1700 MacCorkle Avenue SE
Charleston, WV 25314
Direct: 304.357.2548
Fax: 304.357.3804
mikehoffman@nisource.com

Columbia Pipeline Group
Columbia Gas Transmission

Perry Michael Hoffman
Manager – System Integrity

May 26, 2015

Mr. Byron E. Coy, PE
Director, Eastern Region
United States Department of Transportation
Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety
Eastern Region – New Jersey District Office
820 Bear Tavern Road, Suite 103
West Trenton, NJ 08628

RE: Response to Notice of Probable Violation and Compliance Order CPF 1-2015-1008

Dear Mr. Coy:

This letter is provided on behalf of Millennium Pipeline Company, L.L.C. ("Millennium") and Columbia Gas Transmission LLC (Columbia Gas) in response to Notice of Probable Violation, CPF 1-2015-1008 ("NOPV"), dated April 27, 2015. The NOPV was issued following inspections conducted by the New York State Department of Public Service (NYSDPS) between June 24 and August 8, 2014 of the Millennium Pipeline facilities. The NOPV alleges violations of the general provisions of the natural gas pipeline safety regulations and proposes a compliance order.

This communication addresses the NOPV and provisions of the Compliance Order. The language from the NOPV is provided in bold below, followed by our response.

1. **§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.**
   (a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
      (2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

CPG failed to establish a cathodic protection system designed to protect a new buried pipeline within one year after the pipeline had been placed into operation.

1. **During the first half of 2013, approximately 1,500 feet of large diameter (combination of 36-inch, 30-inch, and 24-inch) piping was installed for the Millennium Pipeline Company (Milennium) Minisink compressor station in Westtown, Orange County, NY.**

2. **The compressor station was placed into operation by CGT on June 1, 2013.**

3. **During the inspection on 6.24/2014, NYSDPS requested that CGT take cathodic protection (CP) pipe-to-soil readings at the Minisink compressor station piping. CGT took the CP readings after the NYSDPS inspection, with no NYSDPS inspector present. Of the three readings taken at the compressor station, NYDDPS noted one less than adequate pipe-to-soil reading of -0.750 volts. On 6/25/2014, CGT found four additional pipe-to-soil potential readings below the -0.85 Volt cathodic protection criteria. CGT did not provide any evidence that cathodic protection was being deemed adequate by any other criteria.**

4. **NYSDPS asked CGT how they provided cathodic protection to the new piping. CGT indicated that they bonded the new station piping to the existing cathodic protection system on the Millennium mainline, and installed bonds across the insulating joints on the inlet and outlet piping to the compressor station. The Operations Manager for CGT, stated that CGT intends to install a separate cathodic protection system at the station, but it has not yet been installed.**

Thus, CGT failed to establish a cathodic protection system designed to protect a new buried pipeline within one year after the pipeline had been placed into operation.

<u>Columbia Gas Response</u>
As noted above, Columbia Gas did provide a means of cathodic protection to protect the compressor station using the existing mainline cathodic protection system, as discussed above, within one year after the beginning of operation of the Minisink Compressor Station. However, since the time of the inspection, a new cathodic protection system has been installed that is separate from the mainline cathodic protection system and is in operation to protect the station piping. Because of equipment order lead times, the system is being energized by a temporary rectifier until a new rectifier can be obtained and installed. While this system has been acting to provide cathodic protection to the station, once the new rectifier has been obtained and installed, Columbia Gas will perform a final re-evaluation and test of the system to re-verify that adequate cathodic protection is being provided to the compressor station and suction and discharge piping in accordance with the compliance order.

2. **§192.605 Procedural manual for operations, maintenance, and emergencies.**
   (b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.
      (2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

CGT Procedure 70.01.01 "External Corrosion Control" is inadequate in that it does not address all of the requirements of §192.455(a)(2) which states in part that "…each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion…"

CGT's procedure (Section 3.2.1) refers only to pipe "<u>installed as a replacement section for a pipeline</u>" and does not refer to newly installed pipe.

In an e-mail from CGT to the NYSDPS dated August 8, 2014, CGT indicated that they were in the process of revising the language of their O&M Plan 70.01.01 "to ensure it is clear that all buried or

submerged metallic piping installed (or replaced) after July 31, 1970 must have a cathodic protection system designed to protect the pipeline installed (or replaced) which is placed in operation within 1 year after the completion of construction."

Columbia Gas Response

Since the time of the inspection, Columbia Gas has revised its Operations and Maintenance Plan 70.01.01 External Corrosion Control to clearly indicate that new piping will be cathodically protected within one year of construction. Specifically, Section 2.1 (B) of the plan was revised to state:

B. Each segment of buried or submerged metallic pipe, newly installed or installed as a replacement, must be cathodically protected to one of the criteria in Section 5 within one (1) year of construction.

A copy of Operation and Maintenance Plan 70.01.01 External Corrosion Control is provided in Attachment A.

If you have any questions or would like additional information, please do not hesitate to contact me.

Sincerely,

Perry M. Hoffman

Perry M. Hoffman
Manager – System Integrity
Columbia Pipeline Group

Attachment A

Columbia Pipeline Group
Operations and Maintenance Manual Plan
70.01.01 External Corrosion Control

External Corrosion Control

Scope

This Plan sets forth the minimal requirements to protect metallic pipeline facilities from external corrosion, including atmospheric corrosion and electrical isolation.

This Plan covers facilities under Federal Regulations 49 CFR Parts 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards and 195 Transportation of Hazardous Liquids by Pipeline.

This plan applies to all jurisdictional Company metallic pipelines.

Safety

The Company is committed to the safety of the public and its employees. Employees are to perform their work in the safest manner with the utmost regard for the safety of themselves and the public. Review all Company safety Plans and Procedures, as well as the appropriate Job Hazard Assessments as necessary.

Operator Qualification

All persons performing covered tasks shall be qualified according to the Company Operator Qualification Plan.

PLAN

1. **Personnel Qualifications**

   Design, installation, operation and maintenance of cathodic protection systems must be carried out by or under the direction of a qualified Engineer, Specialist, other qualified company personnel or a qualified contractor. Columbia Pipeline Group (CPG) provides personnel performing corrosion control related duties, continuing education and training through internal processes, work related experience and industry accepted programs. The education/training includes safety training, work skills, and corrosion science to enable such personnel to perform required job functions in a safe, knowledgeable, competent and consistent manner. Post installation cathodic protection testing is completed to verify the adequacy of the design.

Individuals engaged in corrosion related activities shall be fully qualified to perform required duties. CPG has captured these duties as roles referred to as Subject Matter Experts (SMEs) within the company. These SMEs can be multiple persons as long as they qualify and remain competent in the role. A description of the various SME's roles and qualifications are outlined in the CPG Corrosion Control Personnel Qualifications, included in Attachment A.

2. External Corrosion Control

For gas, facilities regulated under 49 CFR Part 192:

2.1. Buried or Submerged Facilities Installed After July 31, 1971

A. A coating system, per Section 2.5 is required for all new buried or submerged facilities.

B. Each segment of buried or submerged metallic pipe, newly installed or installed as a replacement, must be cathodically protected to one of the criteria in Section 5 within one (1) year of construction.

2.2. Buried or Submerged Facilities Installed Before August 1, 1971

A. All buried or submerged facilities with an effective coating will be cathodically protected to one of the criteria in Section 5.

B. Bare or ineffectively coated facilities operating at or above a stress level of 40% SMYS, or over 600 psig, should be cathodically protected to one of the criteria in Section 5.

For bare or ineffectively coated pipelines not under cathodic protection, "Active Corrosion Zones" must be determined using the guidance of *70.002.051 - Guidelines for the Determination of Boundaries for Active Corrosion Zones*. Pipeline facilities in "Active Corrosion Zones" must be cathodically protected where testing indicates that there is active corrosion that could be detrimental to the public. For the definition of "Active Corrosion Zones", see Definitions.

Testing shall consist of an electrical survey, except in cases that this method of testing is determined to be impractical. If the survey area is determined to be in an "Active Corrosion Zone" that is not practical to electrically survey according to Item C below, instrumented leakage surveys shall be performed in accordance with *Plan 220.03.01 - Facility Patrol and Leakage Inspection*.

C. In the case of leakage areas, the installation of one or more sacrificial anodes, or another method to supply cathodic protection, shall be used at all repaired leaks.

1. Attempt to perform the electrical survey prior to declaring said survey impractical. However, mechanically coupled pipe, or steel pipelines containing a significant number of plastic replacement sections, shall be considered impractical to survey. Other areas where it may be impractical to perform electrical surveys may include, but are not limited to:

   - Partial or wall to wall paving
   - Two or more adjacent pipelines in a common trench or right-of-way
   - Stray current areas
   - Excess cover
   - Plastic pipe

2. Where electrical surveys have been determined to be impractical using the guidelines in Item 1 above, a study of corrosion and leak history records, the use of leak detection surveys or other means shall be used to determine areas of active corrosion within “Active Corrosion Zones”.

3. As a General Rule or Guideline:
   a. Pipelines less than 16” in diameter with a Maximum Allowable Operating Pressure (MAOP) of 50 psig or less can use the 100-foot “Active Corrosion Zone” boundary.

   b. Pipelines 12” in diameter and less with a MAOP of 150 psig or less can use the 100-foot “Active Corrosion Zone” boundary.

   c. Pipeline Engineering can assist with determining the boundaries of other potential “Active Corrosion Zones’ that do not fit the general rule above.

2.3. For hazardous liquids, facilities regulated under 49 CFR Part 195:

Each buried or submerged pipeline that is constructed, relocated, replaced, or altered after the dates listed below must have cathodic protection:

An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid.

An interstate offshore gathering line, other than a low-stress pipeline, on: which construction was begun after July 31, 1977, that transports hazardous liquid.

An interstate offshore gathering line, other than a low-stress pipeline, on which construction was begun after July 31, 1977, that transports hazardous liquid.

An intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid.

A pipeline on which construction was begun after July 11, 1991, that transports carbon dioxide

A low-stress pipeline on which construction was begun after August 10, 1994.

The cathodic protection must be in operation no later than 1 year after the pipeline construction, relocation, replacement or other alteration is completed.

2.3.1. Except bottoms of aboveground breakout tanks, each buried or submerged pipeline meeting the requirements of Section 2.3 must have an external coating for external corrosion control

2.4. Examination of a Buried Facility When Exposed

For gas, facilities regulated under 49 CFR Part 192:

A. When any buried facility is exposed, examine the exposed portion for evidence of external corrosion. Document the examination using *Procedure 70.001.002 - Pipe Inspection and Reporting*.

If significant corrosion is found (significant meaning greater than 20% pit depth), the remaining wall thickness will be evaluated using approved methods (see *Plan 220.02.01 - Pipeline Repair*) to verify that the facility is commensurate with the present MAOP.

B. If the remaining wall thickness is not commensurate with the MAOP, reduce the MAOP to an appropriate pressure until repaired or replaced. If repairs are needed, further investigation is required to determine the extent of the corrosion. Any pressure reduction should be coordinated through the Monitoring Center and Gas Control.

C. Follow *Plan 220.02.01 - Pipeline Repair*, for evaluation of damaged areas, required pressure reductions, acceptable repair techniques, and remedial action timeframes.

NOTE
Lowering the MAOP may trigger Safety Related Condition (SRC) reporting as outlined in *Plan 220.05.02 - Safety Related Conditions – Reporting and Investigating Requirement*. Contact a representative of Engineering Services (ES) – System Integrity for any SRC.

D. If external corrosion requiring remedial action is found, an investigation will be performed circumferentially and longitudinally to determine whether additional corrosion requiring remedial action exists near the exposed portion.

E. If the results of the evaluation of any damaged area show that the remaining wall thickness is commensurate with the MAOP, the line may remain in-service.

F. If the coating is deteriorated, the deteriorated coating will be removed and the area recoated with an approved coating.

For hazardous liquids, facilities regulated under 49 CFR Part 195:

A. When any buried facility is exposed or discovered to be exposed, examine the exposed portion for evidence of external corrosion if the pipeline is bare or the coating is deteriorated. Document the examination using *Procedure 70.001.002 - Pipe Inspection Procedure*.

B. If significant corrosion is found (significant meaning greater than 12.5% pit depth), the remaining wall thickness will be evaluated using approved methods to verify that the facility is commensurate with the present MOP.

C. If the remaining wall thickness is not commensurate with the MOP, reduce the MOP to an appropriate pressure until repaired or replaced. If repairs are needed, further investigation is required to determine the extent of the corrosion. Any pressure reduction should be coordinated through the Monitoring Center. Follow *Plan 400.017.504 - Pipeline Repair*, for evaluation of damaged areas, required pressure reductions, acceptable repair techniques, and remedial action timeframes.

NOTE
Lowering the MOP may trigger Safety Related Condition (SRC) reporting as outlined in *Plan 400.017.103 Safety Related Condition Reporting and Investigating Requirements*. Contact a representative of Engineering Services (ES) – System Integrity for any SRC.

D. If external corrosion requiring remedial action is found, an investigation will be performed circumferentially and longitudinally to determine whether additional corrosion requiring remedial action exists near the exposed portion.

E. If the results of the evaluation of any damaged area show that the remaining wall thickness is commensurate with the MAOP, the line may remain in service.

F. If the coating is deteriorated, the deteriorated coating will be removed and the area recoated with an approved coating.

2.5. Protective Coatings

Engineering Services must approve the protective coatings used. The protective coating selection and application must meet the following conditions.

A. Be designed to mitigate corrosion of the buried or submerged pipe
B. Be applied to a properly prepared surface.
C. All coatings must effectively resist under film migration of moisture.
D. All coatings must resist cracking.
E. All coatings must have enough strength to resist damage due to handling and soil stresses.
F. All coatings must be compatible with applied cathodic protection.
G. Inspect all coatings just before lowering into the ditch and backfilling; repair any damage to the coating.
H. Protect the coatings from damage due to ditch and/or backfill conditions, or due to supporting blocks.
I. All electrically insulating type of coatings will have low moisture absorption and high electrical resistance.

J. Take precautions to protect the coatings if the pipe is installed by using boring, driving, or other similar methods.

2.6. Test Stations

A. Test stations, or test points, are the principal means to evaluate cathodic protection on the pipeline system. All facilities under cathodic protection will have a sufficient number of permanent test stations, or test points, to evaluate the adequacy of the cathodic protection system of the facility. Test stations are also useful for line locating purposes, and should display the information required in *Plan 220.02.04 - Pipeline Markers and Facility Identification*. Generally, test stations should be installed at approximately one (1) mile intervals, and/or where reasonable.

B. Install test stations on the pipeline at all cased crossings unless there is another method of contacting the pipe, such as a service tap or valve available nearby.

EXCEPTION: If the casing is on a facility that is not required to be under cathodic protection, according to Section 2.2., a test station may not be required as long as it is treated as a shorted casing for monitoring purposes.

C. Maintain test stations in functional order. Repair damaged test stations as soon as practical, prior to the next scheduled monitoring cycle.

D. There may be occasions where a test station is abandoned, removed, relocated, or deemed unnecessary for annual monitoring purposes. Approval for this action is required from Engineering Services- Corrosion, and documented using the Company work management system.

2.7. Test Leads

A. Connect each test lead wire to the facility by a method that results in a secure and electrically conductive connection and to minimize stress concentration on the facility.

B. Test leads should be installed with looping or enough slack to minimize stress and remain mechanically secure and electrically conductive after backfilling operations.

C. For test leads installed in conduit, the wire must be suitably insulated to prevent contact between the conduit and/or other wires.

D. When installing test leads, the bared test lead wire and the facility will be recoated with an electrically insulating coating compatible with the facility coating and wire insulation.

E. Where test leads have been damaged the leads shall be repaired or replaced before end of the next monitoring cycle, unless determined to be unnecessary and approved for retirement, as outlined in Section 2.6 D – Test Stations.

2.8. Stray Currents

A. In locations where there may be potentially detrimental effects of stray currents, the effects of these currents will be analyzed and mitigated. Monitoring of these locations is covered in Section 2.9 - Monitoring.

B. Every cathodic protection system will be designed and installed to minimize the effects on or from existing adjacent underground metallic structures.

C. Bonds that have become inoperative, for any reason, or are not adequate to mitigate interference, must receive prompt corrective attention.

D. When a pipeline is located in close proximity to a high-voltage electrical transmission tower; footing, ground cables or counterpoise (see Section 6), or in other areas where fault currents, electrical surges or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents, surges, or lightning. Surge and protection measures must also be taken at electrical isolation devices in areas where fault currents, electrical surges or unusual risk of lightning may be anticipated.

E. In areas where a pipeline shares the right of way with a high voltage electrical line, AC pipe-to-soil potentials should be monitored as follows:

1. In areas where the pipeline parallels high voltage AC power lines:

a. Annually read AC pipe-to-soil potentials at designated cathodic protection (CP) test points along the paralleling section of pipeline.

b. AC Pipe-to-soil potentials should be checked before touching, connecting to, or working on any test points or appurtenances for any reasons including, but not limited to, cathodic protection testing, pipeline locating, coating procedures, pipeline inspection, construction, or any operations and maintenance procedures.

2. In areas adjacent to a section of pipeline that parallels high voltage AC power lines:

   a. Take AC pipe-to-soil potentials annually at existing CP test points that have been demonstrated through CIS or other testing to exceed 10 VAC with or without mitigation and at locations determined by Engineering Services personnel.

   b. AC pipe-to-soil potentials should be checked before touching, connecting to, or working on any test points or appurtenances that have been demonstrated through CIS or other testing to exceed 10 VAC with or without mitigation for any reasons including, but not limited to, cathodic protection testing, pipeline locating, coating procedures, pipeline inspection, construction, and any operations and maintenance procedures.

3. In areas where high voltage power lines cross the pipeline:

   a. Annually take AC pipe-to-soil measurements at existing CP test points located within 300 feet of the crossing.

   b. AC pipe-to-soil potentials should be checked before touching, connecting to, or working on any test points or appurtenances located within 300 feet of the crossing for any reasons including, but not limited to, cathodic protection readings, pipeline locating, coating procedures, pipeline inspection, construction, and any operations and maintenance procedures.

4. Engineering Services- Corrosion may require additional AC pipe-to-soil measurements as determined by separation distance, type, load capacity, and number of high voltage AC power lines located near CPG pipelines at the following locations: M&R stations, compressor stations, foreign pipeline crossings that may have high levels of induced AC voltage, designated anode cells, anode

ground beds, coupon test stations, insulators, and any pipeline locations where hazardous AC voltage or current may exist.

5. Perform AC testing only at existing pipeline test stations and appurtenances. Do not add new test stations for the sole purpose of testing induced AC potentials without the approval of Engineering Services - Corrosion personnel.

F. Where the AC pipe-to-soil potential of the pipeline is tested and shown to exceed 15 VAC, contact Engineering Services to initiate testing and/or mitigation. Adequate safety precautions shall be taken to protect employees and the public in such areas until adequate AC mitigation measures are in place or until Engineering Services - Corrosion determines that the area otherwise meets induced AC safety criteria.

G. Conduct additional testing of AC mitigation systems in accordance with *Procedure* *70.001.048 - Operating Pipelines Sharing the Right of Way with High Voltage AC Power Lines.*

2.9. Monitoring

Keep all facilities associated with cathodic protection in good working condition.

A. Annual Potential Survey – Test each pipeline that is under cathodic protection at least once each calendar year, but not exceeding 15 months, to determine whether the cathodic protection meets the requirements of Section 5. Consider the detrimental effects of excessive pipeline polarization during cathodic protection monitoring to prevent damage to the pipe or protective coating.

B. Rectifiers and Power Sources - Cathodic protection rectifiers, or other impressed current power sources, must be inspected six times each calendar year, but with intervals not exceeding 2½ months (75 days), to ensure that they are operating properly.

C. Stray Current/Interference Mitigation - Each reverse current switch, each diode, and interference bond whose failure would jeopardize the structure protection ("critical"), must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months (75 days). Check other interference ("non-critical") bonds at least once each calendar year, but not exceeding 15 months.

D. Remedial Action - Prompt remedial action to correct any deficiencies indicated by monitoring must be taken. The remedial action shall be performed or be in progress within one year of discovery, not to exceed 15 months, or in the case of rectifiers and critical stray current interference/mitigation devices, before the next scheduled inspection not to exceed 2 ½ months (75 days).

E. Situations may arise where none of the cathodic protection criteria is satisfied, either singularly or in combination. If such situations occur, then the following steps may be used.

Step	Action
1	Conduct an on-site investigation to determine the severity of the anomaly and length of pipeline affected.
2	Increase the output of existing rectifiers, if feasible. If increasing rectifier output is not feasible or does not result in satisfactory protection levels, then develop a plan such as installation of additional cathodic protection system or re-coating the pipe.
3	Verify that existing electrical isolation locations are effective or new electrical isolation locations are needed to control CP current.
	Prepare a work order and purchase any materials necessary, such as anodes, wire, rectifiers, splicing kits, electrical isolation kits, etc.
5	Complete field installation of any materials and/or equipment necessary.
6	Conduct and record the results of the follow-up survey to verify that cathodic protection levels meet appropriate cathodic protection criteria.

Document remedial actions in the Company's work management system.

F. Unprotected Pipelines – Reevaluate unprotected pipelines in "Active Corrosion Zones" every three (3) calendar years, at intervals not to exceed 39 months if corrosive conditions are found, cathodic protection will be provided in accordance with Section 5 - Criteria for Cathodic Protection. There are no unprotected hazardous liquids pipelines regulated under 49 CFR Part 195 operated by the Company.

G. Casings – Document casing potentials during the annual potential survey described in Section 2.9.A. Company operated liquid pipelines do not have any casings.

- Generally, if the potential difference between a casing and the pipeline is 100mV or greater, the casing should be considered not shorted.

- If the potential difference between the casing and the pipeline is less than 100 mV, the casing will be considered shorted until further testing is completed to determine its status (clear or shorted) using one of the methods described in Procedure 70.002.005, *Test for Shorted Condition – Casing*, or Procedure 220.008.001, *External Corrosion Direct Assessment (ECDA)*, Appendix A, *ECDA Process for Cased Gas Transmission Pipelines*.

- If the status of a casing is unknown, treat as a shorted casing. See *Plan 220.03.01 - Facility Patrol and Leakage Inspection*, for shorted casing leakage inspection requirements.

- Casings that have been filled with an approved high dielectric casing filler material will not be considered as shorted for monitoring purposes, and will no longer be required to have leakage inspections as per the requirement of *220.03.01 - Facility Patrol and Leakage Inspection*.

- No further action is required if the casing is not shorted.

- If the casing is on a pipeline facility that is not required to be under cathodic protection according to Section 2.2, it shall be considered shorted for monitoring purposes unless tests have been conducted showing otherwise.

- Shorted casings may be evaluated on their own merits based on safety and facility integrity, and suitable follow-up actions taken, if required. At a minimum, monitor all shorted casings with leakage detection equipment according to *Plan 220.03.01 - Facility Patrol and Leakage Inspection*. Follow-up actions may include:

    - Attempting to clear the short if, it is practical and/or safe to do so. If this requires pipe movement or casing removal, no work shall take place without approval from an Engineering Services - Corrosion engineer.

- If safe and practical to do so, filling the casing with an approved dielectric material.

- Document any remedial action taken in the Company's work management system, if applicable. If the short is cleared or the casing is filled, monitoring with leakage detection equipment other than that required for normal patrolling will no longer be required. If the attempt to clear the short is unsuccessful and the casing cannot be filled, monitoring with a leakage detection instrument is required.

For hazardous liquids, facilities regulated under 49 CFR Part 195:

A. Close Interval Survey

- Newly constructed or newly converted to liquids service pipelines will have a close interval survey performed within 2 years of the in- service date.

- Subsequent close interval surveys will be performed as directed by Engineering Services based circumstances including, but not limited to, the magnitude of cathodic protection system changes, below-criteria pipe-to-soil measurements, coating deterioration, or other evidence of inadequate cathodic protection,

B. Breakout Tanks

- The Company does not have any Breakout Tanks on their liquid pipeline facilities. These facilities were designed to manage surges through relief devices designed to send surges safely toward the Hickory Bend Plant

- If breakout tanks are installed, this Plan will be updated accordingly.

- Breakout tanks will be designed in accordance with 49 CFR Part 195.132, API Specification 12F, and API Standards 620, 650 and 2510.

2.10. New Casings

Do not install new casings in a shorted condition. If a newly installed casing is shorted, the short will be cleared before the line is placed in service.

All new casings must be filled with an approved high dielectric casing filler material per Procedure *70.001.049 - Filling of Pipeline Casings*.

Casings that are fully exposed for longwall mining or other projects should be removed from the pipeline upon Engineering review and approval. If removal is not permitted by Engineering analysis, government regulations or other concerns, the casing should be filled per *70.001.049 - Filling of Pipeline Casings*. Do not rebury casing in a shorted condition.

2.11. Electrical Isolation

A. Bare and Coated Facilities

1 Electrical isolation is required between effectively coated, cathodically protected facilities and bare, unprotected facilities except in situations in Item 2 below.

2 Electrical isolation is not required when coated and bare facilities are cathodically protected as a single unit.

3 Facilities should be electrically isolated from other metallic structures unless the facility and the electrically connected metallic structures are cathodically protected together.

4 Electrical isolation may be required to control the application of cathodic protection current.

5 Do not install an electrical isolation device in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

B. Other Facilities Requiring Electrical Isolation

Facilities that require electrical isolation include, but are not limited to:

- Metallic valve boxes
- Foreign owned facilities
- Existing farm taps where an electrical short is detrimental to the cathodic protection levels on CPG's facility

- New installations of farm taps
- Compressor facilities (except where it is cathodically protected as a single system)
- M&R Stations
- Casings/Sleeves (See Section 2.9 F)
- New or reconditioned storage wells
- Existing storage wells where testing indicates an electrical short is detrimental to the cathodic protection levels on Columbia's pipeline.
- Offshore pipelines from offshore platforms

C. Inspection and Tests

The effectiveness of electrical insulating devices will be determined when the Annual Potential Survey in Section 2.9 A is completed. If the annual survey shows that the pipeline facility is adequately, cathodically protected, electrical isolation is considered adequate. Inspect farm taps every three years in conjunction with the atmospheric corrosion inspection. If the connection to the customer facility is found to be shorted, and is determined to be detrimental to the pipeline facility, corrective measures will be taken.

3. Atmospheric Corrosion

This section describes the inspection requirements for jurisdictional pressure piping and pressure containing equipment exposed to the atmosphere for gas facilities regulated under 49 CFR Part 192 and for hazardous liquids facilities regulated under 49 CFR Part 195. Coat or jacket all aboveground piping and pressure containing equipment, with approved materials, to prevent atmospheric corrosion. Inspect and maintain the coating in accordance with this plan and *Procedure 70.001.001 - Inspection – Atmospheric Corrosion*.

3.1. Monitoring

A. For gas facilities regulated under 49 CFR Part 192:
Inspect all jurisdictional gas pressure piping and pressure containing equipment exposed to the atmosphere for atmospheric corrosion at least once every three calendar years, at intervals not to exceed 39 months. Inspect offshore facilities once every calendar year, at intervals not to exceed 15 months.

Non-jurisdictional production and gathering gas pressure piping and pressure containing equipment exposed to the atmosphere, which are not otherwise inspected in accordance with Item A above, shall be inspected every four (4) years, not to exceed 51 months.

B. For hazardous liquids facilities regulated under 49 CFR Part 195.583, inspect each pipeline or portion of pipeline exposed to the atmosphere for atmospheric corrosion at least once every three calendar years, at intervals not to exceed 39 months.

C. During inspections, pay particular attention to piping at soil to air interfaces, piping, and vessel covered with thermal and sound attenuating (reducing) insulation, pipe resting on support piers or underneath tie down straps, through wall piping in buildings, and piping at splash zones. Also, give attention to locations such as clamps, rest plates, and sleeved openings.

D. For areas under insulation on piping and gas-bearing vessels, the inspection requires the removal of insulation in areas where atmospheric corrosion is likely found and where inspection plugs are located. It is suggested that inspection plugs be strategically located at areas including, but not limited to, where corrosion has been found in the last inspection and where atmospheric corrosion is likely found such as, interface areas, the lower portion of vertical piping and vessels, and other areas that are conducive to moisture. Use the companies Work Management System to document, in detail, the ports, and other pipe sections under insulation that are inspected.

E. Assign atmospheric corrosion a condition level based on visual inspection. For the purposes of this plan, use the following atmospheric condition level definitions:

- Level “1” – Corrosion with pitting or wall loss.
- Level “2” – Flash rust/surface oxidation with no pitting.

A Work Management System entry of “3” indicates no corrosion found during the inspection.

F. For facilities regulated under 49 CFR Part 192, the remaining wall thickness of piping found to have atmospheric corrosion will be evaluated according to Section 2.4 to verify that the calculated safe operating pressure of the piping is commensurate with the MAOP. If the calculated safe operating pressure is not commensurate with the MAOP, repair or replace piping, according to *Plan 220.02.01 - Pipeline Repair*; or reduce the MAOP to the calculated safe operating pressure.

G. For hazardous liquids facilities regulated under 49 CFR Part 195, the remaining wall thickness of piping found to have atmospheric corrosion will be evaluated according to Section 2.4 to verify that the calculated safe operating pressure of the piping is commensurate with the MOP. If the calculated safe operating pressure is not commensurate with the MOP, repair or replace piping, according to *Plan 400.017.504 - Pipeline Repair*; or reduce the MOP to the calculated safe operating pressure.

H. Atmospheric corrosion shall be remediated within the following timeless:

- Level "1" - Corrosion mitigation must be performed within 12 months of discovery;

- Level "2" - Corrosion mitigation or a re-inspection must be performed within 12 months of discovery. If atmospheric corrosion graded at Level 2 is re-inspected and the grade remains at a Level 2, perform mitigation within 13 months of re-inspection not to exceed 24 months from the initial inspection. If the atmospheric corrosion has progressed to a Level 1, perform mitigation within 6 months of the re-inspection. Only a single re-inspection is permitted for Level 2 corrosion.

NOTE: A Work Management System entry of "3" indicates no corrosion found during the inspection.

Corrosion Level	Corrosion Severity	Required Action	Remedial Action Deadline	Notes
1	Corrosion with pitting or wall loss	Remediate as per section 3.4 of this policy.	12 months	Digital photos should be taken of the atmospheric corrosion during inspection.
2	Flash rust/surface oxidation with no pitting	For initial inspection - Remediate as per section 3.4 of this policy	12 months	Digital photos should be taken of the atmospheric corrosion during inspection.

Corrosion Level	Corrosion Severity	Required Action	Remedial Action Deadline	Notes
2	Flash rust/surface oxidation with no pitting	For re-inspection that has remained at Level ‘2’ - Remediate as per section 3.4 of this policy	13 months, not to exceed 24 months from the initial inspection date	Digital photos should be taken of the atmospheric corrosion during inspection.
2	Flash rust/surface oxidation with no pitting	For re-inspection that has progressed from Level ‘2’ to Level ‘1’ corrosion - Remediate as per section 3.4 of this policy	6 months	Digital photos should be taken of the atmospheric corrosion during inspection.

4. Remedial Measures

4.1. General

For gas, facilities regulated under 49 CFR Part 192:

Piping that contains general corrosion and a remaining wall thickness less than that required for the MAOP must be repaired or replaced, or the operating pressure must be reduced to the calculated safe operating pressure in accordance with *Plan 220.02.01 - Pipeline Repair*.

Piping that contains localized corrosion pitting where leakage might result, must be repaired, or replaced in accordance with *Plan 220.02.01 - Pipeline Repair*.

If atmospheric corrosion is determined to constitute a safety related condition as defined in Plan 220.05.02 - *Safety Related Conditions – Reporting and Investigating Requirements* for determination of Safety Related Conditions, promptly notify an Integrity Engineer.

For hazardous liquids, facilities regulated under 49 CFR Part 195:

Piping that contains general corrosion and a remaining wall thickness less than that required for the MOP must be repaired or replaced, or the operating pressure must be reduced to the calculated safe operating pressure in accordance with *Plan 400.017.504 - Pipeline Repair*.

Piping that contains localized corrosion pitting where leakage might result, must be repaired, or replaced in accordance with *Plan 400.017.504 - Pipeline Repair*

If atmospheric corrosion is determined to constitute a safety related condition as defined in *Plan 400.017.103 - Safety Related Condition Reporting*, promptly notify an Integrity Engineer.

4.2. Atmospheric Corrosion – Remedial Measures

If atmospheric corrosion is found during an inspection, then remedial action must be taken as described in Section 2.9 G.

5. Criteria for Cathodic Protection

Acceptable criteria for cathodic protection are one of the following:

A. A negative (cathodic) voltage of at least 850 millivolts, with reference to a saturated copper-copper sulfate reference electrode. Determination of this voltage must be made with the current applied, and voltage (IR) drops other than those across the structure-electrolyte boundary must be considered. The reference electrode must contact the electrolyte directly above the structure.

B. A negative (cathodic) voltage of at least 950 millivolts, with reference to a saturated copper-copper sulfate reference electrode, in the presence of Acid Producing Bacteria (APB) or Sulfate-Reducing Bacteria (SRB). Determination of this voltage must be made with the current applied, and voltage (IR) drops other than those across the structure-electrolyte boundary must be considered. The reference electrode must contact the electrolyte directly above the structure.

- For purposes of this criterion, APB testing must demonstrate greater than 100 cells per ml (>100 cells/ml; 3 or more APB vials turned).
- For purposes of this criterion, SRB testing must demonstrate greater than 10 cells per ml (>10 cells/ml; 2 or more APB vials turned).

C. A negative (cathodic) voltage of at least 950 millivolts, with reference to a saturated copper-copper sulfate reference electrode, where soil temperatures directly surrounding the pipeline exceed 140°F (60°C). Determination of this voltage must be made with the current applied, and voltage (IR) drops other than those across the structure-electrolyte boundary must be considered. The reference electrode must contact the electrolyte directly above the structure.

D. A minimum negative (cathodic) polarization shift of 100 millivolts. The polarization voltage shift must be determined by interrupting the current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading (instant off) after the immediate shift must be used as the base reading from which to measure the polarization decay.

E. A minimum negative (cathodic) polarization shift of 200 millivolts in the presence of APB or SRB. Determine the polarization voltage shift by interrupting the current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading (instant off) after the immediate shift must be used as the base reading from which to measure the polarization decay.

- For purposes of this criterion, APB testing must demonstrate greater than 100 cells per ml (>100 cells/ml; 3 or more APB vials turned).
- For purposes of this criterion, SRB testing must demonstrate greater than 10 cells per ml (>10 cells/ml; 2 or more SRB vials turned).

F. A minimum negative (cathodic) polarization shift of 200 millivolts where soil temperatures directly surrounding the pipeline exceed 140°F (60°C). Determine the polarization voltage shift by interrupting the current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading (instant off) after the immediate shift must be used as the base reading from which to measure the polarization decay.

G. A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

H. For offshore pipeline and platform facilities, -0.80 volt using a silver-silver chloride reference half-cell in seawater. The Company does not operate any offshore hazardous liquids pipelines.

NOTE
For further information on Criteria for Cathodic Protection, particularly in areas affected by high temperature or bacteria, please reference NACE SP0169- Control of External Corrosion on Underground or Submerged Metallic Piping Systems or TM0106 - Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines. See Exhibit A for the Practical Galvanic Series table.

6. Special Permit Reassessment and CIS Requirements (Part 192 regulated facilities only)

PHMSA has granted CPG several Class Change Special Permits. These permits allow the continued operation of the specified class change areas at their existing MAOP subject to compliance with several stringent permit conditions. Each special permit granted to CPG is included in Appendix T of the CPG Integrity Management Plan. Each permit lists the special permit segments and special permit inspection areas associated with the covered pipeline. A few of the special permit conditions associated with the requirements for reassessment using in-line inspection and close interval surveys are covered below.

A. Special Permit Segments and Special Permit Inspection Areas will be assessed by in-line inspection within six months of issuance of each permit. In addition, Special Permit Segments and Special Permit Inspection Areas will be reassessed by in-line inspection along the entire length of Special Permit Segments and Special Permit Inspection Areas in accordance with the maximum reassessment intervals specified in 49 CFR 192, Subpart O, but at least once every five calendar years at reassessment intervals not exceeding 63 months. In-line inspection will include the use of both high-resolution MFL and deformation in-line inspection tools. Reassessment schedules will be listed in the CPG Integrity Management Reassessment Plan (include in Appendix N to the IMP Plan).

B. Close Interval Surveys will be performed over the Special Permit Segments and Special Permit Inspection Areas at a frequency consistent with 49 CFR Part 192, Subpart O but at least once every five calendar years at reassessment intervals not exceeding 63 months.

RESPONSIBILITIES

Operations

Team Member

Qualified personnel will conduct the corrosion tests, inspections, perform repairs, and provide proper documentation. The person performing the work is responsible to ensure that only approved procedures and materials are used to inspect, test, or repair the facilities or coatings.

Team Leader

The Team Leader is responsible for scheduling and completion of required work, and if appropriate, taking prompt remedial action.

Support Staff

Engineering Services-Corrosion is responsible for recommending materials, operational plans and installation procedures, and assisting operations personnel or corrosion personnel with remaining wall strength calculations, cathodic protection system designs, proper repair methods or replacements, determination of "Active Corrosion Zones," and operation of the facilities. Engineering Services-Corrosion will review and update this plan annually.

Documentation Requirements:

Company Forms/Database

A. Use the approved work management system to store the official records for annual test data, bond data, atmospheric corrosion data, buried pipe inspections, rectifier data, leak reports, facility patrols, valve inspections, pipeline inspection reports, and repairs to cathodic protection systems. The appropriate work management system job plan can be printed and used if the electronic data gathering equipment is not available. Transfer this data to the approved electronic database as soon as practical after the work is completed.

B. Use the approved work management system to store the official records for annual test data, bond data, atmospheric corrosion data, buried pipe inspections, and rectifier data.

For Columbia Gas Transmission, and other facilities operated by Columbia Gas Transmission, after May of 2001, electronic data collection and retention is required for the data formerly collected on Forms 1071, 1317, and most corrosion-related functions such as rectifier readings, test station readings, and atmospheric corrosion surveys. For work performed before May of 2001, data will be stored on paper format.

For Columbia Gulf Transmission, all corrosion records, with exception to maps, will be maintained in the appropriate work management systems. A transition period will be recognized from form records to the work management system throughout 2006. Before 2006, the required information was recorded on the appropriate form(s).

Crossroads Pipeline has transitioned into a work management system. Records prior to 2006 are maintained on Forms 1071, 1317, and other forms related to corrosion functions such as rectifier readings, test station readings, and atmospheric corrosion surveys. Some corrosion data may be stored in electronic format as well.

Prior to the implementation of the Company's work management system, the required information was recorded on the appropriate form(s).

Records Retention

A. Retain all records pertaining to rectifier inspections reverse current switches, diodes and interference bonds for a minimum of five years, plus current year.

B. Retain the two most recent Atmospheric Corrosion inspections for onshore facilities. Retain the five most recent Atmospheric Corrosion inspections for offshore.

   Retain all corrosion surveys, including pipe inspection reports, annual electrical and active corrosion zone surveys for the life of the facility. This includes paper and electronic records. The exceptions to this rule are Close Interval Potential Surveys (CIPS), Direct Current Voltage Gradient (DCVG), AC or DC Mitigation studies, and other detailed corrosion tests, surveys or studies. The retention period for these types of surveys will be determined on a case-by-case basis by corrosion engineers or corrosion specialists for gas facilities regulated under 49 CFR Part 192.

C. Close Interval Potential Survey records will be retained for the life of the facility for hazardous liquids facilities regulated under 49 CFR Part 195.Retain all evaluations and records showing remedial action or investigation of casings and interference analysis for the life of the facility. This includes paper and electronic records.

D. Retain all remedial action documentation for repairs to cathodic protection facilities for the life of the facility. This includes paper and electronic records.

E. Retain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system for the life of the facility. Records or maps showing a stated number of anodes installed in a stated manner or spacing need not show specific distances to each buried anode. This includes paper and electronic records.

F. All results and input data from the evaluation of the strength of the remaining pipe RSTRENG or ASME B31G analysis for pipe that remains in service must be retained for the remaining life of the facility.

REFERENCES

Related Plan Documents

Plan Number	Title
70.01.02	Internal Corrosion
220.02.01	Pipeline Repair
220.02.02	Maximum Allowable Operating Pressure (MAOP)
220.02.04	Pipeline Markers and Facility Identification
220.03.01	Facility Patrol and Leakage Inspection
220.03.02	Valve Inspection and Maintenance
220.03.05	Continuing Surveillance
220.05.02	Safety Related Condition – Reporting and Investigating Requirements
N/A	CPG Operator Qualification Plan
400.017.103	Safety Related Conditions Reporting
400.017.405	Operating Pressure
400.017.504	Pipeline Repair

Related Procedure Documents

Procedure Number	Title
70.001.001	Inspection – Atmospheric Corrosion
70.001.002	Pipe Inspection Procedure
70.001.003	Close Interval Survey
70.001.004	Inspection - Atmospheric Corrosion – Consumer/Farm Taps
70.001.005	CP Repair – Cathodic Protection Cable
70.001.006	Voltage (IR) Drop Consideration
70.001.007	External Corrosion Products – Sampling and Analysis
70.001.011	Internal Corrosion Products – Sampling and Analysis
70.001.012	Mitigate (Repair) Atmospheric Corrosion

Procedure Number	Title
70.001.048	Operating Pipelines Sharing the Right-of-Way with High Voltage Power Lines
70.002.001	Data Take Readings – Casing
70.002.002	Data Take Readings – External Coupon
70.002.003	Data Take Readings – Rectifier
70.002.004	Data Take Readings – Resistance Probe
70.002.005	Test for Shorted Condition – Casing
70.002.006	Test Station-Data-Take Reading (Foreign Line Crossing)
70.002.008	Data Take PS Readings – Test Station
70.002.009	Data Read Bond – Test Stations
70.002.010	Interference Testing – Cathodic Protection
70.002.012	Data Take P/S Readings – Electrical Isolation
70.002.013	Insulation Test – Electrical Isolation
70.002.014	Inspection – Device, Reverse Current
70.002.022	Data Take Cable Voltage Reading – Test Station
70.002.026	External Coating – Underground Facilities
70.002.027	Data Take Readings (AC) – Test Station
70.002.028	Data Take Reading (Calibrated Span) – Test Station
70.002.029	Inspection AC Mitigation Polarization Cell & Surge Arrestor
70.002.030	Inspection AC Mitigation Grounding Mat, AC & DC Potential, and External Coupon
70.002.031	Inspection AC Mitigation Ground Mat and DC Potentials
70.002.032	Inspection AC Mitigation Ground Mat and AC/DC Casing Potentials
70.002.033	Inspection AC Mitigation Ground Mat and Foreign Line Crossing and DC Potentials
70.002.034	Inspection AC Mitigation Anode Cell – Decoupled Inspection
70.002.035	Linear Anode Groundbed Monitoring
70.002.036	AC Mitigation Anode Cell – Direct Connect Inspection
70.002.051	Guidelines for Determination of Boundaries for "Active Corrosion Zones
70.003.001	Remove Or Replace - Internal Corrosion Weight-Loss Coupons
70.003.002	Liquid/Solid Corrosion Sampling
70.003.003	Corrosion/Quarterly/ Extended Gas Sampling
70.003.004	Laboratory Analysis - Internal Corrosion Weight-Loss Coupons
70.003.005	Laboratory Analysis - Liquid and Solid Testing
70.003.006	Laboratory Analysis - Corrosion - Gas Samples
70.003.007	Recording Volumes of Liquids From Blowing Drips/Running Pigs to Control Internal
70.003.008	Internal Inspection of a Filter Device

Procedure Number	Title
70.003.009	Ship Gas Sample Cylinders
220.008.001	External Corrosion Direct Assessment (ECDA)

Operator Qualification Tasks

This list of Operator Qualification tasks indicates the tasks that may be associated with this plan.

Task Number	Title
PLOQ.0004	Monitor for Internal Corrosion – Obtain Gas Samples
PLOQ.0028	Leak Classification
PLOQ.0030	Operate Portable Gas Detectors – Presence of Gas
PLOQ.0031	Operate Portable Gas Detector - % of Gas
PLOQ.0040	Prepare Pipe for Coating
PLOQ.0043	Inspect for Atmospheric Corrosion
PLOQ.0044	Install Test Leads to Pipe
PLOQ.0045	Inspect Rectifier
PLOQ.0046	Pipe to Soil Measurements – Non Interrupted
PLOQ.0047	Pipe to Soil Measurements – Interrupted
PLOQ.0048	Inspect Interference Bonds
PLOQ.0049	Simple Pipe Inspection
PLOQ.0050	Corrosion Inspection - External and Internal
PLOQ.0052	Liquid / Solids Corrosion Sampling
PLOQ.0053	Monitor for Internal Corrosion – Change Corrosion Coupons
PLOQ.0054	Evaluate Remaining Strength of Defective Pipe
PLOQ.0056	Install Pipe Coating
PLOQ.0060	Test for Electrical Isolation – Aboveground
PLOQ.0061	Test for Electrical Isolation – Belowground/Shorted Casing
PLOQ.0062	Inspect AC Mitigation Systems
PLOQ.0063	Inspect Pipe Coating with Holiday Detector
PLOQ.0068	Test Anode Cell
PLOQ.0069	Inspect Polarization Cell and/or Arrestor
Veriforce Task Number	**Title**
401OP	Examination of Buried Pipelines when exposed.
402OP	Apply approved coatings to above ground piping
403 OP	Apply approved coatings to below ground piping
407OP	Perform cathodic protection survey
408 OP	Inspect cathodic protection rectifier
409 OP	Inspect intereference current bonds

Task Number	Title
411 OP	Inpect/Test electrical isolation
412 OP	Inspect CP leads on pipeline using exothermic weld
414 OP	Inspect for external corrosion when pipe is removed
415OP	Monitoring for internal corrosion with Probes and Coupons
418OP	General and localized corrosion measurement
419OP	Cathodic Protection Potential Measurement
427OP	Inspection of the application of above or below ground coatings

Other References and Related Specifications

- ASME B31G – Manual for Determining the Remaining Strength of Corroded Pipelines
- AGA Pipeline Research Committee Project PR 3-805 (RSTRENG)
- Guide for Gas Transmission and Distribution Piping Systems (GPTC)
- NACE SP0169-2013 - Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0169-2007 - Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- NACE SP0204-2008 – Stress Corrosion Cracking Direct Assessment Methodology
- NACE TM0106-2006 - Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines
- Peabody's "Control of Pipeline Corrosion", Second Edition A. W. Peabody NACE Press 2001

REGULATORY CITATIONS AND EXCEPTIONS

Federal Requirements

Citation Number	Title
49 CFR Part 192, Subpart I	Requirements for Corrosion Control
49 CFR Part 195 Subpart H	Corrosion Control
49 CFR Part 192, Subpart L	Operations
49 CFR Part 192, Subpart M	Maintenance
49 CFR Part 192, Subpart N	Qualification of Pipeline Personnel
49 CFR Part 195 Subpart G	Qualification of Pipeline Personnel
49 CFR Part 192, Subpart O	Pipeline Integrity Management
49 CFR Part 192, Appendix D	Criteria for Cathodic Protection and Determination of Measurements
49 CFR Part 192	OPS Interpretation 192.467-10

DEFINITIONS

AC: Alternating Current

Acid Producing Bacteria (APB): Bacteria that produce Organic Acids as an end product of their metabolism which may be aerobic or anaerobic.

Active Corrosion: Continuing corrosion, which could, unless controlled, result in a condition that is detrimental to public safety. Consideration should be given to those areas near people, homes, buildings, and road crossings, in conjunction with pipe conditions that could result in a failure due to remaining wall thickness and pipeline operating pressures.

Active Corrosion Zone: An area where the public could be exposed to hazards caused by active corrosion. Generally, pipelines less than 16" in diameter and operating at 50 psig or less, or pipelines 12" or less in diameter and operating below 150 psig can use the 100-foot "Active Corrosion Zone" boundary. An Integrity Engineer will determine the boundaries of other "Active Corrosion Zones". This boundary was derived from an industry study (referenced in 7.2(c)) and provides a method for calculating a probable safe radius from the pipeline in the event of failure by rupture. The "Active Corrosion Zone" is determined by the nominal pipe size (NPS) and the MAOP of the pipeline segment in the location of concern. This method will not apply to pipelines under cathodic protection.

Atmospheric Corrosion: Corrosion attack caused by the exposure of a pipeline facility surface to an aboveground environment. The type of corrosion attack includes area of extensive uniform pitting, galvanic and crevice corrosion.

NOTE
The following condition, which tends to be "cosmetic," does not affect the integrity of the steel substrate and does not qualify as atmospheric corrosion, but may be considered for maintenance in the future: • Faded, peeling, chalking, disbonded paint, and/or miscellaneous rust bleed onto a coated steel surface.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Coating Definitions/Classifications:

- **Bare or Uncoated**: By design, no protective coating applied.
- **Fail Safe Coating**: A coating that will allow cathodic protection current to pass through it to protect the substrate in the event of coating disbondment.

- **Excellent Coating**: Very good adhesion with less than 1% disbondment and occasional holidays. No electrolyte beneath the coating. Very minor to non-existent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Uniform thickness of asphalt and coal tar coatings with no evidence of wrinkling.
- **Good Coating**: Good adhesion with 1% to 10% disbondment and scattered holidays. Isolated locations with electrolyte beneath the disbonded coating. Minor intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Isolated evidence of poor adhesion, wrinkling, or other damage associated with soil stress on asphalt and coal tar coatings.
- **Fair Coating**. Fair adhesion with 10% to 50% disbondment and scattered to numerous holidays. Intermittent locations with electrolyte beneath the disbonded coating. Intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Random areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Brittle asphalt and coal tar coatings.
- **Poor Coating**. Poor adhesion with 50% to 80% disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.
- **Very Poor Coating**. Very Poor adhesion with greater than 80% (>80%) disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.

Coating Fault: Any anomaly in the coating, including disbanded areas and holidays.

Coating System: The complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pre-treatments, dry film thickness, and manner of application are included.)

Close Interval Survey: An electrical survey technique used to determine cathodic protection levels or corrosion potential of a metallic structure. This survey is also known as the Over the Line Survey technique. This type of survey is performed by taking structure to soil or half-cell to half-cell (bottle to bottle) readings at short intervals. These intervals can be anywhere from 2.5 feet to 10 feet in length, depending on the need. Remote (Side Drain) readings may be included. A Close Interval Survey may be used in conjunction with interrupting all known current sources to determine IR drop.

Corrosion: Metal loss on a surface of pipe resulting from oxidation, electrochemical action, bacterial action, abrasion, cavitation, erosion, or other processes.

Counterpoise: A buried cable installed and maintained by the power company connecting a series of electric power line towers used for grounding the towers. The counterpoise may be located under the towers or to the side of the towers.

DC: Direct Current

Disbonded Coating: Any loss of adhesion between the protective coating and a surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday. Also, see *Cathodic Disbondment.*

Electrical Survey: A series of closely spaced pipe to soil readings over a pipeline that is subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

External Corrosion, Contiguous Pitting: Individual corrosion pits that join together on the pipe surface. Contiguous means that the boundary of adjacent pits overlap or touch to the extent that they cannot be clearly separated as individual pits.

External Corrosion, Erosion: An acceleration of a corrosion process caused by the removal of corrosion products from an external surface due to the abrasive action of suspended particles and/or high velocities and turbulence (i.e. continuous running water).

External Corrosion, General Corrosion: Corrosion attacks that result in a uniform wall loss over the entire exposed area without measurable pitting.

External Corrosion, Localized Pitting: Individual corrosion pits that do not necessarily join together on the pipe surface to form a contiguous area of corrosion.

Fault Current: A current that flows from power line conductors to ground or to another conductor due to an abnormal connection (including an Arc) between the two. A “Fault Current” flowing to ground (earth) may be called a “Ground Fault Current.”

Gas facilities or gas pipeline: In this document, the use of the term ‘gas’ to describe a Company facility indicates the facility is in natural gas service.

Hazardous liquids: In this document, the use of the term ‘hazardous liquids’ to describe a Company facility indicates the facility is regulated under 49 CFR Part 195.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Interstate pipeline: a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

Intrastate pipeline: a pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.

IR Drop or Voltage Drop Error: The potential error in the "on" pipe to soil potential that is caused by current flow in the soil. Interrupting all known current sources minimizes IR Drop errors.

Jurisdictional Pipeline:

1. A transmission or storage pipeline, or,
2. An onshore gathering pipeline that meets the Type A or Type B line and location characteristics below:

Gathering Line Classification	Line Characteristics	Location Characteristics:
Type A	• Metallic lines with a hoop stress of 20% or more of SMYS based on MAOP • Non-metallic lines with an MAOP more than 125 psig.	Located in Class 2, 3 or 4 location
Type B	• Metallic lines with a hoop stress of less than 20% of SMYS based on MAOP • Non-metallic lines with an MAOP of 125 psig or less.	- Located in a Class 3 or 4 location or - Located in an areas within a Class 2 location as determined by any of the following methods: 1) Class 2 location (as applicable to transmission lines); 2) 300 foot corridor (150 feet each side of line) with more than 10 but less than 46 dwellings within any one continuous mile**;** 3) 300 foot corridor (150 feet each side of line) with five or more dwellings within any continuous 1000 feet.
Note: The definition of an onshore gathering line is set out in Procedure 220.001.038 Guidelines for Determination of Jurisdictional Gathering Lines.		

Low-stress pipeline: a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Maximum Allowable Operating Pressure (MAOP): The maximum pressure at which a line segment is qualified to operate under 49 CFR 192. It is the pressure allowed on a piping system between designated control points. This pressure will not exceed the design pressure of the weakest link in a piping system, published MAOP's, or the pressure certified by the FERC certificate of any line segment, and includes all components or adjoining facilities between such points.

Maximum Operating Pressure (MOP): the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under 49 CFR 195.

Mill Scale: The oxide layer formed during hot fabrication or heat treatment of metals.

Parallel High Voltage AC Power Lines: AC power lines sharing the ROW in close proximity to a pipeline with a separation distance that may induce measurable AC voltage on the pipeline or AC power lines that have a ROW crossing angle between 0 degrees and 45 degrees.

Passive Surface Oxidation: Or "surface rust" is corrosion that does not show signs of corrosion pitting or peeling scale, or pipe damage. It is an oxide film on a steel surface, which forms naturally, when the surface is exposed to its environment. This film can provide substantial protection against further corrosion attack.

Perpendicular High Voltage AC Power Lines: AC power lines sharing the ROW with a pipeline that have a ROW crossing angle between 46 degrees and 90 degrees.

Pipeline: All parts of those physical facilities through which a product moves in transportation, including pipe, valves and other appurtenances attached to pipe, compressor units, pumping units, metering stations, regulator stations, delivery stations, holders, breakout tanks and fabricated assemblies.

Pipeline Environment: The pipeline environment includes soil resistivity (high and low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

RSTRENG: A software program developed by the American Gas Association to predict the remaining wall strength of corroded pipe. Contact a Pipeline Services engineer for the latest information on the use of RSTRENG.

Selective Seam Corrosion (SSC): A form of internal or external corrosion typically associated with the longitudinal weld seam of older ERW or flash-welded pipe. Such corrosion appears as an elongated, narrow, sharp-bottomed groove usually located at the weld centerline parallel to the pipe axis. SSC usually (but not always) occurs along with other forms of corrosion that involve the longitudinal weld seam. Short lengths of SSC can be detrimental to pipeline integrity and should be removed from the pipeline. Neither B31G nor RSTRENG should be used to determine the acceptability of SSC. Contact a Pipeline Services engineer for evaluation assistance.

Special Permit Segment (SPS): An area where a class change has occurred and a special permit had been issued by PHMSA allowing the operation of that area at its current maximum allowable operating pressure without pipe replacement subject to several stringent conditions as specified in that individual permit. Each individual Special Permit Segment is defined and specified in the special permit issued.

Special Permit Inspection Area (SPIA): Is generally an area extending 25 miles on each side of the special permit segment or to the nearest upstream or downstream pig launcher/receiver or compressor station. Each individual Special Permit Inspection Area is defined and specified in the special permit issued.

Sulfate Reducing Bacteria (SRB): A group of anaerobic bacteria that reduces sulfate to sulfide.

Change Log

Date	Change Location	Change By	Brief Description of Change
8/8/2014	Section 2	Michael Ferenchick	Updated language requiring cathodic protection on new facilities
09/15/2014	Other References	Chris Legg	Updated reference to NACE SP0169-2013, formerly SP0169-2007.
10/15/2014	Throughout	Juanita Scaggs	Accepted changes, corrected formatting and made grammatical changes.
04/01/2015	Throughout	Mike Ferenchick	Changes throughout based on Part 195, references cleaned up. Atmospheric section wording changed.
04/02/2015	OQ, throughout	Dave Anderson	Corrected Veriforce task numbers, typos and edits
04/19/2015	Throughout	Dave Anderson	Changed Engineering Services to either Engineering Services- Corrosion or Corrosion as

Date	Change Location	Change By	Brief Description of Change
			appropriate.
5/12/2015	Change Log	J. Scaggs	Removed changes for 2012 and 2013 from change log. Accepted changes.
5/14/2015	Throughout	J. Scaggs	Updated template, and corrected Section references.

Appendix

Exhibit A

Practical Galvanic Series using a Copper Sulfate Reference Electrode (CSE)

Material	Potential in Volts using a Copper Sulfate Electrode
Carbon, Graphite and Coke	+0.300
Platinum	0.00 to -0.100
Mill Scale on Steel	-0.2
High Silicon Cast Iron	-0.2
Copper, Brass and Bronze	-0.200
Mild Steel in Concrete	-0.200
Lead	-0.500
Cast Iron, not graphitized	-0.500
Mild Steel, rusted	-0.200 to -0.500
Mild Steel, clean and shiny, no rust	-0.500 to -0.800
Commercially Pure Aluminum	-0.800
Aluminum Alloy (5% Zinc)	-1.05
Zinc	-1.100
Magnesium Alloy	-1.600
Commercially Pure Magnesium	-1.75

Source: Peabody's Control of Pipeline Corrosion, Second Edition Table 1.1

Attachment A

CPG CORROSION CONTROL PERSONNEL QUALIFICATIONS

PERSONNEL QUALIFICATIONS

Individuals engaged in corrosion related activities shall be fully qualified to perform required duties. Minimum requirements or qualifications and specific responsibilities required by these roles are identified in job descriptions. Personnel qualifications ensure that the individuals are qualified to perform the roles and related duties identified in the respective job descriptions.

CPG's hiring and selection process, maintained by the Human Resource department, screens applicants against minimum qualifications. The screened applicants are then evaluated by Asset Corrosion personnel to determine whether or not they can immediately perform the functions of the role, or can they become competent within an acceptable period of time based on specific experiences to perform the functions of the role. The best candidate for the role will be selected based on established selection criteria.

CPG also provides continuous training for its employees to ensure they maintain and update their competencies and certifications. Employees who are required to perform tasks associated with the SME roles associated with the Corrosion Control Program will complete training to maintain their competency in the SME roles as outlined below.

In addition, CPG also provides supervisor personnel responsible for corrosion related work training to ensure that they maintain competencies in the supervisory role and understand the requirements under the Corrosion Control Program. Persons who qualify as a supervisor for the Corrosion Control program will have training or experience in the area of Corrosion and will have a thorough knowledge and understanding of the Corrosion Control program.

Some corporate training, in addition to the SMEs role training, is related to corrosion control, and is applicable to more than just corrosion personnel in regard to building bench strength. The corporate training covers operations and maintenance proficiency in the categories of: 1) safety and security, 2) environmental, 3) human resources, 4) operating and maintenance, and 5) operator qualifications (OQ). The applicability of these training categories to corrosion control is the regulatory and preventive maintenance component of operations and maintenance.

JOB DESCRIPTIONS

Engineer – Pipeline Corrosion Control (minimum requirements)

- Operator Qualifications for specific fieldwork will be required as needed.
- Bachelor's degree in engineering or work under direct supervision of an engineer and
- One or more of the following:

- ✓ minimum 8+ years industry experience in corrosion engineering
- ✓ NACE C/P Specialist certification (or can attain certification within a specified time frame), AND/OR
- ✓ NACE Senior Internal Corrosion Technologist certification (or can attain within a specified time frame)
- ✓ familiar with the management and control of pipeline corrosion control construction contracts and practices

<u>Corrosion Specialist – Pipeline Corrosion Control (minimum requirements)</u>

- Operator Qualifications:

  - ✓ PLOQ 0030 Operate Portable Gas Detectors – Presence of Gas
  - ✓ PLOQ 0040 Prepare Pipe for Coating
  - ✓ PLOQ 0041 Pipe Protection in a Ditch
  - ✓ PLOQ 0043 Inspect for Atmospheric Corrosion
  - ✓ PLOQ 0044 Install Cathodic Protection Leads to Pipe
  - ✓ PLOQ 0045 Inspect and Read Rectifiers
  - ✓ PLOQ 0046 Measure Pipe to Soil Potential – Non Interrupted
  - ✓ PLOQ 0047 Measure Pipe to Soil Potential – Interrupted
  - ✓ PLOQ 0048 Inspect Interference Current Bonds
  - ✓ PLOQ 0049 Simple Pipe Inspection
  - ✓ PLOQ 0050 Corrosion Inspection – External and Internal
  - ✓ PLOQ 0052 Liquid Solids Corrosion Sampling
  - ✓ PLOQ 0056 Install Pipe Coating
  - ✓ PLOQ 0060 Test for Electrical Isolation Above Ground
  - ✓ PLOQ 0061 Test for Electrical Isolation Below Ground - Shorted Casing
  - ✓ PLOQ 0073 Abnormal Conditions

- High School education level is required, and
- One or more of the following:

  - ✓ 10 or more years' experience in corrosion control, monitoring and mitigation
  - ✓ AUCSC Basic, Intermediate, Advanced Corrosion
  - ✓ NACE CP-1, CP-2, Internal Basic and CIP-1 certifications (Based on experience, one or more of these certifications will be attained within the suggested time frame)

<u>Corrosion Technician / Leakage Corrosion Mechanic – Pipeline Corrosion Control (minimum requirements)</u>

- Operator Qualifications:

  - ✓ PLOQ 0030 Operate Portable Gas Detectors – Presence of Gas
  - ✓ PLOQ 0040 Prepare Pipe for Coating

- ✓ PLOQ 0041 Pipe Protection in a Ditch
- ✓ PLOQ 0043 Inspect for Atmospheric Corrosion
- ✓ PLOQ 0044 Install Cathodic Protection Leads to Pipe
- ✓ PLOQ 0045 Inspect and Read Rectifiers
- ✓ PLOQ 0046 Measure Pipe to Soil Potential – Non Interrupted
- ✓ PLOQ 0047 Measure Pipe to Soil Potential – Interrupted
- ✓ PLOQ 0048 Inspect Interference Current Bonds
- ✓ PLOQ 0049 Simple Pipe Inspection
- ✓ PLOQ 0050 Corrosion Inspection – External and Internal
- ✓ PLOQ 0052 Liquid Solids Corrosion Sampling
- ✓ PLOQ 0056 Install Pipe Coating
- ✓ PLOQ 0060 Test for Electrical Isolation Above Ground
- ✓ PLOQ 0061 Test for Electrical Isolation Below Ground - Shorted Casing
- ✓ PLOQ 0073 Abnormal Conditions

- High School education level is required, and
- One or more of the following:

  - ✓ 2 or more years' experience in corrosion control, monitoring and mitigation
  - ✓ AUCSC basic Corrosion
  - ✓ NACE CP-1 certifications (Based on experience, one or more of these certifications will be attained within the suggested time frame)

<u>Engineering Consultants – Pipeline Corrosion Control (minimum requirements)</u>

- Operator Qualifications for specific fieldwork will be required as needed.
- Bachelor's degree in engineering or under direct supervision of an engineer and
- One or more of the following:

  - ✓ minimum 8+ years' industry experience in corrosion engineering
  - ✓ NACE C/P Specialist certification (or can attain certification within a specified time frame), AND/OR
  - ✓ NACE Senior Internal Corrosion Technologist certification (or can attain within a specified time frame)
  - ✓ familiar with the management and control of pipeline corrosion control construction contracts and practices

<u>CORROSION CONTROL ROLES</u>

The following roles within the CPG organization are identified for the design, construction, operations and maintenance activities along with other aspects of corrosion control. The roles are referred to as Subject Matter Experts (SMEs). These roles are independent of the job titles held by individuals within the CPG organization. In addition, some individuals may hold various SME roles.

External Corrosion Design and Specification SME

External corrosion control designs are prepared or reviewed by company personnel, corrosion control vendor personnel, or independent consultants. The responsibilities for this role may include but may not be limited to:

- Direct, supervise or perform the design, installation, operation and maintenance of cathodic protection systems and procedures.
- The preparation of design plans, specifications, drawings, project scopes, construction practices, specifications, plans and procedures for new external corrosion control facilities, including, but not limited to, the following:

  - ✓ Cathodic protection systems
  - ✓ AC personnel protection systems
  - ✓ AC or DC interference mitigation systems
  - ✓ Testing facilities and practices
  - ✓ Equipment specifications

- Reviewing the results of field inspections in comparison to ILI results
- Identify appropriate data for integration and perform analysis of integrated ILI data
- Perform testing or provide direction to other personnel in the performance of testing to determine solutions for CP problems and/or to determine requirements for the design, installation or construction of cathodic protection, safety or interference mitigation systems or solutions
- Test new devices and practices to determine applicability for system wide use.
- Train personnel on the external corrosion design, installation, operation and maintenance related practices and procedures.
- Obtain and maintain company operator qualifications as required for all applicable OQ tasks performed.
- Keep abreast of product developments and product testing results relative to cathodic protection equipment.
- Maintain presence with industry and regulatory developments through professional, trade, and government opportunities

Coating SME

Pipeline and facility coatings selection and specifications are prepared by company personnel and/or consultants/contractor personnel. The responsibilities for this role may include but may not be limited to:

- Prepare and/or review company policies, plans, procedures and specifications regarding coatings, coating applications, surface preparation, coating inspections and coating related subjects.
- Specify appropriate underground and aboveground coatings for specialty applications where needed.
- Train personnel and/or work with vendors to train personnel on coating procedures including coating selection, surface preparation, testing, and application.
- Perform coating inspections where necessary and/or specify coating inspection procedures or supervise others installing coating.
- Test performance of new coating products.
- Work with coating mills to coordinate coating applications in accordance with specifications
- Where necessary, coordinate testing of mill applied coating in accordance with specifications. Review results of coating application tests to ensure proper surface preparation, coating thickness, and other properties for new pipe.
- Maintain presence with industry developments through professional, trade, and government opportunities.

External Corrosion Monitoring SME

The corrosion role is conducted through company and/or contractor personnel. The responsibilities for this role may include but may not be limited to:

- Prepare, review or provide input on company policies, plans, procedures and specifications regarding cathodic protection monitoring and testing.
- Monitor and/or perform tests on cathodic protection related systems for compliance with cathodic protection criteria, for compliance with regulatory requirements, to determine requirements for new cathodic protection installations or for other reasons, as necessary. Tests may include but may not be limited to annual pipe to soil surveys, rectifier inspections, bond inspections/measurements, ACVG, DCVG, PCM field testing, CIS, AC readings, interference testing, testing for shorted conditions, soil resistivity testing, current demand testing, as well as chemical testing of soils and corrosion by products.
- Recognize and respond to sub-criteria readings, as appropriate.
- Perform and documents pipe inspections, as necessary, if buried pipe is exposed or internally if pipe is opened.
- Perform and document atmospheric corrosion control inspections.
- Where possible, recommend further action to troubleshoot or correct problems found and when necessary, work with others to trouble shoot and resolve problems.
- Install or repair test stations, as necessary.
- Install, trouble shoot and repair cathodic protection systems (including rectifiers) and remote monitoring.
- Obtain and maintain company operator qualifications as required for all applicable OQ tasks performed.

- Maintain presence with industry developments and training through professional, trade, and government opportunities.

Internal Corrosion SME

This role is conducted through company and/or contractor personnel. The responsibilities for this role include but may not be limited to:

- Prepare, review, revise and or provide input on comprehensive site specific corrosion control plans where they are prepared by the company to control internal corrosion.
- Recommend sampling and monitoring points and practices within facilities to monitor conditions and minimize internal corrosion.
- Recommend liquid removal facilities, practices and liquid removal frequencies.
- Recommend practices, measures and testing to ensure the integrity of the pipeline system and minimize internal corrosion.
- Compile, integrate and review sampling, monitoring and other data to reveal trends, determine risk for internal corrosion and/or determine compliance with regulatory requirements. React to data as appropriate.
- Determine, or work with vendors or others to determine practical and effective chemical treatment, inspection, monitoring or other preventive measures to minimize internal corrosion risks.
- Review proposed pipe changes to ensure compliance with 49 CFR Part 192.476 for gas pipelines and 49 CFR Part 195.579.
- Train personnel on the internal corrosion design, installation, operation and maintenance related practices and procedures.
- Prepare and recommend projects to mitigate and minimize internal corrosion.
- Obtain and maintain company operator qualifications as required for all applicable OQ tasks performed.
- Maintain presence with industry developments and training through professional, trade, and government opportunities.

Internal Corrosion Monitoring SME

The internal corrosion role may be conducted through company and/or contractor personnel. The responsibilities for this role may include but may not be limited to:

- Direct, supervise or perform the design, installation, operation and maintenance of internal corrosion practices and procedures.
- Prepare, review or provide input on company policies, plans, procedures and specifications regarding internal cathodic protection monitoring and testing.
- Monitor and/or perform tests on pipe and related systems for compliance with company internal corrosion criteria, for compliance with regulatory requirements and to determine requirements for internal corrosion prevention measures. Tests/monitoring activities may

include collection and/or testing of liquid water samples and collection and packaging of corrosion coupons, chemical testing of internal corrosion products.
- Recognize and respond to sub-criteria readings, as appropriate or as directed.
- Perform and documents pipe inspections, as necessary, if pipe is opened.
- Where possible, recommend further action to troubleshoot or correct problems found and when necessary, work with others to trouble shoot and resolve problems.
- Install or repair coupon holders and extraction devices.
- Provide input on site-specific corrosion control plans and/or monitoring and corrosion prevention measures, as applicable.
- Obtain and maintain operator qualifications, as required, for all applicable tasks performed.
- Maintain presence with industry developments and training through professional, trade, and government opportunities.

Direct Assessment SME

Direct Assessment results are reviewed by company personnel and/or vendor personnel. The responsibilities for this role include but may not be limited to:

- Ensuring that external corrosion direct assessment (ECDA) is performed and validated in accordance with CPG Procedure 220.008.001 External Corrosion Direct Assessment, NACE RP 0502-2002, 49 CFR Part 192.925, and 49 CFR Part 195.588.
- Ensuring that internal corrosion direct assessment (ICDA) is performed and validated in accordance with CPG Procedure 220.008.002 Internal Corrosion Direct Assessment Procedure, NACE RP 0206 and 49 CFR Part 192.927.
- Ensuring that stress corrosion cracking direct assessment (SSCDA) is performed and validated in accordance with CPG Procedure 220.008.003 Stress Corrosion Cracking Direct Assessment, NACE SP 0204-2008 and 49 CFR Part 192.929.
- Reviewing DA results to identify appropriate response and remediation activities in accordance with CPG Procedures for ECDA, ICDA or SSCDA.
- Identify appropriate data for integration and perform analysis of integrated DA data.
- Perform validation associated with ECDA, ICDA and SSCDA procedures.
- Train personnel on the ECDA, ICDA and SCCDA procedures.
- Maintain presence with industry developments through professional, trade, and government opportunities.

Corrosion Regulatory SME

- Maintain the corporate corrosion prevention processes and procedures.
- Maintain all engineering material and equipment specifications related to corrosion prevention.
- Perform validation audits associated with corrosion prevention procedures.
- Train personnel on corporate corrosion prevention procedures.

- Maintain presence with industry developments through professional, trade, and government opportunities.

Corrosion Measurement SME

The corrosion measurement role may be conducted through company and/or contractor personnel. The responsibilities for this role may include but may not be limited to:

- Identification of corrosion on pipe and related facilities.
- Proper surface preparation for corrosion measurement.
- Where necessary, the gridding, accurate measurement and documentation of nominal wall thickness, corrosion length, width and depth.
- Closely coordinate with personnel who are Operator Qualified to perform remaining strength calculation for pipelines or others, where necessary, to facilitate accurate assessment of the remaining strength of the pipeline.
- Obtain and maintain operator qualifications, as required, for all applicable tasks performed.

Corrosion Remaining Strength SME

The corrosion remaining strength SME role is conducted through company personnel. The responsibilities for this role may include but may not be limited to:

- Work with corrosion measurement SME to ensure the availability of accurate data for the facility and corrosion associated with facility.
- Perform remaining strength calculations in accordance with approved procedures and, where necessary, provide recommendations for repair, if necessary.
- Obtain and maintain operator qualifications, as required, for all applicable tasks performed.

The company believes a strong training program is essential to the success of the corrosion control program. A newly hired employee is considered a trainee during his/her first several months on the job. On-the-job training supervised by other experienced employees or contracted consultants is used to indoctrinate the employee as to the specific procedures, specifications, tests, and mitigation strategies used for the CPG system.

On-the-job training includes emphasis on the use of industry standards, best practices, risk management principles, and regulatory compliance. Employees complete training courses provided by vendors and consultants as well when special knowledge not available internally is required. CPG representatives also sit on various industry committees and sub-committees such as INGAA and GPTC which provide training and education benefits.

CPG has developed a training program for its corrosion personnel involved in design and construction of cathodic protection systems. The program includes a plan and schedule to provide the additional training or skills acquisition to both achieve and maintain qualification requirements for these individuals performing the roles outlined above. The ***Corrosion Control***

Training Requirements Matrix (shown below) outlines the curriculum, frequency, and roles for the different training requirements. Curriculum associated with outside workshops and seminars are specific to the event and captured after participation by the SME. Information from such events may also be disseminated through the organization by the SME, via e-mail, at appropriate team meetings and training sessions.

Corrosion Control Training Requirements Matrix

Corrosion Roles	Vendor Training, Seminar or On the Job Learning Opportunities	PHMSA Workshop/ Seminars	Industry (AUCSC, NACE, etc.,) Consultant & Vendor Seminars	New Technology/R&D
External Corrosion Design and Specification SME	X		X	X
Coating SME	X		X	
External Corrosion Monitoring SME	X		X	
Internal Corrosion SME	X		X	X
Internal Corrosion Monitoring SME	X		X	
Direct Assessment SME	X		X	X
Corrosion Regulatory SME	X	X	X	
Corrosion Measurement SME	X		X	
Corrosion Remaining Strength SME	X		X	

In addition to these training requirements, CPG maintains corporate procedure, safety, supervisory, environmental, OQ, and other training programs.

Just as classroom and on-the-job training are important to the success of CPG Corrosion program, so is self-assessment. Self-assessment requires each employee to honestly evaluate the strengths, areas for improvement and weaknesses of his/her own performance, as well as team performance. Based on these self-assessments, the employee would work with their supervisor to develop employee opportunities. In addition to self-assessment, salaried employees receive regular, formal performance appraisals by their supervisors. A Human Resource Department Performance Management process ensures that employees are performing their job satisfactorily. Supervisors are trained to implement this process and salaried employees are required to use to develop annual goals and long-term development programs. These goals are also used to generate team goals, which factor into corporate performance and ultimately sustaining corporate strategies.

Contractors who perform corrosion control related functions are required to provide evidence of personnel qualifications in accordance with procurement procedures for contractor selection and qualification. In evaluating the training and qualification programs, CPG will review the specific vendor qualifications. Individuals who perform operator qualification tasks on the CPG pipeline system must be qualified under CPG Operator Qualification program (qualified either in house or through an approved third party evaluator or approved third party plan).

Records of the current employees and contracted personnel performing corrosion control related functions, along with their job descriptions and qualifications, are maintained by the Corrosion Control group and/or Operations.

OPERATOR QUALIFICATION

Operations and maintenance tasks that are performed on a pipeline facility as a requirement of 49 CFR Part 192 or 49 CFR Part 195 and affect the operation or integrity of the pipeline are considered covered tasks under the CPG operator qualification program. Individuals who perform such tasks on the CPG pipeline system must be qualified under CPG Operator Qualification program (qualified either in house or through an approved third party evaluator or approved third party plan).

CONTRACTOR QUALIFICATION

When contractors are used to perform tasks that are associated with processes related to the implementation of the corrosion control program they will be required to follow Company policies and procedures related to these activities. The qualifications of individuals that perform tasks subject to the Operator Qualification program will be documented in accordance with that program. Inspectors who oversee work performed by these contractors will report any observed deviations from these policies and procedures. Where inspectors are not used, the results of the work completed will periodically be reviewed for any indications of incorrect performance that could affect results.