CORROSION CONTROL OF GAS FACILITIES			O-16
Department: Technical Services		**Section:** Gas Engineering and Planning	
Approved by: [redacted]		**Date:** 06-16-98	
Rev. #01: This document replaces Revision #00. For a description of the changes, see Page 7.			

Purpose and Scope

This gas standard outlines PG&E's corrosion-control program for all gas facilities including company-owned gas gathering lines, gas transmission facilities, and gas distribution facilities.

1. Requirements for Protection

   All new, reconditioned, or replaced buried metallic pipeline facilities must be installed with an approved coating and must be cathodically protected for one year after installation. This requirement applies to all gathering lines, transmission lines, distribution mains, and services. This requirement also applies to company-owned, buried, metallic gas houselines.

   A. Appendix A describes cathodic-protection guidelines for steel mains and services.

   B. Transmission and gathering line cathodic-protection requirements shall be determined either by testing or by investigating the historical current requirements. Galvanic anodes or rectifier stations shall be installed as required.

   C. Ensure the following coated equipment is cathodically protected: gathering lines, transmission lines, mains, services, company-owned gas houselines, and other buried metallic gas facilities. Bare or poorly coated steel pipe shall not be cathodically protected.

2. Designing and Installing Cathodic Protection Systems

   Design cathodic protection areas (CPAs) according to the following guidelines.

   A. Use good judgment when engineering main and service CPAs so they are not excessively large or small. Ideally, an area should contain no more than 50,000 square feet of steel pipe. This guideline may not be applicable to some existing systems or to long-line systems.

   B. Design and operate cathodic protection systems to ensure they do not significantly interfere with other underground metallic structures. Select rectifier sites which maintain a minimum distance of separation between the anode bed and any foreign, underground metallic structures such as water lines, underground electric lines with bare neutral wires, metal-sheathed telephone or television cable, metal fence posts, electric ground rods and guy wire anchors, and similar facilities. A minimum distance of separation is any distance, verifiable through testing, that does not register interference. Workers must maintain a minimum distance of separation between all anodes and protected gas mains or services to prevent coating damage.

      To prevent coating damage, pipe-to-soil (P/S) on-potentials shall not exceed 1600 millivolts (mV) when measured with a copper-copper sulfate electrode anywhere on the protected structure. Voltage (IR) drop should be considered in this measurement. Perform interference response testing or make engineering calculations on rectifier sites that cannot meet the requirements documented in this subheading (2.B.), as well as in locations where foreign facilities may be affected. Notify foreign facility owners of the new or proposed rectifier sites or of the possibility of increased current outputs. Arrange to conduct testing, if required. Testing should include interrupting the rectifier current and measuring the on and off P/S potentials on nearby foreign facilities. Measure and record hard wire current flows, when necessary.

      For proposed sites, consider establishing temporary drains to measure potential influences and current flows.

   C. Insulating devices may be used in underground vaults. Take care to prevent possible electrical arcing. Use only approved flanges, gaskets and insulating sleeves for insulating purposes (as described in Gas Standard O-22 or Gas Standard B-45.1). Design the facility to prevent accidental contact or shorting across the insulating device (i.e., avoid using foil-backed sound insulation on vault lids; it could fall and contact the insulating device).

D. It may be necessary to provide galvanic grounding or other protection:

1. On pipelines which closely parallel High Voltage Alternating Current (HVAC) electric transmission lines, and
2. On pipelines where the anticipated or measured voltage between the pipeline and ground exceeds 15 volts alternating current (vac) open circuit or has a source current capacity of 5 milliamps (mA). (For example, protect pipelines that parallel 230 kilovolts (kV) or 500 kV HVAC circuits of appreciable distance (over one mile) and are within 1,000 feet of a HVAC conductor AND any pipeline that parallels a HVAC circuit for any distance when the separation is small.)

The need for special precautions is greater when electric loads are higher and when pipelines are well-coated and/or installed in high-resistance soil. These precautions apply to both pipelines under construction and pipelines operated under the conditions described in this section (2.D.). See the National Association of Corrosion Engineers (NACE) Standard RPO177 for additional guidelines or contact the CGT Corrosion Engineering Section.

E. Install wire test leads according to Gas Standard 0-10 AND at the following locations.

1. At new installation transmission/distribution pipeline areas.
2. On both sides of buried insulated fittings (Type D installation).
3. On pipeline at cased crossings (Type B installation).
4. On pipeline at crossings with other metallic pipelines.
(Additional test leads should also be attached to major foreign pipelines, if the owners will consent.)
5. In enough additional locations to ensure that the pipeline is accessible at least every 1/2 mile.
6. Current span test stations should be installed at least every mile for distribution mains and services and every five miles for gathering and transmission lines (Type E installation).
7. One on each side of a rectifier (Type F installation).
8. When numerous plastic services are installed on a steel main, test leads are required every 500 feet, unless there is sufficient access to the pipeline at existing test leads or existing steel services.

F. Where stray currents from foreign protection systems, both cathodic and anodic, are detrimentally affecting the cathodic protection of PG&E gas lines, foreign facility owners should be contacted and corrective measures should be taken to limit or eliminate the stray current condition. Foreign protection systems may include pipelines, transit systems, telluric earth currents, etc.

G. Clear all CPA contacts before designating the CPA as protected. Before excavation, when practical, verify the location of underground contacts with current span calculations or pipeline current mapper (PCM) current spans as well as with a locator PCM, tinker, or pipe locator. Cathodic protection systems will be considered adequately protected when the lowest P/S on-potential is a minimum of –850 mV with reference to copper-copper sulfate electrode with protective current applied. Other criteria are normally not applicable, but may be used when the –850 mV on-potential criteria is not practical. All current flow must be accounted for using PCM or DC hardwire current spans before protection can be considered adequate. Wherever possible, PCM spanning should be used for final spanning measurements.

H. When trying to account for current on transmission and gathering lines, workers may use a combination of protective current history, current requirements representative of the age and type of coating, P/S potentials, electrical surveys, or other methods to account for current when spanning is not practical (i.e., too few spans or services off the pipeline). In areas where there is reasonable evidence that other facilities contact the transmission lines, perform electrical surveys such as close interval P/S potential readings, PCM or tinkering.

I. The number of final P/S potential readings (P/S profile), approximately one per block, are to be considerably greater than the number of locations selected for maintenance readings.

J. Gathering lines and transmission lines shall use the method described above (2.I.) except when there are no branch services. Final P/S readings should document approximately one per mile, unless field conditions warrant otherwise.

K. Meet cathodic protection requirements for buried, metallic, company-owned gas houselines by ensuring that the gas houseline is insulated from the service line (normally at the service riser valve) and is insulated at the original gas meter location or at the first point that the gas houseline comes above ground. Do this by using an insulating union. Cathodic protection will be applied with at least one 5-pound zinc or at least one 9-pound magnesium anode that is electrically attached to the buried gas houseline. The coating on the gas houseline will be an approved company coating as listed in Gas Standards E-24 and E-25.

3. Cathodic Protection Maintenance

   Cathodic protection systems shall be maintained according to the following procedures.

   A. **Rectified Areas**

      In rectified areas, workers shall monitor for cathodic protection effectiveness according to the schedule listed below.

      Transmission, Gathering Lines, and Distribution Mains

      Test locations selected for monitoring shall be representative of locations where the level of protection is the lowest for that CPA or shall be in areas where the loss of effective cathodic protection would be noticeable.

      Monitoring Schedule

      As documented in a State of California Public Utilities Commission (CPUC) Waiver Resolution, PG&E is exempt from the federal CPA Rectifier Inspection Monitoring Schedule as required in 49 CFR 192.465 (b). Reference: CPUC Resolution SU-39, February 23, 1996, Order Authorizing Pacific Gas and Electric Company to Deviate From General Order 112-D, Section 192.465 (b), to Exempt the Company From the Requirement of Bi-Monthly Rectifier Inspection. (A copy of this waiver is located in the *Gas Distribution Maintenance Manual*, Section II, Part O.) The schedule of monitoring shall be as indicated below.

Table 1 Schedule of Monitoring Intervals

	Pipe-to-Soil (P/S) Monitoring	Rectifier Monitoring
DCS [1], CGT [2, 3]	Bi-monthly [4]	Annually [5]
CGT [2]	Annually [5]	Bi-monthly [4]

1 DCS is the Distribution and Customer Services organization.
2 CGT is the California Gas Transmission organization within PG&E.
3 CGT intervals are the same as DCS when maintained by DCS.
4 "Bi-monthly" means six times each calender year with intervals not to exceed 2-1/2 months.
5 "Annually" means once each calender year with intervals not to exceed 15 months.

Rectifier Monitoring

Rectifiers shall be monitored to ensure that they are functioning correctly. Include the voltage and amp measurements when taking rectifier readings.

Remote Monitoring

Cathodic protection rectifier locations, or P/S locations, can be monitored remotely to meet company requirements. The cathodic protection remote monitoring system will take a minimum of one reading daily.

CPA Restoration

Schedule CPAs for restoration when the areas show P/S on-potentials below adequate levels of protection. Check the rectifier levels after restoring a CPA. Restore areas within 30 calendar days from the date they are found inadequate, as defined by the current version of 49 CFR 192, Subpart I (barring acceptable extenuating circumstances). Document the reason(s) for any delays in the restoration work. Once restored, an area shall have approximately the same P/S on-potentials and rectifier output as existed before the level dropped, unless re-evaluation of the system indicates that different values are more appropriate.

Some extenuating circumstances will cause the restoration of a CPA to go beyond the 30 calendar day restoration timeframe. Examples of acceptable extenuating circumstances may include worker safety, public safety, population density, environmental concerns, climatic conditions, material availability, government permitting processes, land acquisition requirements and workloads. PG&E personnel shall determine if CPA restoration work is being delayed by an acceptable extenuating circumstance.

If the CPA restoration work is (or is expected to be) delayed, then an action plan for addressing the CPA restoration work must be developed within 30 days from the date the CPA is found below adequate levels of protection, as defined by current 49 CFR 192, Subpart I. The action plan shall list and document: the extenuating circumstance(s), the cause of the CPA problem (to the extent the cause is known), the desired solution(s), the actions needed to implement the solution, the estimated time to take those actions, and the personnel who will perform those actions. The action plan shall be updated every 30 days, or as established by the action plan, until the CPA restoration work is completed and the CPA shows adequate levels of protection. Updates to the action plan shall document the work that has been completed to date and the work that still needs to be completed to achieve adequate protection. (Reference: WIN. DOT - DOT RSPA Interpretation Letter #16 for 49 CFR 192.465 — May 19, 1989)

Appendix B is a sample "CPA Follow-up Action Plan." If using this action plan, file it with the respective CPA P/S maintenance worksheet.

The area headquarter Operations Maintenance and Construction Department (OMC) or California Gas Transmission Organization (CGT) Pipeline Department must provide a monthly status report regarding the CPA maintenance to the Engineering and Planning (E&P) Department or the asset owner.

B. Monitor facilities protected with galvanic anodes by using P/S on-potentials as follows.

   1. Monitor isolated main pipe segments that are over 100-feet long at least once each calendar year, but with intervals not exceeding 15 months. Monitoring includes plastic systems using locating wire to distribute protection to multiple service risers, steel pipe, steel valves, etc. Consider monitoring these sections more frequently, as conditions justify.

   2. Monitor individual isolated services of any length; fittings; individually buried, metallic, company-owned gas houselines; and isolated main segments less than 100-feet long at least once each ten years. Each year, at least 10% of all such facilities will be monitored. Each successive year, monitor a different selection of at least 10% of the facilities.

   3. Evaluate (using leak detection surveys) the galvanic anode protection installed at leak repairs as well as short (less than 100 feet), non-insulated sections of pipe at three-year intervals.

C. Monitor the cathodic protection on bare transmission line either by performing an electrical survey every three years or by performing an annual flamepack ionization leak survey.

D. Review the gas distribution CPAs using the CPA Assessment Worksheet at intervals not to exceed five years, using DCS Guideline D-G0050. This guideline is located in the *Gas Distribution Maintenance Manual*, Section II, Part O.

E. Transmission line CPAs shall be reviewed according to methods, schedules and priorities developed by the CGT Pipeline Re-evaluation Program. Divisions should use DCS Guideline G-D-G0050, located in the *Gas Distribution Maintenance Manual*, Section II, Part O, except when other methods are developed and recommended by the CGT Corrosion Engineer. CGT will normally use electrical surveys to reevaluate pipelines, but may also use the Distribution method if it is determined to be appropriate by the CGT Corrosion Engineer.

4. Voltage (IR) Drop Considerations

Always consider the IR drop in the measurement circuit when interpreting the results of P/S on-potential measurements. Elements of the measuring circuit that may cause IR drop include the volt meter, reference cell placement, reference cell contact resistance, test leads, and pipe and soil resistance.

A. Volt Meters: Take all P/S on-potential measurements with an approved electronic volt meter, having an input impedance equal to or greater than 10 megaohms.

B. Reference Cell Placement: Since it is not always expedient to excavate for the sole purpose of taking P/S on-potential measurements, place the reference cell as closely as possible over the pipe. At risers, place the reference cell approximately 6 inches to 12 inches from the riser and over the service.

C. Reference Cell Contact Resistance: Moisten the ground to minimize reference cell contact resistance. Where sufficient moisture does not exist, add water to the P/S on-potential measurement location.

D. Test Leads: Since only approved volt meters for making P/S on-potential measurements are used, IR drop in the test leads is insignificant.

E. CP Current Flow: Current flow on a pipeline from cathodic protection can cause an IR drop in the pipe and in the soil. When conducting close-interval surveys, refer the data to the corrosion specialist and/or corrosion engineer to determine if and how the IR drop in the pipe should be considered.

F. Soil: Evaluate the IR drop in the soil using the following considerations.

   1. The –850 mV criterion for cathodic protection was developed with an allowance of at least 50 mV for IR drop and other measurement errors.

2. Evaluate IR drop considerations by reviewing the historical performance of the cathodic protection system and determining whether or not there is physical evidence of corrosion.
3. The IR drop from a galvanic anode system is usually insignificant due to the small amount of current flow. Therefore, soil IR drop is considered insignificant if the reference cell is placed over the pipe and away from the galvanic anode.

5. Inspection and Leak Repair

Inspect a pipeline for evidence of external corrosion and take remedial action, as appropriate, any time it is exposed.

A. A written report shall be made of each inspection as outlined in DCS/GTS Standard D-S0350/S4110. Form 62-3117, "Leak Survey, Inspection and Repair Report," Form "A," shall be used for all distribution and transmission pipelines facilities and services. Do not mark "Corrosion" unless it is observed. If in doubt, contact the corrosion department.

B. Corrosion damage is to be repaired or replaced according to the applicable gas standards.

C. When external corrosion leaks are repaired on steel pipe that is not cathodically protected, regardless of whether the pipe is wrapped or bare, install at least one nine-pound magnesium or one five-pound zinc anode without the shunt and without the valve frame and cover according to the instructions found in Gas Standard O-13.1. Do not install anodes at leak repairs in cathodically protected areas unless they are part of a cathodic protection improvement plan. However, investigate continuing corrosion leakage in protected areas and take corrective measures.

D. Where an external corrosion leak occurs on a buried gas steel transmission line, take a P/S on-potential measurement at the leak site when a corrosion mechanic makes the repair. If safe and practical, take the P/S on-potential reading immediately at the corroded site as pipe is exposed. If low levels of protection are identified as a possible cause for the leak, take remedial measures.

E. Where an external corrosion leak occurs on a buried gas steel distribution facility, take a P/S on-potential measurement at the leak site at the time of the repair. If low levels of protection are identified as a possible cause for the leak, take remedial measures.

6. Internal Corrosion

A. Perform internal corrosion tests where evidence of internal pipeline corrosion is noted and has been verified, or where pipeline liquids are present. Record all information on Gas Department Form 75-95.

B. When found, sample and analyze pipeline liquids according to guidelines in the *Corrosion Manual.* If the sample has been determined to be corrosive, initiate an internal corrosion-control program . If evidence of internal corrosion has been found, regardless of the pipeline liquid sample analysis results, an internal corrosion-control program must be initiated.

C. The effectiveness of the internal corrosion-control program is usually monitored with electrical resistance probes or coupons and data recorded on "Probe Data Sheets" or "Coupon Data Sheets." Also, inhibitor concentrations may be measured by properly sampling liquid and analyzing it at designated liquid collection points. Each pipeline section may have its own internal corrosion-control program depending on the operation and environment of that section of the system. Consult the *Internal Corrosion Mitigation Plan* for the specific pipeline sections and for details regarding the internal corrosion-control program.

D. It is recommended to take all electrical resistance probe readings and to log them in at monthly intervals not to exceed a period of 90 days for the life of the system or until the probe is retired from service.

E. Whenever steel pipe is removed from a pipeline, inspect it for evidence of internal corrosion. Record this inspection as outlined in DCS/GTS Standard D-S0350/S4110 using Form 62-3117, "Leak Survey, Inspection and Repair Report," Form "A."

F. It is required to frequently and regularly drain dip tubes and bottom tap drains on pipelines to decrease the amount of stagnating liquids and, therefore, the potential for severe internal corrosion. Log the volume of liquids removed and the frequency of their removal. If liquid is discovered in a pipeline, it is recommended that the pipeline be drained monthly. Also, samples of the liquid must be taken and analyzed and the results logged. A damaged or malfunctioning dip tube or drain must be repaired within one year.

G. It is strongly recommended to swiftly retire idle pipelines that could potentially be wet. This action significantly reduces the risk of internal corrosion and, therefore, the need to eventually treat these idle pipelines with other methods (i.e., installing probes and inhibitor injection sites).

H. All pipeline installed in potentially internally wet areas of operation should follow the piggable pipeline design standard.

I. Well sites upstream of PG&E-owned lines that are in potentially internally wet areas of operation (i.e., downstream of a wet well but upstream of dehydration facilities) should be evaluated as described in the *Corrosion Manual*. Log the result of these evaluations.

J. Locate all inhibitor-injection sites on a map. Include information on the type of chemical found, the volume of the chemical tank, and county where the site is located. Send the information to the district's Environmental Coordinator in Gas System Technical Support (GSTS). Update these maps as necessary. They are used to track and determine our county permitting and spill plan requirements. Log all information regarding the type of inhibitor and the delivery rates. If possible, set the delivery rates off of the total flow to ensure that chemicals are not delivered to the pipeline when the gas flow is zero. Ensure that all inhibitor injection sites have a Material Safety Data Sheet (MSDS) displayed and placarding indicating the inhibitor is flammable since it is considered to be a hazardous material.

7. Records

A. Records shall be maintained to show the location details of all protected structures and contain sufficient test data to demonstrate the adequacy of installed corrosion-control measures. A file folder containing location maps illustrating the protected piping system shall be maintained for each cathodic protection system. The file folder should also contain information on the number, kind and location of rectifiers and anodes; a complete history of monitoring information (form 62-4953); current span/PCM data; bond data; pipe square footage; final P/S on-potentials; final current (PCM/hardwire) spans; gas facility maps; and any other pertinent information. These records are to be maintained for the life of the facility.

B. Use an approved computer software data base management system to maintain part or all of the records and information required in 7.A.

8. Atmospheric Corrosion Control

A. General

This section outlines requirements for lessening the damage caused by corrosive environments to above-ground PG&E gas facilities in compliance with current CPUC General Order 112 and 49 CFR 192.

1. All new pipe installed above ground must be coated with a PG&E-approved product (Section "E", *Gas Standards and Specifications*).

2. Operating departments are responsible for designating areas subject to atmospheric corrosion. Electric Engineering Standard, Drawing 032911, defines atmospheric corrosion areas and should be used. Maps of the atmospheric corrosion areas shall be prepared and maintained by the operating departments. Areas affected by atmospheric corrosion monitoring are made up of all the areas bordering the ocean, including North Coast, North Bay, San Francisco, Peninsula, Central Coast, and Los Padres Divisions.

B. Monitoring

1. In atmospheric corrosion areas, all above-ground gas facilities must be inspected at intervals not greater than three years.

2. During inspection, all piping or metersets with active corrosion shall be analyzed to indicate whether the damaged facility may be repaired by removing the corrosion and recoating, or whether it must be replaced.

C. Maintenance

1. All repairs or replacements will be completed according to appropriate gas standards and specifications.

D. Coatings

1. Galvanized piping does not require coating. Take care to limit the number of scratches on galvanized pipe.

E. Records

1. Each operating department shall maintain a file that includes the following information.

(a) A map of the atmospheric corrosion area(s).

(b) Documentation from each survey indicating the following: dates the surveys were taken; physical locations of the pipe requiring remedial attention; the type of action required; and dates of remedial actions taken.

Revision Notes: 1

Revision 01 has the following changes:

1. Paragraph 3.A.: Definitions of "Annually" and "Bi-monthly" added.
2. Paragraph 3.A.: Changed verbiage from "should" to "shall."
3. Appendix A: Changed description of "Plastic Main with Adequate Locating Wire" to "Plastic Main (Insert of Direct Buried) with Locating Wire that is not Part of a Cathodic Protection System" (see Page 10).
4. Appendix A: Changed Note 1 to reflect that No. 10 wire should be used only on plastic main installations.
5. This document is part of Change 43.

Appendix A

Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel Mains and Steel or Plastic Services

	Mains	Services			
Proposed New or Replaced Gas Facility/ Existing Main Piping System	**Steel Main**	**Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) with Noncorrodible Riser**	**Plastic Service Insert with Noncorrodible Riser where Plastic Service Locating Wire cannot be Inserted Through Service Case Pipe**	**Plastic Service Insert Through Existing Steel Riser (See Note 7)**	**New or Transfer Steel Services or Steel Risers**
Cathodically Protected Steel Main or Plastic Main with a Locating Wire a Part of a Cathodic Protection System	1. Tie new steel main into existing steel main. 2. Bond existing plastic main locating wire to installed steel main, if doing so does not cross cathodic protection area (CPA) boundaries. 3. Ensure adequate pipe-to-soil (P/S) readings on installation. 4. Contact corrosion mechanic to ensure proper cathodic protection requirements are met.	1. Bond installed plastic service wire to existing steel main or existing plastic main locating wire. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing steel main or existing plastic main locating wire. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Bond another plastic service locating wire at to the plastic service case pipe at the riser-end of the service case pipe and insulate plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at riser valve.	1. Insulate plastic service locating wire from existing steel main or plastic main locating wire. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Insulate at riser valve.	1. Tie steel service at steel main. 2. Bond steel service to plastic main wire. 3. Insulate at riser.
Wrapped, Unprotected Steel Main	**100 feet or less:** 1. Tie new steel main to existing steel main. 2. Install at least one 17-pound magnesium or one 15-pound zinc anode on each end of the new pipe. 3. Monitor in accordance with applicable leak survey requirements. **Over 100 feet:** 1. Insulate on each end of the main to main connection. 2. Install the appropriate number of galvanic anodes. 3. Monitor pipe-to-soil (P/S) annually. 4. Ensure adequate P/S readings on installation.	1. Bond installed plastic service wire to existing steel main. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing steel main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Bond another plastic service locating wire at to the plastic service case pipe at the riser-end of the service case pipe and insulate the plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at the riser valve.	1. Insulate plastic service locating wire from existing steel main. 2. If the plastic service locating wire is needed (see Note 7), bond the plastic service locating wire to the inserted steel casing and wrap around the tee. 3. Insulate at the riser valve.	**Any length:** 1. Tie to existing steel main. 2. Use insulated valve stop riser (Gas Standard F-80). 3. Install at least one 17-pound magnesium or one 15-pound zinc anode on each end of service pipe. 4. Monitor in accordance with applicable leak survey requirements.

Appendix A, continued

Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel Mains and Steel or Plastic Services

	Mains	Services			
Proposed New or Replaced Gas Facility/ Existing Main Piping System	**Steel Main**	**Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) with Noncorrodible Riser**	**Plastic Service Insert with Noncorrodible Riser where Plastic Service Locating Wire cannot be Inserted Through Service Case Pipe**	**Plastic Service Insert Through Existing Steel Riser (See Note 7)**	**New or Transfer Steel Services or Steel Risers**
Unwrapped, Unprotected Steel Main	**10 feet or less:** 1. Tie new main to existing main. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode. 3. Monitor in accordance with applicable leak survey requirements. **Over 10 feet:** 1. Insulate at each end of main-to-main connections. 2. Install appropriate number of galvanic anodes. 3. Ensure adequate pipe-to-soil (P/S) readings on installation. 4. Monitor P/S on 10% of those pipe sections which are 100 feet long or less yearly; if pipe length is over 100 feet, monitor yearly.	1. Bond installed plastic service wire to existing steel main. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing steel main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Bond another plastic service locating wire at to the plastic service case pipe at the riser end of the service case pipe and insulate plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at riser valve.	1. Insulate plastic service locating wire from existing steel main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Insulate at riser valve.	**Any length:** 1. Insulate steel service at both the main and the riser. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode on the service pipe. 3. Ensure adequate pipe-to-soil (P/S) readings on installation. 4. Monitor P/S on 10% of these installations per year.
Cast Iron Main	**Any length:** 1. Insulate cast iron-to-steel transition with approved insulating coupling (per Gas Standard B-91.4). 2. Install appropriate number of galvanic anodes. 3. Ensure adequate pipe-to-soil (P/S) readings on installation. 4. Monitor P/S on 10% of those pipe sections which are 100-feet long or less yearly; if pipe length is over 100 feet, monitor yearly.	1. Insulate installed plastic service wire from existing cast iron main by wrapping around tee. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing cast iron main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Bond another plastic service locating wire at to the plastic service case pipe at the riser end of the service case pipe and insulate plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at riser valve.	1. Insulate plastic service locating wire from existing cast iron main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Insulate at riser valve.	**Any length:** 1. Install malleable iron saddle, Universal 90 Install a small section of plastic pipe to isolate service from C. I. main. 2. Wrap saddle and tee according to Section E of the Gas Standards. 3. Install appropriate number of galvanic anodes (normally one 9-pound magnesium or one 5-pound zinc anode). 4. Ensure adequate pipe-to-soil (P/S) readings on installation. 5. Monitor P/S on 10% of these installations per year.

Appendix A, continued

Cathodic Protection Guidelines for Installing New, Replaced, or Transferred Steel Mains and Steel or Plastic Services

	Mains	Services			
Proposed New or Replaced Gas Facility/ Existing Main Piping System	**Steel Main**	**Direct Burial Plastic Service (See Note 5) or Plastic Service Insert (See Note 6) with Noncorrodible Riser**	**Plastic Service Insert with Noncorrodible Riser where Plastic Service Locating Wire cannot be Inserted Through Service Case Pipe**	**Plastic Service Insert Through Existing Steel Riser (See Note 7)**	**New or Transfer Steel Services or Steel Risers**
Plastic Main (Insert or Direct Buried) with Locating Wire that is not Part of a Cathodic Protection System	1. Insulate at each end of main-to-main connection. 2. Do not bond existing plastic main locating wire to steel main. 3. Install appropriate number of galvanic anodes. 4. Ensure adequate pipe-to-soil (P/S) readings on installation. 5. Monitor P/S on 10% of those pipe sections which are 100-feet long or less yearly; if pipe length is over 100 feet, monitor yearly.	1. Insulate installed plastic service wire from existing plastic main by wrapping around tee. 2. Insulate plastic service locating wire from the riser by wrapping it around the service riser. 3. Insulate at riser valve. 4. Insulate plastic service locating wire from inserted steel casings.	1. Insulate plastic service locating wire from existing plastic main locating wire. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Bond another plastic service locating wire to the plastic service case pipe at the riser end of the service case pipe and insulate plastic service locating wire from the riser by wrapping it around the service riser. 4. Insulate at riser valve.	1. Insulate plastic service locating wire from existing cast iron main. 2. If plastic service locating wire is needed (see Note 7), bond plastic service locating wire to inserted steel casing and wrap around tee. 3. Insulate at riser valve.	**Any length:** 1. Insulate steel service at both the main and the riser. 2. Install at least one 9-pound magnesium or one 5-pound zinc anode on the service pipe. 3. Ensure adequate pipe-to-soil (P/S) readings on installation. 4. Monitor P/S on 10% of these installations per year.

Notes:

1. For new business or reconstruction of plastic services by insertion, use AWG No. 14 copper HMWPE wire (Code 294378). Use AWG No. 10 copper HMWPE wire (Code 294414) for mains.
2. Compression fittings should be used and wrapped with Tac-Tape (Code 507036). Splices should then be wrapped with electrical tape. Soldered splices may be used instead of compression fittings (refer to Gas Standard O-12).
3. All wire connections to steel shall be thermite welded. Locating wire may be strapped to service line with electrical tape or tie lock (Code 399093) to ensure close proximity. Tapes other than electrical are not permitted for strapping unless approved by the Corrosion Supervisor.
4. Anodes must be a minimum of 12 inches from other U.G. metallic facilities.
5. A locating wire shall be strapped to the service riser above ground, but below an insulated service valve. Use Tie-Locks (Code 399093). Do not bond the wire to the riser.
6. Do not bond plastic service locating wire to existing service case pipe or new noncorrodible, prefabricated riser. If plastic service locating wire can be inserted successfully, it should be strapped to service riser above ground, but below an insulated service valve. Use tie-locks (Code 39-9093).
7. Do not bond plastic service locating wire to steel main or plastic main locating wire. For distances less than 3 feet from the metallic service case pipe to the main, a plastic service locating wire is not required. For longer distances, a plastic service locating wire should be bonded to a metallic service case pipe, but never to steel main or the plastic main locating wire.
8. Driveable anodes can be thermite welded or clamped.

Appendix B

CPA FOLLOW-UP ACTION PLAN

CPA # ______________ CPA Description ____________

Corrosion Mechanic: _________ Location: ___________ Date: ________ Page # ______

OBJECTIVE: This follow-up action plan facilitates completing actions needed to restore a CPA to adequate levels of cathodic protection and to meet the requirements for documenting extenuating circumstances as required in Gas Standard O-16, Section 3, Paragraph A.

Date CPA Found Below Adequate Levels of Cathodic Protection: ____

Date of Action Plan: ______________________

Date Next Action Plan Update Needed: _______ Date CPA Restored: _______________________

Cause of CPA Problem: ____

Desired Solution: ____

Description of Extenuating Circumstances: ____

	Recommended Action / Work Completed	Assigned Person	Estimated Date	Date Done
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				

Reviewed by: ___________________________________ / ___________ Date: / ___________________