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Kelly S. Lucas, Executive Director

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SEP 18 2012

September 12, 2012

SU-3358

Mr. Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W. Dakota Avenue, Suite 110
Lakewood, CO 80228

RE: CPF 5-~~2005-0026~~ 2011-0024M
Compliance Order – Sunrise Power Company, LLC

Dear Mr. Hoidal:

In response to your letter dated August 23, 2012, Sunrise Power Company respectfully submits the following responses and O&M manual attachments for each inadequacy referenced in the Findings of Violation:

Item 1: §192.605 Procedural manual for operations, maintenance, and emergencies.

(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

"Edison Mission's O&M manual review records did not specify the day of the month the O&M manual was reviewed. Only the month and year are noted. In order to accurately document that each review is completed within the required time period, Edison Mission must specify the day of the month when recording the date an O&M manual review is performed."

Sunrise's Response: See attached "Annual Review and Update of Manual" Sunrise Form 0218. The standard requires reviews be conducted each calendar year, not to exceed 15 months. All dates on Form 0218 include month, day, and year with the exception of March of 2003 and 2004. For these two years the review was conducted by a third party vendor, and the day of the month the review was completed was not documented.

Item 2: §192.613 Continuing Surveillance

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).

"Edison Mission's O&M manual section 2.11 does not include written procedures that reduce the maximum allowable operating pressure (MAOP) if a segment of pipeline is determined to be in unsatisfactory condition. Edison Mission must amend their O&M manual to include procedures that address continuing surveillance as required above."

Sunrise's Response: See attached O&M manual section 2.5, "Continuing Surveillance." Section 2.11 is titled Maximum Allowable Operating Pressures (MAOP). We believe the auditor used the incorrect reference in the finding. O&M manual section 2.5, "Continuing Surveillance," has been amended to reflect actions to be taken to reduce MAOP if a pipeline is in unsatisfactory condition.

Item 3: §192.703 General

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

"Edison Mission's O&M manual does not include written procedures to replace, repair or remove each segment of pipeline that becomes unsafe. In addition, the O&M manual does not include procedures requiring the prompt repair of hazardous leaks. Edison Mission must amend their O&M manual to include procedures that address pipeline maintenance as required above.

Sunrise's Response: See attached O&M manual section 3.01, "General Maintenance Statement." This section was inserted per the auditor's recommendation.

Item 4: §192.713 Transmission Lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be-

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.

"Edison Mission's O&M manual does not include written procedures that address transmission line field repairs and testing of repairs as specified in 192.713. Edison Mission must amend their O&M manual to include procedures that address the requirements stated above.

Sunrise's Response: See O&M manual section 3.21, "Permanent Field Repair." This section was inserted per the auditor's recommendation. Sub-section V.B. satisfies the audit inadequacy.

Item 5: §192.715 Transmission Lines: Permanent field repair of welds.

Each weld that is unacceptable under §192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of §192.245.

(b) A weld may be repaired in accordance with §192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking:

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

"Edison Mission's O&M manual does not include written procedures that address transmission line field repairs and testing of repairs as specified in 192.715. Edison Mission must amend their O&M manual to include procedures that address the requirements stated above."

Sunrise's Response: See attached O&M manual section 3.21, "Permanent Field Repair." This section was inserted per the auditor's recommendation. Sub-section V.B. satisfies the audit inadequacy.

Item 6: §192.717 Transmission Lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by-

(a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) Repairing the leak by one of the following methods:

(1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

(2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

(3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.

(5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

"Edison Mission's O&M manual does not include written procedures that address transmission line field repairs and testing of repairs as specified in 192.717. Edison Mission must amend their O&M manual to include procedures that address the requirements stated above.

Sunrise's Response: See attached O&M manual section 3.21, "Permanent Field Repair." This section was inserted per the auditor's recommendation. Sub-section V.C. satisfies the audit inadequacy.

Item 7: §192.719 Transmission Lines: Testing of repairs.

(a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to be pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with §§192.713, 192.715, and 192.717 must be examined in accordance with §192.241.

"Edison Mission's O&M manual does not include written procedures that address transmission line field repairs and testing of repairs as specified in §192.719. Edison Mission must amend their O&M manual to include procedures that address the requirements stated above."

Sunrise's Response: See attached O&M manual section 3.21, "Permanent Field Repair." This section was inserted per the auditor's recommendation. Sub-section V.D. satisfies the audit inadequacy.

Item 8: §192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

"Edison Mission's O&M manual does not include written procedures that address the remedial measures taken for corroded pipe as specified in 192.485 (a) and 192.485 (b). In addition, the O&M manual does not include written procedures for determining strength of pipe based on actual remaining wall thickness. Edison Mission may determine pipe strength using the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Edison Mission must amend their O&M manual to include procedures that address the requirements stated above."

Sunrise's Response: See the following attachments, as they have been revised to incorporate the audit's recommendations:

- **3.4, Atmospheric Corrosion**
- **3.7, Internal Corrosion**
- **3.8, Exam of Buried Pipelines**

These recommended changes address the remedial measures taken for corroded pipe and include actions to determine pipe strength using referenced procedures.

These recommended changes were applied immediately following the verbal draft audit report provided by U.S. DOT Pipeline and Hazardous Materials Safety Administration Auditor, Mr. Stephen Bender. Mr. Bender was forwarded these appropriate revisions approximately one week after his on-site visit via email.

In order to ensure proper mail delivery, please use the following address for all correspondence:

Sunrise Power Company
PO Box 5485
Bakersfield, CA 93388-5485

After reviewing the attachments, if you have any questions, please contact me at (661) 615-4684.

Sincerely,

Kelly Lucas

Kelly Lucas
Executive Director
Sunrise Power Company, LLC

Attachments

cc:	David King	Dave Leach
	Paul Dumke	Shelley Rosas
	Yvonne Hoeke	Ben Burns

ANNUAL REVIEW AND UPDATE OF MANUAL

Date of Review	Reviewed by	Sections Updated
March 2003	Jeff Gurican with Process Unlimited	No revisions.
March 2004	Jeff Gurican with Process Unlimited	No revisions.
March 15, 2005	Jeff Gurican with Process Unlimited	Reviewed and Updated (WO# 9944300)
January 1, 2006	T. Hutson and Jeff Gurican with Process Unlimited	Updated Plan to reflect correct designation of pipeline as a direct lateral transmission line.
December 10, 2007	David Leach	Reviewed and Updated (WO# 9967964)
June 1, 2008	David King and Norman Fox with In-Focus Consulting	Updated Plan to include Vault Maintenance
September 1, 2009	David King and Ben Burns	2.9, 2.14, 2.17, 2.18, 3.11, Appendix 4 DOT Operator Qualifications Covered Tasks for ChevronTexaco/Edison Mission Energy Partnership
October 13, 2010	David King, Ben Burns, David Leach, Shelley Rosas, Tonya Short	1.1, 2.1, 2.5, 2.9, 2.17, 2.18, 2.20, 2.21, 3.18, 4.5, 6.2, SU-0204, SU-0216
September 29, 2011	David King, Ben Burns, David Leach, Paul Dumke, Shelley Rosas, Tonya Short	1.0 TOC Added, 1.1, 4.3, 5.1, 6.1, 6.2, SU-0204, SU-0218, Appendix 2 Glossary, Appendix 3 49CFR Yearly Checklist
July 9, 2012	David King, Ben Burns, David Leach, Shelley Rosas, Tonya Short, Norman Fox (iNFocus Consulting)	Revisions 1.1 O&M Manual General Information, 2.15 Public Education, 2.17 Review of Operations and Maintenance Procedures, 3.20 Visual Inspection and Nondestructive Testing, 5.1 Emergency Response Plan, 6.2 Operator Qualification Program, 6.2 Required Training Matrix, Appendix 4 DOT Operator Qualification Covered Tasks for Sunrise. Corrected formatting 2.11 Maximum Allowable

		Operating Pressures (MAOP), 4.2 Flow Rate-Increase, 4.3 Flow Rate-Decrease, 4.4 Pressure-Increase In, 4.5 Pressure-Decrease In, 4.6 Unintended Shutdown, 4.7 Unintended Valve Closure, 4.8 Safety Device-Actuation, 4.9 Loss of Communications, 4.10 Notifying Operating Personnel of Abnormal Events, 4.11 Personnel Error, 4.12 Review of Personnel Actions during Abnormal Event, 4.13 Review of Written Procedures for Abnormal Events

2.5 Continuing Surveillance

I. PURPOSE

A. The purpose of this procedure is to describe the continuing surveillance program for identifying segments of the pipeline facility requiring evaluation as well as taking appropriate action.

II. SCOPE

A. This Plant Procedure is to be reviewed with employees at the time of inspection and on an intermittent basis such as operations meetings and at tailboards. It's also used to periodically communicate to employees that the purpose of continuing surveillance is used to detect changing conditions that could eventually result in a hazard to the public.

III. RESPONSIBILITY

A. It is the responsibility of the Plant Supervisor to utilize personnel and historical records to continuously monitor the pipeline facilities for class location changes, failures, leakage history, corrosion, cathodic protection requirements, pipeline efficiency, and unscheduled equipment maintenance conditions.

B. Operating personnel are responsible for reporting findings of any of the items in paragraph A. above to the Plant Supervisor.

IV. DEFINITIONS

V. DESCRIPTION

A. As a means of maintaining the safety and integrity of the pipeline, continuing surveillance through the analysis of completed pipeline inspection and maintenance records, daily operating reports, and other operating records shall be conducted so as to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions.

B. Immediate action shall be taken by the Plant Supervisor and his personnel to correct a hazardous or potentially hazardous condition that may influence the integrity of the pipeline or pipeline facility.

C. If a segment of pipeline is determined to be in unsatisfactory condition, but no immediate hazard exists, the Plant Supervisor shall initiate action to recondition or replace, if necessary, the segment involved.

D. If any hazardous or unsatisfactory conditions are found, a complete investigation shall be initiated by the Plant Supervisor. The Plant Supervisor shall document the following:

1. Reduce the MAOP of pipe to 80%.
2. A statement of the problem
3. Documentation of facts related to the problem
4. Proposed plan of correction, and
5. Timetable for plan of correction.

VI. REFERENCES

A. Title 49 CFR, Section 192.613

VII. ATTACHMENTS/LINKS

VIII. RECORDS

A. The records that should be monitored and maintained may include, but not be limited to the following:

1. Pipeline Patrolling
2. Class Location Survey and Documentation
3. Leak and Failure Records
4. Pipeline Inspection Records
5. Pipeline Repair Records
6. Test Records
7. Corrosion Control Records

B. The above documentation must be completed by personnel whose duties include monitoring, inspecting, operating and maintaining the pipeline and such documentation made available to personnel in a convenient manner.

3.01 General Maintenance Statement

I. PURPOSE

A. The purpose of this procedure is to establish general maintenance guidelines of natural gas pipeline facilities.

II. SCOPE

A. This procedure applies to maintenance activities performed on the SPC natural gas pipeline.

III. RESPONSIBILITY

A. The Plant Supervisor is responsible for determining when maintenance should be performed on the SPC natural gas pipeline.

IV. DEFINITIONS

V. DESCRIPTION

A. No person may operate a segment of pipeline, unless it is maintained in accordance with 49 CFR Part 192.

B. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service immediately.

C. Hazardous leaks must be repaired promptly.

VI. REFERENCES

A. Title 49 CFR Part 192.703.

VII. ATTACHMENTS/LINKS

VIII. RECORDS

3.21 Permanent Field Repairs Procedure

I. PURPOSE

A. The purpose of this procedure is to establish general guidelines to be used in case of pipeline damage requiring field repairs.

II. SCOPE

A. This procedure applies to permanent field repairs required on SPC natural gas pipeline.

III. RESPONSIBILITY

A. The Plant Supervisor is responsible for determining when and if repairs are required on SPC natural gas pipeline.

IV. DEFINITIONS

V. DESCRIPTION

A. Permanent field repair of imperfections and damages.

1. Each imperfection or damage that impairs the serviceability of the natural gas pipeline must be:

    a. Removed by cutting out and replacing a cylindrical piece of pipe; or,

    b. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

2. Operating pressure must be at a safe level during repair operations. The Plant Supervisor shall reduce the MAOP of the pipeline to 80%.

B. Permanent field repair of welds.

1. Each weld that is deemed unacceptable by means of non-destructive testing or visual inspection, in accordance with API Standard 1104, must be repaired as follows:

    a. If it is feasible to take the segment of pipeline out of service, the weld must be repaired in accordance with the following:

i. The weld must be removed if it has a crack that is more than eight (8) percent of the weld length.

ii. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be non-destructively tested to ensure its acceptability.

iii. Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures.

a. Welding must be performed by a qualified welder in accordance with welding procedures stipulated in Section 5 of API 1104 or section IX of the ASME Boiler and Pressure Vessel Code "Welding and Brazing Qualifications." The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s).

b. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

iv. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

b. A weld may be repaired while the segment of transmission line is in service if:

i. The weld is not leaking.

ii. The MAOP is reduced to 80%.

iii. Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains.

c. A defective weld which cannot be repaired in accordance with paragraph (a) or (b) above must be repaired by installing a full encirclement welded split sleeve of appropriate design.

C. Permanent field repair of leaks.

1. Each permanent field repair of a leak on the natural gas pipeline must be made by:

a. Removing the leak by cutting out and replacing a cylindrical piece of pipe, or,

b. Repairing the leak by one of the following methods:

i. Install a full encirclement welded split sleeve of appropriate design.

ii. If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

iii. If the leak is due to a corrosion pit, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

iv. Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

D. Testing of repairs.

1. *Testing of replacement pipe.* If a segment of pipeline is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

2. *Testing of repairs made by welding.* Each repair made by welding must be examined by non-destructive testing methods following API Standard 1104, Section 9.

VI. REFERENCES

A. Title 49 CFR 192.713 through 192.719.

B. Title 49 CFR 192.241.

C. API Standard 1104, Section 9.

VII. ATTACHMENTS/LINKS

VIII. RECORDS

3.4 Corrosion Control – Atmospheric Corrosion

I. PURPOSE

A. The purpose of this procedure is to establish the requirements for inspection and maintenance of above ground pipeline systems for atmospheric corrosion.

II. SCOPE

A. This procedure applies to all parts of the pipeline that are aboveground and susceptible to atmospheric corrosion.

III. RESPONSIBILITY

A. The Plant Supervisor will ensure that the corrosion control procedure will be followed and corrections and/or repairs made to the pipeline as needed.

B. Employees are responsible for inspecting the pipeline as prescribed by this procedure.

IV. DEFINITIONS

V. DESCRIPTION

A. General

1. A pipeline system includes all pipeline facilities used in the transportation of gas, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, fabricated assemblies, and metering stations.

2. Pipeline systems or portions thereof, subject to atmospheric corrosion or moisture penetration and retention, shall be inspected to assure detection of corrosion before detrimental damage is sustained.

3. The facilities' operating history, future anticipated operating conditions, evidence of possible corrosion found during routine observations, and actual inspection results shall be considered when establishing inspection frequencies.

4. Inspection programs for atmospheric corrosion shall include, but not be limited to, areas such as:

   a. under hold-down straps

b. between pipe and pipe supports

c. platform risers and riser clamps

d. at pipe penetrations of building walls

e. thermally insulated meter piping.

5. Periodically, not exceeding three (3) years between inspections, check the condition of wear pads, supports or sleeves on a sample basis to confirm continued protection of the pipe, especially in areas conducive to corrosion. Such areas would typically be those where moisture is present on the pipe due to reasons other than normal precipitation. The results of inspections, geographic location, and pipe environment will be used to determine an appropriate continuing inspection level.

6. Corrosion, leaks, and defects may be Safety Related Conditions. Refer to Section 2.18 Safety Related Conditions Reporting procedure of this manual.

B. Inspection and Maintenance

1. Inspect all bare aboveground piping at intervals not exceeding three (3) years.

2. The primary method of inspection is visual.

3. Non-destructive testing (NDT) techniques (such as ultrasonic thickness measurements, pit depth gauge readings, radiography, etc.) may be implemented if visual evidence of corrosion damage or other conditions warrant.

4. Inspect the transition zone of pipe entering the ground to confirm it is properly coated whereby penetration of moisture between the pipe and coating is prevented.

5. Whenever a condition is observed where moisture may be retained between the coating and pipe, remove the coating, inspect the pipe, evaluate severity of corrosion if present, take remedial actions if necessary, and recoat the pipe prior.

6. For thermally insulated systems, visual inspection of the external jacket to ensure its integrity against moisture intrusion under the jacket is usually sufficient; if the integrity of the external jacket has been breached and

liquid water may be present against the carrier pipe surface, additional inspection techniques may be required to detect possible corrosion.

7. Maintain a continuing program of painting based upon results of the external inspection program.

8. Areas where liquid water may accumulate or be trapped against the outside of the pipeline (including, but not limited to, under pipe hold-down straps or at pipe supports) may require special attention. Caulks, mastics or other sealants should be used to prevent water accumulation at these sites.

9. References for determining the remaining strength of a pipeline are:

   a. ASME/ANSI B31G (latest edition), "Manual for Determining the Remaining Strength of Corroded Pipelines".

   b. AGA Pipeline Research Committee, Project PR-3-805 (with RSTRNG disk), "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (latest edition).

C. Repairs

1. Repairs and preventative maintenance actions necessitated by these inspections shall be completed prior to the next inspection.

2. Each segment of a transmission line showing general corrosion with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure (SU pressure 900 PSIG, MS pressure 700 PSIG) reduced commensurate with the strength of the pipe based on actual remaining wall thickness.

3. Each segment of a distribution line with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based o the actual remaining wall thickness in the pits.

VI. REFERENCES

A. Title 49 CFR Sections 192.479, 192.481, 192.487, 192.491, 192.605, and 192.613

VII. ATTACHMENTS/LINKS

A. Section 3.5 Corrosion Control – External Corrosion Cathodic Protection

B. Section 3.6 Corrosion Control – External Protective Coating

C. Section 3.7 Corrosion Control – Internal Corrosion

D. Section 3.8 Corrosion Control – Internal and External Examination of Buried Pipelines

E. Section 3.9 Corrosion Control – Underground Pipeline Cathodic Protection System Test Procedures

F. Section 3.10 Corrosion Control-Maps and Records

VIII. RECORDS

A. Complete SU-0202, Corrosion Control – Atmospheric Report to document the external corrosion on aboveground facilities.

B. Complete SU-0210 Pipeline Repair Report, whenever external corrosion is identified and a repair or a preventative maintenance action, other than painting, is required.

C. Maintain the above records for at least five years.

3.7 Corrosion Control – Internal Corrosion

I. PURPOSE

A. The purpose of this procedure is to establish the requirements for the detection, monitoring, and control of internal corrosion, and required corrective actions for pipeline facilities.

II. SCOPE

A. This procedure applies to the inspection, monitoring and remedial actions of internal pipeline corrosion.

III. RESPONSIBILITY

A. The Plant Supervisor will ensure that pipelines will be inspected and monitored for internal corrosion and install methods of control.

B. Employees are responsible for inspecting the pipeline as prescribed by regulatory requirements.

IV. DEFINITIONS

V. DESCRIPTION

A. General

1. This procedure is required if corrosive gas flows through or remains in the pipeline.

2. A pipeline system includes all pipeline facilities used in the transportation of gas, including, but not limited to, gathering lines, line pipe, valves and other appurtenances connected to line pipe, fabricated assemblies, and metering stations.

3. Corrosive gas shall not be transported unless the corrosive effect of the gas has been investigated and measures have been taken to eliminate or minimize internal corrosion.

4. Potential corrosive gas shall not be transported without monitoring equipment that will detect the presence of internal corrosion. Where corrosive gas is being transported, coupons or other suitable means shall be used to determine the effectiveness of the steps taken to minimize internal corrosion.

5. If repair, replacement or operating pressure reduction is necessary, review Section 2.18, Safety Related Condition Report, to see if a reportable safety related condition exists.

B. Corrosive Conditions

1. Gas containing water in liquid phase and at least one of the following components is considered to be potentially corrosive.

   a. A combination of two or more components is considered to be potentially corrosive.

   b. A combination of two or more components with water in liquid phase may be potentially corrosive at lower concentrations of each component.

   c. Gas having a water vapor below the point of saturation may contain concentrations of H_2S and CO_2 and O_2 greater than those listed below and remain non-corrosive.

      i. Hydrogen sulfide (H_2S) concentration greater than .05 psia partial pressure for systems operating at or above 65 psia total pressure.

      ii. For system pressure less than 65 psia total pressure, H_2S content of 50 ppm or greater is considered corrosive.

      Note: Gas containing more than 0.25 grams of H_2S per 100 SCF (4 ppm) may not be stored in pipe-type or bottle-type containers.

      iii. Carbon dioxide (CO_2) concentration greater than 3 psia partial pressure regardless of total pressure.

      iv. Oxygen (O_2) concentration greater than 50 ppm or greater than 20 ppb where dissolved in a liquid phase.

3. Review the gas source dew point history. Water dew points within 10°F of the minimum ambient temperature to which the pipeline is exposed may indicate the presence of liquid water in the pipeline.

4. Corrosion will be more severe if any of the following conditions are present in conjunction with the conditions listed above.

a. Produced liquids containing sulfate-reducing or acid-producing microbiological colonies with culture test indicating over ten (10) colonies per milliliter should be considered to be potentially corrosive.

b. Liquids or materials having a pH less than 5.5.

C. Internal Inspections

1. Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion.

2. If internal corrosion is noted visually, other Non-Destructive Testing (NDT) techniques such as ultrasonic thickness measurements, pit depth gauge readings, radiography, etc. shall be used to quantify the extent of the corrosion.

3. Vessels and other fabrications shall be visually inspected internally when the opportunity to do so exists in conjunction with other maintenance activities or at intervals dictated by code requirements.

4. When internal corrosion or metal loss is observed in piping not previously monitored, remedial action and monitoring shall be initiated prior to the next inspection.

5. A sample of any foreign material recovered from inside the pipeline system shall be submitted for analysis and any necessary remedial action indicated by the analysis must be taken prior to the next inspection.

6. Electromagnetic flux leakage or ultrasonic "smart" pigs may be run in a pipeline at intervals of two to five years, or as required, to supplement other inspection techniques.

D. Gas Analysis and Evaluation

1. If there is a reasonable possibility that corrosive gas could occur in a pipeline system, gas samples shall be taken at applicable locations and tested for the presence and concentration of corrosive components. Testing shall be done at least twice each year with intervals not exceeding 7-1/2 months.

2. Dew point (water content) analysis shall be performed on gas sources once each month not to exceed six (6) months between inspections. Where

potentially corrosive gas is found as a result of gas testing, initiate the remedial action prior to the next test.

E. Installation and Monitoring Devices

1. No internal corrosion monitoring devices exist. Pipeline will be inspected for corrosion during repairs and corrections made with pipeline repair company and plant management.

2. Monitoring and Detection

   a. Monitor checkpoint and record the results at least twice each calendar year with intervals not exceeding 7-1/2 months. Monitor more frequently if the level of the corrosive component increases or the effectiveness of the anti-corrosion measures needs to be confirmed.

   b. If liquids are present, collect and analyze liquid samples from the gas stream on a semiannual basis.

3. Remedial Action

   a. Make a study of the pipeline systems to determine the scope of the possible internal corrosion if it is determined by inspection or analysis that internal corrosion is occurring, or has occurred.

4. References for determining the remaining strength of a pipeline are:

   a. AMSE/ANSI (latest edition) "Manual for Determining the Remaining Strength of Corroded Pipelines".

   b. AGA Pipeline Research Committee, Project PR-3-805 (with RSTRNG DISK), "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", (latest edition).

5. Apply at least one of the following mitigation measures prior to the next inspection if inspection reveals internal corrosion to be occurring, or if previously installed monitoring equipment shows corrosion to be occurring in conjunction with plant management approval:

   a. Eliminate free water in the pipeline by implementing an adequate pigging program, or by other appropriate methods.

   b. Remove corrosive components.

c. Inject corrosion inhibitors.

F. Repair

1. If internal corrosion has, or may have, reduced the wall thickness of a segment of pipe to less than that required for the maximum allowable operating pressure, pipe repair or replacement should be planned or the working pressure reduced prior to the next inspection.

G. Conversion Equations

Partial pressure (psia) = PPM x Line Pressure (psia)/1,000,000

Partial pressure (psia) = Mole % x Line Pressure (psia)/100

ppm = parts per million 1/1,000,000

ppb = parts per billion 1/1,000,000,000

VI. REFERENCES

A. Title 49 CFR Sections 192.475, 192.477, 192.487, 192.491, 192.605 and 192.613

VII. ATTACHMENTS/LINKS

A. Section 3.4 Corrosion Control – Atmospheric Corrosion

B. Section 3.5 Corrosion Control – External Corrosion, Cathodic Protection

C. Section 3.6 Corrosion Control – External Protective Coating

D. Section 3.8 Corrosion Control – Internal and External Examination of Buried Pipelines

E. Section 3.9 Corrosion Control – Underground Piping Cathodic Protection System Test Procedures

F. Section 3.10 Corrosion Control – Maps and Records

VIII. RECORDS

A. Complete the SU-0209 Pipeline Leak Report, SU-0210 and SU-0203 Corrosion Control Report as appropriate whenever pipeline is checked internally, repaired, or replaced.

B. Retain all studies, reports, checks of monitoring devices and other data that may be accumulated for the pipeline. Inspection reports are to be retained for at least five (5) years while smart pigging results are kept for the life of the facility.

C. Maintain gas water dew point historical log for gas sources where dew points or gas analysis are being performed for at least five (5) years.

3.8 Corrosion Control – Internal and External Examination of Buried Pipelines

I. PURPOSE

A. The purpose of this procedure is to establish a standard program of examination of buried pipelines for evidence of internal or external corrosion.

II. SCOPE

A. This procedure applies to the buried pipeline that is exposed for any reason. An examination should be completed for the external portion of the pipeline that is exposed. If there is cause to open or cut the pipeline, then an internal examination for corrosion and condition of pipe should occur at that time.

III. RESPONSIBILITY

A. The Plant Supervisor will ensure that pipelines will be inspected and monitored for internal and external corrosion anytime the buried pipeline is exposed for maintenance or other reasons.

B. Employees are responsible for inspecting the pipeline as prescribed by this procedure.

IV. DEFINITIONS

V. DESCRIPTION

A. General

1. A continuing program of examination and recording of the results of the inspection of buried pipelines is mandatory for both internal and external corrosion.

2. It is intended that examinations will monitor pipelines for the effectiveness of both internal and external protective measures.

3. Corrosion, leaks, and defects shall be evaluated to determine if they are safety-related conditions.

B. Examination of Pipeline

1. Whenever buried piping is exposed for any reason, the exposed portion of the coating must be visually examined to determine external coating condition.

2. If a line is bare or the coating has deteriorated, or the coating is removed on a well-coated line, inspect the pipe for external corrosion.

3. If corrosion is observed on a coated line, a condition may exist warranting further investigation (disbanded coating, unique soil environment, etc.).

4. Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion. If internal corrosion is noted visually, other NDT techniques shall be used to quantify the extent of the corrosion.

5. Visually inspect the full circumference of piping if one or more of the following conditions exist:

   a. Continuing corrosion is observed

   b. CP test, current requirements or surveys indicate corrosion may be occurring

   c. Previously unidentified coating deterioration is observed or suspected

   d. Corrosion is observed on the piping, which is of a magnitude not previously documented or which may require repair. If repair is required, continue inspection longitudinally until pipe condition is satisfactory.

6. If visual examination indicates corrosion has occurred, initiate one or more of the following actions:

   a. Calculate the acceptable minimum wall thickness limit after corrosion. If wall thickness is less than the calculated minimum, initiate a repair method and or reduce the pipeline MAOP.

   b. If repair is required, limit the operating pressure accordingly, until the repair is made.

   c. Apply coating and/or additional cathodic protection, as necessary, where active external corrosion is present.

   d If internal corrosion is noted, apply or confirm compliance with the requirements of 3.7 Corrosion Control -Internal Corrosion.

e. Determine if a safety related condition exists.

VI. REFERENCES

A. Title 49 CFR Sections 192.459, 192.475, 192.487, 192.491, 192.605, 192.613

VII. ATTACHMENTS/LINKS

A. Section 3.4 Corrosion Control – Atmospheric Corrosion

B. Section 3.5 Corrosion Control – External Corrosion, Cathodic Protection

C. Section 3.6 Corrosion Control – External Protective Coating

D. Section 3.7 Corrosion Control – Internal Corrosion

E. Section 3.9 Corrosion Control – Underground Piping Cathodic Protection System Test Procedures

F. Section 3.10 Corrosion Control – Maps and Records

VIII. RECORDS

A. Complete SU-0209 Pipeline Leak Report and/or SU-0203 Corrosion Control Report and/or SU-0210 Pipeline Repair Report

B. Keep the records for the life of the pipeline.

C. If a safety related condition exists, file SU-0213 Safety Related Condition Report with the D.O.T.