysis. All available required data is evaluated for each threat when conducting the risk analysis. Conservative assumptions are employed in the risk assessment by threat and segment. If data is not available for a particular threat, the most conservative attribute default value is assigned. A threat can be removed for consideration from that segment if the threat can be shown by documentation and review that it does not apply.

Risk Estimation, Evaluation, and Decision Making [192.921(b)]

The ***IMP Engineer*** performs risk estimation and evaluation on EnLink pipeline segments using *RIPL©*. The risk assessment methods address the covered pipelines as currently configured, operated, and maintained.

Pipeline Segment Risk-Ranking

The ***IMP Engineer*** employs the *RIPL©* risk model to determine Risk (total likelihood multiplied by total consequence) for covered segments annually. During the annual process, which includes case-by-case periodic evaluations, the following items are considered:

- Data integration and risk assessment information.
- Past and present risk assessment results.
- Decisions about preventive and mitigative actions.
- Decisions about attribute and threats will be reviewed with ***Regional Teams and SMEs.***

Output from *RIPL©* contains the segment description, potential threats, start and end re-chain numbers, threat scores and consequences. The ***IMP Engineer*** ranks the risks of all covered segments from across the EnLink natural gas transmission system to generate a prioritized list. The risk analysis will be completed, and a ranked segment list will be generated annually.

Decision Analysis

From this risk-ranked list, ***IMP Team*** conduct further project review (logistics, business and customer impacts, corporate goals, and system-wide integrity) to finalize the prioritized integrity project list. A separate list is generated for HCA segments, which includes ranking the highest risk segments. Integrity assessment projects are planned in conformance with IMP Section 7 – Continual Evaluation and Assessment, and preventive and mitigative measures are selected and implemented in conformance with IMP Section 9 – Preventive and Mitigative Measures.

4.3.4 Validation of Risk Assessment [192.917I]

To ensure that threat and risk information obtained from RIPL© is valid and accurately reflects the true nature of threats and risks for EnLink pipeline segments, risk results are validated by both the ***IMP Engineer*** and ***IMP Team***.

Each calendar year, the ***IMP Team*** reviews threats and risk for all segments as a group to validate results and verify consistency in the evaluation process. The project schedule developed as a result of risk assessment is reviewed by the ***IMP Team*** each year.

4.3.5 Plastic Transmission Pipe [192.917(d)]

Reference Section 4.3.1

5 DIRECT ASSESSMENT PLAN [192.911(D)]

5.1 Introduction

This section describes the process for employing direct assessment to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

49 CFR 192.911(d) establishes that if operators elect to employ Direct Assessment (DA), they must develop a process that conforms to the requirements of 49 CFR 192.923, 49 CFR 192.925, 49 CFR 192.927 and 49 CFR 192.929.

Direct assessment is an integrity assessment methodology that utilizes a structured process to evaluate certain corrosion related integrity threats. The direct assessment process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

5.2 Roles and Responsibilities

Position	Responsibility
IMP Team	Performs DA Feasibility Study

5.3 Process

5.3.1 ECDA Programmatic Requirements [192.925]

ECDA, a structured process for establishing underground pipeline integrity, is a method for addressing identified external corrosion threats. Reference ENL-IMP-00003 – Direct Assessment Procedure for the standards by which EnLink completes ECDA.

5.3.2 Dry Gas ICDA Programmatic Requirements [192.927]

ICDA, a structured process for establishing underground pipeline integrity, is a method for addressing identified internal corrosion threats. The procedure for Internal Corrosion Direct Assessment defines steps and provides instruction to evaluate the internal corrosion integrity threat by direct assessment using proven industry practices and processes. Reference ENL-IMP-00003 – Direct Assessment Procedure for the standard by which EnLink completes ICDA.

5.3.3 SCCDA Data Gathering and Evaluation [192.929]

SCCDA, a structured process for establishing underground pipeline integrity, is a method for addressing identified stress corrosion cracking threats. Reference ENL-IMP-00003 – Direct Assessment Procedure for the standard by which EnLink completes a structured process to implement SCCDA. SCCDA is a four-step, structured, continuous improvement process that combines pre-assessment, indirect examination, direct examination, and post-assessment to evaluate the threat of stress corrosion cracking.

6 REMEDIATION [192.911(E)]

6.1 Introduction

This section describes the process for discovery, prioritization, evaluation, and remediation of anomalies.

49 CFR 192.907 establishes that operators must develop a written integrity management program that addresses the risks on each covered segment. As part of its Integrity Management Program, an operator must include provisions meeting the requirements of 49 CFR 192.933 for remediating conditions found during an integrity assessment. 49 CFR 192.903 defines remediation as:

"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."

6.2 Roles and Responsibilities

Position	Responsibility
IMP Engineer	Issue dig sheets and maps for anomaly remediation
IMP Specialist	Evaluate and remediate identified conditions in coordination with Operations personnel and contractors
IMP Team	notifies appropriate regulatory agencies of any extended pressure reduction

6.3 Process

6.3.1 Program Requirements for Discovery, Evaluation, and Remediation Scheduling [192.933; Protocol E.01]

EnLink completes evaluating and remediating an identified condition on a covered segment according to a schedule that prioritizes conditions for evaluation and remediation.

ENLINK GIMP Procedure 104, *Gas Assessment Results Review and Remediation,* provides additional details of review integrity assessment results.

Evaluation is performed in conformance with EnLink Procedure for In-Line Inspections, Stress Corrosion Cracking, SCC Direct Assessment, External Corrosion Direct Assessment, Internal Corrosion Direct Assessment and Direct Examination.

49 CFR 192.933(b), states that *"…discovery of a condition has occurred when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under 49 CFR 192.933(d)(1) through 49 CFR 192.333(d)(3). An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable."*

EnLink defines discovery as a written notice (emails, vendor documents, spreadsheets, etc.) from vendor/s and or company representatives that satisfies conditions that presents a potential threat to a pipeline or pipelines. EnLink IMP Team must validate date and time of discovery based on information provided.

Remediation is performed in conformance with EnLink Procedures for Pipeline Coatings, Pipe and Equipment Damage, Maximum Corrosion Limits, the MAOP of Corroded Pipe, and Stress Corrosion Cracking. The required response schedule interval begins at the time the condition is discovered and is documented by the ***IMP Engineer***.

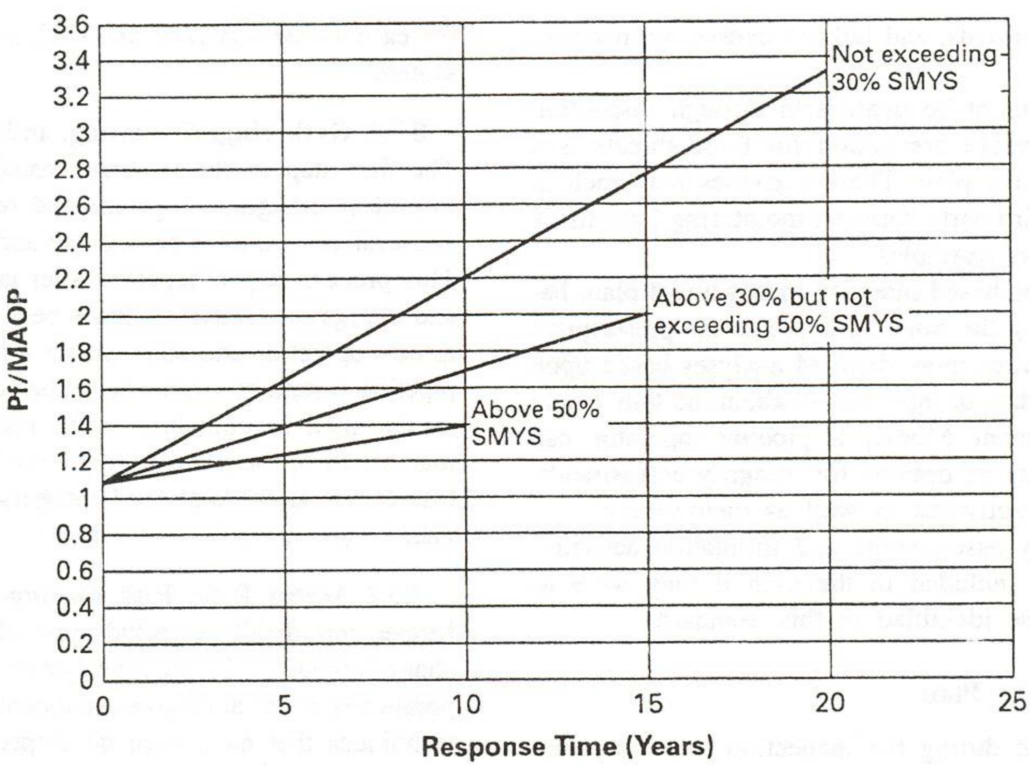
Discovery of Condition applies to each of the assessment methods in 49 CFR 192.933(b) shown below:

- In-Line Inspection – see definition in ILI Procedure
- Pressure test – date of pressure test
- ECDA, ICDA, SCCDA, Direct Examination – see definition in the following procedures:
  - SCC Direct Assessment
  - External Corrosion Direct Assessment
  - Internal Corrosion Direct Assessment
  - Direct Examination
  - Other Technology – when there is adequate information about the condition to determine that it presents a potential threat to pipeline integrity.

Within an HCA, adequate information must be obtained promptly, but no later than 180 days after conducting an integrity assessment; otherwise the 180-day period must be demonstrated to be impracticable.

The ***IMP Engineer*** maintains the prioritized schedule for covered pipeline segments requiring remediation related to in-line inspection. Evaluation and remediation is normally performed for time-dependent threats within the period allowed for the prioritized conditions on a covered segment (Figure IMP 8-2 – Timing for Scheduled Responses – Time Dependent Threats). The ***IMP Engineer*** and ***IMP Specialist*** maintains the prioritized schedule for covered pipeline segments requiring remediation associated with assessment methods other than ILI.

Figure IMP 8-2 – Timing for Scheduled Responses – Time Dependent Threats (ASME B31.8S, Section 7, Figure 4)



6.3.2 Program Requirements for Identifying Anomalies [192.933(a) and (d);

EnLink identifies and prioritizes repair conditions as detailed in the Baseline Assessment Plan. EnLink meets or exceeds the repair timeframes required by 49 CFR 192.933(d) and contained in Sections 8.2.1 through 8.2.3. Procedures pertaining to anomaly conditions contain provisions for EnLink to temporarily reduce pressure or shut down the pipeline upon discovery of immediate repair conditions.

Immediate Repair Conditions – Defects

A defect is a condition of the line pipe that represents an immediate hazard and repair condition to a covered segment. To maintain safety, ***IMP Specialist*** will initiate steps necessary regarding an immediate repair condition as outlined below.

A temporary reduction in pressure shall immediately be performed within a period not exceeding 5 days following the discovery of the condition and the condition shall be scheduled for direct examination. Otherwise, the pipeline segment must be taken out of service until examination and/or repairs are completed. EnLink will base the temporary operating pressure reduction (at the indication) as calculated by remaining strength methods accepted by the Rule (ASME B31G, AGA/Battelle Modified B31G with RSTRENG disk), or other effective methods of calculation. If no suitable remaining strength calculation method can be identified, a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two months prior to the date of inspection, must be implemented until the anomaly is repaired. A continued reduction of pressure cannot exceed 365 days without a technical justification defining safe operation.

Non-HCA Immediate Condition: If the anomaly is located outside the HCA, the pressure in that pipe segment must be ‘restricted’ to a pressure less than or equal to the operating pressure experienced at the date of assessment to the date of discovery. The pressure restriction must be initiated within a period not exceeding 5 days following the discovery of the condition. A safe operating pressure to be used for digging, based on evaluating remaining wall strength, is required prior to exposing the anomaly for repair.

Safety-Related Condition: Determine if an HCA or non-HCA immediate condition warrants Reporting Safety-Related Conditions according to 49 CFR 191.23 & 191.25.

Scheduled Conditions
Those conditions in a covered segment that require repair before the next reassessment are:

- Internal/External Corrosion that the Pf/MAOP ratio is > 1.10 and less than 1.39 for pipelines of MAOP greater than 50% SMYS.
- Internal/External Corrosion that the Pf/MAOP ratio is > 1.10 and less than 2.00 for pipelines of MAOP greater than 30% SMYS but nor exceeding 50% SMYS.
- Internal/External Corrosion that the Pf/MAOP ratio is > 1.10 and less than 3.30 for pipelines of MAOP not exceeding 30% SMYS.
- Remediation within 1-year of Discovery – 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 pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
- Remediation within 1-year of Discovery – A dent with a depth greater than 2% of the pipeline’s diameter that affects pipe curvature at a girth weld or a longitudinal seam weld. (greater than 0.250 inches in depth for a pipeline diameter less than NPS 12).

Monitored Conditions

- ***IMP Specialist*** and ***IMP Engineer*** will not schedule the following conditions for remediation, but will monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation via the P&M:
    - 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 position and the 8 o'clock position (bottom 1/3 of the pipe);
    - A dent with a depth greater than 6% of the pipeline diameter (greater than 0.5 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12) located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) and engineering analysis of the dent demonstrate critical strain levels are not exceeded;
    - A dent with a depth greater than 2% of the pipeline's diameter (greater than 0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature of a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

Response to a Dent Condition

Prior to excavating a dent/deformation anomaly, a Safe Digging Pressure will be determined according to above remaining wall thickness calculation (such as modified B31.G). A lesser pressure determined of the reduction to 80% of the operating pressure and remaining strength calculation will be employed for safe digging and actual repair. (It is noted that the safe digging pressure may be lower than the non-HCA pressure restriction or HCA reduction to 80% pressure reduction). Initiation of necessary steps to reduce the operating pressure of the pipeline segment includes:

- Notify ***IMP Team Chairman***
- Notify Operations Manager
- Notify Pipeline Control
- Notify Commercial (affected customers)
- Perform Reduction of pressure to appropriate level.

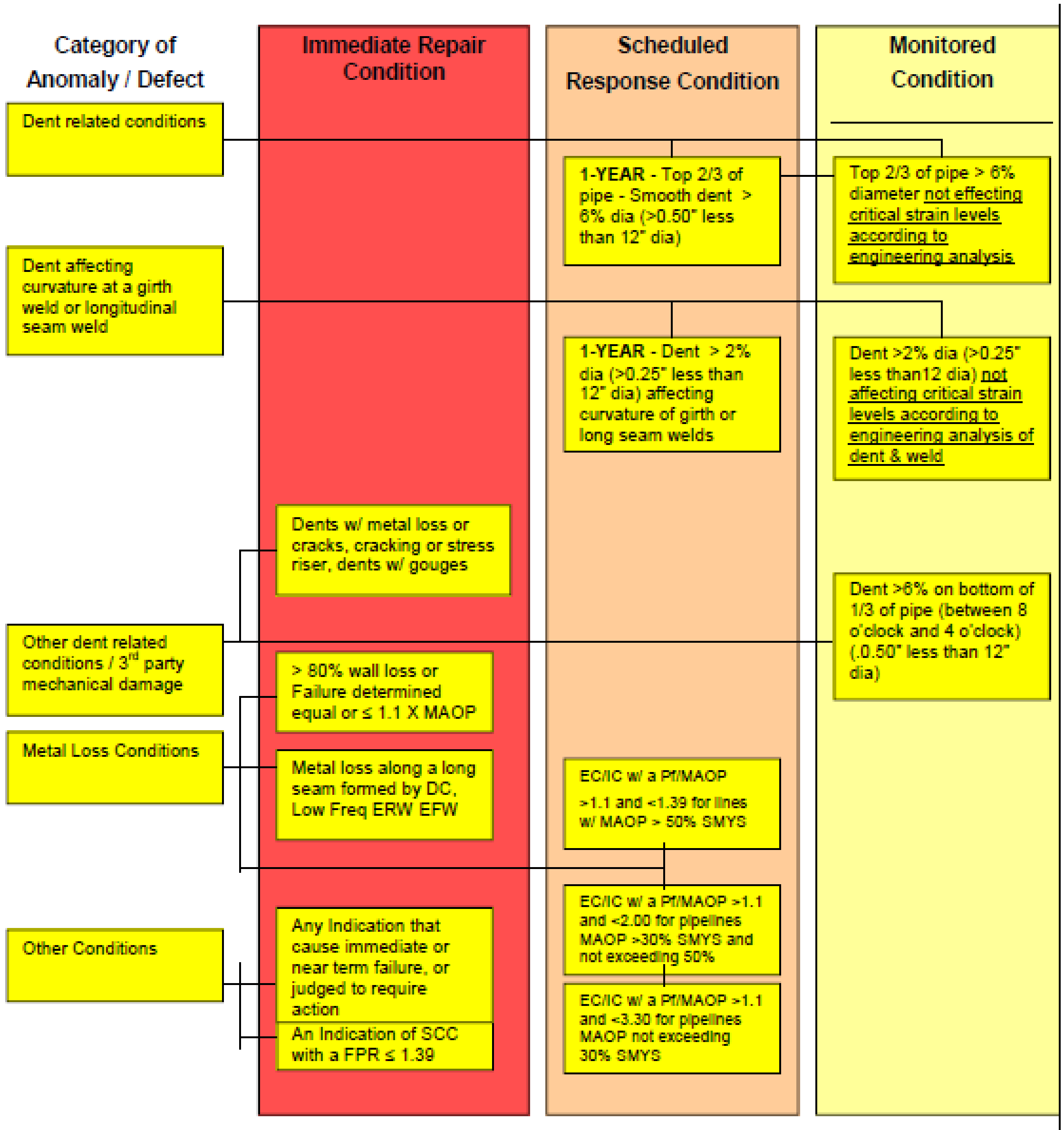
The option of reducing the operating pressure to 80% of the recent maximum operating pressure is the only option available for certain anomaly conditions (such as dents with gouges) because there is currently no industry accepted standard for calculating safe operating pressure for such anomalies.

Those conditions that require immediate repair are:

- Metal loss indicated to be greater than 80 percent of nominal wall loss regardless of dimensions.
- Internal/External Corrosion anomaly that Pf/MAOP ratio is $\leq$ 1.1.
- A dent with any indication of metal loss, cracking or stress riser.
- An indication of Metal-Loss in a detected Direct Current or Low Frequency-ERW or EFW longitudinal seam.
- An indication of Stress Corrosion Cracking with a Failure Pressure Ratio (FPR) $\leq$ 1.39.
- An anomaly that in the judgment of the IMC or a designee requires immediate action.

Any indication that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

Anomalous Conditions for Remediation



6.3.3 Operator Response when Timelines for Evaluation and Remediation Cannot be Met [192.933(a)]

If EnLink is not able to respond within specified time limits for conditions outlined in this section, EnLink will temporarily reduce the pipeline operating pressure or take other action that ensures the covered segment safety. The operating pressure is reduced per calculations performed by the ***IMP Engineer.***

The ***IMP Specialist*** prepares a justification for any condition that cannot meet the schedule and documents that the changed schedule will not jeopardize public safety. The ***IMP Team Chairman*** notifies the appropriate agencies in conformance with IMP Section 15 – Submittal of Program Documents, in the event that EnLink will not meet the evaluation and remediation schedule and cannot provide safe operating conditions by temporarily reducing operating pressure or by other action.

Any reduction of operating pressure in an HCA as a result of condition(s) as defined in IMP Section 6.3.2 cannot exceed 365 days without notifying PHMSA, and appropriate state authorities, in conformance with192.18. The notice must explain the reasons for the delay and provide technical justification that the continued pressure restriction will not jeopardize pipeline integrity. The ***IMP Team*** notifies PHMSA, and appropriate state authorities, in conformance with CFR192.18. See IMP Section 15.1 for additional notification details.

7 CONTINUAL EVALUATION AND ASSESSMENT [192.911(F)]

7.1 Introduction

This section describes the process for planning and completing reassessments of covered segments.

In conformance with 49 CFR 192.917, 192.937, and ASME B31.8S, EnLink has developed a written process for periodic evaluations of pipeline integrity based on data integration and risk assessment.

7.2 Roles and Responsibilities

Position	Responsibility
IMP Team Chairman	Conducts annual evaluation process with ***IMP Team***
IMP Engineer	Review reassessment plans and document new threats
Regional Teams and SMEs	Review post assessment analysis
IMP Specialist	Documents periodic evaluations and reassessment planning

7.3 Process

7.3.1 Periodic Evaluations [192.937(a); 192.937(b)]

Periodic evaluations are based on data integration and risk assessment of the pipeline system and are completed in conformance with IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment. For transmission pipelines other than plastic pipelines, the evaluation will consider past and present integrity assessment results, data integration and risk assessment information, remediation decisions, and additional preventative and mitigative actions.

Periodic evaluation triggers include, but are not limited to, the completion of integrity assessments and data evaluation, substantial leaks, failures or incidents, and the availability of new integrity information. As with baseline assessments, reassessment method determinations are made in conformance with the particular threats for each segment. The ***IMP Specialist*** documents periodic evaluations and reassessment planning. Documentation consists of decision making and rationale for reassessment planning.

Reassessment plans are reviewed by the ***IMP Engineer*** annually to determine if new information of threats and pipeline conditions warrants changes to the reassessment plans. Pipeline segments are risk ranked annually in *RIPL*© (total probability multiplied by total consequence) as described in IMP Section 4.3.3 – Risk Assessment. The risk ranked list is employed to re-evaluate the baseline assessment / reassessment plan. The annual risk evaluation and prioritization process is conducted in a similar manner as the initial risk ranking and prioritization process as described in IMP Section 3 – Baseline Assessment / Reassessment Plan.

The ***IMP Team Chairman*** will conduct a review of the HCAs where an integrity assessment was completed during the previous calendar year. This review will include the following:

- Review the assessment activities and results completed for the HCA. This also includes gathering data on any pipe inspections and repairs as a result of the remedial actions taken and any findings and reviews from ***Regional Teams and SMEs*** related to post assessment analysis.
- Review and verify that periodic evaluations of data are thorough, complete, and adequate for establishing reassessment methods and schedules.
- Review variance requests identifying and documenting whether a shorter reassessment interval is warranted.

- Review Mitigation Measures and Preventative Measures.
- Review assessment information, review changes to threats, and set the re-assessment interval. Communicate results and conclusions.
- Document this information in the IMP Database.

7.3.2 Reassessment Methods [192.937l]

Integrity assessment methods are selected using the process in IMP Section 3 – Baseline Assessment Plan. EnLink employs the following method(s), where appropriate, for the threats to which the covered segment is susceptible:

- Internal inspection tool or tools capable of detecting corrosion and any other threats to which the covered segment is susceptible.
- Pressure testing.
- Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking.
- Direct examination to address the threats of external corrosion, internal corrosion, stress corrosion cracking and/or third party/mechanical damage.
- Other technology that can be demonstrated to provide an equivalent assessment of line pipe condition, if this method is utilized, PHMSA, and appropriate state authorities, must be notified 180 days prior to utilization. See IMP Section 3 – Baseline Assessment Plan for details.
- Low Stress Reassessment and applicable only to segments that operate below 30% SMYS.
- Confirmatory direct assessment for a covered segment that is scheduled for reassessment at an interval greater than 7 years for external or internal corrosion. Periodic evaluations of plastic pipeline will be based on the specified threat analysis identified in IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment.

7.3.3 Low Stress Reassessment – For Corrosion Threats [192.941]

When selected as the assessment method, EnLink may employ the following to reassess a covered segment that operates below 30% SMYS. However, this reassessment method addresses the threats of external and internal corrosion only. In order to use this method, a baseline assessment of the covered segment must have been conducted in accordance with IMP Section 3 – Baseline Assessment Plan.

External Corrosion [192.941(b)]

To address external corrosion on the low stress covered segment, EnLink employs one of the following, depending on whether cathodic protection is available and/or practical:

- Cathodically protected pipe:
  - An electrical survey (i.e., indirect examination tool/method) is performed at intervals not to exceed seven years on covered segments. EnLink employs the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation considers, at a minimum, leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- Unprotected pipe or cathodically protected pipe where electrical surveys are impractical:
  - Conduct leakage surveys at four-month intervals; and

- At intervals not to exceed 18 months, Corrosion Technicians evaluate leak, repair, and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment to identify and mitigate areas of active corrosion.

Internal Corrosion [192.941I]

To address the identified threat of internal corrosion on a covered segment, EnLink performs the following:

- Conduct a gas analysis for corrosive agents.
- Periodically test fluids removed from the pipeline segment.
- At intervals not to exceed seven years, ***IMP Specialist*** evaluates and integrates data from the gas analysis and fluid testing with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records to define, recommend, and implement appropriate remediation actions.

7.3.4 Reassessment Interval [192.939; 192.943(b)]

When making the determination for the reassessment intervals, the ***IMP Engineer*** considers the requirements codified in 49 CFR 192.939 and employs covered segment integrated data and risk analysis results. Reassessment intervals are documented in the IAP. A detailed procedure of risk analysis steps is provided in **ENLINK GIMP Procedure 105**, *Gas Risk Analysis.*

EnLink will plan to conduct the reassessment within the required interval from the previous assessment completion date. If necessary, the reassessment deadline can be extended to, but no later than, December 31 of the reassessment year. If the December 31 deadline cannot be met, a request for a 6-month extension must be submitted to OPS with sufficient justification for the need of the extension, at least 180 days before the end of the required reassessment interval. Refer to Integrity Management FAQ #41 for confirmation of the December 31 deadline date.

For Steel Pipelines Operating At or Above 30% SMYS [192.939(a)]

✓EnLink establishes a reassessment interval for each of the covered segments operating at or above 30% SMYS. In the event that the ***IMP Team*** evaluation determines the reassessment interval is greater than seven years and there is not an SCC threat, unstable manufacturing, or unstable construction threat, EnLink may elect to conduct a Confirmatory Direct Assessment on the covered segment within the seven-year period and then conduct the follow-up reassessment at the established interval. Otherwise, the covered segment will be reassessed in seven years. For all other threats, the maximum reassessment interval by an allowable reassessment method is seven years. Refer to above paragraph regarding clarification of the reassessment interval.

Reassessment intervals will be established by at least one of the following:

Assessment Using ILI, Pressure Test, or Other Technology

When using pressure testing, in-line inspection, or other equivalent technology as an assessment method, the reassessment interval for a covered pipeline segment is either 1) based on the identified threats for the segment and along with the analyzed results from the last integrity assessment, or 2) established by the intervals specified for different stress levels of pipeline (operating at or above 30% up to 50% SMYS or at or above 50% SMYS) listed in Table IMP 9-1, Integrity Assessment Intervals – Time Dependent Threats. Direct Examination will follow the same requirements as Direct Assessment in Table IMP 9-1.

Assessment Using Direct Assessment

When using ECDA, ICDA, or SCCDA as the reassessment method, refer to EnLink's Direct Assessment Procedures for of each assessment method type and for the reassessment interval determination in Table IMP 9-2.

For Steel Pipelines Operating Below 30% SMYS [192.939(b)]

EnLink establishes a reassessment interval for each of the covered segments operating below 30% SMYS (Table IMP 9-2, Maximum Reassessment Intervals, and Table IMP 9-3, Assessment Requirements for Transmission Pipelines in HCAs).

The maximum reassessment interval by an allowable reassessment method is seven years and the reassessment is established by at least one of the following:

- Confirmatory direct assessment at seven-year intervals in conformance with the procedures for External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, and with reassessment by pressure test, internal inspection, ECDA, or ICDA by year twenty of the interval.
- Low stress assessment method at seven-year intervals with reassessment by pressure test, internal inspection, ECDA, ICDA, or SCCDA by year twenty of the interval (low stress assessment method follows).
- Gas test at seven-year intervals is sufficient for reassessment in class 2,3, and 4 sections. Lines in these sections can be tested with gas to 1.5 times MAOP to get a seven-year re-assessment interval.

In the event that an established interval is greater than seven years and the threat is external or internal corrosion, a confirmatory direct assessment or a low stress reassessment may be conducted in lieu of ILI, pressure testing or Direct Assessment by the end of seventh year of the interval. When using ECDA, ICDA, or SCCDA as the reassessment method, the reassessment interval is determined as indicated in Section 9.4.2.2, Assessment Using Direct Assessment.

Low Stress Method. Prior to using this method, a baseline assessment should be performed. This method addresses the threats of external and internal corrosion as follows:

i. For addressing External Corrosion on:
   - Cathodically protected pipeline perform an electrical survey (i.e. indirect examination tool / method) at least every 7 years on the covered segment. Use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
   - Unprotected pipe or cathodically protected pipe where electrical surveys are impractical. Conduct leakage surveys at four-month intervals; and every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

ii. For addressing Internal Corrosion:
   - conduct a gas analysis for corrosive agents at least once each calendar year.
   - conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment.

At least every seven years, integrate data from the analysis and testing with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

The ***IMP Specialist*** will remediate all anomalies identified in the most recent assessment according to the requirements in §192.933 and incorporate the results and lessons learned from the most recent assessment into the operator's data integration and risk assessment when determining the reassessment interval.

Table IMP 9-2, Maximum Reassessment Intervals, and Table IMP 9-3, Assessment Requirements for Transmission Pipelines in HCAs identify criteria to be used when evaluating and determining HCA reassessment intervals. Table IMP 9-2, Maximum Reassessment Intervals identifies the maximum reassessment interval allowed for various pipeline operating parameters with an associated assessment method. Table IMP 9-3, Assessment Requirements for Transmission Pipelines in HCAs provides guidance on implementing requirements on assessment methods for addressing time dependent and independent threats for a transmission line in an HCA. In the event of a disagreement between tables, intervals established in Table IMP 9-2, Maximum Reassessment Intervals take precedent over guidance presented in Table IMP 9-3, Assessment Requirements for Transmission Pipelines in HCAs.

Reassessment Interval – Alternative MAOP / Waiver / Special Permit Pipelines

The reassessment interval for pipeline segments operating with an alternative MAOP, waiver, or special permit shall be considered in the same manner as HCAs in the IAP regardless of HCA classification.

Reassessment Interval – Outside of HCAs (MCA's, Class 3, and Class 4) 192.710.

For reassessment intervals on areas outside of HCAs, reference ENL-GOM-00098 procedure.

7.3.5 Deviation from Reassessment Requirements [192.943]

After completing at least two integrity assessments on each covered pipeline segment, and completing remediation in conformance with IMP Section 6 – Remediation, the ***IMP Team Chairman*** may evaluate whether to employ the performance-based approach. In the event that the ***IMP Team Chairman*** demonstrates that the minimum requirements (listed below) and those performance-based requirements in ASME B31.8S are satisfied for a covered segment, EnLink may choose to adopt the exceptional performance-based plan and notify PHMSA, and appropriate state authorities, of using this approach.

7.3.6 Waiver from Reassessment Interval [192.943; 192.939; 192.18]

The ***IMP Team Chairman*** will submit a waiver request to extend a reassessment interval for an HCA segment in the following situations (see IMP Section 15- Submittal of Program Documents for details):

- Lack of internal inspection tools – a longer reassessment period may be necessary for a covered segment if internal inspection tools are not available to assess the line pipe, and actions taken in the interim will ensure the covered segment's integrity.
- Maintain supply of product – a longer reassessment period is needed for a covered segment that cannot maintain local city product supply if the reassessment is performed within the required interval.

The waiver request will be submitted in conformance with 49 CFR 192.943 at least 180 days before the end of the required reassessment interval. If circumstances make the prior notification period impractical, the waiver request will be made as soon as the need for the waiver is known.

If the seven year re-assessment interval cannot be met and a 6-month extension is necessary, then the **IMP Team** will submit a written notice to the Secretary with sufficient justification of the need for the extension. If a written notice to PHMSA is required, EnLink will notify PHMSA by.

1) sending a notification by electronic mail to InformationResourcesManager@dot.gov
   -or-
2) sending a notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590

Table IMP 9-1 – Integrity Assessment Intervals – Time Dependent Threats [ASME B31.8S, Table 3]

INTEGRITY ASSESSMENT INTERVALS—
TIME-DEPENDENT THREATS PRESCIPTIVE INTEGRITY MANAGEMENT PLAN

		Criteria		
Inspection Technique	Interval (years) [Note (1)]	At or above 50% SMYS	At or above 30% up to 50% SMYS	Less than 30% SMYS
Hydrostatic testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.4 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]	TP to 2.2 times MAOP [Note (2)]
	15	Not allowed	TP to 2.0 times MAOP [Note (2)]	TP to 2.8 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.3 times MAOP [Note (2)]
In-line inspection	5	PF above 1.25 times MAOP [Note (3)]	PF above 1.4 times MAOP [Note (3)]	PF above 1.7 times MAOP [Note (3)]
	10	PF above 1.39 times MAOP [Note (3)],	PF above 1.7 times MAOP [Note (3)]	PF above 2.2 times MAOP [Note (3)]
	15	Not allowed	PF above 2.0 times MAOP [Note (3)]	PF above 2.8 times MAOP [Note (3)]
	20	Not allowed	Not allowed	PF above 3.3 times MAOP [Note (3)]
Direct assessment	5	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	10	All indications examined	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	15	Not allowed	All indications examined	All indications examined
	20	Not allowed	Not allowed	All indications examined

NOTES:
(1) Intervals are maximum and may be less depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate re-assessment of the interval.
(2) TP is Test Pressure.
(3) PF is Predicted Failure Pressure as determined from ASME B31G or Equivalent.
(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for re-inspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% of SMYS.

Table IMP 9-2 – Maximum Reassessment Intervals [192.939(b)(6)]

Assessment method	**Pipeline operating at or above 50% SMYS**	**Pipeline operating at or above 30% SMYS, up to 50% SMYS**	**Pipeline operating below 30% SMYS**
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

(*)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.

(**)A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

Table IMP 9-3 – Assessment Requirements for Transmission Pipelines in HCA's

	Reassessment Requirements (see Note 3)					
	At or above 50% SMYS		**At or above 30% SMYS up to 50% SMYS (See Note 4)**		**Below 30% SMYS**	
Baseline Assessment Method (see Note 3)	Max Reassessment Interval	Assessment Method	Max Reassessment Interval	Assessment Method	Max Reassessment Interval	Assessment Method
Pressure testing	7	CDA	7	CDA	Ongoing	Preventative and Mitigative Measures (see Table IMP 7-1 and Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15 (see Note 1)			
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative and Mitigative Measures (see Table IMP 7-1 and Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)			
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test
						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative and Mitigative Measures (see Table IMP 7-1 and Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)			
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: EnLink may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S.

Note 2: EnLink may choose to utilize CDA at year 7 and 14 in lieu of P&M.

Note 3: EnLink may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe". [192.937I(4)]

Note 4: In class 3 or 4 locations or in an MCA, a spike hydrostatic pressure test conducted in accordance with §192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects.

8 CONFIRMATORY DIRECT ASSESSMENT [192.937]

8.1 Introduction

This section describes the process for completing confirmatory direct assessment (CDA) of covered segments.

Confirmatory direct assessment (CDA) may be employed on a covered segment that is scheduled for reassessment at a period longer than seven years.

If EnLink uses CDA as the reassessment method, EnLink will provide the following, should a defect be found requiring remediation prior to the next scheduled assessment:

- Schedule the next assessment in accordance with NACE SP0502-2010, Section 6.2 and Section 6.3.
- If the defect requires immediate remediation, EnLink will reduce the pressure until the reassessment, per 192.937, is completed.

The method of confirmatory direct assessment (CDA) should be used on covered segments where:

- external or internal corrosion is the threat of concern, and
- the scheduled reassessment period is longer than seven years.

CDA is integral to the reassessment process and should be implemented as indicated by Section 5 to periodically monitor the integrity of the pipeline. The CDA methodology adds value to the baseline and subsequent assessments thereby further enhancing the pipeline integrity.

8.2 External Corrosion Plan

To identify external corrosion using CDA follow the direct assessment methodology outlined in Section 5 of this manual except that:

1. Only one suitable indirect examination tool is required;
2. For Direct Examination:
   - Excavate all immediate action indications for each ECDA region; and
   - Excavate at least one high risk indication that meets the criteria of scheduled action in each ECDA region.

8.3 Internal Corrosion Plan

To identify internal corrosion using CDA follow the direct assessment methodology outlined in Section 5 of this manual except that it is necessary to only excavate one high risk location in each ICDA region.

8.4 Defects Requiring Near-Term Remediation

IMP Team will evaluate all anomalous conditions that could reduce a pipeline's integrity using remaining life calculations and reassessment intervals as defined in Section 6.2 and 6.3 of NACE SP0502-2010. In addressing all conditions, remediate those that could reduce a pipeline's integrity. Demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

If the defect requires immediate remediation, then reduce pressure of the pipeline or take other action that ensures the safety of the covered segment. If the pressure is reduced, then determine the temporary operating pressure of the pipeline using ASME/ANSI B31G or RSTRENG or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. If the operating pressure is reduced for more than 365 days, then be able to provide technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

8.5 Roles and Responsibilities

Position	Responsibility
IMP Specialist	Evaluate and remediate all anomalies identified in the CDA

8.6 Process

8.6.1 Confirmatory Direct Assessment [192.931]

CDA is a follow-up integrity assessment method to assess external corrosion and/or internal corrosion threats. The ***IMP Specialist*** uses CDA to reassess covered segments following assessments completed by In-Line Inspection (ILI), pressure test, external corrosion direct assessment (ECDA), or internal corrosion direct assessment (ICDA).

9 PREVENTIVE AND MITIGATIVE MEASURES [192.935]

9.1 Introduction

This section describes the process for evaluating and selecting P&Ms for covered segments.

In conformance with 49 CFR 192.935, EnLink evaluates and employs Preventive and Mitigative Measures (P&Ms) that exceed the minimum requirements in part 192 to prevent and mitigate the consequences of a pipeline failure. The P&M process consists of the following key components:

- Identification of P&Ms
- Evaluation of P&Ms
- Documentation
- Management of Change

As established in IMP Section 4 – Threat Identification, Data Integration, Risk Assessment, EnLink conducts threat identification and risk ranking. For each identified threat in a covered segment, EnLink evaluates the necessity of additional P&Ms that exceed the requirements in CFR Part 192.917.

9.2 Roles and Responsibilities

Position	Responsibility
IMP Specialist	Evaluate and select the appropriate P&M measures Presents the proposed P&Ms to EnLink Operations personnel
IMP Engineer	Runs risk analysis to determine if remote-control valves are efficient means of protection

9.3 Process

9.3.1 General Requirements [192.935(a)]

P&M evaluations are completed for covered sections in response to the following events:

- Integrity assessment and subsequent remediation.
- Significant leaks, failures, or incidents.
- New information providing substantial changes to identified threats or relative risk ranking.

To identify additional or new P&Ms, the ***IMP Specialist*** conducts an evaluation based on the following:

- Threat-based P&M identification
- Scenario comparisons
- Preliminary Evaluation and Decision Making
- Formal P&M Reviews

The following sections establish the requirements and methodology for each of these steps.

Threat Based P&M Identification [192.917; 192.935(a)]

Decisions regarding P&Ms are based on the threats identified using the P&M template within RIPL. Specific pipeline threats are identified and P&Ms are evaluated by the ***IMP Specialist***.

In order to consistently and systematically identify P&Ms, the ***IMP Specialist*** utilizes Table IMP 11-1 – Preventive and Mitigative Measures Selection Criteria to identify appropriate P&Ms for each threat.

- Enhancements to leak detection systems.
- Addition of Automatic Shut-off Valves or Remote-Control Valves.
- Enhancements to corrosion control efforts.
- Enhancements to third party damage prevention programs.
- Enhancements to inspections and maintenance programs.
- Conduct drills with local emergency responders.
- Replace pipe segments with segments of heavier wall thickness.
- Better monitoring of cathodic protection where corrosion is a concern.
- Conducting CIS or DCVG electrical surveys.
- Establishing shorter inspection intervals.
- Provide additional signage, protective structures or assemblies, patrolling, etc.
- Perform repairs according to a risk-based repair schedule.
- Providing additional training to personnel on response procedures.

The following describes the process for identifying and implementing preventive and mitigative measures based on the identified threats to pipeline integrity in a given covered segment:

A) Review the threats for each covered segment as determined in IMP Section 4 – Threat Identification, Data Integration, and Risk Assessment;

B) Determine if the following threats or situations apply to the covered segment and ensure the specific preventive and mitigative measures for each are identified and implemented.

  - 3rd party damage threat.
  - Outside forces threat.
  - Covered segment operates below 30% SMYS.

C) For each threat identified, conduct a review to determine whether adequate preventive and mitigative measures are already implemented in the covered segment to meet the identified threats. Table IMP 11-1 lists preventive and mitigative measures that are appropriate for addressing each threat. To be considered adequate, a minimum of one preventive and mitigative measure listed in Table IMP 11-1 must be in place to address each applicable threat in a covered segment.

D) If the current preventive and mitigative measures do not meet the requirements in step C, the ***IMP Specialist*** will identify appropriate additional measures for the covered segment based on the applicable threats with a minimum of one preventive and mitigative measure listed in Table IMP 11-1 to address each applicable threat to a covered segment.

E) The measures identified in steps B, C, and D (above) will be documented, communicated to Operations and then implemented. Operations will be responsible for implementation and documentation of the day-to-day preventive and mitigative measures such as patrolling, leak surveys, etc. The preventive and mitigative measures selected for each covered segment will be documented in the EnLink Maintenance Database.

F) Preventive and mitigative measures for each covered segment will be reviewed as part of the Formal P&M Review as described below.

Table IMP 11-1 – Preventive and Mitigative Measures Selection Criteria

	Time-Dependent Group			Stable Group			Time-Independent Group		
	Corrosion Related Threats			Manufacturing Related Threats	Welding / Fabrication Related Threats	Equipment	Third Party / Mechanical Damage	Incorrect Operations	Weather Related and Outside Forces
Preventive and Mitigative Methods	External	Internal	SCC	Pipe Seam, Pipe	Girth Weld, Fabrication Weld, Coupling Failure, Wrinkle Bend or Buckle	Gasket/O-Ring Failure, Stripped Threads, Broken Pipe, Control/Relief Malfunction, Seal/Pump Packing Failure	Third Party Damage, Previously Damaged Pipe, Vandalism	Incorrect Operational Procedure	Cold Weather, Lightning, Heavy Rains/Floods, Earth Movement
Increased Patrols	X				X		X		X
Enhance Public Awareness Program							X		
Operator Training (Procedures and Response)							X	X	
Conduct Emergency Response Drills							X		
Increase Signage on ROW							X		
Install Mechanical Barrier or External Protection							X		X
Install Warning Tape Mesh							X		
Increased CP Monitor	X								
Close Interval Survey	X								
Install ACV's, RCV's	X	X	X	X	X	X	X	X	X
Install Leak Detection and Monitoring System	X	X			X	X	X		
Strain Measurement									X
Reduce External Stress					X	X			X
Line Relocation							X		X
Recoat	X		X	X	X		X		X
Increase Depth of Cover							X		X
Pipe Replacement/Increase Wall Thickness	X	X	X	X	X	X	X		X
Install Moisture Reduction Equipment		X							
Internal Corrosion Monitoring		X							
Biocide Inhibiting Injection		X							
Monitor Gas Quality		X							
Internal Cleaning Pig Program		X							
Pressure Reduction	X	X	X	X	X		X		

Formal P&M Reviews

Upon having completed threat-based P&M identification, scenario modeling, and preliminary evaluation of P&Ms, the ***IMP Specialist*** presents the proposed P&Ms to EnLink Operations personnel. Formal P&M reviews may combine several covered segments with similar characteristics in a single discussion. Representatives from Field Operations are present for the formal P&M reviews to finalize the selection of P&Ms. As with each component of the P&M process, review results are documented in the EnLink Maintenance Database. An implementation decision for each proposed P&M and the basis for P&M sufficiency is documented on **ENLINK LIMP Form 106**, *P&M Evaluation*. The ***IMP Specialist*** is responsible for maintaining associated records in appropriate segment files.

9.3.2 Third Party Damage [192.935(b)(1)]

In supplement to the Damage Prevention Program and in conformance with 49 CFR 192.935 (b), EnLink has developed enhanced measures to prevent third party damage. These enhanced measures include the following:

- Using qualified personnel for IMP work tasks such as marking, locating, and direct supervision of direct excavation work.
- Collecting location-specific information in a central database on excavation damage (covered and non-covered segments) and root cause analysis.
- Participation in one-call systems.
- Monitoring of excavations on covered segments by EnLink personnel or Representative.

In the event that third party damage is identified as a threat, EnLink, at a minimum, enhances its damage prevention program with the listed actions below to prevent and minimize the consequences of a release due to third party damage:

- Using qualified personnel for work conducted by EnLink.
- Collecting and reporting incident-tracking on Third Party damage that occurs on covered and non-covered segments in the transmission system. It will include root cause analysis to support identifying targeted additional preventive and mitigative measures in covered segments.
- Participating in one-call systems in locations with covered segments.
- Providing pipeline personnel to monitor excavations conducted on covered pipeline segments. Unmonitored excavations will be investigated.

9.3.3 Pipelines Operating Below 30% SMYS [192.935(d)]

For pipelines operating below 30% SMYS and located in a covered segment, EnLink implements the following actions:

- Use qualified personnel for work conducted by EnLink.
- Participate in one-call systems in locations with covered segments.
- Monitor excavations near the pipeline or conduct bi-monthly pipeline patrols. If an indication of an unreported construction activity is discovered, a follow-up investigation will be required to determine if mechanical damage has occurred.

For pipelines operating below 30% SMYS and located in a Class 3 or 4 area but not in a covered segment, EnLink will implement the following actions:

- Use qualified personnel for work conducted by EnLink.

- Participate in one-call systems in locations with covered segments.
- Monitor excavations near the pipeline or conduct bi-monthly pipeline patrols.
- Perform semi-annual leak surveys or quarterly leak surveys for unprotected pipe or cathodically protected pipe where electrical surveys are impractical.

In the event that an indication of an unreported construction activity is discovered, a follow-up investigation will be required to determine if mechanical damage has occurred.

9.3.4 Plastic Transmission Lines [192.935(e)]

In the event that EnLink operates a plastic transmission pipeline in a covered segment, EnLink will consider the following P&Ms:

- Use qualified personnel for work conducted by EnLink.
- Participate in one-call systems in locations with covered segments.
- Provide pipeline personnel to monitor excavations conducted on covered pipeline segments.

9.3.5 Outside Force Damage [192.935(b)(2)]

In the event that EnLink determines damage by outside forces (earth movements, floods, and unstable suspension bridge) is a threat, EnLink may implement measures to minimize the consequences from the outside force threat. Additional measures to minimize the consequences of damage from outside forces include, but are not limited to:

- Increasing patrol frequency
- Increased signage
- Adding external protection
- Reducing external stress
- Relocating the line

9.3.6 Corrosion [192.917(e)(5)]

If corrosion that could adversely affect pipeline integrity is identified on a covered segment per 49 CFR 192.933(d)(1)(1), the ***IMP Specialist*** will evaluate associated non-covered segments with similar coating and environmental characteristics. If the evaluation identifies the potential for corrosion that could adversely affect pipeline integrity on the other segments, the ***IMP Specialist*** will establish a schedule for evaluating and remediating these segments in conformance with applicable O&M Procedures.

9.3.7 Automatic Shutoff Valves or Remote-Control Valves [192.935I]

The ***IMP Engineer*** will conduct a risk analysis to determine whether an automatic shutoff valve or remote-control valve would be an efficient means of adding protection to a covered segment in the event of a gas release. The review includes, at a minimum: swiftness of leak detection speed and pipe shutdown capabilities (handled by Pipeline Control), the type of gas transported, operating pressure, rate of potential release, pipeline profile, potential for ignition, and nearest response personnel location. The ***IMP Specialist*** helps evaluate the installation feasibility.

In determining the need for installation of an ASV or RCV, the Operations Supervisor will review the following:

a. The swiftness of leak detection and pipeline shutdown capabilities:

   i. System detection times;

   ii. Operator response times;

   iii. Remotely controlled valve response characteristics; and

   iv. System isolation time, if applicable.

b. Type of gas and operating pressure being transported;

c. Rate and volume of leakage / release;

d. Potential for ignition;

e. Location of the nearest response personnel; and

f. Benefits expected by reducing the release size.

10 PERFORMANCE MEASURES [192.945]

10.1 Introduction

This section describes the process for evaluating program performance.

In an effort to determine program effectiveness and in conformance with 49 CFR 192.945, EnLink evaluates its Integrity Management Program annually.

10.2 Roles and Responsibilities

Position	Responsibility
IMP Team Chairman	Conducts annual evaluation team meeting to evaluate the performance program
IMP Team	Actively participate and evaluate performance measures

10.3 Process

10.3.1 General Performance Measures [192.945]

The Integrity Management Program employs performance measures to determine effectiveness and to initiate changes or additions, as warranted. The ***IMP Team Chairman*** provides PHMSA, and appropriate state authorities, with an overall HCA program measurement report (Performance Report) for covered pipeline segments, which includes the following:

- Number of miles of pipeline inspected versus program requirements.
- Number of immediate repairs completed as a result of the integrity management inspection program as defined by 49 CFR 192.933(d)(1).
- Number of scheduled repairs completed as a result of the integrity management inspection program as defined by 49 CFR 192.933(d)(2) and scheduled according to Figure IMP 8-2 – Timing for Scheduled Responses – Time Dependent Threats, in IMP 6 – Remediation.
- Number of leaks, failures, and incidents (classified by cause).

The annual Federal Gas IMP report (**ENLINK GIMP Form 112**, *Annual Federal Gas IMP Meeting Report*) is developed and submitted each year to the ***IMP Team***. The annual Federal Gas IMP meeting is held no later than December 31 of each year.

In addition, the ***IMP Team Chairman*** measures and documents the program effectiveness for each identified threat as illustrated in Table IMP 12-1 – Performance Measures and ASME B31-8S Table 9.

10.3.2 Performance Measures Records Verification [192.945]

General Performance Reports are compiled and submitted to PHMSA, and appropriate state authorities, on an annual basis. The Performance Reports are submitted on DOT Form PHMSA 7100.2.1.

10.3.3 Exceptional Performance Measures [192.913(b)(vii)]

EnLink employs a risk-based prescriptive integrity management program. In the event that EnLink chooses to utilize the performance-based approach, additional performance measures will be selected, and all performance measures will be submitted to PHMSA, and appropriate state authorities, on a semi-annual frequency.

Table IMP 12-1 – Performance Measures
(ASME B31.8S, Table 9)

Threat	Performance Measure
External Corrosion	1. Number of hydrostatic test failures caused by external corrosion
	2. Number of repair actions taken due to in-line inspection results (immediate and scheduled)
	3. Number of repair actions taken due to direct assessment results (immediate and scheduled)
	4. Number of external corrosion leaks
Internal Corrosion	5. Number of hydrostatic test failures caused by internal corrosion
	6. Number of repair actions taken due to in-line inspection results (immediate and scheduled)
	7. Number of repair actions taken due to direct assessment results (Immediate and scheduled)
	8. Number of internal corrosion leaks
Stress Corrosion Cracking	9. Number of in-service leaks/failures due to SCC
	10. Number of repair or replacements due to SCC
	11. Number of hydrostatic test failures due to SCC
Manufacturing	12. Number of hydrostatic test failures caused by manufacturing defects
	13. Number of leaks due to manufacturing defects
Construction	14. Number of leaks or failures due to construction defects
	15. Number of girth welds/couplings reinforced/removed
	16. Number of wrinkle bends removed
	17. Number of wrinkle bend inspections
	18. Number of fabrication welds repaired/removed
Equipment	19. Number of regulator valve failures
	20. Number of relief valve failures
	21. Number of gasket or O-ring failures
	22. Number of leaks due to equipment failures
Third Party Damage	23. Number of leaks or failures caused by third party damage
	24. Number of leaks or failures caused by previously damaged pipe
	25. Number of leaks or failures caused by vandalism
	26. Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect Operations	27. Number of leaks or failures caused by incorrect operations
	28. Number of audits/reviews conducted
	29. Number of findings per audit/review (classified by severity)

Threat	Performance Measure
	30. Number of changes to procedures due to audit/review
Weather-Related and Outside Forces	31. Number of repair, replacement or relocation actions due to weather-related or outside force threats
	32. Number of leaks that are weather-related or due to outside force

11 RECORD KEEPING [192.947]

11.1 Introduction

In conformance with 49 CFR 192.947, this section establishes how EnLink maintains, for the useful life of the pipeline, records that demonstrate compliance with the requirements of the integrity management regulations.

This section contains record keeping requirements for the integrity management program.

11.2 Roles and Responsibilities

Position	Responsibility
IMP Specialist	Maintains all pertinent IMP records
IMP Team Chairman	Maintains copy of all required documents in a company central repository

11.3 Process

11.3.1 Records to be Maintained by EnLink [192.947]

For the life of the pipeline, ***IMP Specialist*** maintains the following records, which will be stored in the IMP Database:

- Written Pipeline Integrity Management Program.
- Class Location Evaluation Documentation is maintained by GIS
- Documents supporting the threat identification and risk assessment.
- Written Baseline Assessment Plans.
- Documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the baseline assessment plan and Pipeline Integrity Management Program. This includes documents developed and used in support of any identification, calculation, amendment, modification, justification, deviation, determination made, and any action taken to implement and evaluate any of the program elements.
- Documents to demonstrate that personnel possess the required training, including a description of the training program.
- Details of a schedule that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications.
- Documents to carry out the Direct Assessment Plan.
- Documents to carry out the requirements for Direct Examination.
- Documents to carry out the requirements for Confirmatory Direct Assessment.
- Documents that define and monitor measures to determine the effectiveness of the ECDA process used for direct assessment to assess the external corrosion threat.

A record retention schedule is generated for required forms and documents.

The ***IMP Team Chairman*** maintains a copy of any required documentation or notification provided to PHMSA, a State authority, and a State or local pipeline safety authority that regulates a covered pipeline segment within that state. The ***IMP Team Chairman*** also maintains the record that verifies the documentation submission or notification.

12 MANAGEMENT OF CHANGE [192.911(K)]

12.1 Introduction

In conformance with 49 CFR 192.911(k), this section establishes a means of incorporating changes into the Pipeline Integrity Management Program (IMP). The Management of Change (MOC) elements of ASME B31.8S, Section 11 have been incorporated into the MOC process.

This section identifies areas where EnLink's eMOC (electronic MOC) process is employed, and provides guidance on specific information needs, to be included in the MOC process.

12.2 Roles and Responsibilities

Position	Responsibility
Operations	Submit eMOC's causing Pipeline Integrity action or review.
Engineering	Submit eMOC's causing Pipeline Integrity action / review.
IMP Team Chairman	Submit eMOC's that Pipeline Integrity cause. Approve eMOC's causing Pipeline Integrity action / review. Accountable for all IMP notifications to PHMSA, state or local applicable authorities.
IMP Specialist	Submit eMOC's that Pipeline Integrity cause. Approve eMOC's causing Pipeline Integrity action / review.
IMP Team	Review and document projects for the current calendar year.

12.3 Process

12.3.1 Documentation and Notification of Changes to the Integrity Management Program [192.909]

The Pipeline Integrity Management Program is continually evaluated and revised as necessary to:

- Reflect operating and industry experience.
- Incorporate conclusions drawn from the Integrity Management process results.
- Reflect continued evolution.
- Incorporate tools and techniques as they become available.

Modifications and/or revisions to the Pipeline Integrity Management Program are documented and tracked via eMOC processes.

Each year, projects scheduled and budgeted for the current calendar year are reviewed and documented by the ***IMP Team***. Changes made to the assessment years will be summarized and reported to Management per IMP 13 – Quality Assurance. This process does not apply to IAPs that are in the project phase of assessment by the appropriate assessment method and that are carried over into the next calendar year as a continuous project.

Change Notification [192.909(b)]

The ***IMP Team Chairman*** identifies situations requiring notification to PHMSA and applicable state or local authorities having pipeline safety oversight jurisdiction and communicates these situations.

The ***IMP Team Chairman*** notifies PHMSA, and appropriate state authorities, concerning covered (HCA) pipeline segments within 30 days after adopting any significant change to the Pipeline Integrity Management Program that may affect the program's implementation or may significantly modify the program or schedule for carrying out program elements, along with reasons for the change before implementation. Significant changes include, but are not limited to:

A) Changes to the HCA identification process that result in changes to a significant number of overall plan HCA mileage;
B) Changes to threat identification that result in changes to a significant number of covered segments for which the threat is identified;
C) Changes to the risk ranking process that result in significant changes to the relative risk ranking of covered segments;
D) Changes to the PHMSA condition repair criteria or timelines;
E) Changes to the Preventive and Mitigative Measure (P&M) selection process.

Notification of significant changes to a covered (HCA) segment program are provided to the following agencies, as required or other local pipeline safety authorities, as appropriate:

PHMSA

- By mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE, Washington, DC 20590, or
- Via facsimile to (202) 366-7128, or
- By entering the information directly on the PHMSA Portal @ https://portal.phmsa.dot.gov/phmsapub/

12.3.2 Attributes of the Change Process [192.909(a)]

EnLink has created standards and procedures that purposely consider changes to pipeline systems and their integrity. These standards and procedures also address technical, physical, procedural, and organizational changes to EnLink pipeline operations (reference EnLink Standards and Procedures).

The following requirements for standards, modifications and variances are:

- Reason for change
- Authority for approving changes
- Analysis of implications
- Documentation
- Communication of change to affected parties
- Time limitations
- Qualification of staff

The following requirements for pipeline system or integrity management program changes are:

- Reason for change
- Authority for approving changes
- Analysis of implications
- Acquisition of the required work permits
- Documentation
- Communication of change to affected parties

- Time limitations
- Qualification of staff

A preliminary Pipeline Integrity MOC review shall be performed where a connection or other change (or group of connections or changes) according to the *EnLink Management of Change Procedure for Gas and Liquid Pipelines, which includes the EnLink Pipeline MOC Checklist*.

EnLink's MOC program can be accessed on the company eMOC intranet site: https://enlinkmidstreamoperating.sharepoint.com/aim/Procedures/ENL-AIM-00001.1%20CMS%20MOC%20Procedure.pdf. Instructional documents are available on the site as a process guide.

13 QUALITY ASSURANCE [192.911(L)]

13.1 Introduction

This section describes the quality assurance process for the Integrity Management Program (IMP). In addition, it defines personnel responsibilities, qualifications and training requirements.

49 CFR 192.911(l) establishes that operators must develop a quality assurance process as outlined in ASME / ANSI B31.8S, section 12.

13.2 Roles and Responsibilities

Position	Responsibility
IMP Team Chairman	Accountable for IMP overview training for the ***IMP Team*** and company personnel.
IMP Team	Conducts internal audits for program effectiveness and quality assurance. Provide recommendations for Plan improvements based on QA annual reviews. Responsible for maintaining audit findings.

13.3 Process

13.3.1 Program Requirements for the Quality Assurance Process [192.911(i); Protocol L.01]

EnLink implements a quality assurance process to evaluate whether the Pipeline Integrity Management Program (IMP) is effective in assessing, evaluating, and protecting the integrity of each high consequence segment. The quality assurance process consists of:

- Management review meetings
- Program audits
- Documented corrective and preventive actions
- Contractor qualifications

The ***IMP Team Chairman*** develops a schedule of quality assurance reviews and meetings. ***IMP Team*** review meetings, quality audits, peer reviews, and contractor qualification provide feedback of program implementation and suggestions for program improvement.

The entire Pipeline Integrity Management Program is reviewed annually no later than the fourth quarter of each year. The review process includes review of applicable Federal, State, and local regulations, operational procedures, quality assurance results, and industry standards.

All changes, modification and/or revisions to the Pipeline Integrity Management Program are implemented, documented, and tracked by the MOC process.

IMP Team Review Meetings

IMP Team review meetings are conducted each calendar year. The ***IMP Team Chairman*** sets the specific meeting date, location, agenda, and attendees. Corrective and preventive actions are incorporated in the management review document.

The objectives of the team review meeting include reviewing the IMP and associated documents for:

- Continued suitability, adequacy, and effectiveness in assessing, evaluating, and protecting the integrity of each HCA.
- Opportunities for improvement.

- Any necessary corrective and preventive actions and changes to the program.

The management review includes but not limited to:

- Performance measures reported to PHMSA, and appropriate state authorities.
- Performance measures for identified threats.
- Performance measures and effectiveness of direct assessment processes.
- Internal audit reports.
- Status of corrective and preventive actions.
- Contractor performance review.
- Follow-up actions from previous management review meetings.
- Changes to 49 CFR Part 192, ANSI/ASME B31.8S, PHMSA advisories, or other related documents that could affect the Pipeline Integrity Management Program.
- Internal benchmarking, where applicable, to compare integrity management metrics for different segments.
- External benchmarking.
- Recommendations for improvement.

The ***IMP Team*** review meeting includes any decisions and actions related to:

- Improving Pipeline Integrity Management Program effectiveness
- Resource and information needs
- Training needs
- Additional performance metrics
- Applicable corrective and preventive actions
- Internal audit assignments and objectives
- Integrity management program objectives

Program Audits

EnLink conducts internal quality audits to validate the Pipeline Integrity Management Program effectiveness and verify the program meets all requirements of applicable regulations.

An internal audit team conducts an annual audit and review of the Integrity Management Program**.** The internal audit team reports its findings at the next team review meeting. The internal audit team evaluates the IMP with the current PHMSA Gas Integrity Management Inspection Protocols. Protocol areas are reviewed during the internal audits at the discretion of the ***IMP Team*** as protocols change.

The ***IMP Team*** responsible for monitoring audit findings. Audit findings are monitored and tracked.

External (third party) audits may also be scheduled, as needed, to validate the results of internal audits or in the event that an internal audit is impracticable.

In addition to program audits, peer reviews are conducted to verify IMP implementation.

Contractor Requirements

Then contractors are used to perform tasks that are associated with processes related to the implementation of the integrity management program, they will be required to follow EnLink policies and procedures related to these activities. The qualifications of individuals that perform tasks subject to the Operator Qualification program will be documented in conformance with the Operator Qualification program.

13.3.2 Personnel Qualification and Training Requirements [192.915]

Integrity Management personnel are required to participate in the IMP overview training.

Persons Who Carry Out Assessments and Evaluate Assessment Results

Qualifications are included in the following procedures for individuals that are responsible for analysis of assessment results and/or decision making:

- In-Line Inspection
- ECDA
- SCCDA
- For pressure tests on covered segments, the following shall apply:
  - Reassessment intervals for pressure tests are established in the IMP 7 - Continual Evaluation and Assessment. Personnel in the ***IMP Team*** will review and analyze the results from a pressure test conducted in an HCA to validate the required integrity reassessment interval based on the minimum test pressure within an HCA segment;
  - In instances where contract support is employed, the ***IMP Team*** provides oversight. Qualification of personnel assigned to integrity assessments are documented by the ***IMP Specialist*** on **ENLINK GIMP Form 103**, *Qualification Verification*. Forms are maintained with the project documentation file.

Operator Qualification (OQ) Program

The Operator Qualification (OQ) Program assigned task list is designed to ensure that all Field Operations personnel working on DOT-regulated pipeline facilities are OQ-qualified in conformance with Part 192, Subpart N. The EnLink DOT department manages EnLink's OQ program.

The qualifications of all individuals who review pressure test data to establish reassessment intervals must be validated by the ***IMP Team Chairman***.

13.3.3 Invoking Non-Mandatory Statements in Standards [192.7(a)]

EnLink has chosen to include non-mandatory recommendations from standards in the IMP. In the event that EnLink elects to exclude a non-mandatory recommendation, EnLink will include one of the following: 1) an equivalent method and justification for accomplishing the same objective, or 2) justification that demonstrates the technical basis for exclusion.

EnLink will integrate compliance with the Federal and State regulations when the State Rule for natural gas transportation pipelines are promulgated. The most restrictive requirements will be observed where specific parameters must be met for protection of High Consequence Areas (HCA's), and maximized to the extent technologically and economically feasible.

14 COMMUNICATIONS PLAN [192.911(M)]

14.1 Introduction

This section describes the process for the communications of information regarding the integrity management program.

In conformance with 49 CFR 192.911(m), this section establishes a process by which EnLink communicates information regarding the integrity management program to EnLink employees, the general public, and regulatory agencies. This process has been developed in conformance with the principles and elements detailed in Section 10 of ASME B31.8S.

14.2 Roles and Responsibilities

Position	Responsibility
IMP Team	Communicates with Operations / Pipeline Control on IMP changes and results
IMP Team Chairman	Submit annual report to PHMSA, and appropriate state authorities Communicates with jurisdictional authorities
IMP Public Awareness Coordinator	Accountable for the development and implementation of public education activities

14.3 Process

14.3.1 External and Internal Communication Requirements [192.911(m)]

The communication plan is designed to keep appropriate Company personnel, jurisdictional authorities, and the public informed about current integrity management efforts and results.

External Communications

The intent of this program is to provide the public with general pipeline safety information.

The ***IMP Public Awareness Coordinator*** is accountable for the development and implementation of public education activities. Furthermore, the ***IMP Team Chairman*** is responsible for ensuring that any new public awareness regulatory requirements are evaluated and incorporated into this program, as necessary. Public education efforts include distribution of information to the following four target audiences:

- Local and Regional Emergency Responders
- Excavators
- Affected / General Public (including land owners and tenants along right-of-ways)
- Public Officials

For each target audience, EnLink prepares and conveys pertinent pipeline safety information. Additionally, signage along the pipeline right-of-way identifies EnLink as the pipeline operator and provides emergency contact information. Safety and public communication activities are communicated to each target audience.

The ***IMP Team Chairman*** is responsible for submitting required reports, and responds to any requests from PHMSA, and appropriate state authorities, for information regarding pipeline integrity management programs. All reports submitted to PHMSA, appropriate state authorities, or other regulatory agencies are retained by the ***IMP Team Chairman***. Submittals are prepared in conformance with IMP Section 15 – Submittal of Program Documents.

In the event that PHMSA and State or local pipeline safety authorities (when a covered segment is located in a State where PHMSA has an interstate agent agreement) raise safety concerns, EnLink's ***IMP Team Chairman*** communicates these concerns with the ***IMP Team***. Subsequent to the notifications, the ***IMP Specialist*** works with the ***IMP Team*** to develop a resolution to these concerns. Corrective measures or actions taken in response to regulatory authorities are communicated by the ***IMP Public Awareness Coordinator***.

Internal Communications

In order to ensure that pertinent IMP information is conveyed to management and supporting staff, internal communications occur on an ongoing basis. The general activities that are utilized by EnLink to communicate the intent, lessons learned, and progress associated with the IMP are as follows:

- Risk Assessments.
- Integrity Assessment with associated data integration efforts and resulting repairs.
- Annual IMP Report.
- IMP Training per IMP 13 - Quality Assurance.
- Annual IMP Management Review meeting per IMP 13 - Quality Assurance.
- Annual Public Awareness meetings with stakeholders.
- Modifications to the Pipeline Integrity Management Plan are distributed and communicated to field locations. MOC modifications to the Pipeline Integrity Management Plan are communicated as provided for in that procedure.

15 SUBMITTAL OF PROGRAM DOCUMENTS [192.911(N)]

15.1 Introduction

In conformance with 49 CFR 192.911(n), this section establishes a process by which EnLink submits integrity management program documents to:

- Office of Pipeline Safety and/or PHMSA
- A State or local pipeline safety authority

This section describes the process for submitting program documents to regulatory authorities.

15.2 Roles and Responsibilities

Position	Responsibility
IMP Team	Submit annual report to PHMSA, and appropriate state authorities
IMP Team Chairman	Submit requested documents to the appropriate regulatory authority
GIS Department	Submit Data for annual report to IMP Team

15.3 Process

15.3.1 Integrity Management Document Submittal [192.911(n)]

The ***IMP Team Chairman*** will notify regulatory authorities concerning covered (HCA) pipeline segments in the following situations:

- Within 30 days after adopting any significant change to the Pipeline Integrity Management Program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out program elements, along with reasons for the change before implementation.
- 180 days before using other technology (besides internal inspection tools, pressure tests, or direct assessments) for a baseline assessment or reassessment that can provide an equivalent understanding of the pipeline condition.
- 180 days before implementing a plan to use ICDA for covered segments operating with electrolytes present.
- If an evaluation and remediation schedule (IMP Section 6 – Remediation) cannot be met and safety cannot be provided through a temporary reduction in operating pressure or other action.
- When a pressure reduction performed within an HCA as a result of anomalous condition(s) as defined in (IMP Section 6 – Remediation) exceeds 365 days. Requirements include a notification that explains the reasons for the remediation delay and provides a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

In the event that PHMSA, a State Authority, or a Local Pipeline Safety Authority requests a copy of the IMP or related supporting documents, the ***IMP Team Chairman*** will submit requested documents to the appropriate regulatory authority.

Notification of substantive changes to a covered (HCA) segment program, or requested IMP related information will be made to the appropriate agency listed under the Change Notification section of IMP Section 12 – Management of Change:

The ***IMP Team Chairman*** is responsible for the submittal of IMP documents in electronic or other form.

16 REFERENCES

- EnLink Gas Operations and Maintenance Manual
- EnLink Operator Qualification Manual
- EnLink Public Awareness Manual
- EnLink In-line Inspection Procedure
- EnLink Direct Assessment Procedure
- Department of Transportation. Title 49 Code of Federal Regulations, Part 192

16.1 Federal Gas IMP Procedure References

- ENLINK GIMP Procedure 101, *Gas HCA Field Validation*
- ENLINK GIMP Procedure 102, *Could Affect Segment and Facility Validation*
- ENLINK GIMP Procedure 103, *Gas - Select Appropriate Assessment Tool and Vendor*
- ENLINK GIMP Procedure 104, *Gas Assessment Results Review and Remediation*
- ENLINK GIMP Procedure 105, *Gas Risk Analysis*
- ENLINK GIMP Procedure 106, *Review Gas Risk Algorithm*

16.2 Federal Gas IMP Form References

- ENLINK GIMP Form 101, *HCA Field Validation*
- ENLINK GIMP Form 102, *Assessment Planning*
- ENLINK GIMP Form 103, *Qualification Verification*
- ENLINK GIMP Form 104, *Risk Results Validation*
- ENLINK GIMP Form 106, *P&M Evaluation*
- ENLINK GIMP Form 107, ASV/RSV EvaluationENLINK GIMP Form 109, *Assessment Results Review*
- ENLINK GIMP Form 112, *Annual Gas IMP Meeting Report*

16.3 Appendix References

- Appendix A, Gas IMP Jurisdictional Pipelines and Facilities
- Appendix B, ENLINK Federal Gas IMP Roles
- Appendix C, Could Affect Segments and Facilities
- Appendix D, Risk Analysis
- Appendix E, Risk Algorithm
- Appendix F, Integrity Assessment Plan
- Appendix G, Performance Measures
- Appendix H, Revision Log
- Appendix I, Training Log
- Appendix J, ILI Vendor Reporting Requirements
- Appendix K, PHMSA Incorporated by Reference (IBR) Documents

17 ACRONYMS, ABBREVIATIONS, AND DEFINITIONS

Term	Definition
Anomaly	A possible deviation from sound pipe material or weld. Indication may be generated by non-destructive inspection, such as in-line inspection. Definition based on NACE Technical Committee Report, *In-Line Nondestructive Inspection of Pipelines*, already published. Also see, defect; imperfection.
Buffer zone	A specified spatial distance applied around a mapped object.
Certification	Documented testimony of qualification.
Condition	An anomaly confirmed to meet criteria for immediate, 60-day, 180-day, or other repairs.
Defect	An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API 570. Also see, anomaly; imperfection.
Emergency Flow Restriction Device (EFRD)	A check valve or remote-control valve as follows: Check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the opposite direction. Remote Control Valve (RCV) means any valve that is operated from a location remote from where the valve is installed. The RCV would most likely be operated by the ENLINK Pipeline Control Center.
HVL	These are Highly Volatile Liquids characterized by a vapor pressure of greater than 40 psia at 100°F. Ex: Y Grade, Ethane, Propane etc.
Non - HVL	These are Non-Highly Volatile Liquids characterized by a vapor pressure of less than 40 psia at 100°F. Ex. Gasoline, Crude etc.
High Consequence Area (HCA)	(1) An area defined as— (i) A Class 3 location under §192.5; or (ii) A Class 4 location under §192.5; or (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site. (2) The area within a potential impact circle containing— (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or (ii) An identified site.

Term	Definition
Idle Pipelines	"Idle Pipelines" are pipelines not currently in operation. The idle pipelines are considered "in service" or "out of service" pipelines. In service "idle" pipelines are isolated from the system but contain hazardous material. Out of service "idle" pipelines are isolated from the system and are filled with non-hazardous materials. All "idle" pipelines can be returned to service at any time, provided that the requirements of this Program are satisfied.
ILI Piggable	A pipeline is able to pass an in-line inspection tool without requiring the modification of the pipeline.
Integrity Management Program (IMP)	A written document that is directed towards maintaining the integrity of the subject pipelines and controlling the risks associated with their operation. Those risks mainly include societal and environmental risks. Per the requirements of 49 CFR Part 195, §195.452(b), the IMP comprises: • An identification of all pipelines that could affect an HCA; • A plan for baseline assessment of the line pipe; • A framework addressing each element of the IMP
IMP Team	***IMP Team*** include ENLINK personnel who have involvement in Federal Hazardous Liquid IMP processes and the management to whom they report.
Indication	A finding of a nondestructive testing or inspection technique. Definition based on NACE Technical Committee Report, *In-Line Nondestructive Inspection of Pipelines*".
Line Pipe	A tube, usually cylindrical, through which a hazardous liquid flows from one point to another.
Line Segment	A segment of line pipe that could affect a high consequence area.
Line Section	A continuous run of line pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

Term	Definition
MCA	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.
Maximum Operating Pressure	The maximum pressure at which a pipeline or segment of a pipeline may be normally operated.
Operator	A person or entity that operates pipeline facilities.
Pipeline	All parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation including, but not limited to, line pipe, valves, and other appurtenances connected to the line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.
Qualification	Demonstrated skill and knowledge, along with documented education, training and experience required for personnel to properly perform the duties of a specific task.
Risk	A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.
Risk Assessment	A systematic analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined.

Term	Definition
Safe Operating Pressure	The calculated pressure using remaining strength formulas, where the pipeline will withstand a pressure equal to 1.25 times the maximum operating pressure.
Subject Matter Expert	A person who by a combination of education, training, and/or experience has knowledge in a particular area(s).
Threat	Factors that can negatively impact pipeline integrity, such as external corrosion, internal corrosion, stress corrosion cracking, manufacturing defects, third party damage, incorrect operations, equipment failures, outside force damage, and construction.
Vendor Report	Documentation provided by an integrity assessment vendor that provides with interpretation of data from an integrity assessment.

Term	Definition
IAP	Integrity Assessment Plan
CDA	Confirmatory Direct Assessment
ECDA	External Corrosion Direct Assessment
ERW	Electric Weld Resistance Weld
HCA	High Consequence Area
GIS	Geographic Information System
GPS	Global Positioning System
ICDA	Internal Corrosion Direct Assessment
ILI	In-Line Inspection
IMP	Integrity Management Program
LOF	Likelihood of Failure
MAOP	Maximum Allowable Operating Pressure
MOC	Management of Change *(eMOC = EnLink MOC)*
MOP	Maximum Operating Pressure
MFL	Magnetic Flux Leakage
NPMS	National Pipeline Mapping System
O&M	Operations and Maintenance
P&M	Preventive & Mitigative Measures
PF	Probability of Failure
PHMSA	Pipeline and Hazardous Material Safety Administration
PIC	Potential Impact Circle
PIR	Potential Impact Radius

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Term	**Definition**
RCA	Root Cause Analysis
RCV	Remote Control Valve
RIPL	Risk Intelligence Platform
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SME	Subject Matter Expert
SMYS	Specified Material Yield Strength

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APPENDIX A. GAS IMP JURISDICTIONAL PIPELINES AND FACILITIES

See Pipeline Integrity Group for Gas IAP spreadsheet, which lists all jurisdictional natural gas pipeline facilities.

APPENDIX B. ENLINK FEDERAL GAS IMP ROLES

Name	Job Title	IMP Role
Prasanna Swamy	Director of Asset Integrity Management	***IMP Team Chairman***
Hagan Henley	Lead Pipeline Integrity Specialist	***IMP Team***
Brandon Martin	Pipeline Integrity Specialist	***IMP Team***
Dennis Bayham	Sr. Pipeline Integrity Specialist	***IMP Team***
Justin Ojemi	Sr. DOT Specialist	***IMP Team***
Cordell Theriot	Sr. DOT Specialist	***IMP Team***
Archie Buchman	Sr. Integrity Risk Engineer	***IMP Team***
Alex Bridges	Pipeline Integrity Engineer	***IMP Team***
Kyle McClellan	Director of Operations - NTX	***IMP Team***
Tad Stallings	Director of Operations – Permian/Delaware Basin	***IMP Team***
Rob Haley	Principal Engineer	***IMP Team***

APPENDIX C. COULD AFFECT SEGMENTS AND FACILITIES

See Pipeline Integrity Group for Gas IAP spreadsheet, which lists all jurisdictional natural gas pipeline facilities.

APPENDIX D. RISK ANALYSIS

See Pipeline Integrity Group for Gas IAP spreadsheet, which lists all jurisdictional natural gas pipeline facilities.

APPENDIX E. RISK ALGORITHM

Refer to Pipeline Integrity Group for copy of risk algorithm spreadsheet.

APPENDIX F. INTEGRITY ASSESSMENT PLAN

See Pipeline Integrity Group for Gas IAP spreadsheet, which lists all jurisdictional natural gas pipeline facilities.

APPENDIX G. PERFORMANCE MEASURES

See Pipeline Integrity Group for Gas Form 112.

APPENDIX H. REVISION LOG

Rev	Date	Comments/Affected Pages
0		Initial version.
	2/8/2005	Issue Revised IMP (revised from original RRC IMP to Federal IMP)
1.0	1/7/2019	Completed draft of V1.0, plan is now ready for Committee Review. See IMP Team member for copy of detailed revisions.
1.0	1/18/2019	Final approval given by Committee. Final revision posted to EnSite.
1.1	5/10/2019	Final approval given by Committee. Final revision posted to EnSite.
1.2	10/25/2019	Minor revisions. Final approval given by Committee.
1.2	10/28/2019	Final revision posted to EnSite
3.0	12/9/2020	Completed draft of V3.0, plan is now ready for Committee Review. See IMP Team member for copy of detailed revisions.
3.0	12/21/2020	Final annual review completed after Committee review.
4.0	6/17/2021	Final annual review completed after Committee review. For list of detailed changes see DOT Team.
4.1	10/28/2021	Completed final review with Committee. For list of detailed changes see DOT Team.

APPENDIX I. TRAINING LOG

See Pipeline Integrity Group for EnLink Training Log spreadsheet.

APPENDIX J. ILI VENDOR REPORTING REQUIREMENTS

Report Name	Comments
Field Report	Includes site survey, data checks, preliminary survey criteria (distances, min/max velocities, tool condition, AGM coverage, pipeline debris, etc.), magnetization levels, sensor loss & sensor coverage, XYZ data checks (if applicable). Etc.
Preliminary Report	Includes Data recorded and quality, Line condition statements with suspected ML signals. Detailed anomaly information including (Metal Loss >70%, Metal Loss with a PBurst <MAOP*1.1, Dents >6%, and any Dent >2% with Metal Loss >10%.)
Draft Final Reports	Draft reports will be compromised of adjustments made by the ILI vendor analyst. Adjustments can be made after additional data is discovered, field validations are made, and repair data is gathered, etc.
Final Report	Includes Level 3 Analyst approvals, ILI Run summaries with inspection findings, anomaly distribution & Depth charts, summary of anomaly clock orientations, etc. Additionally, the final report will include the final client listing.

NOTE: Before ILI Vendors send ANY report to EnLink, a phone call must be made to the IMP Specialist and IMP Engineer.

Below is a listing of conditions that ILI vendors will be required to notify the IMP Specialist and IMP Engineer prior to issuing hard copy reports (including email, share files, etc.):

- Metal Loss >70%
- Metal Loss with a PBurst < MAOP*1.1
- Dents >6%
- Dent >2% with Metal Loss >10%

APPENDIX K. PHMSA INCORPORATED BY REFERENCE (IBR) DOCUMENTS

Any documents referenced in this manual and procedures are the current Incorporated by Reference versions approved by PHMSA, listed below:

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. All approved material is available for inspection at Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202-366-4046 *https://www.phmsa.dot.gov/pipeline/regs*, and is available from the sources listed in the remaining paragraphs of this section. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fedreg.legal@nara.gov* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html*.

(b) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202-682-8000, website: *https://www.api.org/*.

(1) API Recommended Practice 5L1, “Recommended Practice for Railroad Transportation of Line Pipe,” 7th edition, September 2009, (API RP 5L1), IBR approved for § 192.65(a).

(2) API Recommended Practice 5LT, “Recommended Practice for Truck Transportation of Line Pipe,” First edition, March 2012, (API RP 5LT), IBR approved for § 192.65(c).

(3) API Recommended Practice 5LW, “Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,” 3rd edition, September 2009, (API RP 5LW), IBR approved for § 192.65(b).

(4) API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (API RP 80), IBR approved for § 192.8(a).

(5) API Recommended Practice 1162, “Public Awareness Programs for Pipeline Operators,” 1st edition, December 2003, (API RP 1162), IBR approved for § 192.616(a), (b), and (c).

(6) API Recommended Practice 1165, “Recommended Practice for Pipeline SCADA Displays,” First edition, January 2007, (API RP 1165), IBR approved for § 192.631(c).

(7) 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.

(8) ANSI/API Specification 6D, “Specification for Pipeline Valves,”23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for § 192.145(a).

(9) 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(b) and (c); 192.241(c); and Item II, Appendix B.

(10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for § 192.12.

(11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for § 192.12.

(12) API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), *http://www.asme.org/*.

(1) ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1), IBR approved for § 192.147(c).

(2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).

(3) ASME B16.40-2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI, (ASME B16.40-2008), IBR approved for Item I, Appendix B to Part 192.

(4) 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).

(5) ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§ 192.112(b) and 192.619(a).

(6) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ANSI B31.8S-2004), 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).

(7) [Reserved]

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§ 192.153(a), (b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§ 192.153(b), (d); and 192.165(b).

(10) ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§ 192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: *https://www.asnt.org/*.

(1) 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.

(2) [Reserved]

(e) ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, website: *http://astm.org*.

(1) ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M), IBR approved for § 192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M), IBR approved for § 192.177(b).

(5) ASTM A381-96 (reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M), IBR approved for § 192.112(c).

(7) ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M), IBR approved for § 192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/672M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M-09, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009, (ASTM A691/A691M), IBR approved for § 192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638-03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638), IBR approved for § 192.283(a) and (b).

(11) ASTM D2513-18a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved August 1, 2018, (ASTM D2513), IBR approved for Item I, Appendix B to Part 192.

(12) ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§ 192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(13) ASTM D2564-12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems," Aug. 1, 2012, (ASTM D2564-12), IBR approved for § 192.281(b)(2).

(14) ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055-98 (2006)), IBR approved for § 192.283(a), Item I, Appendix B to Part 192.

(15) ASTM F1924-12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1924-12), IBR approved for Item I, Appendix B to Part 192.

(16) ASTM F1948-12, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948-12), IBR approved for Item I, Appendix B to Part 192.

(17) ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973-13), IBR approved for § 192.204(b); and Item I, Appendix B to Part 192.

(18) ASTM F2145-13, "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145-13), IBR approved for Item I, Appendix B to Part 192.

(19) ASTM F 2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," April 1, 2009, (ASTM F 2600-09), IBR approved for Item I, Appendix B to Part 192.

(20) ASTM F2620-19, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," approved February 1, 2019, (ASTM F2620), IBR approved for §§ 192.281(c) and 192.285(b).

(21) ASTM F2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution," Oct. 15, 2012, (ASTM F2767-12), IBR approved for Item I, Appendix B to Part 192.

(22) ASTM F2785-12, “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings,” Aug. 1, 2012, (ASTM F2785-12), IBR approved for Item I, Appendix B to Part 192.

(23) ASTM F2817-10, “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair,” Feb. 1, 2010, (ASTM F2817-10), IBR approved for Item I, Appendix B to Part 192.

(24) ASTM F2945-12a “Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings,” Nov. 27, 2012, (ASTM F2945-12a), IBR approved for Item I, Appendix B to Part 192.

(f) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: *www.gastechnology.org*.

(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology,” (GRI 02/0057), IBR approved for § 192.927(c).

(2) [Reserved]

(g) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: *http://www.mss-hq.org/*.

(1) MSS SP-44-2010, Standard Practice, “Steel Pipeline Flanges,” 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for § 192.147(a).

(2) [Reserved]

(h) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: *http://www.nace.org/Publications/*.

(1) ANSI/NACE SP0502-2010, Standard Practice, “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).

(2) 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.

(i) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: *http://www.nfpa.org/*.

(1) NFPA-30 (2012), “Flammable and Combustible Liquids Code,” 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for § 192.735(b).

(2) NFPA-58 (2004), “Liquefied Petroleum Gas Code (LP-Gas Code),” (NFPA-58), IBR approved for § 192.11(a), (b), and (c).

(3) NFPA-59 (2004), “Utility LP-Gas Plant Code,” (NFPA-59), IBR approved for § 192.11(a), (b); and (c).

(4) NFPA-70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA-70), IBR approved for §§ 192.163(e); and 192.189(c).

(j) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: *http://www.ttoolboxes.com/*. (Contract number PR-3-805.)

(1) 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).

(2) [Reserved]

(k) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, *http://www.plasticpipe.org/*.

(1) PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "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.

(2) PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, "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.

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1000 Rio Brazos Rd., Aztec, NM 87410
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District IV
1220 S. St Francis Dr., Santa Fe, NM 87505
Phone:(505) 476-3470 Fax:(505) 476-3462

State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

QUESTIONS

Action 127106

QUESTIONS

Operator:	
Delaware G&P LLC 1722 Routh Street Dallas, TX 75201	OGRID: 373760
	Action Number: 127106
	Action Type: [NGGS] NGGS Operations Plan (NGGS-OP)

QUESTIONS

Verification	
Does the operator own the selected facility	Yes
Is the selected facility a natural gas gathering system	Yes

District I
1625 N. French Dr., Hobbs, NM 88240
Phone:(575) 393-6161 Fax:(575) 393-0720
District II
811 S. First St., Artesia, NM 88210
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District III
1000 Rio Brazos Rd., Aztec, NM 87410
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State of New Mexico
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Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

ACKNOWLEDGMENTS

Action 127106

ACKNOWLEDGMENTS

Operator:	
Delaware G&P LLC 1722 Routh Street Dallas, TX 75201	OGRID: 373760
	Action Number: 127106
	Action Type: [NGGS] NGGS Operations Plan (NGGS-OP)

ACKNOWLEDGMENTS

☑	I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Gathering System Operations Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.