Internal Corrosion Control: Mitigation

SUMMARY

This procedure describes the process for developing an internal corrosion control mitigation plan for Pacific Gas and Electric Company (Company).

Level of Use: Information Use

TARGET AUDIENCE

Corrosion personnel developing and managing internal corrosion control mitigation plans.

SAFETY

Compliance with this procedure reduces the risk of internal corrosion in transmission, gathering, storage, and distribution lines, which results in increased public and personnel safety. No specific safety concerns are associated with the use of this procedure by a user developing mitigation plans.

BEFORE YOU START

Corrosion personnel developing internal corrosion control mitigation plans must receive training from the appropriate subject matter expert (SME) corrosion engineer.

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PROCEDURE STEPS

1 Initiate Mitigation Process

Corrosion services initiates an internal corrosion mitigation plan for transmission, gathering, or storage facilities as described in this section.

Corrosion services may initiate mitigation processes for distribution as determined by the number of internal corrosion issues identified on distribution assets in a fixed area.

1.1 Corrosion services identifies locations where one or more of the following conditions exist:

- Corrosion rates from monitoring devices have exceeded the established thresholds as referenced in Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring."
- Liquid sample collection identifies water via a positive indication on water finding paper in the field or subsequent lab analysis determines a water content greater than 5% by volume and lab test results exceed any of the criteria in Table 2 in Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities."

1.2 Corrosion services develops internal corrosion mitigation plans for the above locations as described in Section 2 below, Section 3, or both.

2 Select Mitigation Method

2.1 General

- Corrosion services selects the mitigation method for the mitigation plan.
- Corrosion services considers corrosion mechanisms impacting the pipeline when determining the appropriate mitigation method (e.g., biocide should not be used to treat mechanisms other than microbiologically influenced corrosion [MIC]). Additional investigation beyond corrosion rate monitoring or discovery of internal corrosion may be needed to make this determination.
- The Company's general preference is to use liquid removal, biocide, corrosion inhibitor, gas dehydration, and pigging (cleaning) for corrosion mitigation. However, there are numerous mitigation strategies that can address different sources of corrosive conditions. Depending on the root cause of the corrosive conditions, it may be necessary to use more than one mitigation technique to provide effective mitigation.

2.2 Mitigation Techniques

A brief description of various mitigation methods is provided below:

1. Gas Dehydration

- Installation of gas dehydration facilities can decrease the amount of water vapor entering the system.
- Existing dehydration facilities may be modified to more effectively remove water vapor. Factors that may impact the feasibility of design changes include cost of equipment, footprint of equipment, and necessary effectiveness of dehydration.

2. Liquid Separation

- Installation of liquid separation facilities can decrease the amount of liquids entering the system.
- Existing liquid separation facilities may be modified to more effectively remove liquids. Factors that may impact the feasibility of design changes include cost of equipment, footprint of equipment, and necessary effectiveness of liquid separation.
- Operational changes may reduce the potential for liquid upset; for example, increasing the maintenance frequency on scrubbers or filters. Operational changes such as increasing flow rates may be used to sweep liquids from low spots into separation facilities.

3. Maintenance Pigging

a. General

- Cleaning by pigging is an effective way to remove solids and liquids from a pipeline.
- Pigging may be considered part of the mitigation strategy whenever under-deposit corrosion or microbiologically influenced corrosion (MIC), or both are contributing corrosion mechanisms.
- Pigging may also be considered for pipelines that have a confirmed presence of internal corrosion and are known to contain liquids and/or solids.
- Where pipelines are piggable, consider pigging the pipelines prior to batch treatment.
- Launcher and receiver facilities are generally necessary to perform pigging.

2.2.3 (continued)

b. Frequency

- Base the frequency of pigging on the volume of liquids and/or solids recovered during pigging operations. Corrosion services determines the initial pigging frequency of the pipelines in the pigging program based on in-line inspection (ILI) and liquid sample data.

- The resulting volumes of liquids and solids removed should be trended and used to adjust the pigging frequency.

- Each time pigging is performed, run multiple pigs in succession to ensure that the line is fully cleaned.

c. Pig Types

Pig size and type are dependent on the line and the internal corrosion mechanism being mitigated.

- Scraper or brush pigs may be used to mitigate internal corrosion related to solids, deposits, or under-deposit corrosion.

- Multi-ribbed or disc pigs may be used to remove liquids from a system where liquid accumulation is contributing to the corrosion. Multi-ribbed or disc pigs will not remove tenacious scale.

- Spheres or foam pigs should generally not be used for mitigation as they are less effective at removing liquids and solids from the pipeline. However, they may be considered where the pipeline configuration prevents the use of scraper pigs or disc pigs. For example, foam pigs may be used in systems with obstructions that prevent other types of pigs from being used (e.g., diameter changes).

4. Scrubbing / Scavenging

a. Scrubbing

- Potentially corrosive constituents (CO_2, H_2S, O_2, or a combination) can be removed using amine treatment (CO_2 or H_2S) or catalytic combustion (O_2).

2.2.4 (continued)

- Factors that may impact the feasibility of installing equipment such as amine units include the following:
  - Cost of equipment
  - Footprint of equipment
  - Necessary reduction in constituent concentration

b. Scavenging

- H_2S or O_2 can also be removed using scavengers (chemical treatment).
- Factors that may impact the feasibility of using chemical scavengers include the following:
  - Compatibility with other chemicals being used in the system
  - Availability of chemical pumps
  - Water chemistry

5. Biocide

WARNING

Biocides may present significant health, safety, and environmental issues.

- Biocides may be applied to systems to mitigate microbiologically influenced corrosion (MIC). Simply attempting to kill microorganisms, however, may not necessarily mitigate MIC. Biocides can be corrosive in concentrated form because of their low pH.
- Biocides may be applied in either batch or continuous form (in the same manner as described for corrosion inhibitor application); however, batch treatment is more common.
- To be effective, the biocide must be able to reach the bacteria attached to the pipe surface.
- Where pipelines are piggable, it is recommended to use a scraper or wire brush pig prior to batch treatment to remove any sludge, solids, and biofilms.

2.2.5 (continued)

- Planktonic bacteria testing with a positive result does not necessarily mean that MIC is occurring. Positive planktonic bacteria results simply indicate the one component necessary for MIC to occur is present. Therefore, planktonic bacteria testing results are not used as the single source of information for determining the need for biocide treatment. Corrosion rate monitoring and testing for sessile bacteria should be performed to determine the need for biocide treatment.

- When determining the dosage rates for biocide, consider the following:

  - Line history

  - Expected volume of water

  - Flow rates

  - Contact time at the target concentration

  - Vendor recommendations

  - Impact of biocide upsets on customer service lines

6. Corrosion Inhibitor

   a. General

      - Corrosion inhibitors may be selected to mitigate internal corrosion. Corrosion inhibitors form a film or lay down a barrier between the metal surface and corrosive constituents that are present in the pipeline.

      - Corrosion inhibitors should be selected based on testing to determine effectiveness at reducing corrosion in the region to be treated and also considering compatibility with other chemicals that are being used.

      - Corrosion inhibitors may be applied continuously or in the form of batch treatments.

2.2.6 (continued)

- Determine dosage rates for corrosion inhibitor with consideration of the following:
  - Line history
  - Expected volume of water
  - Flow rates
  - Target residual concentration
  - Vendor recommendations
  - Impact to customer service lines

b. Continuous

- Continuous chemical treatment is typically used when sufficient liquids are present in a system and ongoing application of chemicals is desired.
- It is important to base the chemical injection rate on the volumetric flow rate of water in the system. The volumetric flow rate of water can be calculated by dividing the volume of liquid removed or recovered from the pipeline by the time period over which it was removed.
- Chemical pumps and tanks are required for continuous injection. Injection can be performed by using injection or quills.

c. Batch

- Batch chemical treatment is typically used in piggable pipelines where liquids are not transported or their flow is very low or intermittent.
- The volume of the chemical diluents used, contact time, and application interval are important in determining the effectiveness of the inhibitor.
- Batch treatments can also be applied as a slug (as opposed to between two pigs) in non-piggable pipelines; however, slug treatment is less effective at coating the entire surface area of the pipeline than batch treating between two pigs.

3 Develop and Implement Mitigation Plan

NOTE
Each pipeline may have its own corrosion mitigation plan, depending on the operation environment of that section of the system.

3.1 Corrosion services completes the following:

1. Develop an internal corrosion mitigation plan based on the mitigation method selected by corrosion services.

2. Document the mitigation plan on Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment." The plan should include the following:

   - Mitigation method
   - Location where mitigation is being applied
   - Frequency of mitigation
   - Dosage rates for any chemical injection
   - Other information at the discretion of corrosion services

3.2 Corrosion personnel manage mitigation plans for the pipelines in their system.

4 Monitor Mitigation Effectiveness

Corrosion personnel monitors whenever mitigation is applied to determine the effectiveness of mitigation.

- Corrosion services selects the monitoring device and location per Gas Utility Procedure TD-4186P-300, "Internal Corrosion Control: Corrosion Rate Monitoring." Interpretation of corrosion rate monitoring results for pipelines with mitigation are also located in this utility procedure.

- Corrosion personnel perform monitoring two times per year, at intervals not exceeding 7-1/2 months to the date per Gas Utility Standard TD-4186S, "Internal Corrosion Control of Gas Facilities."

5 Evaluate Effects of Operating Changes on Mitigation Plans

5.1 As operating conditions change, corrosion services evaluates the need for changes to the mitigation plan. 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

5.2 Corrosion services, with corrosion personnel, document data reviewed and changes made to mitigation activity plans based on the review.

6 Maintain Records

Corrosion personnel ensure the following tasks are performed:

- Document chemical injection sites on a map or form.
- Send the following information to the district's environmental coordinator:
  - Type of chemical
  - Volume of the chemical tank
  - Location
- Ensure chemical injection sites have appropriate fire and material safety data sheet (MSDS) placarding.
- Document mitigation plan and findings on Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment."
- Maintain documents at the local district or division office.
- Send a copy of the records to corrosion services annually.

END of Instructions

DEFINITIONS

Batch Treatment: Chemical treatment performed by injecting a specified volume of corrosion inhibitor or biocide at one location or various selected points on a system. Sometimes known as slug treatment.

Biocides: An additive used to kill or control bacteria.

Cleaning Pig: A utility pig that uses cups, scrapers, or brushes to remove liquid, dirt, sludge, and other debris from the pipeline.

Inhibitors: A chemical substance or combination of substances that, when present in the proper concentration and forms in the pipeline, prevents or reduces corrosion.

Microbiologically Influenced Corrosion (MIC): Metal corrosion or deterioration which is aided by metabolic activity of microorganisms.

Planktonic Bacteria: Free-floating or free-swimming bacteria in bulk fluids.

Sessile Bacteria: Bacteria attached to a surface.

Upset Conditions: Abnormal operating conditions. With respect to internal corrosion, the concern is when corrosive constituents are temporarily introduced to the gas stream.

Under-deposit Corrosion: Localized corrosion under or around a deposit or collection of material on a metal surface. The deposit(s) may be due to corrosion product accumulation, precipitation of solids from the water, or microbiological activity.

Additional definitions are available in 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.

Supervisors communicate this procedure to personnel developing internal corrosion control mitigation plans and ensure that personnel are trained 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"

Supplemental References:

NA

APPENDICES

NA

ATTACHMENTS

NA

FORMS

Gas Utility Form TD-4186P-400-F01, "Evaluation and Mitigation Plan for Internal Corrosion Assessment"

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"

Internal Corrosion Control: Mitigation

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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.

