Internal Corrosion Control: Corrosion Rate Monitoring

SUMMARY

This procedure describes how to select and locate corrosion rate monitoring devices used to verify internal corrosion conditions within Pacific Gas and Electric Company (Company) pipelines. It also describes how to interpret the results of corrosion rate monitoring to determine if mitigation or additional monitoring is needed.

Level of Use: Information Use

TARGET AUDIENCE

Personnel engaged in or supervising internal corrosion control work.

SAFETY

Potential hazards impacting this work include, but are not limited to, the following:

- Chemical hazards
- Electrical hazards
- Traffic conditions
- Tripping and slipping hazards
- Environmental surroundings
- Construction sites

ABNORMAL OPERATING CONDITIONS (AOCs)

Abnormal operating conditions (AOCs) that could be encountered while performing this procedure may include, but are not limited to, the following:

- Internal corrosion present
- Corrosion rate and pit rate do not meet the acceptance criteria

BEFORE YOU START

Personal Protective Equipment (PPE): The following PPE must be worn by field personnel (or must be available for use if indicated):

- Traffic vest
- Proper footwear
- Long sleeve shirt
- Long pants
- Hard hat (must be available)
- Gloves (must be available)
- Safety glasses (must be available)

Operator Qualifications (OQ): Field personnel conducting internal corrosion monitoring must be certified for the following Operator Qualification tasks (to be updated):

- Operator Qualification 03-09.00, Internal Corrosion / Monitor

Tools: Use only Company-approved tools and equipment.

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PROCEDURE STEPS

1 General

- Perform corrosion rate monitoring to verify if corrosive conditions are present within a pipeline.
- Perform corrosion rate monitoring whenever mitigation is applied to a pipeline to verify the effectiveness of mitigation.
- IF there are no additional inputs within a segment of pipeline,

  THEN corrosion rate monitoring results at one location can be applied to the remaining locations.
- Perform corrosion rate monitoring on each device per Table 1. "Internal Corrosion Monitoring Frequencies."

Table 1. Internal Corrosion Monitoring Frequencies

Liquid Quantity/Analysis Pipeline Features			
Type	**Routine Frequency**	**"Dry" Condition Frequency***	**Reference**
Drips	Bi-monthly, not-to-exceed 2.5 months to the date	IF found dry for 6 consecutive periods, THEN drips can be blown once each calendar year, not-to-exceed 15 months	TD-4186S
Bottom Taps	Bi-monthly, not-to-exceed 2.5 months to the date	IF found dry for 6 consecutive periods, THEN bottom taps can be blown once each calendar year, not-to-exceed 15 months	TD-4186S
Corrosion Rate Monitoring Devices			
Type	**Routine Frequency**	**Special Notes**	**Reference**
Coupons	Must be installed for 1 month minimum, but must be changed 2 times per year, not-to-exceed 7.5 months	Interval at the discretion of corrosion services.	TD-4186S
UT Probes	2 times per year, not-to-exceed 7.5 months to the date	More-frequent interval is at the discretion of corrosion services.	TD-4186S
ER Probes	2 times per year, not-to-exceed 7.5 months to the date	More-frequent interval is at the discretion of corrosion services	TD-4186S

* Drips/Bottom taps are considered dry if less than 500ml of liquid is collected per TD-4186S

2 Selecting the Corrosion Rate Monitoring Device Location

2.1 Corrosion services determines the locations for corrosion rate monitoring devices.

- Install corrosion rate monitoring devices such that the device is exposed to the conditions at the bottom of the pipeline where water may accumulate.
- Locate monitoring device where condensing water causing corrosion in the top of the line is a concern.
- Place devices verifying the effectiveness of mitigation downstream of the chemical injection point.
- Install devices at locations identified through routine maintenance.
- Place devices at locations with a high internal corrosion threat or where internal corrosion has been found.
- Maintain compliance with Gas Design Standard A-05, "Piggable Pipelines."

3 Selecting the Corrosion Rate Monitoring Device

3.1 General

Corrosion services selects the appropriate monitoring device for each location.

- Use electrical resistance (ER) probes (corrosometers) for corrosion rate monitoring, where feasible.
- Several monitoring devices are available and are listed in Section 3.2 below. The specific monitoring device selected is based on operating conditions and the anticipated type and severity of corrosion.

3.2 Common Corrosion Monitoring Devices

A brief description of the most common monitoring devices and their effective use is provided below.

1. Weight Loss Coupons

   Weight loss coupons provide a measurement of general corrosion rate by measuring the exact weight of the coupon before and after service, and converting material loss to a corrosion rate. Weight loss coupons may also be visually examined for the presence of pitting, and pit depths may be measured. However, unless pitting is significant, pit depth measurements may be difficult to obtain depending on the surface finish of the coupon. Weight loss coupons cannot determine the mechanism of corrosion. Normal exposure periods for weight loss coupons vary between 30 days to 6 months.

3.2 (continued)

2. Evaluation and Monitoring (EM) Coupons

   EM coupons provide an extended analysis in comparison to weight loss coupons. In addition to providing information regarding corrosion rate, pitting rate can be determined, and the type and cause of corrosion can be identified. Additional analyses may include energy dispersive spectroscopy (EDS) of the corrosion products on the coupon surface and epifluorescent microscopy of replicas of the coupon surface to identify the presence of bacteria.

3. Electrical Resistance (ER) Probes

   ER probes can be used in a gas or liquid environment. They measure the general corrosion rate based on the change in electrical resistance in the probe element as its cross sectional area is reduced by corrosion. ER probes cannot be used to measure pitting rates.

4. Linear Polarization Resistance (LPR) Probes

   LPR probes must be used in contact with an electrolyte to work properly. They measure the degree of resistance to a small applied potential. LPR probes cannot distinguish between general corrosion and pitting; although they can be used in conjunction with electrochemical noise to identify a potential for pitting. Hydrocarbons can cause fouling of LPR probes; therefore, LPR probes should not be used in environments where liquid hydrocarbons are known to be present.

5. Electric Field Mapping (EFM)

   - Electrical Field Mapping (EFM) measures corrosion using a series of sensing pins that are attached to the external surface of the pipeline. The pins may be welded or glued (permanently mounted) or spring-loaded (temporarily mounted and movable). EFM determines a corrosion rate by applying a current to the pipeline and then measuring the voltage created by the distortion of the electric field, which results from corrosion. The voltage measurements over time are compared to the original measurements (when the monitoring device was first installed) to identify where corrosion is occurring.

   - EFM may be used to monitor for general corrosion or localized corrosion (pitting) depending on pin placement. The closer together the pins are placed, the higher the sensitivity to detect localized corrosion.

   - EFM may be a preferred monitoring method for locations such as buried low points that are not accessible on a routine basis. An EFM monitoring device may also be used following an in-line inspection (ILI) run or internal corrosion direct assessment (ICDA) examination to monitor the growth of an internal indication.

3.2 (continued)

6. Permanently Mounted Ultrasonic Thickness (UT) Probes

> **NOTE**
>
> To function properly, most UT probes operate within a specified range of pipeline wall thickness.

- Permanently mounted UT probes measure the wall thickness of the pipeline in a specific location. The wall thickness measurements can be compared to previous measurements at the same location to calculate an average general corrosion rate. Permanently mounted UT probes are available as single transducers or in mats with many transducers.

- Because UT probes measure wall thickness in the exact area where the probe is located, the resulting rate is a general corrosion rate, unless the probe is known to be mounted at the location of a pit (in which case the calculated rate may be considered a pitting rate).

- Permanently mounted UT probes may be a preferred monitoring method for locations such as buried low points that are not accessible on a routine basis. Permanently mounted UT probes may also be used following discovery of internal corrosion to monitor corrosion growth.

7. Other Internal Corrosion Monitoring Methods

Several other methods for corrosion monitoring are available, such as periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. This method, however, does not provide a corrosion rate; it only indicates the presence of a corrosive environment. See Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities," for additional information on liquid sampling, if needed. The use of other monitoring methods is at the discretion of corrosion services.

4 Installing and Removing Corrosion Monitoring Devices

Contact corrosion services for instructions on how to install and remove coupons and ER probes.

5 Interpreting the Results of Corrosion Rate Monitoring

5.1 General

- Corrosion personnel interprets the results of corrosion rate monitoring to determine if mitigation is required or additional corrosion rate monitoring is needed.
- IF mitigation measures are applied,

  THEN corrosion personnel interprets the results of corrosion monitoring to determine whether the mitigation strategy is effective.

5.2 Pipelines without Mitigation

1. When corrosion rate monitoring is performed on a pipeline or associated facility on which mitigation activities are not currently being performed, compare the results to the criteria identified in Table 2, "Corrosion Rate and Pit Rate Acceptance Criteria."

Table 2. Corrosion Rate and Pit Rate Acceptance Criteria

Measurement	Criteria
General Corrosion Rate	< 1.0 mpy*
Pit Rate	< 5.0 mpy*
*mpy = milli-inches per year	

2. IF the results of corrosion rate monitoring meet the criteria in Table 2,

   THEN the following actions can be taken:

   a. Continue monitoring per Table 1 at each selected location until the criteria in Table 2 are met for two consecutive monitoring periods.

   b. Corrosion personnel determines the need for further monitoring at those locations.

5.2 (continued)

3. IF monitoring results exceed either criterion in Table 2,

   THEN the following actions must be taken:

   a. Perform corrosion rate monitoring per Table 1 for a minimum of two consecutive periods before initiating mitigation measures.

   b. IF monitoring data from two consecutive evaluation periods exceeds either criterion identified in Table 2,

      THEN corrosion personnel initiates a mitigation plan by completing Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment."

   c. Investigate upstream receipt points to determine the source of corrosive gas, if unknown.

   d. See Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation," for developing a mitigation plan if needed.

5.3 Pipelines with Mitigation

1. When corrosion rate monitoring is performed on a pipeline or associated facility undergoing mitigation, the effectiveness of the mitigation is determined by comparing the monitoring results to the criteria identified in Table 2 and Table 3, "Criteria for Immediate Mitigation Strategy Re-Evaluation."

Table 3. Criteria for Immediate Mitigation Strategy Re-Evaluation

Measurement	Criteria
General Corrosion Rate	> 5.0 mpy*
Pit Rate	> 8.0 mpy*
* mpy = milli-inches per year	

2. IF monitoring results for a selected location meet the criteria in Table 2,

   THEN mitigation is considered effective in reducing the corrosion rate.

NOTE

Corrosion services may set more restrictive criteria than those in Table 2 (i.e., lower general corrosion and pitting rates).

5.3.2 (continued)

a. IF the criteria in Table 2 are met for three consecutive monitoring periods,

   THEN corrosion services may consider adjusting or eliminating the mitigation measures in place.

b. Changes in mitigation measures should be accompanied by corrosion rate monitoring and evaluation.

3. IF monitoring results meet either criteria identified in Table 3,

   THEN the mitigation strategy must be re-evaluated within 30 days.

4. IF monitoring results exceed the criteria in Table 2, but do not meet the criteria in Table 3,

   THEN proceed with the following:

   a. Perform corrosion monitoring per Table 1 for an additional evaluation cycle.

   b. IF monitoring results exceed the criteria in Table 3 for two consecutive evaluations,

      THEN reevaluate the mitigation strategy.

6 Evaluating Effects of Operating Changes on Monitoring Plans

6.1 As operating conditions change, corrosion services evaluates the need for changes to monitoring. Operational changes that initiate such a review include the following:

- Addition or removal of receipt points
- Significant change in composition of a gas source (as identified by a change or exception in gas tariff limits)
- Addition of processing units
- Significant changes in operating temperatures or pressures
- Change in flow direction
- Design modifications

6.2 Corrosion services, with the local corrosion supervisor, document data reviewed and changes made to monitoring plans based on the review.

7 Records

- Record electrical resistance probe data on Gas Utility Form TD-4186P-300-F01, "Corrosometer Probe Data Sheet."
- Record ultrasonic thickness probe data on Gas Utility Form TD-4186P-300-F02, "UT Probe Data Sheet."
- Record field-related coupon data on Gas Utility Form TD-4186P-300-F03, "Coupon Field Form."
- Record corrosion rates exceeding the criteria in Table 2 and Table 3 on Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment."
- Maintain documentation at the local district or division office.
- Send a copy of the records to corrosion services annually.

END of Instructions

Internal Corrosion Control: Corrosion Rate Monitoring

DEFINITIONS

See Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities."

IMPLEMENTATION RESPONSIBILITIES

Corrosion services ensures all impacted personnel are aware of this utility procedure.

Superintendents and supervisors communicate this procedure to personnel who perform corrosion rate monitoring for internal corrosion and ensure that personnel are trained and qualified to perform these tasks.

GOVERNING DOCUMENT

Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

49 CFR 192.475 "Internal corrosion control: General"

49 CFR 192.476 "Internal corrosion control: Design and construction of transmission line"

49 CFR 192.477 "Internal corrosion control: Monitoring"

49 CFR 192.491, "Corrosion control records"

REFERENCE DOCUMENTS

Developmental References:

NACE SP0106-2006, "Control of Internal Corrosion in Steel Pipelines and Piping Systems"

NACE RP0775, "Preparation, Installation, Analysis and Interpretation of Corrosion Coupons in Oilfield Operations"

Supplemental References:

NA

APPENDICES

NA

ATTACHMENTS

NA

FORMS

Gas Utility Form TD-4186P-300-F01, "Corrosometer Probe Data Sheet"

Gas Utility Form TD-4186P-300-F02, "UT Probe Data Sheet"

Gas Utility Form TD-4186P-300-F03, "Coupon Field Form"

DOCUMENT RECISION

Gas Design Standard O-16, "Corrosion Control of Gas Facilities" is being replaced by the following document set:

Gas Utility Standard TD-4180S, "General Corrosion Control of Gas Facilities"

Gas Utility Standard TD-4181S, "External Corrosion Control of Gas Facilities"

Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities"

Gas Utility Standard TD-4188S, "Atmospheric Corrosion Control of Gas Facilities"

Gas Utility Procedure TD-4181P-101, "Cathodic Protection Area (CPA) Design and Modification"

Gas Utility Procedure TD-4181P-201, "Cathodic Protection Monitoring and Restoration"

Gas Utility Procedure TD-4181P-202, "Cathodic Overprotection"

Gas Utility Procedure TD-4181P-301, "Rectifier Maintenance and Adjustment"

Gas Utility Procedure TD-4186P-100, "Internal Corrosion Control: Liquid and Solid Sampling and Testing"

Gas Utility Procedure TD-4186P-200, "Internal Corrosion Control: Design Review"

Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring"

Gas Utility Procedure TD-4186P-400, "Internal Corrosion Control: Mitigation"

Gas Utility Procedure TD-4186P-500, "Internal Corrosion Control: Annual Program Review"

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REVISION NOTES

Where?	What Changed?
All	This is a new utility procedure, part of the document set replacing the internal corrosion control requirements portion of Gas Design Standard O-16, "Corrosion Control of Gas Facilities." O-16 is being updated and rewritten to comply with the new Company guidance document requirements, and is being reorganized and expanded into the following four standards with multiple procedures under each standard: • General Corrosion Control • External Corrosion Control • Internal Corrosion Control • Atmospheric Corrosion Control See the Guidance Document Analysis for details.