Pacific Gas and Electric Company	**UTILITY OPERATIONS (UO)**
	UO Standard S4133
ISSUING DEPARTMENT: GSM&TS	EFFECTIVE DATE: 1-03
UO SPONSOR: VP – CGT	REVIEW DATE: 1-08
	PAGE NO. 1 OF 3
TITLE: Corrosion Control Of Gas Transmission Facilities	

Purpose

This gas standard outlines PG&E's corrosion control program for all gas facilities operating over 60 psig, including PG&E-owned gas gathering lines, gas transmission, and local transmission facilities.

Safety

Failure to follow the corrosion control program could pose a risk to public safety in the event of a pipeline failure. For employee safety, follow the proper clearing and rubber gloving procedures

Implementation Responsibilities

The vice president of California Gas Transmission (CGT) is responsible for approving, revising and distributing this standard.

Compliance

The director of Gas System Maintenance and Technical Support (GSM&TS) is responsible for establishing and maintaining procedures to comply with this standard

The director of GSM&TS is authorized to modify the standard's attachments, as needed, or approve variances to the attachments, on an exception basis

Definition of Terms

Transmission: for the purpose of this document only, the term "transmission" means all gas pipeline facilities operating over 60 psig

Attachment/ Appendices

Procedure: This standard is comprised of the following attachment and appendices.

1. Attachment 1. Procedures for Corrosion Control of Gas Transmission Facilities
2. AppendixA. Cathodic Protection Station Reports
3. AppendixB. Internal Corrosion Mitigation Plan

Acronyms

AWG: American wire gauge
CGT: California Gas Transmission (organization within PG&E)
CPA: cathodic protection area
CPUC: California Public Utilities Commission
DC: direct current
GSTS: Gas System Technical Support
HMWPE: high molecular weight polyethylene
HVAC: high voltage alternating current
kV: kilovolts
mA: milliamperes
MSDS: material safety data sheet
mV: millivolts
NACE: National Association of Corrosion Engineers
OM&C: Operations, Maintenance and Construction
PCM: pipeline current mapper
P/S: pipe-to-soil
C/S: casing-to-soil
GD&TS: Gas Distribution and Technical Services (organization within PG&E)
GSM&TS: Gas System Maintenance and Technical Support (organization within PG&E)
VAC: volts alternating current

Date Issued/Updated

Effective: January 2003

Review Date: January 2008

Signed,

Name: Michael A. Katz
Title: Vice President
California Gas Transmission

Reference Documents	Electrolysis Test Station Connection to Main	Gas Standard 0-10
	Wire Splicers	Gas Standard 0-12
	Zinc Anode Reference Cell Application Installation and Purchasing Data	Gas Standard 0-15
	Corrosion Control of Gas Facilities	Gas Standard 0-16
	Installation and Monitoring of Coupon Test Stations	Gas Standard 0-10.2
	Copper - Copper Sulfate Reference Electrode	Gas Standard 0-71
	Cathodic Protection Standards for Cased Pipeline Crossings	UO/CGT Standard D-S0354/S4126
	Leak Survey and Repair of Gas Transmission and Distribution Facilities	UO/CGT Standard S0350/S4110
	NACE	Standard RP0177
	GSM&TS Clearance Standard	CGT Standard
	Rubber Glove Insulating Standard	

Attachment I – Procedures for Corrosion Control of Gas Transmission Facilities

I. REQUIREMENTS FOR PROTECTION

All new, reconditioned, replaced, or buried metallic pipeline facilities shall be coated and cathodically protected within one year after the installation date

Bare or poorly coated (essentially bare) steel pipe installed prior to 1971 shall be cathodically protected, if practical, as determined by the GSM&TS Corrosion Engineering Section.

II. DESIGN AND INSTALLATION OF CATHODIC PROTECTION SYSTEMS

Cathodic Protection for Transmission Lines shall be designed in accordance with the following guidelines

A. Cathodic protection systems shall be designed and operated to ensure they do not significantly interfere with the cathodic protection of other underground metallic structures Rectifier sites shall be selected to maintain a minimum distance of separation between the anode bed and any foreign underground metallic structures such as oil lines, water lines, underground electric lines with bare neutral, metal sheathed telephone or cable TV, metal fence posts, electric ground rods and guy wire anchors and similar facilities

B. When interference with foreign structures is suspected, testing shall be performed. Testing should include interrupting rectifier current and measuring the on- and off- pipe-to-soil potentials on nearby foreign facilities. Close interval surveys, measurement of hard wire current flows, or other testing shall be conducted, when necessary

C. Transmission Line Compressor Stations, Terminals, and other major Pipeline Stations shall be protected separately, when practical.

D. Approved electric insulating devices may be used as appropriate. For underground vaults care must be exercised to prevent possible electrical arcing. Only approved flanges, gaskets and insulating sleeves shall be used for insulating purposes. The facility shall be designed to prevent accidental contact or shorting across the insulating device (i.e. avoid using foil backed sound insulation on vault lids that could fall and contact the insulating device)

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

- On pipelines which closely parallel High Voltage Alternating Current (HVAC) electric transmission lines, and
- On pipelines when the anticipated or measured voltage between the pipeline and ground exceeds 15 VAC open circuit or a source current capacity of 5 ma. For example, pipelines that parallel 230 KV or 500 KV HVAC circuits (within 1,000 feet) for appreciable distances (over one

mile) 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, when pipelines are well coated, and/or when pipelines are buried in high resistance soil These precautions apply to pipelines being constructed and/or operated under the conditions described above Contact the GSM&TS Corrosion Engineering Section for additional guidelines

F Wire test leads (ETS) are to be installed in accordance with Gas Std 0-10 and at the following locations

- One at least every 1 mile, where practical (Type A installation)
- Consider installing one current span at least every 5 miles (Type E installation)
- Both sides of buried insulated fittings (Type D installation)
- Each end of pipeline casings (Type B installation)
- At metallic pipeline crossings (Type C installation) Test leads should be attached to foreign pipeline(s), if consent can be obtained from the owner(s)

G All gas construction jobs installing buried pipeline facilities must ensure that the P/S potentials are read before closing out the job Note P/S measurements on the as-built construction drawing at the location they were taken A qualified corrosion mechanic or other qualified employee must take the P/S readings and sign off on the as-built construction drawing(s), see stamp (Figure 1 below) A construction job shall not be considered complete and ready to be closed out until the stamp below is completed

P/S Potentials Inspected As Noted on Drawing.
Potentials satisfy GSM&TS Standard S4133
Qualified Employee ____________________ **Date**________

Figure 1
Stamp Used on the Construction Job Drawings

III. CATHODIC PROTECTION MAINTENANCE AND OPERATION

Cathodic protection systems shall be maintained and operated in accordance with the following procedures

A. Cathodic Protection Criteria

Cathodic protection systems will be considered adequately protected when the lowest P/S potential is a minimum of -850 mV, with reference to copper-copper sulfate electrode, with protective current applied. IR drop is part of this potential measurement and must be considered per Section IV. Alternatively, the criteria listed below and other NACE recognized protection criteria may be used, when the -850 mV on-potential criteria is not practical and when approved by the GSM&TS Corrosion Engineering Section.

1) 100 mv Polarization. P/S potentials, with current briefly interrupted, must be at least 100 mv more negative than the native or depolarized potential. The native or depolarized potential may be established by the following methods:

- Native potentials shall be determined by reading potentials when the pipeline is initially installed, with the cathodic protection current off. Or later, by reading fully depolarized potentials, with the cathodic protection current off.
- Depolarized potentials shall be determined by allowing the cathodic protection current to be interrupted long enough to demonstrate the P/S potential has depolarized to a value at least 100 mv more positive than the instant off potential.

The native potentials, used in evaluations, must be reestablished when conditions exist that may significantly affect these potentials, such as stray current, reconditioned pipe or coating, excavated sites, etc.

2) Coupon Stations. Coupon Stations, installed per GS O-10.2, may be used to demonstrate, evaluate and/or verify cathodic protection. Coupon Stations may be used for any location and may be especially useful when the environment makes conventional measurements inaccurate or not representative. At each coupon test station three readings shall be taken and used to show compliance with a minimum of 100 mV of polarization. These are the "on" read, the "instant off" read, and the "native" read. In certain situations a depolarization read shall also be taken. Sufficient cathodic protection shall be determined by one of these methods:

- Pipe to soil potential. 850 mv or more negative, with cathodic protection current applied.
- Disconnected pipe coupon to soil potential. 850 mv or more negative (also called "instant off" potential).
- 100 mv polarization, established by one of the following methods:
  1. At least 100 mv difference between the disconnected pipe coupon and the native coupon

2. At least 100 mv difference between an initial disconnected pipe coupon to soil potential and a subsequent depolarized reading

3) Overprotection If the pipe potential exceeds -1600mV on, additional tests are needed to ensure the polarized potential does not exceed -1200mV. Contact GSMTS Corrosion Group for information on this test

All the above potentials shall be taken with reference to a copper-copper sulfate electrode, except for Zinc Anode Reference Cell Applications (GS O-15) or for special applications approved by the GSM&TS Corrosion Engineering Section. The copper-copper sulfate electrodes shall be maintained according to GS O-71

B Monitoring Schedule

1) Rectifiers, bonds, and other sources of protective current shall be read bi-monthly (6 times each calendar year not to exceed 2-1/2 months).

2) P/S potentials shall be read annually (once each calendar year with the interval not to exceed 15 months)

3) For GSM&TS Local Transmission, monitoring will be as specified below.
As documented in a State of California Waiver Resolution, PG&E is exempt from the federal CPA Rectifier Inspection Monitoring Schedule as required in 49CFR 192.465 (b). Reference SU-39, February 23, 1996, order authorizing PG&E 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 with the CGT System Integrity Standards and Compliance Section).

The approved monitoring schedule is shown in this table

	P/S Monitoring	Rectifier Monitoring
GSM&TS Local Transmission[1]	Bi-Monthly[2]	Annually[3]
GSM&TS Transmission	Annually[3]	Bi-Monthly[2]

[1] CGT Local Transmission frequencies when maintained by OM&C When Local Transmission is maintained by CGT Districts the monitoring frequencies may be modified to be the same as CGT Transmission
[2] "Bi-Monthly" means six times each calendar year with intervals not to exceed 2 ½ months
[3] "Annually" means once each calendar year with intervals not to exceed 15 months.

C Monitoring Points (P/S Potentials)

Approximately one potential reading per mile of pipeline, one potential reading on both the pipe and casing at the same casing end(s), and one potential reading both sides of insulating devices shall be maintained. Data is to be gathered using a calibrated hand held digital multimeter and a calibrated copper - copper sulfate reference cell (Gas Standard O-71). The number of pipeline monitoring points may be greater or less than one per mile when field conditions warrant, with the consultation of the GSM&TS Corrosion Engineering Section.

1) The monitoring points may be closer than one per mile when evaluations indicate existing monitoring points may not be representative of adequate cathodic protection, including considerations such as

- Readings taken at other locations indicate the monitoring points are no longer representative
- Potentials at monitoring points are marginal.
- Potentials show a decreasing trend over a period of 5 or more years
- Soil properties change along the pipeline
  - Clay/loam/sand/marshy/rocky/etc.
  - Resistivity and soil ph
  - Wet to dry, fallow to farmed
  - Coating type and condition: Asphalt to Tape, Poor to Good
- Stray current
- Leak or corrosion history.

2) The monitoring points may be farther apart than one per mile when it is not practical to increase the monitoring points and when evaluations indicate the monitoring points are adequate to demonstrate cathodic protection, including considerations such as:

- Readings taken at other locations indicate the monitoring points are representative
- Potentials at monitoring points are substantially above criteria.
- Potentials have changed little with time.
- The environment is uniform along the pipeline:
- Soil type remains relatively uniform along the pipeline.
  - No sections of different or corrosive soil
  - Resistivity and soil pH are relatively uniform.
  - No unusually wet or dry sections, land use is the same.
  - Coating type and condition. Current requirements are uniform and coating is in good condition
- No significant stray current
- No leak or corrosion pitting history.

D. Rectifier Monitoring

Rectifiers shall be monitored to ensure that they are functioning correctly. Both voltage and amperage measurements shall be taken for bi-monthly rectifier readings. Only digital multi-meters shall be used. Current shall be determined by measuring voltage across the calibrated shunt.

E. Rectifier Adjustment

Rectifiers may require adjustment over time. Some reasons this occurs include:

- Improvements for low potential areas
- Improvements to increase the margin of protection
- Changes in cathodic protection currents, including interference/stray current
- Changes in the amount of pipeline required to be protected.
- Adjustments for seasonal conditions
- Adjustments to balance current and/or P/S potentials
- Changes in pipe coating condition

In light of the above, PLM has been set to highlight any change in rectifier output of greater than 20% between monitoring cycles, and will automatically generate a work request to evaluate the reason for the change.

F. Remote Monitoring

Cathodic protection rectifier locations, or P/S locations, can be monitored remotely to meet PG&E requirements. It is acceptable to use remote monitoring reads to comply with the requirements of this section.

G. Casing Monitoring

Pipe and casing to soil potentials at casings shall be read annually and maintenance shall be performed as required by PG&E Standard S 0354 Cathodic Protection Standards for Cased Pipeline Crossings. Contact the Corrosion Engineering Section for assistance on verifying the existence of a casing contact, and for guidance on specific testing. The same criteria in the casing test procedure (GTS Standard S4126) are set as triggers in PLM to generate a work request to further evaluate any condition that could be indicative of a casing short.

H. Cathodic Protection Restoration

Any location that does not meet the cathodic protection criteria as defined in Section III A of this procedure, shall be restored according to the following schedule:

1) Restore areas to comply with standard within 60 calendar days from the date they are found to be inadequate, as defined by the current version of this standard. 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

2) If restoration within 60 days is not practical, an action plan must be established within that 60 day period to restore protection in an acceptable time frame. The action plan shall be reviewed and updated as required. Updates to the action plan shall document the work that has been completed to date and the work that needs to be completed to achieve adequate protection

IV. CONSIDERATION OF VOLTAGE (IR) DROP

When making pipe-to-soil on-potential measurements, the IR drop in the measurement circuit must be considered for proper interpretation of the results per DOT 49 CFR Part 192 Appendix D, Paragraph II. Elements of the measuring circuit that may cause IR drop include: the voltmeter, reference cell placement, reference cell contact resistance, test leads, and pipe, coating and soil resistance. The following guidance is provided to help minimize the IR drop in the measurements:

- Volt Meters: P/S on-potential measurements shall be taken with an approved electronic voltmeter, having input impedance equal to or greater than 10 Mega-ohms.
- Reference Cell Placement: Place the reference cell as close as possible over the pipe
- Reference Cell Contact Resistance: Where sufficient moisture does not exist, add water to the P/S on-potential measurement location to minimize reference cell contact resistance.
- Test Leads: Since only approved voltmeters are used for making P/S on-potential measurements, IR drop in the test leads is insignificant.
- Corrosion coupons can also be used to measure and account for the IR drop in the circuit. The specifics of how this is done are itemized in Section III of this procedure
- Special testing when determined necessary by the GSM&TS Corrosion Engineering Section.

V. ADDITIONAL TESTING AND INVESTIGATIONS

The GSM&TS Corrosion Engineering Section may perform additional testing and investigations at any time for informational purposes. This may include Close Interval Electrical Surveys, direct assessment of the pipeline, and remediation efforts. This work is not considered compliance work, unless it is required to restore cathodic protection, or is being performed to meet the requirements of the new pipeline safety regulations.

VI. INSPECTIONS AND CORROSION ASSESSMENT

A. Any time a pipeline is exposed, it shall be inspected for evidence of external corrosion and remedial action shall be taken, as appropriate. Consideration shall be given to installing an ETS or a corrosion coupon prior to backfill

B. A written report shall be prepared for each inspection as outlined in UO/CGT Standard D-S0350/S4110. Use GSM&TS Form F4110, "CGT Leak Survey, Repair, Inspection and Gas

Quarterly Incident Report". "Corrosion" shall not be marked unless it is observed. If in doubt, contact the GSM&TS Corrosion Engineering Section.

C- Any pipe segment with corrosion damage shall be evaluated using RSTRENG and repaired, replaced, or recoated according to the applicable gas standards.

D - Anodes shall not be installed at leak repairs in cathodically protected areas, unless they are part of a cathodic protection improvement plan, and are routed through junction boxes so they can be disconnected from the pipeline to facilitate electrical testing.

E- Where an external corrosion leak occurs on a buried steel gas transmission line, a P/S on-potential measurement at the leak repair site must be obtained. In order to minimize the IR drop, this measurement must be taken in the ditch adjacent to the pipe surface. If it is safe and practical, the P/S on-potential reading shall be read at the corroded site after the pipe is exposed. If low levels of protection are identified as a possible cause for the leak, remedial measures must be taken.

VII. INTERNAL CORROSION

A. General Requirements

Any time internal corrosion is found the findings and a mitigation plan shall be documented on the Internal Corrosion Mitigation Plan Form.

Where evidence of internal pipeline corrosion is noted and has been verified an internal corrosion mitigation plan should be developed. Similarly, whenever a leak has developed, the presence of water is confirmed, or corrosometer probe reads are out of specification, a mitigation plan shall be developed. All information shall be recorded on the Internal Corrosion Mitigation Plan Form. Each pipeline section may have its own internal corrosion mitigation plan depending upon the operation and environment of that section of the system.

Well sites upstream of PG&E owned lines that have the potential to contain standing water or contain gas with greater than 7# per mmscf of water vapor (i.e. downstream of a wet well but upstream of dehydration facilities) should be evaluated for the presence of water. The result of these evaluations shall be logged on the Internal Corrosion Mitigation Plan Form. Whenever steel pipe is removed from a pipeline, it and the adjacent pipe must be inspected and evaluated to determine the extent of internal corrosion. This inspection is recorded as outlined in UO/CGT Standard D-S0350 S4110,using GSM&TS Form F4110, "CGT Leak Survey, Repair, Inspection and Gas Quarterly Incident Report".

All new pipelines installed in areas that have the potential to contain standing water should follow the piggable pipeline design standard.

B Liquids

Frequent and regular drainage of dip tubes and bottom tap drains are required to decrease the amount of stagnating liquids, and therefore decrease the potential for severe internal corrosion. If liquid is found drainage should be performed monthly but not to exceed a frequency of 90 days. The frequency and volume of liquids removed shall be logged. A damaged or malfunctioning dip tube or drain shall be repaired within one year.

When found, pipeline liquids must be sampled by the District and analyzed. If the sample has been determined by the Corrosion Engineering Section to be corrosive, an internal corrosion mitigation plan shall be developed. The results of the testing shall be logged. If evidence of internal corrosion has been found, then regardless of the pipeline liquid sample analysis results, an internal corrosion control program shall be initiated at that location.

Dosage rates for chemical injection shall be determined by the Corrosion Engineer considering line history, expected volume of water, flow rates, and vendor recommendations. Where possible, chemical injection rates shall be geared to the volume of water suspected to be in the pipeline. Chemical injection can be continuous or batch. If possible the chemical injection rates should be set off the Total Flow to insure that chemicals are not delivered to the pipeline when the gas flow is zero.

C Corrosion Probes, Inhibitors, & Biocides

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". All electrical resistance probe readings should be taken and logged at monthly intervals, but shall not exceed a period of 90 days for the life of the system or until the probe is retired from service. Also, the effectiveness of chemical treatments should be evaluated by measuring the residual inhibitor and biocide concentrations in the liquids.

All inhibitor and biocide injection sites must be located on a map or form and information including the type of chemical, volume of chemical tank, and location sent to the district's Environmental Coordinator in GSM&TS. These maps are to be updated as necessary since they are used to track and determine county permitting and spill plan requirements. All information regarding type, dosage rate, and volume of inhibitor and/or biocide shall be logged. All inhibitor and biocide injection sites must have an MSDS and appropriate fire placarding since these substances are considered hazardous materials.

D Other

Swift retirement of idle pipelines that are potentially wet is strongly recommended since this action significantly reduces the risk of internal corrosion in those lines and therefore eliminates the need to treat these idle pipelines with other methods, i.e. installing probes and inhibitor or biocide injection sites.

IX. ATMOSPHERIC CORROSION CONTROL

This section outlines requirements for monitoring and mitigating atmospheric corrosion on aboveground gas facilities, in compliance with 49 CFR Part 192

A. Atmospheric Corrosion is evidenced on above ground or exposed piping by corrosion pitting or substantial wall thickness loss. Surface rust or passive surface oxidation does not constitute Atmospheric Corrosion

B. All above ground pipeline facilities shall be coated with a PG&E approved product (Section "E", Gas Standards and Specifications Book)

C. Above ground pipeline facilities shall be inspected for atmospheric corrosion annually. The inspection and action taken shall be documented according to appropriate Gas Standards.

D. Spans, above ground station piping, air/soil transitions, and piping in pits and vaults shall be evaluated and maintained in accordance with the "Exposed Pipe Coating Program For CGT Owned Transmission Lines" available in GSM&TS Corrosion Engineering Section.

During inspections, all above ground pipeline facilities with active corrosion shall be evaluated to determine whether the damaged facility may be repaired by removing the corrosion and recoating, or whether it must be repaired or replaced.

All repairs or replacements shall be completed according to appropriate Gas Standards and Specifications

VIII. RECORDS

External Corrosion

PLM shall be used to record and maintain records and information required to demonstrate adequate cathodic protection. This includes P/S potentials, C/S potentials, rectifier readings, identified problems, actions taken, and for problems that cannot be implemented within 60 days, action plans and tracking. Records prior to PLM are available in written format

A current file folder shall be maintained for each cathodic protection system containing

- Location maps delineating the protected piping system.
- Cathodic Protection Station Reports (Appendix A)
- Last calendar year plus year to date potential readings
- Last calendar year plus year to date rectifier, anode and bond readings
- All applicable Action Plans

A separate file folder containing historical CP records shall also be maintained. This file shall be maintained in the District for the life of the facility.

OM&C personnel maintaining GSM&TS Local Transmission will maintain a file in the OM&C facility that includes a map of the corrosion areas and documentation from each survey indicating the following information: dates the surveys were taken, physical locations of the pipe requiring remedial attention, the type of action required and dates of remedial actions taken. These records shall be maintained for the life of the facility.

Internal Corrosion

The following records shall be maintained in the District files for the life of the facility.

- Internal Corrosion Mitigation Plans
- Dip Tube Logs
- Corrosometer Probe Data Sheets
- Chemical Usage Reports

Atmospheric Corrosion

- Station Maintenance Form
- Exposed Piping and Spans Form
- Patrolling Form

APPENDIX A

GSM&TS CATHODIC PROTECTION STATION REPORT

DISTRICT | RECTIFIER ID#

RECTIFIER

LOCATION | LINE NUMBER | GPS MILE POINT

MANUFACTURER | TYPE | MODEL | SERIAL NO

PRIMARY RATING VOLTS | SHUNT VALUE: AMPS | MIL VOLTS | MULTIPLIER

SECONDARY RATING: AMPS VOLTS | INITIAL SETTING: AMPS VOLTS | DATE PLACED IN OPERATION

ANODE

NUMBER | WEIGHT AND/OR SIZE

TYPE | BACKFILL USED

SOIL RESISTIVITY

PIN SPACING - FEET	Ohms	MULTIPLIER	Ohm-Cm
2.5		500	
5.0		1,000	
7.5		1,500	
10.1		2,000	
15.0		3,000	

SHOW LOCATION OF RECTIFIER AND ANODE(S) AND PERTINENT DIMENSIONS

PREPARED BY DATE

APPENDIX B

Internal Corrosion Mitigation Plan

Background Information: Leak #________ Leak Date_ ____ Evaluation By _ _ ________

Location/Line # ____Nearest Well Feeding Pipe________ ____________ System Pressure

.

Flow Rate ____________ Pipe Diameter Wall Thickness __________Coating type

____

Repaired by Welded Sleeve____ Leak Clamp_____Pipe Replaced ___ (Note: If the pipe is replaced, the area that leaked should be cut down to a manageable sample size and saved for analysis by the Corrosion Engineer.) Other leaks occurred on this line in this area ____yes __no.

Failure Characterization: Please draw a simple sketch of the failure (include a photo if possible), indicating location of the leak (bottom, side, top), size of leak, location of additional associated internal corrosion, pit depths, length of internal corrosion, pipe seam location, and Ultrasonic thickness measurements of adjacent pipe

Liquid Sample Removed pH______Corrosion Product Sample Removed_____

Past Corrosion Mitigation Practices: Inhibitor Station on line _____ Distance from leak_ ____

Upstream or Downstream From Leak _Type of Inhibitor Used___ Feed Rate________

Corrosometer Probe installed _ Distance from Leak______(Please attach corrosometer data)

Drip Removal ___ Frequency of Removal ___ Dehydration Additional Comments on Past Practices: ___ _ _ ______________ ______________

Recommendations: ______________________________

Responsibilities/Follow-up Plan: ______________________________