KINDER MORGAN

July 17, 2009

CERTIFIED MAIL 7005 0390 0003 9497 8392

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

Re: CPF 5-2009-1005M; Team Inspection of Kinder Morgan's (KM) Operations and Maintenance Manual.

Dear Mr. Hoidal;

In a letter dated June 26, 2009 PHMSA provided guidance on changes required as the result of a Team Inspection of Kinder Morgan's (KM) Operations and Maintenance (O&M) procedures. The inspection was performed in KM's Lakewood offices between April 14th and 16th and was attended by PHMSA's Western Region, Southwest Region and Central Region.

In this correspondence KM will respond to each issue that PHMSA indicated required a change by repeating PHMSA's request for change and immediately following in bold font KM's response.

1. § 191.15 Transmission and gathering system: Incident report.
KM did not address in its O&M procedure 159 pertaining to a Supplemental Report. Part 191.15(b) requires the operator to submit a Supplemental Report as soon as practical with a clear reference by date and subject to the original report.

**Kinder Morgan's Response:**

**Kinder Morgan's O&M Procedure 159 – Incident Reporting and Investigation Section 3.3.1.2 directs PHMSA reporting requirements to O&M Procedure 219 – DOT and State Pipeline Reports. Kinder Morgan has revised O&M Procedure 219 – DOT and State Pipeline Reports to reflect the required changes. A copy of each O&M Procedure is attached in Appendix 1.**

2. § 191.25 Filing safety-related conditions reports.
KM O&M Procedure 214 Sec. 3.1.2 terminology with respect to the five (5) and ten (10) days reporting requirement is not consistent with the required outlined in Part 192.25(a).

**Kinder Morgan's Response:**

**Kinder Morgan has revised O&M Procedure 214 – Reporting Pipeline Safety-Related Conditions to reflect the required changes. A copy of the O&M Procedure is attached in Appendix 2.**

3. § 192.179 Transmission line valves.
   KM O&M Procedures, the Engineering Design Manual and the Construction Standards Manual did not address the valve spacing with respect to either new construction or any modifications to the existing pipelines.

**Kinder Morgan's Response:**

**Kinder Morgan has revised O&M Procedure 220 - Structure Survey for Class Location and HCA Determination and Engineering Standard E0100 – Pipelines (Onshore) to reflect the required change. A copy of the O&M Procedure and Engineering Standard is attached in Appendix 3.**

4. §192.605 Procedural Manual.
   KM O&M Procedure 100, Section 3.2 did not address the details of how KM would review the work done by the operator's personnel to determine whether the procedures that their personnel follow are adequate for the given task or situation.

**Kinder Morgan's Response:**

**Kinder Morgan would like to rebut the assertion that O&M Procedure 100 – Employees' O&M Responsibilities Sec 3.2 does not adequately meet the requirements of §192.605(b)(8). As evidence of compliance with the fore mentioned regulation KM will describe our process for review of O&M procedures for effectiveness.**

**Kinder Morgan employees whether they are maintenance, technical, supervisory or managerial have the responsibility of being familiar with the contents of the O&M Procedures Manual and following the requirements as they conduct their job responsibilities. Kinder Morgan's O&M Procedure 100 – Employees' O&M Responsibilities describes those requirements and then goes on to direct all employees to engage the Management of Change process embedded in O&M Procedure 001 – Standards Modification if deficiencies in the procedures are discovered. The Action Decision Committee (ADC) meets monthly and reviews requests for change and if appropriate approves the request. The voting membership of the ADC consists of Directors from EHS, Operations, Project Management, Safety and Compliance/Codes and Standards, which helps ensure that all requests for change meet Kinder Morgan's requirements for operating safe and code compliant facilities. Participation in this process is encouraged by KM management and is open to participation by all levels of Kinder Morgan employees.**

**Additionally, the O&M manual is reviewed on an annual basis as required by § 192.605(a) and detailed in KM O&M Procedure 000 - Action Decision Committee, Section 3.5. KM is providing for your review O&M Procedure 100 – Employees' O&M Responsibilities, O&M Procedure 001 – Standards Modification and O&M Procedure 000 – Action Decision Committee located in Appendix 4.**

5. §192.605 Procedural Manual.
KM O&M Procedures 1101 and 1102 did not have adequate procedures to check for variations from normal operations after an abnormal operation has ended at critical locations in the system for safe operation.

**Kinder Morgan's Response:**

**Kinder Morgan requests a 60 day extension to review our internal processes, make the necessary changes to our procedures through our management of change process and communicate with all of the stakeholders.**

6. §192.605 Procedural Manual.
KM O&M Procedures 1101 and 1102 did not specify how KM would review the response of the operator's personnel to determine whether the procedures that their personnel follow are adequate to control an abnormal operation and to take corrective action where deficiencies are found.

**Kinder Morgan's Response:**

**Kinder Morgan requests a 60 day extension to review our internal processes, make the necessary changes to our procedures through our management of change process and communicate with all of the stakeholders.**

7. § 192.614 Damage Prevention Program.
KM O&M Procedure 204 did not have adequate procedures to address how they would temporarily mark buried pipelines in the area of excavation activity before the activity begins.

**Kinder Morgan's Response:**

**Kinder Morgan would like to rebut the assertion that we are not meeting the requirements of § 192.614(c)(4). KM feels that O&M Procedure and Construction Standard 204/C1005 – Construction near Company Facilities does provide instruction to field personnel on how they should temporarily mark KM's buried pipelines in the areas of excavation activity. KM is providing a copy of O&M Procedure and Construction Standard 204/C1005 for your review and calls your attention to Section 3.4.1 where the individual bullet points delineate the requirements for when to mark KM's pipelines and how KM's pipelines are to be marked.**
**A copy of the O&M Procedure and Construction Standard is attached in Appendix 5.**

8. § 192.605 Procedural Manual.
KM O&M Procedure 214 did not have adequate procedures to direct the employees who perform O&M activities to recognize or identify SRCs in the field.

**Kinder Morgan's Response:**

**Kinder Morgan would like to rebut the assertion that we are not meeting the requirements of § 192.605(d) Safety-related condition reports (SRC). KM O&M Procedure 100 – Employees' O&M Responsibilities instructs each employee of their responsibilities to be familiar with the contents of the O&M Procedures Manual and follow the requirements as they conduct their job responsibilities. KM O&M Procedure 214 – Reporting Pipeline**

**Safety-Related Conditions, Section 3.1.1 provides specific instructions on how to identify a potential SRC and the steps necessary to report them. A copy of O&M Procedure 100 and O&M Procedure 214 have been provided in previous appendices.**

9. §192.711 Transmission lines: General Requirements
   KM O&M Procedure 213 did not require the operator to take immediate temporary measures to protect the public when the conditions noted in this subpart exist.

**Kinder Morgan's Response:**

**Kinder Morgan has revised O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage to reflect the required changes. A copy of the O&M Procedure is attached in Appendix 6.**

10. § 192.713 Transmission lines: Permanent Field Repair
    KM O&M Procedure 213 did not have adequate procedures to require a permanent field repair of imperfections and damages in a steel transmission line to be replaced with a cylindrical piece of pipe that is greater than or equal to the design strength of the pipe.

**Kinder Morgan's Response:**

**Kinder Morgan has revised O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage to reflect the required changes. A copy of the O&M Procedure is attached in Appendix 6.**

11. § 192.225 Welding Procedures
    KM's procedures throughout the applicable parts of the O&M and welding manuals are inconsistent in referencing the most current or latest approved versions of API 1104 and ASME Section IX.

**Kinder Morgan's Response:**

**Kinder Morgan is in the process of reviewing our O&M Procedures and Engineering and Construction Standards to ensure consistency in our reference to the use of the appropriate edition of API 1104 and ASME Section IX. Kinder Morgan shall complete this review within 60 days and subsequently communicate to PHMSA that it has been completed on or before September 21, 2009.**

12. § 192.225 Welding Procedures:
    KM O&M Procedure 407 did not have adequate procedures to require that each welding procedure is not only recorded in detail but also includes the results of the qualifying tests. KM's procedures do not discern in the O&M Manual about the retention time frame of each qualifying test compared to retention of the welding procedure itself.

**Kinder Morgan's Response:**

**Kinder Morgan would like to rebut the assertion that KM O&M Procedure and Construction Standard 407/C1067 – Welding Procedures and Selection Guide does not meet the requirements of § 192.225(b). Kinder Morgan's O&M Procedure and Construction Standard 407/C1067 – Welding Procedures and Selection Guide, Section 3.1 provides instruction on how a Kinder Morgan welding procedure is to be qualified following the**

**requirements of API 1104 or ASME Section IX. When the welding procedure has been properly qualified and after it has gone through the Action Decision Committee process as described in KM O&M Procedure 001 – Standards Modification it is then added to our listing of qualified procedures contained in O&M Procedure 407. Any weld performed on Kinder Morgan gas facilities must use a qualified procedure as described in KM O&M Procedure and Construction Standard 402/C1062 Section 3. The procedure qualification reports (PQR) are maintained in the corporate files and are available, upon request, to support the welding procedure. It is required that a welder performing work on a KM facility have a qualified procedure in their possession to perform the weld. It is not necessary for the welder to have the PQR.**

**With regard to KM not specifying the retention requirements related to the PQR, KM has added the PQR to O&M 1400 – Records Retention by O&M Procedure with the requirement that the PQR be maintained for the life of the facilities.**

**A Copy of O&M Procedure 407 (with example of welding procedure 407.060), O&M Procedure and Construction Standard 402/C1062 and O&M Procedure 1400 are attached for your review in Appendix 7.**

13. § 192.243 Nondestructive Testing.
    KM O&M Procedure Series 1400 did not have adequate procedures because it did not require NDT test records to contain all pertinent information that is required by this subpart.

**Kinder Morgan's Response:**

**Kinder Morgan requests a 60 day extension to review our internal processes, make the necessary changes to our procedures through our management of change process and communicate with all of the stakeholders.**

14. § 192.461 External Corrosion Control: Protective Coating
    KM O&M Procedure 203 and Corrosion Procedure 1082 for pipeline coatings did not address or include the requirements outlined in 192.461(a)(2-5) and 192.461(b).

**Kinder Morgan's Response:**

**Kinder Morgan has revised O&M Procedure and Construction Standard 203/C1082 – Coating Pipelines to reflect the required changes. A copy of the O&M Procedure is attached in Appendix 8.**

15. § 192.476 Internal Corrosion Control
    KM O&M Series 900 procedures and Series 1700 I&M procedures did not require new transmission lines and its components to be designed and constructed to reduce the risk of internal corrosion.

**Kinder Morgan's Response:**

**Kinder Morgan has revised Engineering Standard E0100 – Pipelines (Onshore) to reflect the required changes. A copy of the Engineering Standard is attached in Appendix 3.**

16. § 192.476 Internal Corrosion Control
KM O&M Series 900 procedures and Series 1700 I&M procedures did not require changes to existing transmission lines to be evaluated for the impact of the change on internal corrosion risk to the downstream portion of an existing line and to provide for removal of liquids and monitoring of internal corrosion as appropriate new transmission lines and its components to be designed and constructed to reduce the risk of internal corrosion.

**Kinder Morgan's Response:**

**Kinder Morgan has revised Engineering Standard E0100 – Pipelines (Onshore) to reflect the required changes. A copy of the Engineering Standard is attached in Appendix 3.**

In responding to this Notice of Amendment Kinder Morgan chooses to exercise our prerogative as stated in; Procedures for Responding to a NOTICE OF AMENDMENT (NOA) subpart (c) and rebut the allegations numbered; 4, 7, 8 & 12. Kinder Morgan is providing additional information and explanations of our processes that we are hopeful will demonstrate to PHMSA that our procedures are indeed adequate to meet the requirements of the regulations as stated in the NOA. Further Kinder Morgan reserves the right to request a hearing at a later date if this response is inadequate to meet the requirements of the NOA.

Additionally Kinder Morgan requests an EXTENSION OF TIME of 60 days as allowed under the Procedures for Responding to a Notice of Amendment to allegations numbered 5, 6, 11 and 13. This period of time is necessary to examine our existing procedures and make determinations on what changes need to be made to become compliant with the stated regulations.

If there are any questions related to this response please call Mr. Bruce Hancock, Director of Compliance / Codes and Standards at 303-914-7959.

Sincerely,

Bruce Hancock

for M. Dwayne Burton
Vice President, Gas Pipeline
Operations and Engineering
Kinder Morgan, Inc.
One Allen Center
500 Dallas Street
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Houston, TX 77002
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# Appendix 1

## Table of Contents



## 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☒ Kinder Morgan Power Company

This procedure applies to all Company operations and locations, contractors (and their subcontractors) and contract employees (refer to **O&M Procedure 102 – Contractor Safety**).

## 2. Scope

This procedure applies to the following:

- Fatalities involving Company employees and contractors, lost work days and/or modified duty days associated with injuries and illnesses, Occupational Safety and Hazard Administration (OSHA)-recordable incidents and first aid cases
- Damage to Company facilities, equipment, property or vehicles (facilities can include pipelines and associated equipment)
- Damages to customers and third parties
- Potentially high loss near misses that could have resulted in any of the above under slightly different circumstances (as determined by the Environmental, Health and Safety [EHS] representative or the affected area's senior Company official)
- Incidents that result in or could have resulted in an unexpected release of a chemical substance, gas or loss of product into the workplace or environment (refer to **O&M Procedure 1030 – Unmeasured Gas Use/Loss Reporting** and **O&M Procedure 1201 – Environmental Release Response**)

## 3. Core Information and Requirements

An incident is an undesired event that could or does result in harm to people, damage to Company facilities, equipment, property, vehicles or loss to process.

The Company requires reporting and investigating incidents and potentially high loss near misses. Various agencies require incident reporting, including U.S. Department of Transportation (DOT), OSHA, Environmental Protection Agency (EPA) and implementing state or local agencies. The Company uses **STARS** and various forms for reporting, tracking, investigating and documenting incidents.

### 3.1. Initial Response Actions

Table 1 – Initial Response Actions shows the initial response actions to take or consider for each incident. The actual steps taken will depend upon the incident's nature.

| | |
|---|---|
| 1. Determine what happened | • *Injury, property damage, hazardous material release, near miss, etc.* |
| 2. Initiate emergency response, report incident to supervisor and EHS representative | • Medical, fire, hazardous materials (HAZMAT), spill response<br>• Contact Gas Control, which will initiate ERL or ERL+ notification system<br>• Refer to Corporate Crisis Response Manual<br>• Advise supervisor and EHS representative of the accident/incident by telephone |
| 3. Respond to and assess scene | • Identify source of loss (equipment, material, environment) |
| 4. Reduce/eliminate additional losses | • Isolate source of loss and clear area of unnecessary personnel |
| 5. *Preserve evidence/scene* | • People, position, parts, paper<br>• Send employee(s) for drug/alcohol testing. The local Manager and Codes and Standards will determine if drug and alcohol testing is not required. |
| 6. Report workers' compensation and auto incidents to Company 800 number | • Call 1-800-353-2556 within 24 hours |
| 7. Begin formal investigation | • Assemble investigation team members |

**Table 1 - Initial Response Actions**

### 3.2. Determining Reporting Levels

3.2.1. Level I - ERL

**Send an ERL notification for any event associated with a Company operation that includes one or more of the following:**

- Notifying a local, state or federal agency is required
- Unpermitted release of gas, other material or substance or chemical spill that requires reporting to a governmental agency
- Any product or chemical release into a river, stream, creek, pond or other water body
- Any incident where the estimated property damage to company equipment, vehicles or facilities; or Company's portion of the repairs, cost, spill remediation and/or emergency response is likely to be $5,000 or more
- DOT, OSHA, FERC or EPA (or state/local equivalents) inquiry or involvement in any of the above-listed events, including regulatory agency representative on site
- Significant media or public attention
- Unannounced agency inspections (e.g., OSHA, EPA or state agency, DOT/PHMSA, etc.)

3.2.2. Level II – ERL Plus

**Send an ERL Plus notification for any major event associated with a Company operation that includes one or more of the following:**

- Major operations disruption or shutdown
- Service interruption to a wholesale customer, town distribution system, government installation or industrial plant
- Fire, rupture or explosion that involves Company equipment or facilities
- Any employee or contractor injury or illness that requires in-patient hospitalization as the result of work-related activities involving Company equipment and/or facilities

- The death of employee(s) or contract employee(s) as the result of work-related activities involving Company equipment or facilities
- Any fatality or injury to a member of the public

**3.3. Reporting Incidents**

Reporting in a timely manner is important. Agency-reportable incidents must be reported within the DOT's or the state's time frame of two hours from the time of discovery.

Notify your supervisor, EHS representative and Gas Control by telephone of the incidents listed above as soon as possible.

3.3.1. Telephone Notifications

3.3.1.1. Gas Control

The following are examples of incidents for which Gas Control must be contacted as soon as possible:

- Release of gas and/or estimated property damage to Company facilities, including cost of gas lost, of $5,000 or more
- Any natural gas vented to the atmosphere that could exceed EPA regulated reportable quantities (**O&M Procedure 1201 – Environmental Release Response**)
- Hazardous material release (i.e., $H_2S$, sulfuric acid, etc.) that could exceed EPA regulated reportable quantities (**O&M Procedure 1201 – Environmental Release Response**)
- Oil, drip or refined product released off Company property that reaches water or wetlands and causes a sheen (rainbow) on the water's surface
- A release requiring using a spill response/remediation contractor
- Death of an employee, contractor or member of the public
- Personal injury to an employee, contractor or the public requiring in-patient hospitalization
- Fire or explosion involving Company property, pipeline facilities or equipment
- Fire or explosion caused by Company facilities involving public or private property
- Damage to third party property caused by Company facilities, Company personnel, etc. that local Operations personnel deem significant
- Removing a pipeline from service (not including scheduled or temporary shutdowns or pressure reductions connected with routine maintenance, construction or damage repair)
- Interrupting service to a wholesale customer, community, government installation or industrial plant (not including scheduled or temporary shutdowns or pressure reductions connected with routine maintenance, construction or damage repair)
- Unannounced agency inspections (e.g., OSHA, EPA or state agency, DOT/PHMSA, etc.)
- An event that the Operations Manager or EHS representative considers significant although it does not meet any of the listed criteria

3.3.1.2. Telephonic Report to the National Response Center (NRC)

A member of Company's Codes and Standards Group or a member of EHS shall be responsible for reporting incidents as defined in 49 CFR 191.3. The telephonic report shall be made within the two-hour reporting limit by dialing 1-800-424-8802. The caller shall report the following information to the NRC at the time of the call:

- Names of person making report and their telephone numbers
- The location of the incident, the county that the incident occurred in, the nearest town and/or highway near the incident
- The time of the incident
- The number of fatalities and personal injuries, if any
- Other significant facts that are known and the extent of the damages

Document the name of the person who took the call at the NRC, the time the call was made to the NRC and the Report Number under which the NRC recorded the call.

The Company's Codes and Standards Group shall submit Form RSPA F 7100.2 to the DOT as soon as practicable but not more than 30 days after a reportable incident has occurred. **Refer to <u>O&M 219 – DOT and State Pipeline Reports</u>.**

3.3.1.3. Emergency Response Contact Numbers

- For NGPL, Trailblazer and Kinder Morgan North Texas pipeline facility incidents, notify NGPL Houston Gas Control at 800-733-2490.
- For KMTP pipeline facility incidents, notify KMTP Houston Gas Control at 800-633-0184.
- For KM Tejas Pipeline facility incidents, notify KM Tejas Houston Gas Control at 800-568-7512.
- For pipeline facility incidents for all other Company natural gas subsidiaries, notify Lakewood Gas Control at 888-763-3690.

3.3.2. Incidents Requiring Additional Reporting

3.3.2.1. Colorado

In Colorado, each reporting location must report excavation-caused damage to all pipelines to the Utility Notification Center of Colorado (UNCC).

- Damage reports must be made within 90 days after the line has been repaired and service restored.
- The designated Company representative will report excavation-caused damage via the **<u>Common Ground Alliance Damage Reporting Tool</u>** (DIRT) on a quarterly basis.

3.3.2.2. Nebraska

Per Title 155 of the Nebraska Administrative Code: Any failure which results in the explosion or ignition of natural gas downstream of the distribution meter, including failures caused by customer owned facilities, must be reported to the State Fire Marshal Pipeline Safety Division within 2 hours, or as soon as practical, following discovery.

3.3.2.3. Texas

In Texas, each reporting location must report excavation-caused damage to all intrastate pipelines within 10 days of the damage incident or of the operator's actual knowledge of the damage.

- The Operations Manager or designee shall report the damage to the Company's Damage Prevention Group within 7 days of discovery of the damage incident using the **Texas Damage Reporting Form (TDRF) Operator Field Data**.
- A member of Company's Damage Prevention Group shall report the damage to the Texas Railroad Commission, through the **<u>TDRF</u>** (**<u>http://www.rrc.state.tx.us/formpr/index.html</u>**), within 10 days of discovery of the damage incident.

3.3.2.4. Offshore Incidents Only

In addition to field personnel notifying Gas Control, for reportable incidents, the local supervisor will also contact the National Response Center (NRC) and the Minerals Management Service (MMS) to report the incident.

3.3.2.5. NGPL's Risk Management Demonstration Program (RMDP) Only

In addition to field personnel notifying Gas Control, the Manager, Pipeline Integrity, will report all incidents that occur on pipelines within the boundaries of NGPL's RMDP and on those included pipelines beyond the boundary of the Plan up to the first mainline compressor station either upstream or downstream of the demonstration area. The

Pipeline Integrity Department will notify the following personnel and/or agencies:

- The appropriate DOT Region for any incident (reportable or non-reportable) that involves a natural gas leak or third- party damage
- Mr. Bruce Hansen, DOT Project Review Team or his designee for any incident (reportable or non-reportable) that involves a natural gas leak or third party damage within the RMDP area previously identified

If a non-reportable incident occurs after normal working hours, notify both DOT and Mr. Hansen on the next working day.

3.3.2.6. Waiver or Special Permit Pipelines

Pipelines operating under waiver or special permits will notify the Regional Office of PHMSA within 24 hours of any otherwise non-reportable leaks on the pipeline. The Director of Codes and Standards or designee will make the contact with the appropriate PHMSA Regional Director.

3.3.2.7. Motor Vehicle Accidents

Always report all property damage incidents, regardless of severity, that involve a third party, whether a vehicle or other property, i.e., cow, dog, mailbox, etc. to the 1-800-353-2556 Claims Reporting number.

First party vehicle incidents need not be reported to the 800 Claims Reporting number but still require reporting in **STARS** (http://kmonline/ehs/Pages/STARS.aspx). (Link here to report a vehicle accident using **STARS**.)

First party claims are defined as damage or injury caused by a Company employee to a Company vehicle and/or Company property. In other words, a first party claim is any vehicle incident that does not involve a third party.

3.3.2.8. Injuries/Illnesses

Call in all employee injuries/illnesses (Workers' Compensation claims) to the insurance reporting line, 1-800-353-2556, within 24 hours. Notify supervisor immediately.

These types of injuries include but are not limited to the following:

- Injuries involving head, neck, shoulders, back, hips or knees, regardless of severity; no exceptions
- Injuries/illnesses requiring a physician's follow-up medical treatment or a prescription medication

Injuries that require first aid treatment only, i.e., minor cuts and scrapes, dirt in eyes, stubbed or pinched fingers and insect bites do not need to be reported via the 800 insurance reporting line unless the employee will need to seek medical attention.

3.3.3. Forms

3.3.3.1. Injury/illness

All potentially high loss (near miss) injuries or actual injuries (including ones requiring first aid), illnesses or fatalities must be reported to the immediate supervisor and the EHS representative within 24 hours of the incident. Also report the incident in **STARS** (http://kmonline/ehs/Pages/STARS.aspx). (Link here to report an injury/illness, first aid only, near miss or information-only incident using the **STARS**.).

Supervisors – to report an injury/illness, first aid only, near miss or information-only incident on behalf of an employee in your work group, use the **STARS** Production link and type in the employee's complete e-mail address on logon screen.

3.3.3.2. Motor Vehicle Accident or Damage

For detailed information regarding the company-wide EHS policy, vehicle accident reporting and internal benchmarking, refer to the **EHS Policy Manual**.

Employees involved in motor vehicle incidents while on Company business using Company, rented or personal vehicles must report the accident to their immediate supervisor and their EHS representative as soon as possible, regardless of damage severity.

Report all damage to Company motor vehicles, rental vehicles and personal motor vehicles being used for Company business, regardless of damage severity, in **STARS** within 24 hours, including:

- Scratches, bumps and dents
- Damage caused solely by rocks, gravel or other materials thrown by vehicles and/or damage resulting solely from objects falling on a vehicle or from weather related incidents
- Damage caused by vandalism or unknown parties

All motor vehicle incidents, regardless of severity, involving a third party, i.e., non-company vehicle, person, cow, dog, mailbox, etc., must always be reported in **STARS** (http://kmonline/ehs/Pages/STARS.aspx). (Link here to report a vehicle accident using **STARS**.)

Supervisors – to report a motor vehicle accident on behalf of an employee in your work group, use the **STARS** Production link and type in the employee's complete e-mail address on the logon screen.

3.3.3.3. Property Damage

Report any property damage, except damage to motor vehicles, incurred by the Company or other parties to third parties, customers, Company facilities, equipment, tools, etc. using **O&M Form OM100-36 – Property Loss Report**. This includes damage resulting from residential or commercial fires. This does not include pipeline-related incidents.

3.3.3.4. Environmental Releases

Consult **O&M Procedure 1201 – Environmental Release Response** for additional guidelines regarding environmental release response.

3.3.3.5. Gas Lost

Report gas lost through pipeline incidents in conformance with **O&M Procedure 1030 – Unmeasured Gas Use/Loss Reporting** using either **Online Field Ticketing – Unmeasured Gas** and/or **O&M Form OM1000-05 – Gas Lost Report**.

3.3.3.6. Pipeline Facilities Incidents

Report any pipeline facilities incidents (both jurisdictional and non-jurisdictional under 49 CFR 191 and 192, DOT) within ten days from the time of discovery using **O&M Form OM200-08 – Pipeline Incident Report**.

### 3.4. Incident Investigation

The Company will investigate all incidents that result in or have the potential to result in, injury or illness, major property damage, process/product loss or harm to the environment. The investigative process includes identifying root causes or causal factors that contributed to the occurrence, determining the necessary corrective actions and timely follow-up to ensure that corrective actions have been completed.

While lessons learned from conducting investigations may be shared with Company employees, hold specific, sensitive information (names of persons involved, specific locations, financial data, etc.) in strict confidence. The primary purpose of an accident/incident investigation is not to find fault or place blame. Reports resulting from investigations may be discoverable by government *investigators or third parties.* Persons who provide information to an investigator may not be granted immunity from prosecution, third party claims or disciplinary action. Additionally, indemnification may not be available from the Company.

If, in the course of an accident/incident investigation, evidence suggests the possibility that the occurrence was not an accident but an intentional violation of Company policy or procedures, negligence or illegal activity, such evidence will be immediately turned over to the appropriate Company officials or authorities.

Table 2 – Incident Investigating Requirements provides guidance on what level of investigation to conduct for Levels I and II incidents, depending on the magnitude. The supervisor and EHS representative will need to complete the investigation report on **STARS** http://kmonline/ehs/Pages/STARS.aspx. (Supervisors – link here and use the **STARS** Production link to access the Incident Investigation Module.) Certain Level I and II incidents will require a more detailed and formalized investigation.

Additionally, determine immediate and basic (root) causes and remedial actions during the investigation and document in **STARS** (http://kmonline/ehs/Pages/STARS.aspx) using, but not limited to, Attachment 1 – Examples. (Supervisors – link here and use the **STARS** Production link to access the Incident Investigation Module.)

| Incident Level | Requirements |
|---|---|
| **Level 0** | • No regulatory notification is required<br>• No continuing or potential harm to human life or property<br>• Estimated property damage, including gas lost, is less than $5,000<br>• *No significant media or public attention as deemed by local supervisor*<br>• Any personal injury that requires a physician's emergency treatment but that does not require formal hospital admittance<br>• At the close of the business day, supervisory personnel or designee will review leak complaints received and actions taken to ensure no hazardous conditions exist (no documentation required)<br>• Requires completing a report in the appropriate **STARS** module |
| **Levels I and II** | • Notifying a local, state or federal agency is required<br>• Unpermitted release of gas, other material or substance or chemical spill, which requires reporting to a governmental agency<br>• Any product or chemical release into a river, stream, creek, pond or other water body<br>• Any incident where the estimated property damage to company equipment, vehicles or facilities or Company's portion of the repairs, cost, spill remediation and/or emergency response is likely to be $5,000 or more<br>• DOT, OSHA, FERC or EPA (or state/local equivalents) inquiry or involvement in any of the above-listed events, including regulatory agency representative on site<br>• Any employee or contractor injury or illness that requires in-patient hospitalization as the result of work-related activities involving Company equipment and/or facilities<br>• Significant media or public attention<br>• Major operations disruption or shutdown<br>• Service interruption to a wholesale customer, town distribution system, government installation or industrial plant<br>• Fire, rupture or explosion that involves Company equipment or facilities<br>• The death of employee(s) or contract employee(s) as the result of work-related activities involving Company equipment or facilities<br>• Any fatality or injury to a member of the public<br>• Any serious near miss or high potential incident that involves any of the criteria listed above<br>• Requires phoning Gas Control Immediately<br>• Injuries, illness and vehicle accidents require completing the investigation in **STARS**<br>• All other level I and II incidents use **O&M Form OM100-45 – Incident Investigation Summary** or the Taproot computer based investigation system.<br>• Requires Basic Cause Analysis, Taproot Computer Based Investigation System or other accepted incident investigation method at the EHS Department's direction |

**Table 2 - Incident Investigating Requirements**

The Emergency Response Investigation Committee (ERIC) may initiate investigations after consulting with the Legal Department. Employees are to participate in these investigations. Table 3 – Incident Investigation Team Members provides guidance on the types of people/groups to consider when forming an incident investigation team.

| Incident Level | Team Members (ERIC Team) |
|---|---|
| Level 0 | **Leader:** Area/Region EHS representative or appropriately trained delegate<br>**Participants:**<br>• Facility/Area Supervisor<br>• Facility/Area employee<br>(More team members may be added at the Team Leader's request)<br>**In addition, at PSM facilities participants must include:**<br>• At least one employee knowledgeable in the process involved<br>• Contract employee if the incident involved contractor's work<br>• Other persons with appropriate knowledge and experience to properly investigate and analyze the incident if necessary |
| Levels I and II | **Leader:** May be designated by a President or designee, Corporate EHS Department or as determined during the ERL+ conference call<br>**Participants may include:**<br>• Engineering and Technical Services, as applicable<br>• *Environmental or Safety* Department, as applicable<br>• Pipeline Integrity Department, as applicable<br>• PSM Coordinator, as applicable<br>• Facility/Area Manager or Supervisor<br>• Facility/Area employee<br>• Safety Committee member<br>**In addition, at PSM facilities participants must include:**<br>• At least one employee knowledgeable in the process involved<br>• Contract employee if the incident involved contractor's work<br>• Other persons with appropriate knowledge and experience to properly investigate and analyze the incident if necessary |
| | **Team Advisors:**<br>• Legal Department<br>• Insurance Risk Management Department<br>• Depending on the incident type, individuals with metallurgy, corrosion, measurement, compressor station and pipeline expertise<br>(More team members may be added at the Team Leader's request) |

**Table 3 - Incident Investigation Team Members**

### 3.5. Failure Investigation

When an incident is reported to Gas Control, a Company officer or designee will determine to what extent an investigation is required and who will conduct the investigation. An investigation team can be formed from either local management personnel or an ERIC Team (refer to Table 3 – Incident Investigation Team Members).

Depending on the extent of the incident and investigation, the investigative team will:

- Gather all available facts
- Sketch the scene and/or take pictures when possible
- Collect and save physical evidence and pertinent data
  - If specimens are cleaned, use water only
  - Do not use a wire brush or oil
  - Do not fit parts back together during packaging for shipping
  - Carefully mark the direction of gas flow and pipe's orientation to 12 o'clock on specimens
- Interview witnesses and responsible parties, identifying events leading to and during the incident
- Address questions regarding *machinery, personal* protective equipment, tools and equipment, chemicals and environmental concerns and process safety

- Review written procedures, job instructions and specifications covering the operation being performed at the time of the incident
- Review the attitudes, priorities, stress levels, physical condition and perceptions of involved employees. Consult with the Legal Department in any investigative process if it becomes necessary to protect the investigation as privileged in potential liability situations.

After collecting applicable information, the investigation team will prepare and write a report that accomplishes all of the following:

- Interprets the facts
- Determines the possible root cause
- Identifies contributing factors
- Develops corrective actions for each cause or contributing factor
- Makes specific recommendations that consider risk and economic analysis
- Establishes individual responsibilities for and completion dates for each recommendation
- Provides a mechanism that tracks each recommendation to completion

## 4. Training

Provide the information in this procedure to all employees during regularly scheduled safety training sessions:

- Upon policy implementation
- Whenever there is a change
- Once every three years thereafter

Initially train EHS representative in root cause analysis using the Basic Cause Analysis Model, **Taproot**® System or equivalent system.

**STARS** Required 4 Part Online Breeze Training and **STARS** Application Training, both found on http://kmonline/ehs/Pages/EHSHotLinks.aspx. Additional reference and training materials are also available at this site.

## 5. Documentation

Report all incidents and associated gas lost using the applicable O&M forms or electronic systems:

- **O&M Form OM100-36 – Property Loss Report**
- **O&M Form OM200-08 – Pipeline Incident Report**
- **O&M Form OM1000-05 – Gas Lost Report**
- **O&M Form OM100-45 – Incident Investigation Summary**
- **Online Field Ticketing – Unmeasured Gas**

Investigate all injury, illness and vehicle incidents using **STARS**. Use **O&M Form OM100-45 – Incident Investigation Summary** or the Taproot computer based investigation system for all other incident investigations. The Area/Region EHS representative will track incident reporting process completion, determine if incidents are recordable, preventable, etc. and close the incident report in **STARS**.

The Corporate EHS Department documents and tracks remedial actions and distributes reports to other departments as needed and/or required.

The Corporate EHS Department maintains the **STARS** database, including resolutions and remedial actions documentation for at least five years. Do not destroy documents before consulting the Legal and Insurance Risk Management departments.

- Report all gas lost related to pipeline incidents through **Online Field Ticketing – Unmeasured Gas** for all Company assets.

### 5.1. Printed Reports

For the life of the pipeline, maintain copies of completed **O&M Form OM200-08 – Pipeline Incident Report** in the local office files and route copies to the following departments or job titles:

- **Codes and Standards**
- **Engineering Records**
- **Risk Engineering**, when the incident occurs in an HCA

Submit incident investigation reports to the same departments/job titles. If a final report cannot be submitted within ten calendar days, then submit a preliminary report and follow with the final report.

After the required Legal and EHS review, the Corporate EHS Department will provide a copy of the final incident investigation report to affected PSM facilities for their files, to be maintained for at least five years. Additionally, the Corporate EHS Department will provide all field operations "lessons learned" for incidents as needed.

## 6. References

- 29 CFR 1910.119
- 49 CFR Part 191.3 - Definition of incident
- 49 CFR Part 191.5 - Telephone notice
- 49 CFR Part 191.7 - Addressee for written reports
- 49 CFR Part 191.15 – Transmission and gathering systems: Incident report
- 49 CFR Part 191.23 – Reporting safety-related conditions
- 49 CFR Part 191.25 – Filing safety-related condition reports
- 49 CFR Part 192.605(d) – Safety-related condition reports
- Texas Regulations Title 16 TAC 18.11
- Colorado Title 9, Article 1.5, Section 103 – UNCC Utility Damage Reporting
- **O&M Procedure 102 – Contractor Safety**
- **O&M Procedure 219 – DOT and State Pipeline Reports**
- **O&M Procedure 1030 – Unmeasured Gas Use/Loss Reporting**
- **O&M Procedure 1201 – Environmental Release Response**
- **O&M Form OM100-36 – Property Loss Report**
- **O&M Form OM200-08 – Pipeline Incident Report**
- **O&M Form OM1000-05 – Gas Lost Report**
- **O&M Form OM100-45 – Incident Investigation Summary**
- **EHS Policy Manual**
- **STARS**
- *Site-Specific Emergency Plan*
- **Online Field Ticketing – Unmeasured Gas**

## Attachment 1 – Examples

**Examples of Immediate Causes**

| Actions | Conditions |
|---|---|
| 1. Operating equipment without proper authority | 1. Guards or barriers |
| 2. Failing to warn | 2. Protective equipment |
| 3. Failing to secure | 3. Tools, equipment or materials |
| 4. Operating at improper speeds | 4. Congestion |
| 5. Making safety devices inoperable | 5. Warning system |
| 6. Removing safety devices | 6. Fire and explosion hazards |
| 7. Using defective equipment | 7. Poor housekeeping |
| 8. Failing to use PPE properly | 8. Exposure to noise |
| 9. Loading improperly | 9. Exposure to hazardous materials |
| 10. Placing improperly | 10. Exposure to temperature extremes |
| 11. Lifting improperly | 11. Illumination |
| 12. Positioning improperly for task | 12. Ventilation |
| 13. Servicing equipment in operation | 13. Visibility |
| 14. Being under the influence of drugs or alcohol | |
| 15. Participating in horseplay | |

**Examples of Basic or Root Causes**

| Personal Factors | Job Factors |
|---|---|
| 1. Capability | 1. Supervision |
| 2. Knowledge | 2. Engineering |
| 3. Skill | 3. Purchasing |
| 4. Stress | 4. Maintenance |
| 5. Motivation | 5. Tools and equipment |
| | 6. Work standards |
| | 7. Wear and tear |
| | 8. Abuse or misuse |

**Management Programs for Controlling Incidents**

| | |
|---|---|
| 1. Leadership and administration | 9. Health control |
| 2. Management training | 10. Program audits |
| 3. Planned inspections | 11. Engineering controls |
| 4. Task and analysis procedures | 12. Personal communications |
| 5. Task observation | 13. Group meetings |
| 6. Emergency preparedness | 14. General promotion |
| 7. Organizational rules | 15. Hiring and placement |
| 8. Accident/incident analysis | 16. Purchasing controls |

## Table of Contents



## 1. Applicability

☒ Gathering

☐ Processing

☒ Transmission/Regulated Onshore Gathering

☐ Kinder Morgan Power Company

## 2. Scope

This procedure provides guidelines to meet federal and state requirements for reporting Department of Transportation (DOT) storage, transmission and regulated onshore gathering pipeline mileage, and *other information.*

**Refer** to **O&M Procedure 238 – Regulated Onshore Gathering Line** for guidelines for field operations to classify pipe segments that are regulated under 49 CFR 192 and those pipe segments that are not regulated or considered jurisdictional under 49 CFR 192. The **Lakewood Codes and Standards Department (Codes and Standards)** will provide assistance in classifying lines should the field require help.

## 3. Core Information and Requirements

To ensure that mileages of all jurisdictional pipelines in service at the end of a calendar year and other information is reported to the DOT and/or state commissions, both field and corporate offices must maintain and compile data to complete the required reporting in an accurate and timely manner. Pipelines should be identified as Regulated Onshore Gathering, **Offshore Gathering** Transmission, or **Hazardous Liquids**. Pipelines associated with storage fields are considered transmission lines.

### 3.1. Information Gathering

#### 3.1.1. Gas Transmission and Gathering Annual Report

Each year by February 1, each Operations Manager **or their designee** should **report the number of leaks that occurred within the previous calendar year, for each KM-reporting** company, **to Codes and Standards. If there were no leaks notify Codes and Standards via e-mail, include the KM-reporting company name, and the associated pipeline districts and States. Otherwise, complete O&M Form OM200-17 – Annual Leak Report Gas Transmission and Gathering Systems for each KM-reporting company, for each State.** Upon completion, forward **the** form to the **Codes and Standards e-mail** or fax number 1-303-984-3916. **Refer to O&M Procedure 1700 – Inspection and Maintenance: I&M I-0219.02** – Annual Report–Gas Transmission and Gathering Systems. **Codes and Standards will work in conjunction with Engineering Records to obtain pipeline data for annual reporting.**

#### 3.1.2. Hazardous Liquids Annual Report

Each year by **March 14, Codes and Standards will obtain hazardous liquids pipeline data for annual reporting from the Engineering Records and Pipeline Integrity Management Departments for each pipeline facility operated at the end of the previous year. Refer to**

**O&M Procedure 1700 – Inspection and Maintenance**: I&M I-0219.06 – Annual Leak Report–Hazardous Liquids Systems.

3.1.3. Texas Plastic Pipe Inventory Annual Report – **Texas Intrastate pipelines only**

Each year by February 1, each Operations Manager responsible for plastic pipelines should complete and forward Form PS-81 – *Annual Plastic Pipe Inventory Report, found online at* http://www.rrc.state.tx.us/forms/forms/pipeline/index.php, to **Codes and Standards**. Refer to **O&M Procedure 1700 – Inspection and Maintenance**: I&M I-0219.07 – Annual Report - Texas Intrastate Plastic Pipe Inventory.

3.1.4. City of Corpus Christi Annual Report

Each year before March 31, **Codes and Standards** will work in conjunction with the **Engineering Records Department (Engineering Records)** to gather all necessary annual report submission information, in conformance with the **City of Corpus Christi Pipeline Ordinance 021776**, for all Company pipelines (active or inactive) within the jurisdiction of the City of Corpus Christi:

- Updated pipeline facility information, when the location or number of pipelines has changed
- Annual verified safety report
- Copies of all reports submitted to DOT/PHMSA or TRRC related to unsafe pipeline conditions, pipeline emergencies, or pipeline incidents
- *Copies of all reports submitted to state and federal environmental regulatory agencies* pertaining to pipeline releases which threatened to impact the environment, public health or safety

3.1.5. Waiver or Special Permit Pipeline Annual Report

Each year before December 31, **Codes and Standards** will work in conjunction with **Engineering Records**, **Pipeline Integrity Management/Risk Engineering**, and other appropriate Company departments to gather the following information for all pipeline facilities within the waiver or special permit area:

- The results of any in-line inspection (ILI) **and direct assessment results** during the previous year
- Any new integrity threats identified during the previous year
- Any encroachment **in the waiver area**, including the number of new residences or public gathering areas
- Any reportable incidents that occurred during the previous year
- **Any class or HCA changes during the previous year**
- *Any leaks on the pipeline that occurred during* the previous year
- A list of all repairs on the pipeline made during the previous year
- On-going damage prevention initiatives on the pipeline and a discussion of their success **or failure**
- **Any changes in procedures used to assess and/or monitor the pipeline**
- Company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibilities of the company operating the pipeline

3.1.6. Texas **Semi**-Annual Plastic Pipe **Leak** Report – **Texas Intrastate pipelines only**

Each year by **January 7 and July 7**, each Operations Manager responsible for plastic pipelines should **report any leaks identified on Company plastic pipeline facilities within the last 6 months, July 1 through December 31 and January 1 through June 30 respectively,** to **Codes and Standards**. Refer to **O&M Procedure 1700 – Inspection and Maintenance**: I&M I-0219.08 – Semi-Annual Report - Texas Intrastate Plastic Pipe Leak Information.

**Codes and Standards will work in conjunction with each Operations Manager and Engineering Records to gather all necessary information for submission to the Railroad**

Commission of Texas (TRRC), in accordance with the PS-95 Semi-Annual Leak Report Electronic Filing Requirements.

3.1.7. Railroad Commission of Texas Biennial Report

Each odd numbered year by December 31, **Codes and Standards** will work in conjunction with the Director of Damage Prevention and **Engineering Records** to compile a list of all Texas public schools located within 1000-feet of any Company pipeline. Schools in Texas are determined by the TRRC using the Texas Education Directory (**TED**) database. The report must be submitted in the same configuration as the **TRRC Form PS-87 – Gas & Liquid Transmission Pipeline Proximity to Public School** but may be submitted in spreadsheet format.

**3.2. Regulatory Submission**

3.2.1. National Pipeline Mapping System Annual Report

Each year by March 15, **Engineering Records** will review the Company's pipeline data for the previous calendar year. If changes have occurred, **Engineering Records** will resubmit the pipeline system information to the National Pipeline Mapping System (NPMS) in accordance with the **NPMS Operator Standards**. If no change has occurred since the last submission, the status may instead be recorded via the PHMSA "Update Your Submission Online" tool on the **NPMS Website**.

3.2.2. Gas Transmission and Gathering, Hazardous Liquids, and Texas Plastic Pipe Inventory Annual Reports

Each year by March 15, Codes and Standards will incorporate all annual report information and submit the appropriate reports to the required regulatory agencies:

- OPS/PHMSA Annual Report – electronically submit the applicable annual reports via the OPS Online Data Entry and Operator Registration System:
  - Transmission, Storage and Regulated Onshore Gathering Annual Report (PHMSA F 7100.2-1)
  - Hazardous Liquid or Carbon Dioxide Systems Annual Report (PHMSA F 7000-1.1)
- Railroad Commission of Texas Annual Report – Texas Intrastate pipelines only
  - Submit a copy of the electronically submitted OPS/PHMSA Annual Reports and confirmation via e-mail to **safety@rrc.state.tx.us**
  - Submit one signed Form PS-81 – Annual Plastic Pipe Inventory Report for each KM-reporting Company, if applicable. Submission must be electronic for systems with more than 1,000 customers (refer to **Form PS-81 – EDI Specifications**); otherwise, the report should be submitted via e-mail to **safety@rrc.state.tx.us**.

3.2.3. City of Corpus Christi – Annual Report

Each year on or before March 31, **Codes and Standards** will submit the annual report and fee, in conformance with the **City of Corpus Christi Pipeline Ordinance 021776**, to the Office of Emergency Management for all Company pipelines (active or inactive) within the jurisdiction of the City of Corpus Christi.

3.2.4. Waiver or Special Permit Pipeline Annual Report

Annually, but no later than December 31, Codes and Standards will submit a report for each waiver/special permit pipeline facilities, as required by the DOT Waiver or Special Permit, to the appropriate PHMSA regional offices. Refer to Subsection 3.1.4 – Waiver or Special Permit Pipelines Annual Report.

3.2.5. Railroad Commission of Texas Semi-Annual Report – Texas Intrastate pipelines only

Each year by January 15 and July 15, **Codes and Standards** will submit the plastic pipe leak report in accordance with the **PS-95 Semi-Annual Leak Report Electronic Filing Requirements**, *for each Company operated plastic pipeline.*

3.2.6. Railroad Commission of Texas Biennial Report

Each even numbered year by January 15, **Codes and Standards** will submit the list of Texas public schools to the Safety Division of the TRRC via Certified Mail.

**3.3. Additional Regulatory Reporting Requirements**

**Codes and Standards** shall submit

- Reportable incident reports to PHMSA for all Company pipelines and to the TRRC for all Texas Intrastate pipelines as soon as practicable but not more than 30 days after a reportable incident has occurred.
- Report Form RSPA F 7100.2 shall be used for submission. OPS/PHMSA Report submission will be online using the **OPS Online Data Entry and Operator Registration System** or by submitting a hard copy via Certified Mail to:

  Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, the Information Resources Manager, PHP–10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001

  When the reportable incident also occurred on Intrastate pipeline facilities regulated by the TRRC then a copy of the PHMSA Report and confirmation shall be submitted to the TRRC electronically via e-mail to **safety@rrc.state.tx.us**

  *Refer to* **O&M 159 – Incident Reporting and Investigation** *for further information related to reporting criteria.*
- Any supplemental information related to a reportable incident, as soon as practicable, to PHMSA and, when applicable, the TRRC. Every 3 months, not to exceed 4 ½ months, **Codes and Standards** will evaluate all open reportable incidents to ensure timely *supplemental and incident closure reporting.*
- Any non-reportable leaks on Waiver or Special Permit pipelines within 24 hours of any otherwise non-reportable leaks. The Director of Codes and Standards or designee will make the contact with the appropriate PHMSA Regional Director
- Any significant changes to the Pipeline Integrity Management Program (IMP) with appropriate regulatory agencies using the **OPS Notification Template**. Refer to the **Pipeline Integrity Management Program Section 14 – Management of Change** for detailed Company revision procedures and regulatory submission criteria

For reporting excavation-caused damage, refer to **O&M Procedure 159 – Incident Reporting and Investigation**.

## 4. Training

No regulatory training requirement.

## 5. Documentation

**Engineering Records** will archive an electronic copy of the NPMS submission and submission confirmations, and document compliance using **O&M Procedure 1700 – Inspection and Maintenance** Procedures:

- I-0219-10 – Annual Report – NPMS Submission

Codes and Standards will archive an electronic copy of all applicable regulatory submissions and submission confirmations, and, where applicable, document compliance using **O&M Procedure 1700 – Inspection and Maintenance** Procedures:

- I-0219-11 - Annual Report – OPS/PHMSA Submission
- I-0219.12 - Annual Report – TRRC Submission

- I-0219.13 - Annual Report – City of Corpus Christi Submission
- I-0219.14 - Annual Report – Waiver/Special Permit Submission
- I-0219.15 - *Semi-Annual Report – TRRC Submission*
- I-0219.16 - Biennial Report – TRRC Submission
- I-0219.17 - DOT Reportable Incident Report Review

Refer to **O&M Procedure 1400 – Records Retention by O&M Procedure** and **O&M Procedure 1401 – Records Retention by Form Number** for records retention.

## 6. References

- 49 CFR Part 191.3, 191.15, 191.17, 192.616, 192.727
- 49 CFR Part 195.49
- TRRC Rules Title 16 TAC 8.210, 8.225, 8.235, and 8.301
- DOT Docket Nos. PHMSA-2006-23998 (REX) PHMSA-2006-25803 (KMLP), PHMSA-2007-27842 (MEP)
- **City of Corpus Christi Code of Ordinances, Chapter 35 Oil and Gas Wells, Article VII – Hazardous Substances, Liquids, and Gas Pipelines and Distribution Systems**
- **NPMS Operator Standards**
- **O&M Procedure 159 – Incident Reporting and Investigation**
- **O&M Procedure 220 – Structure Survey for Class Location and HCA Determination**
- **O&M Procedure 238 – Regulated Onshore Gathering Line**
- **O&M Procedure 1400 – Records Retention by O&M Procedure**
- **O&M Procedure 1401 – Records Retention by Form Number**
- **O&M Procedure 1700 – Inspection and Maintenance**
- **O&M Form OM200-17 – Annual Report Gas Transmission and Gathering Systems**
- **http://www.rrc.state.tx.us/forms/forms/pipeline/index.php**

# Appendix 2

## Table of Contents



## 1. Applicability

☒ Gathering

☒ Processing

☒ Transmission/Regulated Onshore Gathering

☐ Kinder Morgan Power Company

## 2. Scope

This procedure applies to all natural gas facilities the Company operates. The procedure contains guidelines on how to identify a potentially unsafe condition that could endanger employees, contractors, the public, the environment or Company facilities.

## 3. Core Information and Requirements

A pipeline facility is a pipeline and associated equipment (i.e., regulator, valve, controllers, etc.) used in transporting natural gas or in treating natural gas during the course of transportation.

Immediately report potentially unsafe conditions involving pipeline facilities to your local Supervisor and Gas Control.

### 3.1. Reporting Safety- Related Conditions

This is a special set of incident reporting requirements established by DOT for in-service pipeline facilities with known defects or hazards located within areas near the public. The Company will remove or repair pipeline facilities per **O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage** when a hazard or defect is known.

3.1.1. Within the Company

If for some reason field personnel cannot remove or repair a known hazard or defect, telephone the appropriate Gas Control Department and complete **O&M Form OM200-08 – Pipeline Incident Report** when a safety-related condition meets the criteria described below:

- The incident is located within 220-yards from any building intended for human occupancy or outdoor place of assembly or within the right-of-way of an active railroad, paved road, street or highway
- The incident involves a known pipeline defect or hazard on a pipeline that remains in service and meets any one of the following criteria:
  - General corrosion has reduced the pipe wall thickness to less than required for maximum allowable operating pressure (MAOP) and localized corrosion pitting is advanced to a degree that may cause a pipeline operating at a hoop stress of 20 percent or more of its specified minimum yield strength (SMYS) to leak

- Unintended movement or abnormal loading from environmental causes (e.g., earthquake, landslide, flood) that impairs pipeline service
- Material defect or physical damage that impairs service of a pipeline operating at a hoop stress of 20 percent or more of its SMYS
- Malfunction or operating error that causes pipeline pressure to rise above its MAOP
- Leak in a pipeline that constitutes an emergency
- Safety-related conditions (for purposes other than abandonment) that could lead to an imminent hazard and cause a 20 percent or more reduction in operating pressure or pipeline operation shutdown

Do not report temporary shutdowns or pressure reductions connected with routine maintenance or construction activity as unsafe conditions. **(Refer to Attachment 1 – Identifying a Safety-Related Condition).**

3.1.2. Regulatory Reporting

Under the direction of Engineering Technical Services, **Codes and Standards** will file the safety-related condition report as described in 49 CFR 191.23(a). **(Refer to Attachment 2 – *Reporting a Safety Related Condition*).**

**A safety-related condition (SRC) report must be received by the Office of Pipeline Safety (OPS) Associate Administrator, within five working days (not including Saturday, Sunday, or Federal Holidays) after the day the operator first determines that the condition exists, but not later than 10 working days after the day the operator discovers the condition.** (Refer to Attachment 3 – Time to Report).

**In the state of Texas, any safety related condition found to exist on an intrastate pipeline system must be reported to the OPS as described in 49 CFR 191.23. A copy of that report must be sent to the Railroad Commission of Texas (TRRC). Codes and Standards will submit an electronic copy of the SRC report to the TRRC at safety@rrc.state.tx.us as soon as possible after the report has been made to the OPS.**

**3.2. Gas Control Contact Numbers**

For NGPL, **MEP, KMLP**, Trailblazer, and Kinder Morgan North Texas pipeline facility incidents notify NGPL Houston Gas Control at 800-733-2490.

For KMTP pipeline facility incidents notify KMTP Houston Gas Control at 800-633-0184.

For KM Tejas Pipeline facility incidents notify KM Tejas Houston Gas Control at 800-568-7512.

For pipeline facility incidents for all other Company natural gas subsidiaries notify Lakewood Gas Control at 888-763-3690.

## 4. *Training*

Review pipeline safety-related reporting conditions procedures periodically, as applicable.

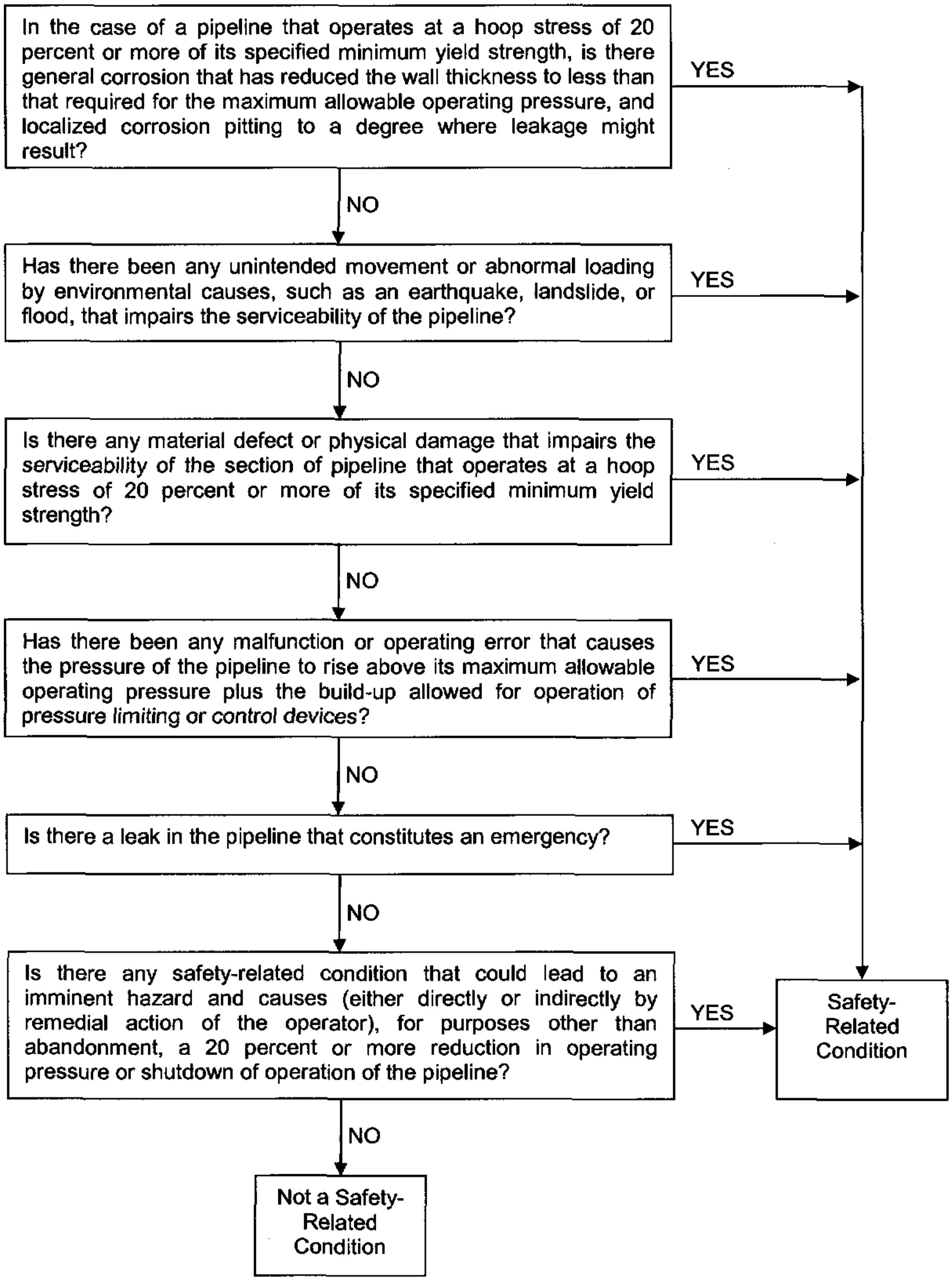
## 5. Documentation

**Refer to O&M Procedure 1400 – Records Retention by O&M Procedure** and **O&M Procedure 1401 – Records Retention by Form Number** for distribution and retention periods for completed forms **O&M Form OM200-08 – Pipeline Incident Report** and documentation provided to OPS.

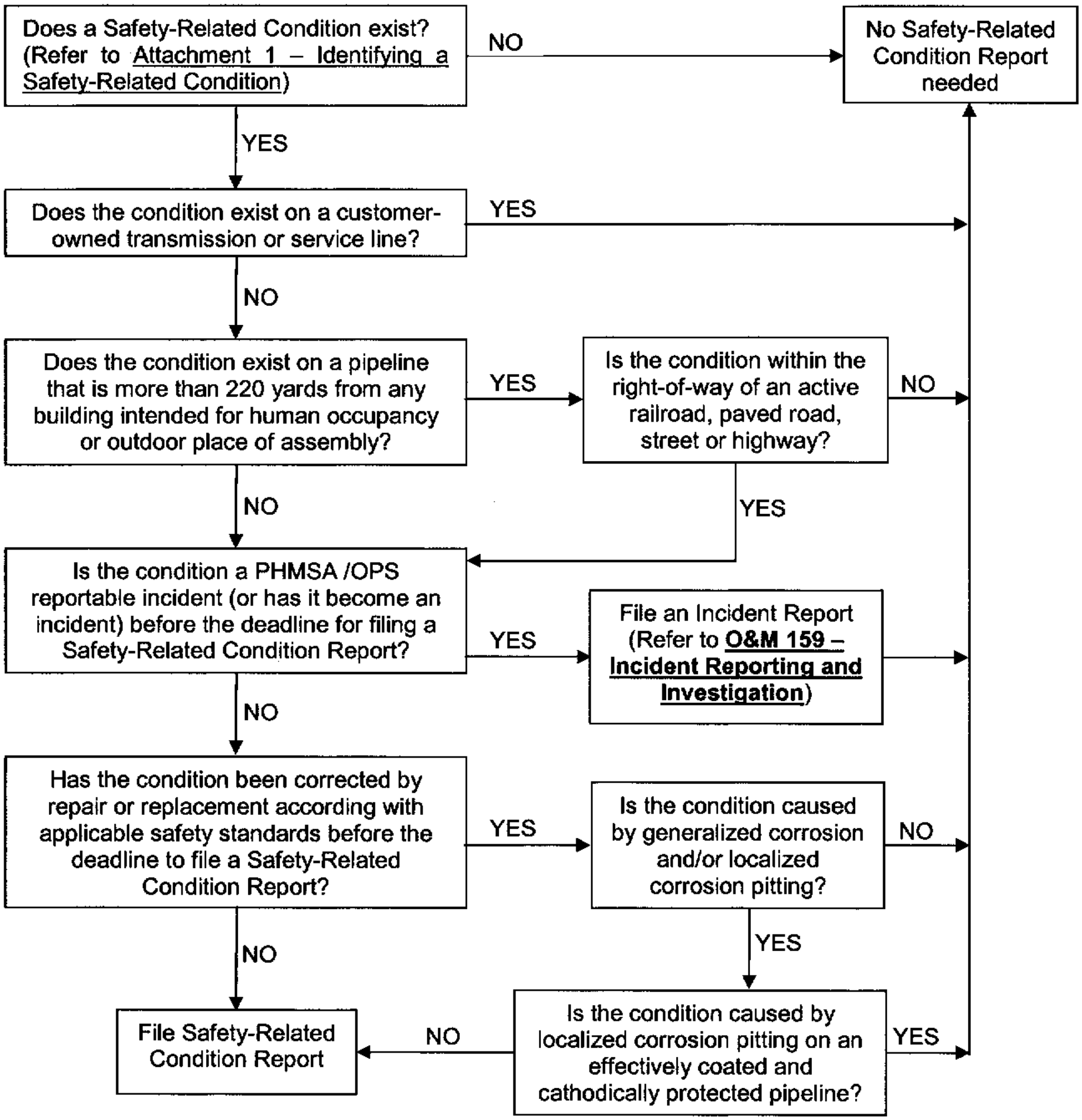
## 6. References

- 49 CFR Part 191.23 – Reporting safety-related conditions
- 49 CFR Part 191.25 – Filing safety-related condition reports
- 49 CFR Part 192.605(d) – Safety-related condition reports
- 16 TAC 8.210(c) – Safety-related condition reports
- **O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage**
- **O&M Procedure 159 – Incident Reporting and Investigation**
- **O&M Procedure 1400 – Records Retention by O&M Procedure**
- **O&M Procedure 1401 – Records Retention by Form Number**
- **O&M Form OM200-08 – Pipeline Incident Report**
- Site-Specific Emergency Plan

## Attachment 1 – Identifying a Safety-Related Condition



## Attachment 2 – Reporting a Safety-Related Condition



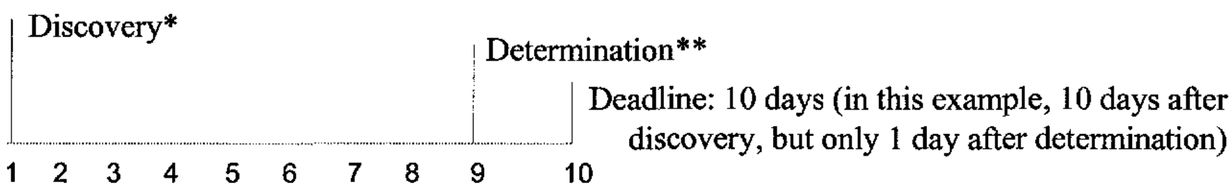
## Attachment 3 - Time to Report

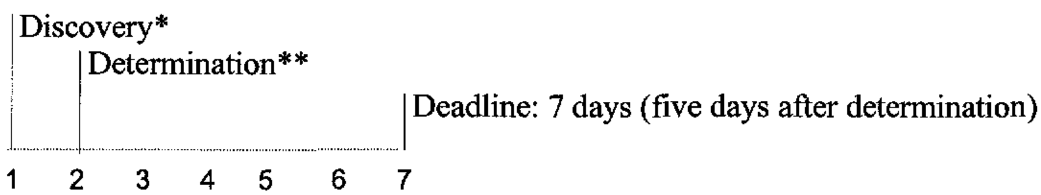
Use the following example to determine the deadline for reporting the safety-related condition.

**Reporting Deadlines:**

A safety-related condition must be reported within 10 working days of discovering a potential safety-related condition or 5 working days after determining it to be a safety-related condition, whichever is sooner (not including Saturday, Sunday, or Federal Holidays).

Examples:




* Discovery of a potential Safety-Related Condition
** Determination that a Safety-Related Condition exists

# Appendix 3

## Table of Contents



# 1. Applicability

- ☐ Gathering
- ☐ Processing
- ☒ Transmission/ Regulated Onshore Gathering
- ☐ Kinder Morgan Power Company

# 2. Scope

This procedure contains proposed/new construction and annual house count requirements to determine changes in pipeline class locations and in High Consequence Areas (HCAs). Changes in population density along the pipeline must be monitored.

# 3. Core Information and Requirements

## 3.1. Proposed, New, Acquired, or Converted Pipelines

Newly constructed pipelines or pipelines converted for service are included in the **Integrity Management Program** within one year of being placed in service. Segments that could affect HCAs are identified prior to the pipeline being placed into service.

Prior to construction of a new pipeline, Project Manager shall ensure that a detailed House Count Survey is performed in accordance with this procedure, **Engineering Standard E0100 – Pipelines (Onshore)**, and **Engineering Standard E2010 – Survey Standards**.

Pipelines obtained through acquisition are reviewed and incorporated into this program within one year of assumption of operational responsibility.

Structures should be gathered on ALL existing or proposed pipelines so that determination can be made as to whether the pipeline is Regulated Onshore Gathering per **O&M Procedure 238 – Regulated Onshore Gathering Line**.

### 3.2. General

At least once each calendar year, but not to exceed 15 months from the previous survey, field personnel will conduct a house count survey. The survey can be completed separately or in conjunction with other routine surveys or patrols. Refer to subsection 3.7 GPS Structure Data Collection below for the method to capture information.

Document immediately any known population changes (planned or in progress) that could affect class location, HCA or requirements for odorization equipment. Do not wait until the next scheduled house count survey. Confirming or revising the MAOP due to a class location change must be completed within 24 months from the time the class location change occurred (not when survey was performed).

Identify buildings intended for human occupancy or small, well-defined areas within a prescribed distance from the pipeline's centerline. The gathered information is used to classify the pipeline *into one of four class locations, described in* Table 1.

The structure information will also be used to determine if the pipeline has any HCAs. The types of structures and outdoor areas that need to be identified are shown in Table 2 and Table 3. Document if a building has been removed or the type of use has changed by adding the word "Delete" or "Change" in the remarks column.

A class change to Class 3 or Class 4 may require gas to be odorized refer to subsection 3.11 Odorization.

### 3.3. Class Location Determination

No later than March of each year, the GIS Group will perform a Class Location Determination on qualifying pipelines.

A Class Location Unit is defined as an onshore area that extends 660-feet on either side of the centerline of any continuous one-mile length of pipeline. The actual Class Location Unit may be less than a mile long. The length of Class Locations 2, 3 and 4 may be adjusted as follows:

- A Class 4 location ends 660-feet from the nearest four-story (or higher) building in a Class location unit where four or more stories are prevalent. Prevalent is determined to be greater than 50% of the structure in the sliding mile.
- When a Class 3 area is caused by a qualifying commercial building lying within 300-feet of the pipeline, the Class 3 area ends 300-feet on either side of the building
- Within each sliding mile, when a cluster of buildings intended for human occupancy causes a Class 2 or 3 location, the class location ends 220-yards from the nearest building in the cluster. If a single structure is built within a Class 2 or 3 sliding mile, the class location for that structure will be determined by the sliding mile and will end 660-feet on either side of the structure. The area between the Class 2 or 3 660-feet boundaries will revert to Class 1 in this instance.

### 3.4. HCA Determination

No later than November of each year, the GIS Group will conduct an HCA determination on the included pipelines and the resulting information will be submitted to the Risk Engineering Department for further evaluation. If an HCA determination is conducted on separate lines or systems during the year, the information on these lines will be submitted to Risk Engineering as it is processed.

HCA means an area established by one of the two methods below:

1. An area defined as either:
    a. A Class 3 or Class 4 location
    b. Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660-feet (200 meters) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy

   c. The area in a Class 1 or Class 2 location where the potential impact circle contains an identified site (see below)
2. The area within a potential impact circle containing either:
   a. Twenty or more buildings intended for human occupancy
   b. An identified site (refer to Table 2 or Table 3 for identified sites)

An HCA will be identified by using either method. One method can be used for the entire system or to identify individual portions of the pipeline system. Each HCA will have a description of the method used to identify it and the potential impact radius when used to establish the area. Table 2 lists buildings that cause an area to become an HCA.

### 3.5. Potential Impact Circle

To determine if an area along the pipeline is an HCA, consider all structures within the PIC of the pipeline. Determine the radius of the PIC by the following calculation:

$R = 0.69\ (P \times D^2)^{1/2}$
Where: R = potential impact radius (feet)
P = MAOP (psi)
D = nominal pipe diameter (inches)

Where a PIC is calculated under either method to establish an HCA, the length of the HCA extends axially along the length of the pipeline from the outermost edge of the first PIC to the last contiguous PIC that contains either an identified site or 20 or more buildings intended for human occupancy.

If the PIC contains an identified site as defined in Table 2 the circle will move down the pipeline in both directions until the outside corner of each structure or outdoor area is just touching the edge of the PIC. The HCA is defined as the area between where the outside of each of the two circles intersects the pipeline refer to Figure 1.

Kinder Morgan has elected to add an additional 40-foot buffer to each PIR, to account for GIS inaccuracies. A route can be exempted from the 40-foot PIR buffer extension if each HCA and structure in the route has been field verified and the centerline and structure points submitted to the GIS Department with sub-meter accuracy. The GIS Group will maintain a list of the pipeline routes to exempt from the buffer extension.

### 3.6. Identified Site

An identified site as defined in Table 2 located from information obtained by routine operations and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate that they know of locations meeting the identified site criteria (such as emergency planning commissions or relevant Native American tribal officials) must be documented and reported per subsections 3.8 Submitting and Reviewing Structure GPS Data, 3.9 Changes in Class Location or HCA, and 3.10 Maintaining and Updating House Count.

If a public official with safety or emergency response or planning responsibilities informs a Company representative that he or she does not have the information to determine an identified site or cannot be contacted, Field Operations and/or the GIS/PODS Group will use one of the following sources, as appropriate, to identify these sites:

- Visible markings such as signs
- The site is licensed or registered by a federal, state or local government agency
- The site is on a list (including an internet web site list) or map maintained by or available from a federal, state or local government agency and available to the general public

Document any meeting/interview with Stakeholders as defined in **O&M Procedure 232 – Damage Prevention and Public Awareness** using form **O&M Form OM200-32 – Public Awareness and Liaison Record**. If HCA identified sites are identified, capture the data per subsection 3.8 Submitting and Reviewing Structure GPS Data.

### 3.7. GPS Structure Data Collection

The Geographic Information System (GIS) Group will maintain field submitted changes and additions from the previous year's surveys in the GIS structures database such as:

- Addition or removal of buildings intended for human occupancy within 660-feet on either side of the pipeline's centerline and/or within the pipeline's PIC, whichever is greater
- New outdoor areas of public assembly (see Table 2)
- New identified sites (see Table 2)

Existing/Acquired/Converted Pipelines:

- The preferred method for gathering GPS coordinates for structures is by digitizing them using the Petris DataViewer polygon "Red Line" tool. However, structure coordinates may also be collected using a hand-held GPS unit or by using the laser offset attachment to the hand-held GPS unit.

Proposed / New Pipelines:

- The only acceptable method for gathering GPS coordinates for structures is by personnel performing an on-site survey using a GPS unit or by using the laser offset attachment to the hand-held GPS unit.

Minimum Requirements for GPS Equipment used to gather structure data:

All hand-held GPS units need to be WAAS enabled and set for WGS84 datum. If the hand-held GPS unit does not have WAAS capabilities or cannot be set for WGS84 datum, **DO NOT** use this unit to collect structure or pipeline data. It will not have the required accuracy.

When collecting structure data, observe the following:

- For an apartment complex, condominium, or any other type of multi-family dwelling, count each building as a separate structure (Table 3, Code 10). Choose Code 10 for the type of structure (Multi-Family Dwelling) and in the Info 1 column, enter the number of individual units in that structure.
- A motel should be coded as either a commercial or non-qualifying commercial building. (Table 3, Code 3 or Code 8)
- A church should **only** be coded as a Code 12, if it does not meet the criteria of Code 3 or Code 15. Example(s): A small church that is occupied by less than 20 persons per day, 5 days per week would be coded as Code 12. A larger church with a staff and/or employees that is occupied by 20 or more persons per day, 5 days per week for 10 weeks in any twelve month period (the days and weeks need not be consecutive), would be coded as a Code 3 (commercial building). A church that has a day care facility, regardless of the number of children enrolled in the day care, should be coded as a Code 15 (day care). Both Code 3 and Code 15 will cause a HCA if they are within a pipeline's PIC. While a Code 12 by itself will not cause an HCA.
- For large buildings or outdoor areas such as malls, schools, apartment buildings, parks or areas of public assembly, etc., gather GPS points at the outside corners of the building or area. These points will be used to create a polygon of the building or area.
- Texas only – Identify all public school areas containing classrooms or where students congregate within 1,000 feet of the pipeline
- List all building additions, revisions or deletions. If a building has been removed or its status (code) has changed, indicate by adding "DELETE" or "CHANGE" in the 'Info. - 2" or Remarks column of the submittal
- You should include abandoned buildings or structures not intended for human occupancy that can be seen in the imagery and provide the proper coding (Table 3, Code 7). These types of structures are not counted in the Class or HCA determination programs. However, this will eliminate any question that the building was missed during the annual data collection.

When Gathering Information for a Structure use either the DataViewer Polygon Red Line tool or a hand-held GPS device.

Determine the type of structure (including company facilities) being recorded and assign it a structure type code from Table 3.

Collect a GPS coordinate of the part of the building or small, well-defined area closest to the pipeline. As stated above, large buildings or outdoor areas will need several points along the perimeter so that a polygon/outline of the area can be created.

Record any additional or required information per Table 3 in the Other Info. 1 & 2 columns. Record the source code used to determine the function of a structure in the "Source Code" column shown in Table 3.

Collect and submit the GPS coordinates electronically to the GIS Group. Document the house count survey in the I&M Program. Hard copy documentation can be obtained by printing the task from the I&M Program.

### 3.8. Submitting and Reviewing Structure GPS Data

After completing the physical house count process, each field survey should e-mail the collected GPS data to the FieldGISGroup@kindermorgan.com mailbox. The GIS Group will update the structure file for the field and/or Project Manager to review for accuracy and comprehensiveness and notify the submitter via e-mail that the structures have been updated.

The field will run the "GIS Updater" program to insure that they have the most current structure and pipeline data.

The field will verify that the GIS information accurately indicates the following:

- All structures within the 660-feet or within the PIR of each pipeline (whichever is greater) have been documented.
- Accurate placement of the structures
- Number and types/codes of the structures
- New station numbers for the class location change boundaries

Once the review is completed, any updates or changes should be e-mailed to the GIS Group so that the corrected data can be merged into the combined structure file. The Class Location and HCA Determination programs will be run using the most current structure data.

### 3.9. Changes in Class Location or HCA

Yearly, a report showing the changes in class location or HCAs will be provided to the Operations Manager and the Regional Technical Manager to review and verify MAOPs.

If a class location change affects MAOPs, the Regional Technical Manager or designee will engage Pipeline Integrity/Risk Engineering, Project Management and the entity business owner to determine the next appropriate steps. These steps may include:

- Changing the documented MAOP
- Maintaining the existing MAOP by upgrading the pipe, hydrostatic testing, etc.
- Determining the need for odorization equipment

Note that any change in MAOP, capacity or facility modification will require following **O&M Procedure 155 – Management of Change** and submitting **O&M Form OM100-15 – Management of Change Form**. Changes to capacity may require regulatory approval.

After the annual house count process concludes, the Regional Technical Manager or designee should provide a summary to the Regional Director indicating that all segments were surveyed and changes addressed. This will be documented per **O&M Procedure 218 – Continuing Surveillance**. The annual review of Class Location data should be documented in **I-0220.01 – Class Location Review**. The annual review of HCA location data should be documented in **I-0220.02 – HCA Location Review**.

### 3.10. Maintaining and Updating House Count

House count, current class locations and HCA information will be maintained in the PODS, SDE and GIS databases for the life of the pipeline. This information can be viewed and printed at each field location using the Petris Data Viewer or ESRI ArcView software. This information should be reviewed and used as a comparison for the following year's house count survey.

The field will verify that the GIS information accurately indicates the:

- Accurate placement of the structures
- Number of buildings
- Number of people normally occupying and the use frequency for buildings or outdoor public assembly areas within 300-feet or within the HCA boundary of any pipeline
- Distance between the pipeline and buildings, assembly areas, etc. within the 660- or 300-foot pipeline corridor or HCA PIC radius
- New station numbers for the class location change boundaries
- Texas only: Distance between public school classrooms or congregation areas and the pipeline (less than or equal to1,000 feet)

In an existing Class 3 area with 46 or more dwellings, it **is** necessary to identify additional dwellings to perform the HCA analysis. If a Class 3 or 4 area is already designated as an HCA, it **is** necessary to identify any additional HCA identified sites (see Table 2).

Any class area identified as Class 4 must have a majority of four-story or higher buildings, determined by comparing houses or dwelling units to the number of buildings in the class location unit.

### 3.11. Odorization

In a Class 3 or Class 4 location, combustible gas in a transmission line must be odorized unless the conditions meet one of the requirements detailed below:

- At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location
- The line transports gas to any of the following facilities, which received gas without an odorant from that line before May 5, 1975:
  - An underground storage field
  - A gas processing plant
  - A gas dehydration plant
  - An industrial plant using gas in a process where the presence of an odorant:
    - Makes the end product unfit for the purpose for which it is intended
    - Reduces the activity of a catalyst
    - Reduces the percentage completion of a chemical reaction
- In the case of a lateral line that transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location
- The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process

### 3.12. Valve Spacing

**Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:**

- **Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.**
- **Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.**
- **Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.**

- Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

## 4. Training

Obtain training for GPS equipment and GIS Data Viewers (includes ArcGIS & Petris DataViewer) and GIS Updater from the GIS Group.

## 5. Documentation

Document the annual house count survey per **I&M Procedure I-0220.00 – House Count Survey**.

At least once per calendar year, the Class Location Determination Program (run in February) and the HCA Determination Program (run in October) will be run using the latest centerline and structure files. The calculated class location and HCAs will be added into PODS and the information will be available to each location via the DataViewer, Facility Manager or other GIS viewer applications. Refer to **O&M Procedure 1400 – Records Retention by O&M Procedure** and **O&M Procedure 1401 – Records Retention by Form Number** for records retention.

Document Class Location Review in **I-0220.01 – Class Location Review**

Document HCA Review in **I-0220.02 – HCA Location Review**

*Document meeting/interviews with public officials on* **O&M Form OM200-32 Public Awareness and Liaison Record**.

## 6. References

- 49 CFR Part 192.5
- 49 CFR Part 192.609
- 49 CFR Part 192.611
- 49 CFR Part 192.613
- 49 CFR Part 192.625
- 49 CFR Part 192.903
- 49 CFR Part 192.905
- ***O&M Procedure 155 – Hearing Conservation***
- **O&M Procedure 208 – Operating Pressure Uprating**
- **O&M Procedure 1400 – Records Retention by O&M Procedure**
- **O&M Procedure 1401 – Records Retention by Form Number**
- **O&M Procedure 1700 – Inspection and Maintenance**, I&M I-0220.00 – House Count Survey
- **O&M Form OM100-15 – Management of Change Form**
- **O&M Form OM200-32 – Public Awareness/ Liaison Record**
- **Integrity Management Program**
- OPS Gas Integrity Management FAQ 18 and 20

## Table 1 - Class Location Area

| | |
|---|---|
| **Class 1** | a. 10 or fewer buildings within the class location unit<br>b. All offshore pipelines |
| **Class 2** | More than 10 and fewer than 46 buildings within the class location unit |
| **Class 3** | a. 46 or more buildings within the class location unit<br>b. An area where the pipeline lies within 300 feet of either a building or a small, well-defined outside area (such as a playground, recreation area or other place of public assembly) that is occupied by 20 or more persons at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. In this case, the Class 3 area ends 300 feet on either side of the qualifying commercial building or outside area. |
| **Class 4** | Buildings with four or more stories above ground are prevalent within the class location unit. More than 50% of the structures in the class location unit must be four or more stories for the area to be Class 4. |

## Table 2 – Identifying High Consequence Areas

| Cause | Description |
|---|---|
| **Family dwellings** | Any location where the PIC contains 20 or more structures intended for human occupancy. |
| **Identified Sites** | Any location where the PIC contains an identified site. Identified sites include qualifying commercial buildings, schools, hospitals, prisons, day care facilities, retirement centers or any other buildings that would house people with limited mobility or that would be hard to evacuate or buildings occupied by 20 or more persons 5 days per week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). |
| **Outdoor area of public assembly** | Any location where the PIC contains an HCA defined outdoor area of public assembly. Park, playground, baseball or other sports field, drive-in theater, golf course, campground or other place of public assembly that is occupied by 20 or more people, at least 50 days in any 12 month period. |

## Table 3 – Facility Descriptions

| Structure Code | Code Description | Other Info. - 1 | Other Info. – 2 | Source Code |
|---|---|---|---|---|
| 1 | Single family dwelling such as a house, trailer house | | | *Source Code:<br>1 – Pipeline Patrol<br>2 – Public Official<br>3 – Signs 4 – Maps<br>5 – Licensing Info.<br>6 – New PL Const. |
| 2 | (Reserved for conditional house) (This Code is not for field use) | | | |
| 3 | Commercial building - store, office, church, warehouse, factory, motel, restaurant, government building, or other building intended for business or related use, occupied by 20 or more persons 5 days per week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). **(If the commercial building is 4 or more stories tall code it as a Code 5).** | | | *Source Code |
| 4 | (Reserved for conditional commercial ) (This Code is not for field use) | | | |
| 5 | Four-story or higher building - indicate type of business or building function (include parking garages) | * Building - type/ function: | | *Source Code |
| 6 | (Reserved for grouped structures) (This Code is not for field use) | | | |
| 7 | Not intended for human occupancy (garages, sheds, etc.) | | | *Source Code |
| 8 | Non-qualifying commercial buildings - business occupied by less than 20 persons 5 days per week | * Max. number of persons occupying: | | *Source Code |
| 9 | DOT defined - Outdoor area of public assembly - park, playground, baseball or other sports field, drive-in theater or other place of public assembly that is occupied by 20 or more people at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive) | * Function: | | *Source Code |
| 10 | Multi-family dwelling - apartment, duplex, high rise, etc. | * Approx. number of units in the building: | | *Source Code |
| 11 | School (within 1000 feet – Texas Only) | | | *Source Code |
| 12 | Church that does not meet criteria for Code 3 or Code 15. Care should be taken in coding churches. Many will fit the criteria for Code 3 or Code 15 and should be coded as such, since both of these codes are identified sites for HCAs | | | *Source Code |
| 13 | Hospital | | | *Source Code |
| 14 | Prison | | | *Source Code |
| 15 | Day care facility that does not meet criteria for Code 3 | | | *Source Code |
| 16 | Retirement center | | | *Source Code |
| 17 | HCA defined - Outdoor area of public assembly – An Outside Area or open structure that is occupied by 20 or more people at least 50 days in any 12-month period (the days need not be consecutive). Examples include but are not limited to, beaches, playgrounds, recreational facilities, campgrounds, RV Parks, outdoor theaters, stadiums, drive-in theaters or areas outside a rural building such as a religious facility. | * Function: | | *Source Code |
| 18 | Non-qualifying - Outdoor area of public assembly – park, playground, baseball or other sports field, campground, RV park, drive-in theater or other place of public assembly that **does not** meet the occupancy criteria for structure Code 9 or Code 17 | | | *Source Code |
| 19 | Other | * Detailed description required | | *Source Code |

*Required Information

To change or remove a structure, place a new GPS coordinate on that structure and write in comments to "Remove" or "Change"

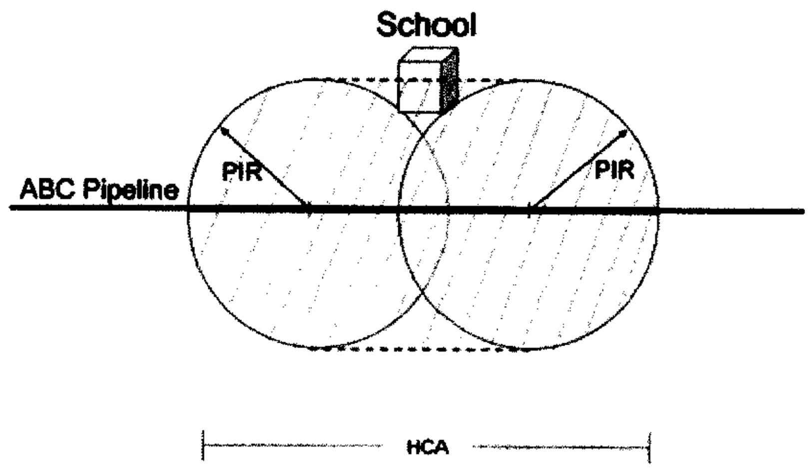



**Figure 1 – Determining High Consequence Area**

## Table of Contents



## 1. Scope

This standard defines the Company's minimum design requirements and general design philosophy for onshore transmission pipelines for natural gas service.

## 2. Definitions

For definitions of terms and acronyms used within this document, refer to **Engineering Standard P0010 – Master Glossary**.

## 3. Codes and Standards

Designing and installing pipeline and related facilities shall conform to 49 CFR 192 (most recent edition), all related and applicable Company standards and all other applicable codes and standards. For codes incorporated by reference in 49 CFR 192, refer to **Engineering Standard P0020 – DOT Incorporated by Reference**. For convenience, references to sub-sections of 49 CFR 192 and other applicable standards are called out in the sections that follow.

Where project-specific issues suggest or require implementing design parameters outside of Company standards, the Project Manager shall use **O&M Procedure 001 – Standards Modification**.

## 4. Line Number Assignment

4.1. The Project Manager shall be responsible for submitting a completed **Engineering Form E0100-01 – Line Number Request** to the PODSGISGroup@kindermorgan.com mailbox, following the approval of an AFE Request on any below ground pipeline or lateral, regardless of length (includes tap and meter installations).

4.1.1. The assigned line number will be used for:

- Storing pipeline information in the PODS database
- Registration with the state One Call Center
- Integrity Management planning
- Assigning drawing numbers for the project

4.2. Before initial gas flow of any new pipeline, the Project Manager or their designee will submit the following information to PODSGISGroup@kindermorgan.com mailbox for entry into PODS:

- Line Number (previously assigned by PODS GIS Group)
- Line type (transmission, storage or gathering)
- Design pressure / MAOP
- Diameter of the pipeline
- Best available data concerning GPS coordinates for the beginning, end, and major PIs OR a geo-referenced centerline shape file (if available)

4.3. "As-Built" pipe survey data and/or Blue Sky Align DB database file shall be submitted with the project Job Book as specified in **E1700**.

## 5. Class Location and Design Factors

5.1. The Project Manager shall ensure completion of a current house count/ class location and high consequence area (HCA) study and follow associated design factors and valve spacings that conform with the most recent edition and interpretation of 49 CFR 192.5 and **O&M Procedure 220 – Class Location and House Count Survey**.

5.1.1. The Project Manager shall pursue the following actions:

1) Utilize aerial imagery in conjunction with on-site field reconnaissance for only preliminary design or preliminary pipe orders.
2) At the beginning of any pipeline project, personnel will perform an on-site, house count survey as described in O&M Procedure 220 – Class Location and House Count Survey, and all house count information (Data) be sent via e-mail to the PODSGISGroup@kindermorgan.com mailbox.
3) PODS/GIS Group to run Class Location algorithm on supplied Data, and forward results of Class Determination to Project Manager.
4) Project Manager shall utilize Class Determination results to verify pipeline's design factors and valve spacings. It is advisable to review the Class Determination results prior to ordering pipe.
5) If routing of pipeline is revised, the Project Manager will repeat the above steps to insure compliance.
6) Area building construction and development should be frequently monitored, and if applicable, the House Count Survey should be updated prior to the pipe delivery to the construction site. Throughout the remainder of the project, area building construction and development should continue to be frequently monitored, and if applicable, the House Count Survey shall be updated to ensure that the class locations are correct when project is placed in-service.

7) Each transmission line, *other than offshore segments*, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:
   - Each point on the pipeline in a Class 4 location must be within 2 ½ miles (4 kilometers) of a valve.
   - Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.
   - Each point on the pipeline in a Class 2 location must be within 7 ½ miles (12 kilometers) of a valve.
   - Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

## 6. Clearance and Encroachment Guidelines

The pipeline shall conform with all clearance requirements specified in **O&M Procedure 204/C1005 – Construction near Company Facilities**. For typical pipeline construction sequence, refer to **Construction Drawing CST-P-1000-B060**.

## 7. Environmental Considerations

The Project Manager shall consider environmental issues and impacts including but not limited to:

- Using, widening or extending existing rights-of-way
- Soil conservation requirements
- Minimizing the footprint/scale of above grade facilities
- Minimizing cleared rights-of-way through wooded areas, hilltops and other high points where highly visible
- Agency regulations requiring the exterior of above grade facilities to be harmonious with immediate surroundings and/or other buildings in the area
- Locating compressor stations and/or other noise-intensive above grade facilities at required distances from noise-sensitive areas or using noise-abatement engineering controls
- Avoiding locations/landmarks listed on or eligible for listing on the National Register of Historic Places, the National Register of Natural Landmarks, officially designated Wild and Scenic Rivers, officially designated parks, wetlands, floodplains, scenic, recreational and/or threatened/ endangered/wildlife lands

Refer to Sub-section 13 – Permits (below).

## 8. Pipeline Sizing

The Project Manager shall be responsible for ensuring a current system hydraulic study has been completed to meet the project performance criteria without compromising existing or future system volume and pressure capabilities and commitments.

For detail on system hydraulic tests, consult with the System Design Department.

## 9. Pipe Support and Piping Flexibility

For pipe support, refer to 49 CFR 192.161, **Engineering Standard E1200 – Civil and Structural** and **Engineering Standard E1100 – Mechanical**. For piping flexibility, refer to 49 FR 192.159 and **Engineering Standard E1100 – Mechanical**.

## 10. Route Selection

In addition to the environmental considerations specified in **Construction Standard C1260 – Environmental Requirements**, route selection shall *defer to the most direct route practicable*. The Project Manager shall consider route selection features in the project design including, but not limited to:

- Permanent easements (e.g., landowner restrictions)

- Populated areas
- HCAs
- Temporary work spaces, turnarounds (e.g., construction)
- Extra temporary work space (e.g., crossings)
- Pipe yards/material marshalling points
- Rig-up space
- Ancillary sites
- Mainline valves
- pig launchers/receivers
- Potential customers
- Anticipated/future classification changes
- Geotechnical obstacles (e.g., karst, bogs, rivers, rough/impassable terrain)
- Saturated soils (e.g., negative buoyancy)
- Utility corridors (HVAC - high voltage overhead/below grade power lines)
- Archeological sites
- Roadways and railroads
- Hydrostatic test water sources

## 11. Right-of-Way (ROW)

The Project Manager shall review and approve ROW conditions or restrictions (as identified by the ROW Department) that affect pipeline design and construction.

Refer to Table E0100 /10 below for guidelines on construction ROW width. Note: Variations in pipe size will affect variations in construction ROW. In addition to the permanent ROW, temporary additional work space may be necessary for larger line sizes, at road and river crossings and in areas with side slopes.

To ensure safe working conditions and to minimize environmental impacts, consult the following table for typical guidelines for construction ROW width. Special conditions may dictate varying construction ROW widths.

| **Construction ROW Width Guidelines** | |
|---|---|
| Pipe Diameter (Inches) | Width (Feet) |
| 3 to 6 | 50 |
| 8 to 16 | 75 |
| 18 to 24 | 90 |
| 26 to 30 | 100 |
| 36 to 42 | 125 |

**Table E0100 / 10 – Construction ROW Width Guidelines**

Refer to **Construction Drawing CST-P-1000-A055**.

## 12. Survey Requirements

Surveys shall conform to **Engineering Standard E2010 – Survey Standards** requirements.

## 13. Permits

13.1. The Project Manager shall coordinate work with the Environmental Regulatory Services and ROW departments during the project-scoping period to identify all necessary permits and develop a detailed permit list and permitting strategy, including anticipated permit timelines.

13.2. The Project Manager shall review and approve permit conditions and restrictions that may obstruct or delay pipeline design and construction. Throughout the project, the Project Manager shall inform all departments of potential and actual scope changes in writing to ensure that resulting scope changes that affect permit strategy are addressed in a timely manner.

13.3. Projects may require a wide variety of permits including, but not limited to (this list is typical and should not be interpreted as comprehensive):

Local:

- Building, curb cut, turn-in
- Road/highway crossings
- Floodplain/flood way crossings
- Planning and zoning
- Condition or special use
- Railroad crossings
- Canal/ditch crossings
- Franchises/pipeline permits

State:

- Land (erosion and sedimentation permit)
- Water
    - Hydrostatic test water acquisition
    - Hydrostatic test water discharge
    - Construction stormwater discharge and stormwater pollution prevention plan
    - Trench de-watering
    - Water quality certification
- Stream and river crossings (state environmental agency)
- Cultural resources preservation (state historic preservation office)
- Threatened, endangered and state-sensitive species preservation (state fish and wildlife agency)
- Timber harvest plans (state forestry commission)
- Air emissions (state environmental agency)
- Noise (state environmental agency)
- Dust control (state environmental agency)
- Open burn permitting (state environmental agency)
- Well installation, water and gas (state environmental agency)
- Septic/underground injection control (state environmental agency)

Federal:

- Wetlands Preservation and Crossings (U.S. Army Corps of Engineers)
- Streams and Rivers (U.S. Army Corps of Engineers)
- Threatened and Endangered Species (U.S. Fish and Wildlife Service)
- Air Emissions (U.S. Environmental Protection Agency)
- Noise (Federal Energy Regulatory Commission)
- Environmental Resource Reports, Environmental Assessment or Environmental Impact Statement and Certificate Order (Federal Energy Regulatory Commission)
- Special Use/Plan of Development (U.S. Fish and Wildlife Service, Bureau of Land Management, Forest Service)
- Coastal Zone Lands (Coastal Zone Management)
- Native American Preservation (Tribal Historic Preservation Office)
- Large Diameter (36 inches and larger) Tunneling (Department of Mines)

## 14. Pipeline Depth of Cover

14.1. At a minimum, all depth of cover shall conform to 49 CFR 192.327.

14.2. Project Managers shall consider population growth potentials, easements, permits, road and railroad crossings, drain tile, agricultural areas (subject to deep cultivation or operating activities) and areas subject to wind or water erosion in determining depth of cover.

## 15. Trench Breakers and Plugs

Refer to **Construction Standards C1020 – Ditching**, **C1100 – Backfilling** and **C1260 – Environmental Requirements**.

## 16. Crossings

16.1. Road and Railroad Crossings

16.1.1. Road and railroad crossings shall conform to 49 CFR 192.111. Unimproved public roads are defined as locations where a filed public easement for a road exists.

16.1.2. Uncased road and railroad crossings shall be installed unless casing is required by federal, state, local or railroad company requirements.

16.1.3. At a minimum, all pipeline crossings at roads/highways and railroads shall meet the requirements set forth in **API** 1102. The Project Manager shall also consider all federal, state and local requirements. The Project Manager shall consider performing pipe stress analysis where same is required to verify code compliance. In addition, where required, railroad crossings shall conform to the American Railway Engineering and Maintenance of Way Association (AREMA) guidelines.

16.1.4. Road Crossing Drawings

For uncased bored road crossing, refer to Typical Drawing TYP-P-0100-A005.
For uncased open cut road crossing, refer to Typical Drawing TYP-P-0100-A010.
For cased road crossing, refer to **Typical Drawing TYP-P-0100-A015**.

16.1.5. Railroad Crossing Drawings

For uncased railroad crossings, refer to **Typical Drawing TYP-P-0100-A020**.
For cased railroad crossings, refer to **Typical Drawing TYP-P-0100-A025**.

16.2. Waterway Crossings (active and intermittent waterways)

16.2.1. Waterways may range from small drainage canals to large navigable rivers and lakes, many of which require crossing permits from jurisdictional authorities. Note: Wetlands and navigable waterways are normally under the jurisdiction of the U.S. Army Corps of Engineers. Specific requirements shall be verified with local jurisdictional authorities before proceeding with crossing design. See water-crossing definitions in **P0010 - Master Glossary**.

16.2.2. The Project Manager shall consider the history, geology and hydrology of the waterway, as well as possible future conditions such as bottom scouring and channel movement in selecting and designing the crossing. Waterway conditions at the time of construction shall also be considered. A current, accurate survey of rivers and related flood plains shall be made, noting caving banks, sand bars and related items to arrive at the optimal location and depth of pipeline below the bottom of the channel.

16.2.3. The Project Manager shall ensure conformance with the requirements of 49 CFR 192.317 to take practicable steps to protect the pipeline from washouts, floods, unstable soil, landslides or other hazards including but not limited to extending carrier pipe/sag bend beyond high bank, increasing the wall thickness, constructing revetments, preventing erosion anchoring/weighting, flexibility, etc. in waterway crossings design criteria.

16.2.4. The Project Manager shall review and consider economic and engineering evaluations to determine the crossing design and construction method to be used. This includes but is not limited to directionally bored crossings (depending on soil conditions) and elevated crossings due to economic restrictions. All crossings shall minimize pipe stress. Note: For large diameter steel pipelines, the wall thickness required to contain the pressure usually provides less weight than that needed to overcome the empty pipe's buoyancy. This buoyancy shall be overcome by adding weights, concrete coating or mechanical anchors to the line. For additional detail on buoyancy, refer to Sub-section 30 – Pipeline Buoyancy Control (below).

16.2.5. Where typical cross-country installation methods are used, such as for minor waterway crossings, the design factor used for the crossing shall be the same as for the pipeline on either side.

16.2.6. Where 49 CFR 192.111 does not address a particular type of crossing, the Project Manager shall select a design factor applicable for the class location, construction and operating loads to be encountered.

16.2.7. Project Manager shall consider a pre-installation strength test of pipeline segments that will be inaccessible or costly to repair after installation. Pre-installation pressure levels higher than post-installation pressure levels shall be considered, provided the maximum allowable test pressures are not exceeded.

- For typical major waterway crossings, refer to **Typical Drawing TYP-P-0100-B180**.
- Intermediate waterway crossing drawing to be developed in future as needed.
- For a typical minor waterway crossing, refer to **Typical Drawing TYP-P-0100-A041**.

16.3. Directional Drilling

16.3.1. Design for crossings shall have entry angles between 8° and 20°. Exit angles shall be designed to allow easy breakover support for the pipe entering the drilled hole. Unless otherwise approved, exit angles between 5° and 12° shall be used for crossings.

16.3.2. Entry and exit tangent lengths below grade shall extend for a minimum of 50-feet prior to any bend beginnings or endings.

16.3.3. The depth of cover beneath an obstacle shall be provided to maintain crossing integrity for the design life of the installation. A large stream crossing shall have a minimum of 20-feet depth of cover. A non-dynamic obstacle shall have a minimum depth of cover of 15-feet.

16.3.4. The design radius of curvature in feet shall be a minimum of 100 times the nominal diameter of the pipe in inches, $R_{(Ft)} = 100 * D_{(In)}$. The radius of curvature may be reduced from this figure if the Project Manager performs a complete analysis of the bending stresses and pulling tensions.

16.3.5. A horizontal directional drilled crossing for pipe diameter greater than 24 inches or 1,000 feet in length shall be analyzed for pipe stress during installation and operation in conformance with the AGA Pipeline Research Committee "Installation of Pipeline by Horizontal Directional Drilling Engineering Design Guide" or equivalent analysis program.

16.3.6. Subsurface survey using vertical soil borings shall be approximately 25 feet off the proposed centerline, 20-feet below the proposed depth and a reasonable interval apart, centered on the proposed bore length for designing the horizontal directional drilled crossings and to inform construction bidders of conditions to be encountered.

16.3.7. For horizontal directional drilled crossings, an abrasion-resistant protective coating in addition to the corrosion coating is required. Refer to **Material Specification M8380 – Yard Application of Power Crete(™) Coating Over FBE**.

16.3.8. Whenever directional drilling operations are performed in close proximity to utilities, adequate measures shall be taken to track drill location relative to utilities.

16.3.9. For additional detail on directional drilling, refer to **Construction Standards C1150 – Water Crossings** and **C1160 – Horizontal Directional Drilling**.

16.4. Miscellaneous Crossings

Crossing Dresser-coupled or acetylene welded lines shall require special precautions. Refer to **O&M Procedure 237 – Dresser-Coupled Pipelines** for additional information concerning anchoring Dresser-coupled compression joints (Dresser coupling). Prior to making revisions to or performing subgrade construction near Dresser-coupled lines, the Project Manager shall determine mitigating strategy for anchoring and/or supporting Dresser-coupled lines. For historical reference, refer to Company **Standard Drawing STD-43-E6 Detail 5**.

## 17. Fabricated Assemblies

When designing a pipeline, the Project Manager shall review and ensure that all fabricated assemblies (including but not limited to mainline block valves, station block valves, pig launchers, pig receivers, slug catchers, branch connections, mainline crossovers, mainline blowoffs, mainline headers, drips, and other miscellaneous assemblies) shall conform to 49 CFR 192.111.

17.1. Mainline Block Valves

*Refer to* **Typical Drawing TYP-P-0100-B120**.

17.1.1. Mainline Block Valve Location

17.1.1.1. The designer shall consider block valve locations that are:

- Adjacent to an all-weather/accessible road whenever possible
- Minimum distance of 50-feet from highway, ROW limit, overhead service lines or where there are floodplains
- Minimum distance of 100-feet from overhead electric transmission lines

17.1.1.2. Whenever possible, mainline block valves shall not be installed below power lines. However, when block valves are installed in proximity of power lines, the Project Manager shall determine if below grade bypass or an extended blowdown line are required.

17.1.2. Valve Selection

17.1.2.1. The Project Manager shall consider full line size trunnion-mounted weld end ball valves or gate valves.

17.1.2.2. The Project Manager shall determine if the valves shall have other than manual operating devices.

17.1.2.3. Where mainline valves have operators other than manual operating devices, operators shall have electronic or pneumatic controls, as determined by the Project Manager.

17.1.2.4. Valves with manual operators shall be designed to locate handwheel centerline at 3 feet, 6 inches above grade/ground clearance or height for optimal ongoing operation. Consideration shall be given to sites where snow accumulation is a risk.

17.1.2.5. Components requiring routine maintenance shall be designed for installation at the most ergonomic height.

17.1.2.6. Valves with operators requiring an adapter flange shall be given special consideration when specifying extension stem length.

17.1.3. Blowdown/Bypass on Mainline Block Valves

For standard blowdown/bypass reference, refer to Sub-section 17.2 – Pipeline Blowdown/Bypass (below).

All mainline block valve assemblies shall have blowdowns, regardless of mainline diameter. All block valves 12-inches and larger shall have a bypass. However, bypasses for valves smaller than 12-inches shall be considered as special cases.

17.2. Pipeline Blowdown/Bypass

17.2.1. The Project Manager shall consider installing a blowdown on each end of all lateral lines that are one mile and longer in length.

17.2.2. The Project Manager shall consider extra heavy wall thickness for blowdown and bypass piping.

17.2.3. Brace pipe for mainline valve sets shall be required and shall be at least standard wall thickness, Grade B, steel pipe. It shall be welded to a full encirclement welded sleeve (refer to **Typical Drawing TYP-P-0100-A055**) for all pipe larger than 3-inches in diameter. Brace pipe installed without a sleeve shall be welded to pressure pipe with low hydrogen welding rods and shall conform to 49 CFR 192.161.

17.2.4. Blowoff sizes 40% or greater than the carrier pipe are prohibited. Guide bars shall not be installed in blowoffs.

17.2.5. Use a tee or drawn nozzle whenever possible.

17.2.6. Blowdown and bypass sizes shall be:

| Line Size | Blowdown | Bypass Size | Brace Pipe Size |
|---|---|---|---|
| 2" to 6" | 2" | 2" | 1-1/2" |
| 8" to 10" | 3" | 3" | 1-1/2" |
| 12" | 4" | 4" | 2-3/8" |
| 16" to 20" | 6" | 6" | 3-1/2" |
| 24" to 30" | 8" | 8" | 4-1/2" |
| 32" to 36" | 10" | 10" | 4-1/2" |
| 42" | 12" | 12" | 4-1/2" |

**Table E0100 / 16.2.6 - Blowdown and Bypass Size Table**

Refer to **Typical Drawing TYP-P-0100-A055**.

17.2.7. For bleeders, vents, drains and purging lines, refer to **Typical Drawing TYP-P-0100-A045**.

17.3. Pigging Facilities (Launchers and Receivers)

17.3.1. Each new pipeline and all existing pipelines added to or replaced shall be designed and constructed to accommodate internal inspection device (smart pig) passage. Designing and constructing pipelines to "accommodate the passage of a smart pig" per 49 CFR 192.150 does not require installing permanent facilities for launching or receiving the pig. If it is anticipated that using smart pigs or maintenance pigs will be infrequent, temporary launchers and receivers will be used for those pipelines that are not equipped with permanent facilities.

17.3.2. Consideration shall be given to installing permanent launchers and receivers for on-stream pigging systems where accumulations of liquids, dirt, wax, etc. would severely decrease pipeline efficiency or contribute to internal corrosion.

17.3.3. For facilities that require frequent pig runs (as determined by the Regional Director of Operations, the Director of Risk Engineering, or the Project Manager) or for major pipelines that cannot be taken out of service, pigging will require installing permanent on-stream launchers and receivers. Temporary or mobile pigging systems may be considered for gathering lines and pipelines that are pigged infrequently.

17.3.4. Unless otherwise specified, a receiver and a launcher or a connection for a temporary launcher and receiver shall be installed where line size changes in the pipeline. Full-opening valves are required. Unless otherwise approved by the Project Manager, minimum 3D bend radius ells and bends shall be used, especially for pipe size 6 inches and smaller. When practical, all bends shall be separated by a straight run at least three pipe diameters long. With the exception of blowoffs, guide bars shall be installed on all branch connections that are 40% the size of the carrier pipe to which the branch is connected or larger. Refer to **Typical Drawing TYP-P-0100-B220** for guide bar installation.

17.3.5. For pigging facilities on mainline installations, refer to:

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B390.1** |
| Launcher Elevation | **TYP-P-0100-B390.2** |
| Receiver Plan | **TYP-P-0100-B390.1** |
| Receiver Elevation | **TYP-P-0100-B390.2** |
| Bi-Directional Plan | **TYP-P-0100-B392.1** |
| Bi-Directional Elevation | **TYP-P-0100-B392.2** |
| Bi-Directional Plan | **TYP-P-0100-B396.1** |
| B-Directional Elevation | **TYP-P-0100-B396.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B400.1** |
| Launcher Elevation | **TYP-P-0100-B400.2** |
| Receiver Plan | **TYP-P-0100-B402.1** |
| Receiver Elevation | **TYP-P-0100-B402.2** |
| Bi-Directional Plan | **TYP-P-0100-B406.1** |
| Bi-Directional Elevation | **TYP-P-0100-B406.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B410.1** |
| Launcher Elevation | **TYP-P-0100-B410.2** |
| Receiver Plan | **TYP-P-0100-B412.1** |
| Receiver Elevation | **TYP-P-0100-B412.2** |
| Bi-Directional Plan | **TYP-P-0100-B416.1** |
| Bi-Directional Elevation | **TYP-P-0100-B416.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B420.1** |
| Launcher Elevation | **TYP-P-0100-B420.2** |
| Receiver Plan | **TYP-P-0100-B422.1** |
| Receiver Elevation | **TYP-P-0100-B422.2** |
| Bi-Directional Plan | **TYP-P-0100-B426.1** |
| Bi-Directional Elevation | **TYP-P-0100-B426.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B430.1** |
| Launcher Elevation | **TYP-P-0100-B430.2** |
| Receiver Plan | **TYP-P-0100-B432.1** |
| Receiver Elevation | **TYP-P-0100-B432.2** |
| Bi-Directional Plan | **TYP-P-0100-B436.1** |
| Bi-Directional Elevation | **TYP-P-0100-B436.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B440.1** |
| Launcher Elevation | **TYP-P-0100-B440.2** |
| Receiver Plan | **TYP-P-0100-B442.1** |
| Receiver Elevation | **TYP-P-0100-B442.2** |
| Bi-Directional Plan | **TYP-P-0100-B446.1** |
| Bi-Directional Elevation | **TYP-P-0100-B446.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B450.1** |
| Launcher Elevation | **TYP-P-0100-B450.2** |
| Receiver Plan | **TYP-P-0100-B452.1** |
| Receiver Elevation | **TYP-P-0100-B452.2** |
| Bi-Directional Plan | **TYP-P-0100-B456.1** |
| Bi-Directional Elevation | **TYP-P-0100-B456.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B460.1** |
| Launcher Elevation | **TYP-P-0100-B460.2** |
| Receiver Plan | **TYP-P-0100-B462.1** |
| Receiver Elevation | **TYP-P-0100-B462.2** |
| Bi-Directional Plan | **TYP-P-0100-B466.1** |
| Bi-Directional Elevation | **TYP-P-0100-B466.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B470.1** |
| Launcher Elevation | **TYP-P-0100-B470.2** |
| Receiver Plan | **TYP-P-0100-B472.1** |
| Receiver Elevation | **TYP-P-0100-B472.2** |
| Bi-Directional Plan | **TYP-P-0100-B476.1** |
| Bi-Directional Elevation | **TYP-P-0100-B476.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B480.1** |
| Launcher Elevation | **TYP-P-0100-B480.2** |
| Receiver Plan | **TYP-P-0100-B482.1** |
| Receiver Elevation | **TYP-P-0100-B482.2** |
| Bi-Directional Plan | **TYP-P-0100-B486.1** |
| Bi-Directional Elevation | **TYP-P-0100-B486.2** |

| [illegible] | |
|---|---|
| Launcher Plan | **TYP-P-0100-B490.1** |
| Launcher Elevation | **TYP-P-0100-B490.2** |
| Receiver Plan | **TYP-P-0100-B492.1** |
| Receiver Elevation | **TYP-P-0100-B492.2** |
| Bi-Directional Plan | **TYP-P-0100-B496.1** |
| Bi-Directional Elevation | **TYP-P-0100-B496.2** |

| | |
|---|---|
| Anchor Plan/Sections | **TYP-P-0100-B380.1** |
| Anchor Reinf Bending | **TYP-P-0100-B380.2** |
| Pipe Spt Pier Launcher | **TYP-P-0100-B385.1** |
| Pipe Spt Pier Receiver | **TYP-P-0100-B385.2** |
| Pipe Spt Pier Rcr/Lnchr | **TYP-P-0100-B385.3** |
| Dim Sch Lnchr/Rcvr Spts | **TYP-P-0100-B385.4** |
| Anchor Bolt Detail | **TYP-V-1200-A070** |

For pigging facilities using sphere launchers/receivers, refer to **Standard Drawings STD-P-0100-B080.1**, **STD-P-0100-B080.2**, **STD-P-0100-B100.1** and **STD-P-0100-B100.2**.

17.3.6. As in-line inspection tools vary in length, the Project Manager shall confirm with the Company Pipeline Integrity Department the required launcher and receiver barrel lengths. Transition from launcher or receiver barrels to mainline pipe shall be made with eccentric reducers, flat side down. Minimum lengths to consider for launchers and receivers are:

Refer to typical drawings for the minimum length of nominal (smaller pipe diameter), and the minimum length from launcher or receiver valve to closure end.

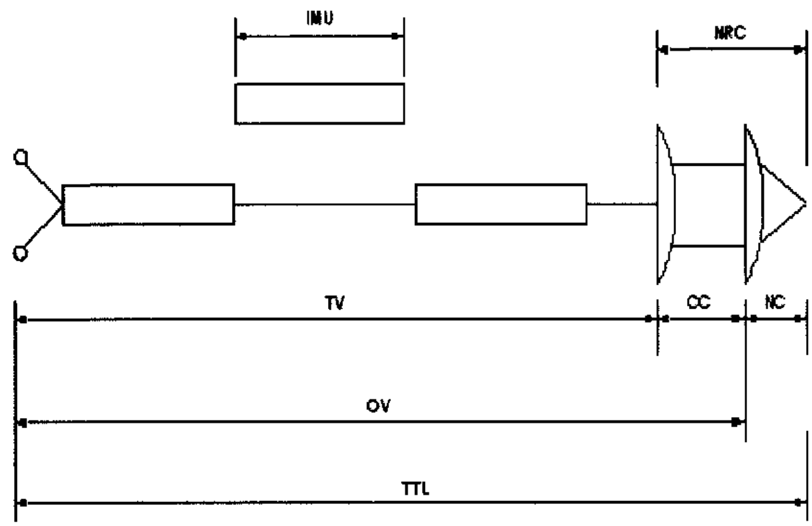



Diagram Key:

| | | | |
|---|---|---|---|
| CC: | Cup to Cup | IMU: | Inertial Mapping Unit |
| NC: | Nose to Cup | NRC: | Nose to Rear Cup |
| OV: | Overall Vehicle | TTL: | Total Train Length |
| TV: | Trailing Vehicles | | |

**Diagram E0100 / 16.3.6 – Launcher and Receiver Dimensions**

17.3.7. The kicker line shall be sized as follows, at a minimum:

| Line Size | Kicker |
|---|---|
| 6" and smaller | 2" |
| 8" and 10" | 3" |
| 12" | 4" |
| 16" thru 20" | 6" |
| 24" thru 30" | 8" |
| 36" | 10" |
| 42" | 16" |

**Table E0100 / 16.3.8 - Kicker Line Diameter**

17.4. Slug Catchers and Liquid Removal/Drip Tanks

If required, the Project Manager will specify drip system and configuration.

17.4.1. Flushable-type drips shall be considered for PCB-contaminated systems and for systems with solids.

17.4.2. Drip storage tanks shall conform to **API** 12F and **NFPA** 30 specifications.

- For single-wall tanks, *refer to* **Typical Drawing TYP-P-0100-B170**. Actual as-built configuration of tanks and related components will be project-specific.

- For double-wall tanks, consult the Manufacturer for details. Actual as-built configuration of tanks and related components will be project-specific.
- An above ground, single-wall storage tank installation requires spill containment provisions. For secondary spill protection requirements, refer to **Engineering Standard E1200 – Civil and Structural**.

17.4.3. The Project Manager shall consider installing slug catchers in conjunction with pigging facilities. A typical slug catcher is shown in **Typical Drawing TYP-P-0100-A075**.

A slug catcher is installed in a lateral and/or mainline pipeline to remove slugs of liquid that would upset adjacent downstream operations.

17.5. Crossovers

The Project Manager shall consider installing crossovers when constructing a new pipeline adjacent to an existing Company pipeline.

Several piping configurations are available for crossovers. Final piping layout is subject to pipe stress analysis, especially for looping existing pipelines. Refer to **Typical Drawing TYP-P-0100-A080** for a typical loop end crossover.

17.5.1. In general, crossover piping shall be a minimum of 60 to 70% of the main line diameter size to handle most of line flow in the event the line flow shall be diverted through the crossover, such that the line section outage has minimal operational impact on the pipeline.

17.5.2. The crossover valve shall be located a minimum of 10 feet from the mainline where possible.

17.5.3. When installing crossovers to be operated in the normally open position, the Project Manager shall consider installing line break detection facilities.

17.6. Branch Connections

17.6.1. Where practical, all branch connections shall be constructed using a forged or extruded tee. For detailed guidelines, refer to **Engineering Standard E1100 – Mechanical**.

17.6.2. All branch connections shall conform to 49 CFR 192.111 design factors for fabricated assemblies. In branch connections into existing pipelines using a hot tap, these design factors shall be applied to the branch piping and existing carrier pipe design factors shall remain unchanged.

17.6.3. Side Tap Connections

For a typical new side tap installation, refer to **Typical Drawings TYP-P-0100-A140** and **TYP-P-0100-A145**.

17.6.4. A check valve shall be considered at each connection to a mainline.

17.6.5. Where a weld end check valve is used, a removable bonnet shall be considered for maintenance.

17.6.6. Installing a bypass shall be considered around a check valve on 4-inch and larger pipeline, pipelines one mile and longer in length and where blowdowns are required. The length and OD of the pipeline shall determine the size of the bypass.

17.6.7. For full encirclement sleeve hot tap details, refer to **Standard Drawing STD-P-0100-B120**.

17.6.8. Ball or gate valves are required.

17.6.9. For line pigging, using scraper bars is required if the d/D ratio for the branch is over 50%. Refer to **Typical Drawing TYP-P-0100-B220**.

## 18. Welding Specifications and Procedures

Refer to **Construction Standard C1060 – Welding and Fabrication** and **O&M Procedures within the 400 series**.

## 19. Pipe Coating and Painting

Refer to **Construction Standards C1080 – Pipeline Coatings**, **C1085 – Cathodic Protection** and **C1230 – Painting**, **Engineering Standard E1300 – Corrosion and Coatings** and **O&M Procedure 203/C1082 – Coating Pipelines**.

## 20. Pipeline Markers and Warning Signs

Pipeline markers and warning signs shall conform to 49 CFR 192.707, **Construction Standard C1120 – Cleanup**, **O&M Procedure 205 – Pipeline Markers and Cover** and as required by other agencies.

## 21. Pipeline Internal Corrosion Control; New Pipelines

The Project Manager shall consider for each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line features which if incorporated into its design and construction would reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

- Be configured to reduce the risk that liquids will collect in the line;
- Have effective liquid removal features whenever the configuration would allow liquids to collect; and
- Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

## 22. Pipeline Internal Corrosion Control; Existing Transmission Lines

When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

## 23. Pipeline Cathodic and Corrosion Protection

Refer to **Engineering Standard E1300 – Corrosion and Coatings**, **Construction Standards C1080 – Pipeline Coatings** and **C1085 – Cathodic Protection** and **O&M Procedures in the 900 series**.

## 24. Pressure Testing Requirements

The Project Manager shall be responsible for developing the pressure test plan in conformance with 49 CFR 192.505. For testing details, refer to **O&M Procedure 1600/C1135 – Strength and Leak Testing** and **Construction Standard C1130 – Pressure Testing**.

## 25. Gas Composition

The Project Manager shall request a current detailed gas composition analysis to facilitate design considerations for any pipeline project expected to carry other than pipeline-quality sweet natural gas. Refer to **E0300 – Gas Processing Sub-Section 5.9** for filters/separators.

## 26. Gas Quality Monitoring/SCADA

If a project requires gas quality monitoring on the mainline, refer to **Meter and Regulation Section E0460 – Gas Quality Measurement**.

The Project Manager shall determine what pipeline data shall be collected and transmitted to the applicable control center(s).

## 27. Gas Measurement

If a project requires gas measurement on the mainline, refer to **Engineering Standard E0400 – Meter and Regulation**.

## 28. Pressure Regulating Stations/Overpressure Protection

28.1. If a project requires pressure regulating stations/overpressure protection on the mainline, refer to 49 CFR 192.195 through 49 CFR 192.201 inclusive and **Engineering Standard E1900 – Overpressure Protection, Pressure Relieving Devices and Flow Control**.

28.2. Overpressure protection devices shall be installed to relieve or limit pressure above the maximum allowable operating pressure (MAOP) during equipment malfunctions and other abnormal conditions in conformance with 49 CFR 192.195 through 49 CFR 192.201 inclusive. Overpressure devices may eliminate or regulate the source of overpressure or may vent the gas as with a relief valve or rupture disc.

28.3. Primary and secondary in-line devices shall be capable of carrying the system's full normal flow/load.

28.4. **ASME** Section VIII, Division 1 vessels shall be designed to be compatible with the pipeline MAOP, including pressure buildup (110% MAOP but not to exceed 75% SMYS).

## 29. Line Pipe Transportation and Handling (D/t)

Line pipe transportation and handling shall conform to API RP 5L1 Recommended Practice for Railroad Transportation of Line Pipe, 49 CFR 192.65 and corresponding **Material Specification M8250 – High Strength, High Toughness Welded Steel Line Pipe for High-Pressure Gas Transmission Service**, **Material Specification M8230 – Seamless Grade B Line Pipe** and **Material Specification M8240 – ERW Line Pipe, 2" – 14", Gr. B – X52**.

## 30. Piping Specification

At a minimum, pipe shall conform to specification API 5L and applicable sections of **Material Specification M8250 – High Strength, High Toughness Welded Steel Line Pipe for High-Pressure Gas Transmission Service**, **Material Specification M8230 – Seamless Grade B Line Pipe** and **Material Specification M8240 – ERW Line Pipe, 2" – 14", Gr. B – X52**.

## 31. Pipe Bend Requirements

31.1. Induction Bends

For induction bend specifications, refer to **Material Specification M8750 – Induction Pipe Bends** and **Engineering Standard E1100 – Mechanical**.

31.2. Field Bends

For field bends, refer to **Construction Standards C1050 – Field Bending Pipe** and **C1090 – Lowering-In Pipe**.

## 32. Pipeline Buoyancy Control

The three most common methods of overcoming the buoyant force exerted on a pipeline by a fluid (water/soil mixture) are soil auger anchors, river weights and continuous weight coating. Plastic pipelines have special requirements, which the Project Manager shall review.

The Project Manager shall consider investing in geotechnical and geophysical survey(s) to verify the absence of subsurface conditions such as liquefaction, high-density water, saturated mud/slurry or other buoyancy conditions and avoid unnecessary cost while maintaining pipeline safety and integrity.

32.1. When the Project Manager determines soil analysis is unwarranted, recommended minimum values of the ratio of total pipe weight to buoyant force for various pipeline environments are as follows:

| **Small Streams and Non-Turbulent Bodies of Water** | **Marsh and Wetlands** | **Erodible Streams and Major Rivers** |
|---|---|---|
| 1.15 | 1.20 | 1.25 |

**Table E0100 / 29.2 - Pipe Weight to Buoyancy**

## 33. Pipeline AC/DC Electrical Transmission Interference Mitigation

33.1. The Project Manager shall determine whether a new pipeline could be susceptible to detrimental effects from stray electrical currents. Based on this evaluation, the Project Manager *shall monitor and take action* to mitigate detrimental effects. The Project Manager shall give special attention to a new pipeline's physical location, particularly a location that may subject the new pipeline to stray currents from other below grade facilities, including other pipelines and induced currents from above grade or below grade electrical transmission lines. Project Managers are encouraged to review their corrosion control programs and to have qualified corrosion personnel present during construction to identify, mitigate and monitor any detrimental stray currents that pose risks to new pipelines.

33.2. Immediately following construction, should a short-interval inspection reveal AC/DC interference, the Project Manager shall initiate mitigation measures, such as applying zinc ribbon.

## 34. Odorization

For odorization relating to a pipeline, refer to 49 CFR 192.625 and **Engineering Standards Meter and Regulation Section E0480 – Natural Gas Odorization**.

## 35. Lowering Pipelines while in Service

Lowering pipelines while in service shall be approved by Senior Operations and Engineering Management. Refer to **API** RP1117.

## 36. Special Considerations for Plastic Pipelines

Refer to 49 CFR 192.121, 49 CFR 192.123, 49 CFR 192.191, 49 CFR 192.193 and **Construction Standard C1240 – PE Plastic Pipe Installation**.

## 37. Abandoning In-Place Pipeline

When projects involve abandoning in-place pipeline, refer to **O&M Procedure 226 – Abandoning, Deactivating and Reactivating Gas Piping** for reporting requirements.

## 38. Pipeline Drawings Not Referenced

Additional Company drawings, though not referenced within this document, may also be applicable or useful in pipeline design and/or installation. These drawings include, but are not limited to:

***TYP-P-0100-A065 – Typical Side Tap with Check Valve***
**TYP-P-0100-A085 – Typical Side Tap Connection**
**STD-P-0100-A110 – Standard Details for Pressure Tap Connection**
**TYP-P-0100-A125 – Typical Thrust Block Support**
**TYP-P-0100-A130 – Typical Support Block**

**TYP-P-0100-A035 – Typical Backfill and Pipe Support**
**TYP-P-0100-A040 – Typical Casing Insulator and Seal**
**TYP-P-0100-A051 – Coupling Installation Details**
**TYP-P-0100-B215 – Anchor Forces Overbends**
**STD-P-0100-B090.1 – Low Press Ball Launcher**
**STD-P-0100-B090.2 – Low Press Ball Launcher**
**STD-P-0100-B110.1 – Low Press Ball Receiver**
**STD-P-0100-B110.2 – Low Press Ball Receiver**
**STD-P-0100-B125.1 – High Press Valve Set**
***STD-P-0100-B125.2 – High Press Valve Set***
**STD-P-0100-B135 – Sloped Branch Tee**
**STD-P-0100-B155 – Standard Detail for Launcher/Receiver Support**
**STD-P-0100-A200 – Standard Pipeline Markers**

To access the Company's comprehensive Drawing files, refer to the **Master Drawing Index**.

# Appendix 4

## Table of Contents



## 1. Applicability

☒ Gathering

☒ Processing

☒ Transmission/Regulated Onshore Gathering

☒ Kinder Morgan Power Company

☒ Kinder Morgan $CO_2$

This procedure applies to all Company operations and locations, contractors (and their subcontractors) and contract employees.

## 2. Scope

This procedure defines the responsibilities of all Company and contractor employees in implementing all Operating and Maintenance (O&M) Procedures Manual requirements.

## 3. Core Information and Requirements

### 3.1. Accountability

Sections 100 and 1200 of the O&M Procedures Manual contain the procedures that comprise the Company Environmental Health and Safety (EHS) Program. All Company employees are *responsible for complying with the information and requirements contained in the O&M* Procedures Manual.

### 3.2. Employee Responsibility

All Company employees are responsible for:

- Working in a safe, healthful and environmentally compliant manner in conformance with Company programs, procedures, work rules, applicable laws and governmental regulations
- Being familiar with the contents of the O&M Procedures Manual and following its requirements
- Periodically reviewing work done to determine effectiveness and adequacy of O&M procedures and following **O&M Procedure 001 – Standards Modification** if it is necessary to modify procedures
- Striving daily for incident-free performance
- Stopping work if an imminently dangerous situation exists
- Asking questions of the supervisor or EHS Project Manager regarding roles, responsibilities or methods of complying with the procedures

### 3.3. Management Responsibility

Company management includes managers and supervisors with office, department, plant, team *or project responsibilities. All levels of Company management will take ownership, accountability* and responsibility for the O&M Procedures Manual.

The Action Decision Committee (ADC) reviews the O&M Procedures Manual annually as specified in **O&M Procedure 000** and approves submitted revisions as needed.

Management is responsible to:

- Guide, direct, coordinate and oversee work teams' overall safety effort
- Ensure that all work is conducted in compliance with all environmental, safety and health laws and regulations
- Make construction records, maps and operating history available to appropriate operating personnel
- Integrate EHS principles into all operations and work
- Set leadership examples by following all safety practices and procedures
- Enlist employee participation and involvement in safety-related decision-making
- Communicate safety issues to employees and EHS Department
- Devote the necessary time, effort and funds to ensure adequate safety equipment is available for all work locations
- Ensure facilities are operated and maintained to protect employees' and the public's safety
- Ensure all employees are trained in procedures, regulations, safe work practices and safety-related devices and equipment
- Ensure that all surveys or analyses required under the O&M Manual and related regulations have been completed, are up-to-date and documentation is in order
- Ensure effective corrective actions are implemented in a timely manner following inspections, audits, incident investigations, etc.
- Enforce the use of disciplinary action when necessary

## 4. Training

No regulatory training requirement.

## 5. Documentation

Document all training per **O&M Procedure 183**.

## 6. References

- 49 CFR 192.605 (a), (b)(3), (b)(8)
- **O&M Procedure 000**
- **O&M Procedure 001**
- **O&M Procedure 183**
- Contractor Safety Manual

## Table of Contents



# 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☒ Kinder Morgan Power Company

# 2. Scope

This procedure provides all Company personnel a method to propose revisions or request variances to the following Company standards and manuals, insofar as they are governed by them.

- The **Operating and Maintenance Procedures Manual** (O&M Manual) and **O&M Forms**
- The Company **Engineering Design Manual**, consisting of **Major Design Installations**, **Engineering Disciplines**, **Material Specifications**, **Equipment Specifications**, and **Vendor Qualifications**
- **Drawings Manual**
- **Construction Standards Manual**
- **Construction Inspection Manual**
- **Master Glossary Compliance**
- **Pipeline Integrity Management Program**
- **Public Awareness Program**

Direct all Technical Reference Manual revisions, additions or deletions to the Regional Technical Manager. The Manager will review these requests for consistency with all other standards.

# 3. Core Information and Requirements

## 3.1. Revision Process

- Go to the **KMOnline – Action Decision Committee** (ADC) website
- Click on the *How to Submit an ADC Request* link for specific editing and revision instructions. You must follow these instructions or the request will be returned. If the Track Changes tool displays previous revisions, do not proceed without first contacting the **ADC Administrator** for assistance.
- Modify all associated Company standards and manuals to reflect the revision including but not limited to the following:
    - **O&M Procedure 1400 – Records Retention by O&M Procedure**
    - **O&M Procedure 1401 – Records Retention by Form Number**
    - **O&M Procedure 1700 – Inspection and Maintenance (I&M) Procedures**
    - **O&M Forms**

- Identify stakeholders[1] who will be affected or governed by the new or revised procedure. If you are unable to identify the stakeholders then consult with your supervisor for guidance.
- Circulate the proposed revisions to the identified stakeholders and gain their concurrence via e-mails. Keep the stakeholders' approval e-mails for submission to the ADC.
- Revisions to the Environmental Health & Safety (EHS) O&M Procedures and Forms shall require approval e-mails from the appropriate EHS Stakeholder. Modifications to Section 100 – Safety requires approval from the Safety Services stakeholder and modifications to Section 1200 – Environment requires approvals from the Environmental stakeholder.
- Include all revised documentation in your ADC request.

### 3.2. Requesting Revisions

To request a revision, deletion, or addition to a manual:

- Complete **O&M Form OM000-01 – Action Decision Committee Request**. *One form may be used to request revisions on multiple documents provided the revisions are related.*
  - Be sure to enter your name and the date at the top of the form
  - Check the appropriate boxes, complete the title and number information
  - Explain the reasons for the request in detail. Do not restate the revisions
- E-mail the form to the **Action Decision Committee** e-mail address with an electronic version of the procedure or standard, edited per the instructions on the **ADC website** to show the requested changes.
- Submit concurring stakeholders' e-mails, obtained during the Revision Process, with the request. The e-mails must accompany the **Action Decision Committee Request** or it will not be placed on the ADC Agenda for the next meeting.

Do not submit hard copies.

### 3.3. Requesting Variances

To request a variance[2]:

- Complete **O&M Form OM000-01 – Action Decision Committee Request**.
  - Be sure to enter your name and the date at the top of the form
  - Check the "Request for a variance to a procedure or standard" box
  - Complete title and number information
  - Explain the reason for the request in detail
  - Specify the location where the variance will be applied
- Identify stakeholders[2] who will be affected or governed by the variance. If you are unable to identify the stakeholders then consult with your supervisor for guidance.
- Circulate the proposed revisions to the identified stakeholders and gain their concurrence via e-mails. Keep the stakeholders' approval e-mails for submission to the ADC.
- E-mail the form to the **Action Decision Committee** e-mail address and attach any pertinent supporting documentation. An electronic version of the procedure or standard is not necessary for submission.

Do not submit hard copies. If approved, the ADC will issue a signed copy of the variance to the requestor. It is the requestor's responsibility to ensure that the document is kept at the appropriate location.

### 3.4. Expedited Variances

An alternate method for obtaining a variance when it is needed before the ADC meets is to

[1] **Stakeholder:** Company employee who has final decision-making authority and has a stake in or may be affected by a given change to Company Standards and/or Procedures.

[2] Variance: A document that provides a license to perform a task in a manner contrary to the language contained in an existing procedure, standard or specification.

- Obtain, in e-mail form, permission from two of the following:
  - Director, Engineering Services
  - Director, Project Management
  - Director, Pipeline Integrity
- Complete **O&M Form OM000-01 – Action Decision Committee Request** as described in Subsection 3.3 – Requesting Variances.
- Attach the form to the e-mail request. Copy the **Action Decision Committee** on the e-mail to ensure approval e-mails are received for documentation and to initiate processing for confirmation at the next ADC meeting. Once the expedited variance is confirmed, the ADC Administrator will issue a signed hard copy variance to the requestor. It is the requestor's responsibility to ensure that the document is kept on file at the appropriate location.

### 3.5. Emergency Variances

Although rare, there may be emergencies where two of the three listed directors are not available in a timely manner. Typically, this might occur after hours or when a situation requires immediate resolution. In that case, a single, temporary variance approval from a vice president, a regional or corporate director, technical or operations manager will suffice.

When an emergency variance is used, as soon as possible but no later than the second ADC meeting after the variance has been granted:

- Submit **O&M Form OM000-01 – Action Decision Committee Request** requesting the variance as described in Subsection 3.3 – Requesting Variances. Attach the approval e-mail from the vice president, regional or corporate director, technical or operations manager or an e-mail verifying the variance was granted verbally. The variance will be reviewed at the next ADC meeting. Once it is confirmed, the ADC Administrator will issue a signed, hard copy variance to the requestor. It is the requestor's responsibility to ensure that the document is kept on file at the appropriate location.

### 3.6. ADC Meetings

The ADC meets the second Thursday of each month via telephone conference call. Properly completed requests received by noon Thursday one week before a meeting will be placed on the agenda for the next ADC meeting. Requests received after that time will be on the following month's meeting agenda.

You will be invited to attend the meeting at which the ADC discusses the request. The ADC will not address the request if you (or your representative) are not present. Your representative must be able to answer any questions and clarify any wording. If you or a representative cannot attend an ADC meeting within three months of submitting a request, the ADC will suspend your request.

You may submit a new request for the same issue when you will be able to attend the next meeting.

## 4. Training

Not applicable.

## 5. Documentation

ADC meeting minutes are provided each month to a distribution list consisting of members and interested parties. Update notices summarizing revisions are distributed each month to a list of Company manual holders. If you wish to be on either list, contact the **ADC Administrator**. This information as well as approved revisions and variances is available on the ADC website at **KMOnline - Action Decision Committee**.

**Codes and Standards will notify regulatory authorities concerning HCA pipeline segments within 30 days after adopting any significant change to the Integrity Management Program (IMP), as defined by the Integrity Management Program Section 14 – Management of Change and O&M Procedure 219 – DOT and State Pipeline Reports.**

## 6. References

- 49 CFR Part 192.605
- O&M Procedure 000 – Action Decision Committee
- O&M Procedure 219 – DOT and State Pipeline Reports
- O&M Form OM000-01 – Action Decision Committee Request
- Integrity Management Program Section 14 – Management of Change
- KMOnline - Action Decision Committee

## Table of Contents



## 1. Applicability

☒ Gathering

☒ Processing

☒ Transmission/Regulated Onshore Gathering

☒ Kinder Morgan Power Company

## 2. Scope

The Action Decision Committee (ADC) is responsible for approving revisions, additions, deletions and variances to the following Company standards manuals:

- **Operating and Maintenance Procedures Manual** (O&M Manual) and **O&M Forms**
- The Company **Engineering Standards Manual**, consisting of Major Design Installations, Engineering Disciplines, Material Specifications and Equipment Specifications
- **Drawings Manual**
- **Construction Standards Manual** (Construction Standards)
- Pipeline **Integrity Management Program**
- **Construction Inspection Manual**
- **Public Awareness Program**

## 3. Core Information and Requirements

### 3.1. ADC Purpose

The ADC reviews requests and approves revisions, additions, deletions and variances to the listed manuals to help ensure company assets are designed, installed, operated and maintained in a safe, reliable and cost effective manner that complies with laws, regulations, company standards and corporate objectives.

### 3.2. ADC Meetings

The ADC meets at 9:00 a.m. Mountain time (MST or MDT) the second Thursday of each month via telephone conference call. If you have a request on the agenda, you (or a representative in an emergency) will be invited and should attend the meeting. Refer to **O&M Procedure 001 – Standards Modification** for more details.

### 3.3. ADC Process

- First Thursday of each month – ADC Administrator distributes agenda and attachments to members and invites requesters to attend the ADC meeting

- Refer to **O&M Procedure 001 – Standards Modification** for the process to submit a request to the ADC. The deadline is the first Thursday of the month at noon for that month's meeting.

- Second Thursday of each month – ADC meets and acts on requests
- Third and fourth weeks of month – ADC Administrator issues meeting minutes and approval notices and makes approved revisions
- End of the month or first of the following month - revisions are uploaded to the appropriate intranet website and update notices are sent to applicable distribution lists

### 3.4. ADC Membership

The ADC is composed of an ADC Administrator and the following voting members:

- Bruce Hancock, Codes and Standards, Chairperson
- Thomas Bach, Environmental Services
- Bruce Olsen, Engineering Services
- Kevin Philbrick, Operations
- Rob Koenig, Project Management
- John Greer, EHS

### 3.5. Yearly O&M Manual Reviews

The O&M Manual must be reviewed at least once each calendar year but not to exceed 15 months. At one of the monthly ADC meetings, members or other knowledgeable parties will be assigned sections of the O&M Manual. It will be their responsibility to review or sub-assign sections for review to determine if procedures are adequate or if revisions or new procedures are needed. If a review indicates procedures need to be revised, follow the process in **O&M Procedure 001 – Standards Modification**.

Revisions need not be completed for the annual review to be considered completed.

### 3.6. Pipeline Integrity Management Program

The Risk Engineering Department must review the Pipeline **Integrity Management Program** every 36 months at a minimum and will document the review to the ADC Committee. The process will include reviewing applicable federal, state and local regulations, operational procedures, quality assurance results and industry standards.

## 4. Training

Not applicable.

## 5. Documentation

Upon completing the annual review, reviewers should e-mail the Action Decision Committee e-mail address a list of procedure numbers reviewed, reviewer name(s) and date(s) completed. The ADC Administrator will track and document the review on a spreadsheet that will become a permanent record.

The ADC Administrator provides meeting minutes each month to a distribution list consisting of members and interested parties and distributes update notices summarizing revisions each month to a list of manual holders. This information as well as approved revisions and variances is available on the ADC website **KMOnline – Action Decision Committee**.

## 6. References

- 49 CFR Part 192.605
- **O&M Procedure 001 – Standards Modification**
- **KMOnline – Action Decision Committee**

# Appendix 5

## Table of Contents



## 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☐ Kinder Morgan Power Company

## 2. Scope

This procedure applies to all facilities and provides **guidance in addressing** all construction projects or activities that encroach upon the Company's pipelines, fee owned property, easements, etc. Such encroachments must be evaluated to assure compliance with Company requirements **as those requirements are prescribed in this procedure**, prevent damage to the pipeline facilities and protect the public and employees.

## 3. Core Information and Requirements

Third Party activities near pipeline facilities that may require *inspection and* or assessment including, but are not limited to:

- Blasting
- Installing foreign pipelines
- Installing electric cables, telephone or cable TV lines
- Drilling holes for poles, posts, anchors or oil, water and gas wells

- Installing parking lots, driveways, mobile homes, garages, sheds, swimming pools, barns, junkyards or trees
- Any other activities that may require excavation
- Crossing pipelines with heavy vehicles or equipment
- Permanent or temporary removal of cover from pipelines (e.g., agricultural land leveling, road or highway construction, drainage work)

### 3.1. Basic Rights

The **Right-of-Way (ROW) Department** enforces Company land rights insofar as or to the extent provided by underlying agreements.

When a third party's activities threaten the safety of Company operated facilities, the Company will request that the third party discontinue such action. If the third party fails to adhere to the request, then assistance from operations management and the **ROW Department** shall be pursued. When a third party damages a pipeline or other Company operated facility, the Company has the right to reimbursement for such damages.

The Company has certain basic land rights through easements, franchises, permits, license agreements, leasehold, fee ownership, etc., that allow for constructing and operating Company facilities. The value and extent of the Company's rights depend upon the underlying agreement's terms and conditions.

The Company has the right to act in accordance with the terms and conditions of the underlying agreement. In cases where the Company owns the property in fee, any encroachment on the property is considered trespassing. The Company is prepared to take any legal action necessary to protect its real and personal property rights and the safety and property of other persons.

### 3.2. Basic Responsibilities

The Company has the following basic responsibilities in relation to its pipelines:

- When Company pipelines are identified by pipeline markers, stakes or by telling a third party where the line is located, such identifiers must be accurate and comply with the requirements of state One-Call organizations and KM procedures whichever is more stringent.
- Managers and supervisors shall plan accordingly for workload fluctuations, vacations, etc. to ensure notices received are completed in a timely manner.
- In states without One-Call organizations, each region should organize a system to record and respond to incoming communications regarding planned construction projects, excavations and encroachments affecting pipeline facilities. Obtain the following information:
    - Excavator's name and telephone number
    - Location of the planned excavation and the type of activity
    - Date and time of the planned excavation

### 3.3. One-Call Systems

Every location will participate in a state One-Call system. Attachment 1 – One-Call Center and Emergency Phone Numbers lists the One-Call center phone numbers, as well as Company control center phone numbers. The One-Call system serves as a means for receiving and recording excavation notification as well as notifying excavators how to identify temporary pipeline markings. In order to maintain the One-Call database; once each calendar year, each location shall review their current pipeline assets and compare them with the lines in PODS or One-Call Agency database to ensure that all lines the Company operates are listed and have not been sold or abandoned.

Participating in the state One-Call program may meet the following damage prevention requirements:

- If the State One-Call Center maintains a list of excavators who have used the One-Call service, document in local files how to easily access this information when it is needed or store the information in the Public Awareness Database.
- If the State One-Call Center provides notification to excavators explaining the One-Call program and excavation procedures, obtain documentation for local files or store the information in the Public Awareness Database.

3.3.1. *Receiving* Notices from One-Call Centers

When the field receives a One-Call notice of intended excavation, a response is required per the procedures below and state One-Call Laws.

When the field receives a notice of intended activity, (One-Call) the person receiving the information will determine as to the location of work versus the Company's assets. If Company assets will not be impacted, document in the electronic One-Call system or use the local district's One-Call form. The documentation must include justification for no physical locate and the individuals name.

When the person receiving the one call determines there is a question as to whether Company assets will be impacted, a Company representative will contact the excavator for additional clarification. If at this time, it is determined that Company assets will not be impacted, document in the electronic One-Call system or use the local district's One-Call form. The documentation must include justification for no physical locate, excavator contacted, and the individuals name.

If the work is within 50-feet of Company assets, or if there is a potential for the work to encroach to within 50-feet of Company assets, **Company Personnel** will physically mark the asset according to Subsection 3.4 – Marking Underground Structures below, and document in the electronic One-Call system or use the local district's One-Call form. For all physical locates, **O&M Form OM200-31 – Line Locate Inspection Report** shall be completed.

3.3.2. Design or Planning Notification

When the one call notification is a request to meet for the purposes of design or planning, the Company Representative is to contact the person designated on the one call ticket as the contact person to ensure that no excavation is planned in the area noted on the one call ticket and to schedule a meeting at a mutually agreeable time. If an excavation is planned, which meets the definition of this procedure or the state one call law then Subsection 3.3.1 – Receiving Notices from One-Call Centers applies. Also, refer to Subsection 3.4.3 – Meeting Requirements with Excavator.

### 3.4. Marking Underground Structures

Company personnel will locate and mark pipelines in areas where excavation activities are observed or will occur as indicated by the One-Call notification. **ONLY Company personnel are approved to locate and mark underground structures.**

**Exception**: Line marking may not be required for routine long-term activities where the depth of cover is known, and it has been established that the activity will not, in any way, affect the integrity of the pipeline. These include activities such as tilling of farmland, and road grading operations. In these cases, a standing procedure may be established with the parties involved that would apply as long as surface conditions and/or activities do not change. All other parts of this procedure do apply.

3.4.1. Locate and mark the pipeline, within 50-feet of the excavation work area, as specified below.

- Pipelines will be marked within 48 hours of receipt of notification (excluding weekends and holidays) or in accordance with local One-Call laws, and before any excavation activities begin. Emergency Notifications will be responded to promptly.

- Locates and markings shall be performed safely. Consideration should be given to items such as, but not limited to; traffic, site conditions, and personal protective equipment (refer to **O&M Procedure 120 – Personal Protective Equipment**).
- Available Company records/strip maps/alignment sheets are to be reviewed prior to marking the pipeline(s). Look for taps, both active and abandoned, or any other below grade facilities. The minimum length of pipeline to be marked shall be as required by conditions of the site and job. Any errors or omissions discovered shall be communicated to the Engineering Records Department immediately
- Perform a visual inspection of the locate area to determine if there is evidence of a Company pipeline which is not on any record, map or alignment sheet. Also, be aware of other pipelines that might be in the area that are not on Company drawings.
- When marking the line, the marks must be able to identify where the pipeline is located, the lesser of within 2-feet off the center point, or as required by state One-Call Laws. If this criterion is not possible, then no mark shall be made, but a positive "finding" (pothole) will be necessary.
- Point of Intersection (PI) and other changes of direction shall be marked so that the pipe's location is clearly delineated.
- When marking facilities, Company is to consider the type of facility being located, the terrain of the land, the type of excavation being done and the method to adequately mark its facility for the excavator. The spacing of the markings shall be 10-feet or less apart.
- Any crossings in the area must be marked.
- Any crossing, not shown on the alignment sheet must be reported immediately to the Engineering Records Department for inclusion on as-built drawings.
- Temporarily mark the physical location of a pipeline using yellow flags, laths and/or fluorescent yellow paint per the ULCC Color Code Guide. Use the appropriate marking for the existing and expected surface conditions.
- When feasible, the owner/operator of a facility is identified by the markings at the time the facility is located.
- Locate and mark any transmission or gathering facility within 50-feet of the excavation work.
- Buoys, poles or PVC markers may be used for submerged underwater facilities in areas such as wide commercially navigable waterways and bays. Markers should be placed as close as practical over the facilities that are submerged in such a manner without impeding or creating additional hazards.

Multiple Company pipelines in the same ROW will be marked individually. Care should be taken at all locations where there are multiple lines in the same ROW (either KM or third party). A sweep of the area should be performed to help identify the intended pipeline as well as any other lines that may be in the vicinity.

- If there is doubt concerning the location or depth of the line, either request assistance to locate or excavate the pipeline to determine exact location.
- Contact the excavator and arrange to meet an authorized representative of the excavator. Discuss provisions in <u>Subsection 3.4.3 – Meeting Requirements with Excavator</u>.
- All marked locations shall be photographed and the photos attached to the completed One-Call ticket, electronically stored in the One-Call system, or attached to **O&M Form OM200-31 – Line Locate Inspection Report** or otherwise tied to the ticket before filing per <u>Section 5 – Documentation</u>.
- All One-Calls must be responded to, via the electronic One-Call system, even if there is no conflict with Company facilities.
- Additional notification may be made by phone, fax, or email. The date and name of the person contacted should be recorded in the electronic One-Call System.

3.4.2. Line Locating Equipment used in Locating Pipelines for Marking

Conductive locating (direct connection to the pipeline) is the preferred method for locating Company pipelines.

Line locating equipment will be field checked for proper operation prior to initial use, each day **that it is used for locating**. Documentation of this check should be recorded in the ticket notes section of the electronic one call system or other approved method. If Inductive locating is used for locating Company pipelines, a direct positive confirmation by a water probe, probe rod, vacuum truck or other methods must be performed.

3.4.3. Meeting Requirements with Excavator

- Meet with the encroaching party's representative. Obtain the information needed by the Company concerning the type of activity, crossing, drawings, schedules, blasting plans including charge size and location (if applicable), contact information (names, numbers), etc. Use this opportunity to obtain contractor information for Company's damage prevention program and to promote the use of the applicable state One-Call systems and the national 811 number.
- Review with the excavator/encroaching party's supervisor or designated responsible person the requirements of this procedure (O&M Procedure 204 – Construction Near Company Facilities) such as scope of the job; location of Company facilities; the requirements for crossing Company lines or facilities; and the requirements that a Company Representative must be on-site whenever work will be done within 25-feet of Company Facilities.
  - **Required clearance from any underground structure not associated with the pipeline is 24-inches**
  - Company pipelines must be exposed per Subsection 3.8 – Excavating Pressurized Lines of this procedure.
- Excavations entered by and performed by Company employees or their representatives must meet the requirements of **O&M Procedure 109 – Excavating, Trenching and Shoring**
- Special provisions are required when working over or near Dresser coupled lines. These provisions are outlined in **O&M Procedure 237 – Dresser-Coupled Pipelines**
- Verify that the information received concerning dates, locations and scope of work is accurate
- The Company representative assigned to locate a pipeline or monitor excavation activities shall complete the **O&M Form OM200-31 – Line Locate Inspection Report** and sign
- For excavations 25-feet or less from Company assets, contractor should counter sign **O&M Form OM200-31 – Line Locate Inspection Report**. The original will be given to the third party excavator's representative on the site during the initial meeting with a copy retained for district records
- For excavations greater than 25-feet, contractor is not required to counter sign **O&M Form OM200-31 – Line Locate Inspection Report**. Retain the document for district records
- The form must be re-issued for changes in activities, including, but not limited to:
- Changes in the scope of work that could affect the safety of the line
- Changes of affected personnel on the site (excavator, supervisor, etc.)
- Changes to the schedule/work plan, that is, digging faster or moving to another area e.g., across the road.

**O&M Form OM200-31 – Line Locate Inspection Report** helps assure communications between the Company representative and the third party excavator regarding the planned or actual date(s) of excavation activities. If applicable, the form should include any observation waivers granted and the basis on which the exception was granted, with instructions to contact the KM Employee if any of the conditions, which was the basis for exception, change.

If the excavator refuses to sign, the Company representative will so indicate on the form.

### 3.5. Surveillance, Awareness and Reporting

Be alert for upcoming projects that may encroach upon or endanger Company operated pipelines or facilities. Construction activity that may involve Company operated pipelines or facilities should be immediately reported to the appropriate supervisor. If the appropriate supervisor cannot be reached, notify the next available supervisor or Gas Control.

The public is often aware of projects, including underground phone, electrical, sewer and water facilities and street construction projects long before work begins. Since rural road construction and land leveling are less publicized, inform area contractors and road crews of Company line locations and the rules regarding construction activity.

Notify Operations Manager or designee of any construction projects that may affect or endanger Company operated facilities. Report any activities on fee owned property to ROW. When construction work is within city or corporate limits or part of a city project, contact city officials and remind them of the Company's rules and policies. Try to attend any city or county planning committee meetings concerning major construction activities that could affect the Company's assets. The necessary provisions can then be written into an ordinance or into the contract under which the work will be performed.

### 3.6. Investigating Third Party Construction Activity – Company Not Notified

Immediately investigate any construction activity near Company pipelines to see that proper procedures are or were followed.

When Third Party construction activity involving a Company pipeline or facility is started without prior approval, notify the operations supervisor immediately. Contact the **ROW Department** to determine the Company's rights. Inspect the premises immediately and take necessary steps to correct or prevent unsafe conditions.

If a Third Party is seen within 50-feet of, or working over the Company's pipeline, the excavation and construction activities shall immediately be stopped until the Company facilities have been located and investigated for possible damage.

High Consequence Areas: When physical evidence of encroachment over the pipeline is discovered in an HCA that was not monitored, the area must be excavated near the encroachment or an above ground survey must be conducted using methods defined in NACE RP-0502-2002.

When land leveling or improvements involving a Company pipeline or facility are started without prior approval, notify the operations supervisor immediately. Contact the **ROW Department** to determine the Company's rights. Inspect the premises immediately and take necessary steps to correct or prevent unsafe conditions.

If excavation activities are identified within *Kinder Morgan's pipeline easement that are not* allowed by the pipeline easement or permit agreement, the activities shall be stopped until an agreement is reached. If excavation activities continue, local management should be advised and Kinder Morgan's Legal Department and/or local law enforcement authorities may be called for assistance.

### 3.7. Inspecting Third Party Construction Activity – Company Notified

**Excavation Monitoring** - A Company **representative** shall, unless excepted by Subsection 3.7.1 – Exceptions to Mandatory Observations, be present during construction activity within 25-feet of the Company operated transmission or gathering pipeline facilities. **Excavation Observation** - A Company **employee** will, **unless excepted by Subsection 3.7.1 – Exceptions to Mandatory Observations**, be continuously present during excavation and backfilling activities to observe compliance with agreed upon design/specification/scope of work and to ensure the excavation and backfilling criteria are being met. If a Company employee is not onsite, absolutely no work is to be allowed without the permission of the Company employee. Observation is mandatory when excavation activity is within 10-feet of the pipeline. If the excavation results in a foreign utility crossing of KM's pipeline, the KM employee shall complete **O&M Forms OM200-01 – Foreign Structures Report** and **O&M Form OM200-03 – Underground Structure Crossing Report**. If the excavation results in the exposure of a KM pipeline, the KM employee shall complete **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report**.

A Company representative may give permission for work over the pipeline to be performed without being on site after they have met with the excavator, marked the pipeline, and reasonably assured themselves that there was no risk of the surface activities affecting the integrity of the asset. Work is defined as disturbing the soil, moving any heavy equipment over the pipeline with less than the required cover.

In the event of parallel encroachments or other circumstances where this provision will require a Company representative to be present for a long duration, and there is to be no crossing of the Company's pipeline, the contractor's work schedule shall be provided to the Company and a meeting held with Company inspector(s) when necessary to review the schedule. Any deviations to the schedule will require advance Company approval.

Company representatives should be aware of the **O&M Form OM200-29 – Guidelines for Design and Construction near Kinder Morgan Operated Facilities** during construction near Company facilities:

3.7.1. Exceptions to Mandatory Observations

3.7.1.1. Alternatives to On-Site Observation **10' to 25'.**

**Acceptable alternatives include:**

- Concrete Barriers installed between the area of excavation and the KM pipe
- Permanent or temporary fencing installed between the area of the excavation an the KM pipe
- Video monitoring

Waiver to Observations

When the scope and location of the proposed excavation is greater than 10-feet from the KM asset and there appears to be no benefit to being continuously present during excavation and backfilling to protect the Kinder Morgan asset, a waiver to the observation may be granted.

Examples where this may be applicable include, but are not limited to:

- Excavation, such as paving or digging foundation footings on private property when the pipeline is under the city street or on the opposite side of the road.
- Replacing utility poles when the utility easement is offset from the pipeline at a distance greater than 10-feet and guy wires will not encroach upon the easement.
- Excavation on the other side of an immovable barrier or natural demarcation, such as, construction separated from our pipeline by railroad, or stone/concrete fence, etc.
- Other digging that will not damage the pipeline, i.e. hand digging, shallow/well defined.
- Other situations where the activity will not affect the pipeline.

Care should be taken to ensure that the scope of work does not include utility work that could potentially cross the pipeline or that the pipeline is not within the designated excavation area (white lined area).

Note: KM does not have the authority to waive a State One-Call requirement.

When seeking a waiver to continuous observation, for construction within 25-feet but greater than 10-feet of the pipeline, the KM Line Locator must contact the Damage Prevention Supervisor, Area Manager or Operations Supervisor to get their concurrence. After approval, the site should be monitored periodically to ensure work remains within the original scope.

- The justification, date and time of the concurrence and the name of the person granting the exception must be recorded in the note section of the electronic one call system.
- The person granting the exception must also record the decision and the basis for the decision in their records.

3.7.1.2. **Exceptions to Company Personnel Observing/Monitoring Excavation and Backfilling Activities**

- **Operations Management will decide when it is necessary to use a contract representative to monitor excavation and/or backfilling activities.**
- **The Damage Prevention Supervisor will follow the appropriate Kinder Morgan procedure(s) for selection and contracting of a contract representative.**
- **The Damage Prevention Supervisor will coordinate with the Operations Manager to ensure that the contract representative has completed the required training and approve the Operator Qualification (OQ) credentials.**
- **The Damage Prevention Supervisor must confirm proficiency and knowledge of covered procedures and training for the contract representative.**
- **As a minimum the contract representative shall be Operator Qualified on the following tasks:**
  - **Abnormal Operations**
  - **Damage Prevention During Excavation Activities**
  - **Backfilling**
  - **Inspection**
  - **Inspection of Materials**
  - **Line Locating (only the written portion of the Line Locating OQ process is required to demonstrate an awareness of this task)**
- **The Damage Prevention Supervisor will be responsible for ensuring that the contract representative has reviewed, understands and provides proper documentation of the following Kinder Morgan Operating & Maintenance (O&M) Procedures.**
  - **O&M Procedure 109 – Excavating, Trenching and Shoring**
  - **O&M Procedure 159 – Incident Reporting and Investigation**
  - **O&M Procedure 166 – Safety Hazard/Near Miss Reporting**
  - **O&M Procedure 168 – Safety Orientation**
  - **O&M Procedure 204 – Construction Near Company Facilities**
  - **O&M Procedure 205 – Pipeline Markers and Cover**
  - **O&M Procedure 214 – Reporting Pipeline Safety-Related Conditions**
- **The Operations Manager will communicate to the Director of Operations the intent to utilize a contract representative for excavations and/or backfilling activities within their area of responsibility.**
- **The Director of Operations will review the need to utilize contract inspectors and if deemed necessary will conditionally approve the use per project.**
- **Final approval to use contract inspectors will not be given until all training is completed.**
- **The Damage Prevention Supervisor will be responsible for ensuring that the contract representative has reviewed, understands and provides proper**

documentation of the following Kinder Morgan Construction Inspection procedures:

- **CON0020 – General Requirements**
- **C1010 – Clearing, Grading and Site Preparation**
- **C1100 – Backfilling**
- **C1160 – Horizontal Directional Drilling**

- The Damage Prevention Supervisor will be responsible for ensuring that the contract representative has reviewed, understands and provides proper documentation of the **Kinder Morgan Contractor Safety Manual**.
- The Damage Prevention Supervisor will be responsible for providing copies of the training requirements stated above to the Operations Manager for approval, then to the Director of Operations for review and approval before proceeding with the use of contract representatives during excavations and backfilling activities on existing Kinder Morgan right-of-ways and property. Including the following:
  - Confirmation of the completion and acceptable scores of the OQ training stated above.
  - Copies of O&M Procedures, Construction Inspection Manual and Contractor Safety Manual - signed and dated by the contract representative as well as the project manager or their designee.
  - A general summary that identifies the planned excavation and backfilling activities.
- The Director of Operations will:
  - Provide confirmation to the Damage Prevention Supervisor and Operations Manager, via email, if they are in agreement that all training requirements have been satisfied and use of the contract representative for monitoring of excavation and/or backfilling activities is approved.

    **- OR -**

  - Respond to the Damage Prevention Supervisor and Operations Manager, via email, that training requirements are deficient and the use of the contract representative is NOT approved.

3.7.2. Kinder Morgan Initiated Excavation Activities

When excavating, Kinder Morgan and Contractors doing work for Kinder Morgan have the same obligations to comply with state one call laws and follow the practices that we expect from 3rd party excavators. To that end, the person responsible for excavating on behalf of KM will:

- Make notification to the appropriate one call center of the intent to excavate.
- If the excavation location cannot be specifically identified by landmark, address, legal description or GPS point, identify the proposed area of excavation using white lining prior to notification of the One-Call center.
- Maintain the ticket number from the one call center that verifies the locate request was requested.
- If multiple excavators for KM are working at the same site, each will have a separate one call reference.
- When practical the KM excavator will request a meeting with the other facility locator(s) at the job site prior to the actual marking of facility locations.
- Coordinate work that requires temporary or permanent interruption of a facility's service with the affected facility owner/operator.
- Re-call the one call center if the facility owner/operator fails to respond to the KM request for a locate (within the timeframe established by the state one call law).

- Verify that the excavation site is at the correct location as described on the one call ticket.
- Verify the locate markings and check for unmarked facilities by conducting an electronic and visual sweep of the site. Perform an "electronic sweep" of the white lined area by using a KM approved locator, set to inductive mode. Visually check for such things as signs, markings, and trenches that might indicate underground utilities are present.
- The excavator should review the location of underground facilities with the facility operator prior to excavation.
- The KM employee on site should have access to the names and phone numbers of all facility owner/operators contacts and the one call center.
- Reasonable care will be used to avoid damaging underground facilities. The excavation should be planned to avoid damage and or minimize interference with the underground facilities in or near the work area.
- Protect and preserve the staking, marking or other designations for underground facilities until no longer required for proper and safe excavation. If any facility mark is removed or no longer visible, excavation is to be stopped and the facility owner or one call center is notified to request a re-mark.
- An observer is required to assist the equipment operator when operating excavation equipment around known underground facilities.
- Mechanical excavation is not allowed within the tolerance zone of the underground facility unless otherwise allowed by this procedure or state law, whichever is more stringent.
- The facility owner/operator is to be contacted, either directly or through the one call center if an underground facility is not found where one has been marked or if an unmarked underground facility is found. Following this notification work can be continued, unless otherwise in state law, if the work can be performed without damaging the facility.
- Exposed **pipeline** facilities will be supported and protected from damage.
- The one call center will be called to refresh the ticket if it is expected that the excavation will continue past the life of the ticket.
- If an underground facility is damaged or is discovered to be damaged, the owner/operator of the damaged facility will be notified either directly or via the one call center (unless otherwise specified by state law). All breaks, leaks, nicks, dents, gouges, grooves, or other damages to facility lines conduits, coatings or cathodic protection will be reported.
- If the damage results in the escape of any flammable, toxic, or corrosive gas or liquid or endangers life, health, or property 911 and the facility owner/operator is to be notified immediately. Reasonable measures will be taken to protect those in immediate danger (employees, contractors, public), property and the environment until the facility owner/operator or emergency responders have arrived and completed their assessment.
- In the case of an emergency excavation of a KM pipeline, maintenance or repairs may be made immediately provided the one call center and impacted facility owner/operators are notified as soon as reasonably possible. This includes situations that involve danger to life, health or property.
- Protect all facilities from damage when backfilling an excavation. Trash, debris or other material that could damage existing facilities or interfere with the accuracy of future locates is not to be buried in the excavation.
- For trenchless excavations (boring, etc.) the KM excavator will adhere to all best practices stated in this section.
- All applicable federal and state safety regulations, which include training as it relates to the protection of underground facilities, will be adhered to.
- High Consequence Areas: An excavation in an HCA shall be evaluated for the potential of stress corrosion cracking (SCC) by reviewing the existing conditions with the SCC criteria (refer to the **Pipeline Integrity Management Program**)

When a KM pipeline is exposed **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report** must be completed

### 3.8. Excavating Pressurized Lines

Before excavation by powered equipment, the line must be located with a water probe, probe rod, vacuum truck or exposed by hand. Prodding shall be done during excavation across the entire ditch. When power equipment is within **24-inches** of any point on the circumference of the pipeline, probe bars shall be used to verify depth and to size the line. Locate the top of pipe and both sides at the point the line is being crossed. When excavating, power equipment shall not dig closer than 18-inches to any point on the circumference of the pipeline and prodding shall be done during excavation. Pipeline shall be exposed by hand digging only at this point. Be aware of possible side taps and or top taps that have been abandoned or are not reflected on alignments; for known taps additional hand digging may be required.

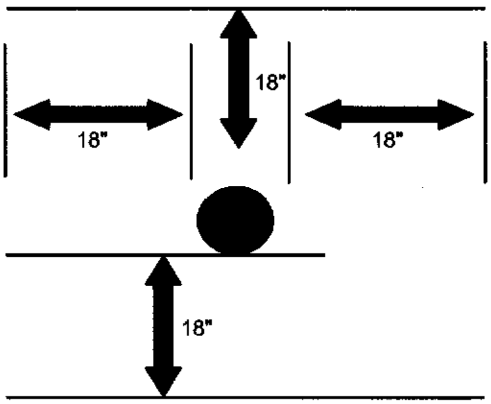



**Figure 1 – Horizontal and Vertical Offsets**

If a probe rod must be used, inspecting the coating in the excavated area is required and any damaged areas must be repaired before backfilling. DO NOT locate pressurized lines using power equipment.

Power equipment excavation should be done **with the equipment positioned** parallel to the pipeline unless ROW congestion prevents adequately positioning excavating equipment. Digging across the line with power equipment **positioned above the line** should be avoided wherever possible.

Care should be used when removing rock adjacent to the pipeline. With any type of rock breaker, the force of the tool should always be directed away from the pipeline. Rock breakers can move in unexpected directions when rock is broken. Use a protective barrier (e.g., wood, rubber) placed between the tool and pipe during this operation. Ensure that the protective barrier is adequate to protect the pipeline integrity should any inadvertent deflection of the tool occur.

If circumstances warrant it a hand held jack hammer may be used within the buffer zone as long as all of the other conditions of this part are met and:

- The tool operator should also exercise caution to avoid placing their body, arms, hands, etc. between the tool and the pipeline in order to avoid "pinch points" if the tool is deflected.
- The pipeline pressure will be reduced as low as operationally acceptable by the system Gas Control
- The excavation meets OSHA requirements with emphasis on the following;
  - Adequate unrestricted work space is provided to allow proper handling and manipulation of the jack hammer and other tools
  - An excavation exit plan is available.
- All other personal protective equipment required for this type of work; gloves, face shield, long sleeves, hard hats, steel-toed shoes, etc. will be utilized.

**High Consequence Areas:** An excavation in an HCA shall be evaluated for the potential of stress corrosion cracking (SCC) by reviewing the existing conditions with the SCC, criteria (refer to **O&M Procedure 917 – Stress Corrosion Cracking**).

### 3.9. Horizontal Distance

When new facility construction parallels the Company's transmission or gathering pipelines, horizontal clearances shall be as defined in Table 1 – Horizontal Distance from Company Facilities or shall be the extent of the ROW, whichever is less. Establish any horizontal clearance less than that specified in the table by agreement between the Company and the underground facility's owner. Discuss horizontal clearances requested within fee owned property with the **ROW Department**.

| Third Party Facility | Horizontal Distance from Company Facilities |
|---|---|
| Buried pipelines | At least 10-feet |
| Buried telephone cable | At least 10-feet |
| Overhead telephone cable | At least 25-feet |
| Buried electric cables 440 VAC or less | At least 10-feet |
| Buried electric cables 440 VAC to 37.5 KVAC | At least 25-feet |
| Overhead electric lines 37.5 KVAC or less | At least 25-feet |
| Buried or overhead electric lines – facilities over 37.5 KV, AC or DC electric cable | Only by agreement between the utility and the Company's Regional Technical Manager or designee |

**Table 1 - Horizontal Distance from Company Facilities**

### 3.10. Vertical Facility Clearance

Follow recommended minimum vertical clearances as shown in Table 2 – Vertical Clearance from Company Facilities when repairing, installing or constructing pipelines or cables across a Company transmission or gathering pipeline. Maintain underground utility depth to obtain these clearances across the entire easement. The Company must approve any deviation from vertical clearance requirements.

| Third Party Facility | Vertical Clearance from Company Facility |
|---|---|
| New construction | When installing underground utilities, the last line should be placed beneath all existing lines unless it is impossible or unreasonable to do so. |
| Buried steel pipelines | At least a 24-inch vertical earth separation from a Company pipeline |
| Buried non-steel pipelines | At least a 24-inch vertical earth separation from a Company pipeline.<br>At least a 24-inch vertical earth separation from a Company pipeline 12-inches or greater in diameter. Install flagging tape above the Company pipeline, approximately 3-feet on each side and directly over the cable or utility line for a distance of at least 15-feet. |
| Buried telephone and electric cables – 440 VAC or less | At least a 24-inch vertical earth separation from a Company pipeline<br>The cable must have a nonconductive outer sheath extending at least 10-feet each direction from the Company pipeline. Install flagging tape above the Company pipeline, approximately 3-feet on each side and directly over the cable or utility line for a distance of at least 15-feet. |
| Fiber optic cables | Efforts should be made to install all fiber optic cable crossings at least 3-feet below Company pipelines.<br>Installing a concrete barrier is recommended but may not be practical when the cable is a direct bore. In that case, the clearance and markings become more critical. |
| Buried electric cables 440 VAC to 37.5 KVAC | At least a 24-inch vertical earth separation from a Company pipeline.<br>The cable shall have a nonconductive outer sheath extending at least 10-feet each direction from the Company pipeline. Install flagging tape above the Company pipeline, approximately 3-feet on each side and directly over the cable or utility line for a distance of at least 15-feet. |
| Facilities over 37.5 KV | Vertical separation of an electric cable or line operating at more than 37.5 Kilovolts A.C. or D.C. will be established by agreement between the utility involved and the Company Regional Technical Manager or designee. |

**Table 2 - Vertical Clearance from Company Facility**

### 3.11. Engineering Assessment

When an encroachment with the potential to impact a Company facility is identified, an assessment and determination of the impact shall be required. Company representatives will notify the Regional Technical Manager or designee, who can include local **ROW Department**, or regional corrosion supervisor, to review information and respond to the third party. Upon notification of an encroachment by a third party, gather pertinent facts, including:

- The exact location, scope, description and schedule of the proposed third party activity
- The exact location and description of the company facility(s)
- Identify encroaching entity and record contact information.
- Identify local Operations contact.
- Determine which pipeline(s) or other company facilities are impacted. Record location and rechain station from inventory sheet or PODS database.
- Gather critical pipeline data such as pipe specifications, MAOP, class location, depth and coating type. Depending on the coating type, it may be necessary to take a coating sample and test for asbestos. Refer to **O&M Procedure 1211 – Asbestos**.
- Contact designated Land Department representative for ROW information.
- Fee property or easement, (i.e. year established) (contact the **ROW Department**)
- ROW width, (i.e. special conditions) (contact the **ROW Department**)
- Determine scope of third party project and scope of Company mitigation work.
- Determine project scheduling.

- Review Corrosion records prior to approval of a parking lot to determine if any recoating or other maintenance work is needed.

The Engineering Assessment required by this section must include analysis of the impact of abnormal loads or stresses on the pipeline.

- The pipe must be protected from hazards that may cause the pipe to sustain abnormal loads.
- Pipe must be of sufficient thickness or adequate protection must be provided to withstand anticipated external pressure and loads.
- Adequate protection must be provided to prevent damage that might result from the proximity of structures that are within 24-inches of the pipeline.

After conducting the Engineering Assessment, the Regional Technical Manager may approve permanent structures to be built with clearance from the pipeline of less than 24-inches but no closer than 12-inches. Variance from the requirements of this procedure for clearance of structures of less than 12-inches must be obtained through **O&M Procedure 001 – Standards Modification**.

### 3.12. Heavy Equipment/Vehicle Crossings, Roadways and Parking Lots:

Roads, construction equipment crossings and parking lots over steel pipelines shall be evaluated using the Company's stress calculation program, "**PLStress**" or other suitable method for calculating stress for uncased pipelines by Regional Technical Manager or designee to determine the total stress on the pipeline. If the total stress exceeds recommended limits, a permanent protective structure should be considered. For pipelines constructed of material other than steel, contact Regional Technical Manger or designee.

The following information will be required for the stress analysis. This information should then be provided to Regional Technical Manager or designee and used as inputs into the stress calculation for heavy loads crossing uncased pipelines.

- Loaded vehicle axle load (single, tandem)
  (1) Heaviest construction equipment evaluated at the bottom of the sub-base
  (2) Street legal vehicles such as concrete truck, trash truck, commercial vehicles evaluated at the top of the finished structure
- Equipment make and model
- Caterpillar equivalent make and model, if available
- Depth of cover over pipeline
- Soil Characteristics
- Roadway or parking lot material (asphalt, concrete, dirt, gravel, etc).

### 3.13. Directional Drilling

A Company representative must follow the procedures outlined in this section when a third party, contractor, etc. will perform directional drilling operations parallel to and/or within the minimum specified clearance of the Company's pipeline facilities.

The Company representative can ask a contractor to stop drilling if the operation is deemed unsafe or there is a concern that damage to the pipeline facilities may occur. A contractor is responsible for any damage to the pipeline facilities incurred because of the drilling.

Before starting a job, the contractor will:

- Notify One-Call for a utility locate request
- Contact the Company and advise of the proposed drilling route, expected clearance between the drilling tool and pipeline facilities and construction schedule
- Demonstrate that the boring tool can be accurately positioned
- The Company representative will periodically measure clearance when practical between the boring tool and pipeline facilities and if necessary, require a viewing window to help

determine that the tool will miss the pipeline. A third party's facility must maintain the vertical and horizontal clearances described in Tables 1 – Horizontal Distance from Company Facilities and Table 2 – Vertical Clearance from Company Facilities.

Upon completion of the directional drill, the Company representative will:

- Conduct a leakage survey along the length of the directional drilled path
- Refer to **O&M Procedure 215 – Patrolling and Leak Detection** for leakage survey documentation.

Field personnel will complete applicable OM Buried Facility Reports and develop as-built Company drawings (except for block cards) and send to Engineering Mapping/CADD in Lakewood. Drawings should indicate the third party's name, location of its utility line and the measured horizontal and vertical separation between the third party's and Company's facilities.

### 3.14. Land Leveling or Improvement – Company Notified

When advance notice of proposed land leveling or improvement is received, field personnel will notify the **ROW Department**. Submit requests to reduce pipeline cover or construction over the pipeline to Regional Technical Manager or designee for review.

- Upon notification, determine to what extent the Company pipeline may be affected.
- Evaluate alternatives for sloping the land or making improvements to avoid relocating Company pipeline or removing soil over a buried line. If possible, the landowner should achieve desired results without jeopardizing or disturbing the Company pipeline.
- Conduct a cover survey, profile and mark the pipeline's location.

If the leveling or improvement cannot be accomplished without relocating or modifying the Company pipeline, gather pertinent facts, including:

- The exact location and description of the proposed leveling or improvement
- A description of the required modification to Company pipeline facilities
- Possible alternatives to avoid disturbing Company pipeline
- The Regional Technical Manager or designee will review the information and determine required modifications.

Regional Technical Manager or designee will provide modification details and costs and will advise what agreements are necessary between the Company and landowner. The **ROW Department** will then contact the landowners and notify them of the portion of the cost for which they are responsible before beginning the project.

### 3.15. Blasting and Seismic Activity

Provide the Technical Manager or designee the following information when blasting is anticipated:

- Configuration of explosive charges (point, line or grid)
- Number of charges, spacing between charges, types of charges and weights
- Distance between pipeline and nearest charge for each pipeline
- Angle between pipeline and explosive line or grid (if grid, number of rows and charges per row)
- Pipe description of each pipeline
- Alternatives to blasting that were considered

Technical Manager or designee will prescribe proper blasting procedures and minimum distances to avoid pipeline damage for all blasting within 300-feet of the pipeline. Standoff distances of 100-feet for line or grid configurations containing a total charge weight of greater than 100 pounds are required.

If the Technical Manager or designee believes blasting could damage a facility, field personnel must perform leakage surveys as often as necessary during and after blasting to verify the pipeline's integrity

### 3.16. Buildings near Pipelines

It is recommended that buildings be a minimum of 25-feet or greater (if required by local ordinances) from any gathering or transmission pipeline or off the pipeline easement, whichever distance is greater. Contact the **ROW Department** to determine the Company's rights.

## 4. Training

Regional management will ensure that individuals involved in tasks required in this procedure are trained in operating locating instruments, appropriate documentation and all other provisions of this procedure.

Persons performing locating functions must meet the requirements of the Company Operator Qualification program.

Personnel should review this information as necessary before performing the procedure.

In order to ensure that responses made by a Company representative to an excavation notification is handled correctly, and that line locating procedures are properly followed, the local supervisor, manager, or director, shall periodically, but at least once each calendar year, accompany the Company Representatives assigned to line locate duties to assess work demands, quality of line marking, and coordination of excavations along the ROW. Records to substantiate these reviews will be maintained by the local manager.

## 5. Documentation

### 5.1. Company Report Forms

With the exception of distribution systems, report all foreign crossings, foreign structure retirements and inspection activities on **O&M Form OM200-01 – Foreign Structures Report** or the state's One-Call form. Report the condition of existing underground pipeline **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report**. Report any pipeline damage or any near-miss from third party activities into **STARS** as soon as possible.

Report metallic foreign structure crossings on **O&M Form OM200-03 – Underground Structure Crossing Report**. Use **O&M Form OM200-31 – Line Locate Inspection Report** to document on-site communications with contractors or other third parties. Report any pipeline damage or near-miss into **STARS** as soon as possible.

### 5.2. Response to Third Party

A response letter should be written to the third party outlining what impact the encroachment has to our pipeline(s), request additional information, if needed, identify any special requirements and relay our expectations for reimbursement (if adjustment is required).

The Company's **O&M Form OM200-29 – Guidelines for Design and Construction near Kinder Morgan Operated Facilities** should be included, in their entirety, in the response letter.

All correspondence should be sent to the appropriate Operations and ROW Department/ROW representative for review/comment prior to sending to the encroaching entity. Consideration should be given as to whether any response should be recorded as a legal document along with the existing easement.

### 5.3. Photographs

Photographs shall be maintained in local files where they will be readily identifiable to the location. Photographs shall be attached to a hard copy of the completed One-Call ticket, or electronically stored in the electronic One-Call system, or attached to **O&M Form OM200-31 – Line Locate Inspection Report**. Photographs shall be retained in accordance with applicable state laws for One-Call documentation.

### 5.4. All Documentation

In the event of litigation, unresolved situations, or as instructed by management, affirmative steps must be taken to preserve all records (whether in electronic or written form) until such time as otherwise directed by a representative of Company's legal department.

## 6. References

- 49 CFR 192.614 (c)(3), (4) and (6)(ii), 192.929(b)1, 192.935(d)2; 192.935(b)1ii
- Iowa Chapter 479, Section 479A.26
- Common Ground Alliance Best Practices
- **O&M Procedure 120 – Personal Protective Equipment**
- **O&M Procedure 205 – Pipeline Markers and Cover**
- **O&M Procedure 206 – Land and Right-Of-Way**
- **O&M Procedure 214 – Reporting Pipeline Safety-Related Conditions**
- **O&M Procedure 215 – Patrolling and Leak Detection**
- **O&M Procedure 232 – Damage Prevention and Public Awareness**
- **O&M Procedure 237 – Dresser-Coupled Pipelines**
- **O&M Procedure 903 – External Corrosion Control for Buried or Submerged Pipelines**
- **O&M Procedure 917 – Stress Corrosion Cracking**
- **O&M Procedure 1700 – Inspection & Maintenance, I-0265.00 – Maintain Pipelines in One-Call System**
- **O&M Form OM200-01 – Foreign Structures Report**
- **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report**
- **O&M Form OM200-03 – Underground Structure Crossing Report**
- **O&M Form OM200-29 – Guidelines for Design and Construction near Kinder Morgan Operated Facilities**
- **O&M Form OM200-31 – Line Locate Inspection Report**
- **Construction Drawing CST-P-1000-A305 – Typical Undercrossing of Tile Drainlines**
- **Construction Drawing CST-P-1000-A325 – Crossing Foreign Pipelines**
- **STARS**
- **Pipeline Integrity Management Program**
- **PLStress** Pipeline Stress Calculation

## Attachment 1 – One-Call Center and Emergency Phone Numbers

| State | One-Call Center | Telephone Number |
|---|---|---|
| Alabama | Alabama One-Call | 800-292-8525 |
| Arkansas | Arkansas One-Call System, Inc. | 800-482-8998 |
| Colorado | Utility Notification Center of Colorado | 800-922-1987 |
| Illinois | JULIE, Inc. | 800-892-0123 |
| Indiana | Indiana Underground Plant Protection Service | 800-382-5544 |
| Iowa | Underground Plant Location Service, Inc. | 800-292-8989 |
| Kansas | Kansas One-Call System, Inc. | 800-344-7233 |
| Louisiana | DOTTIE – Louisiana One-Call System, Inc. | 800-272-3020 |
| Mississippi | Mississippi One-Call | 800-227-6477 |
| Missouri | Missouri One-Call System, Inc. | 800-344-7483 |
| Montana | Montana One-Call | 800-551-8344 |
| | Utilities Underground Locating Center | 800-424-5555 |
| Nebraska | Diggers Hotline of Nebraska | 800-331-5666 |
| New Mexico | New Mexico One-Call System, Inc. | 800-321-2537 |
| Oklahoma | Oklahoma One-Call System, Inc. | 800-522-6543 |
| Ohio | Ohio Utilities Protection Service | 800-362-2764 |
| Texas | TESS - Texas Excavation Safety System, Inc. | 800-344-8377 |
| | Texas One-Call System | 800-245-4545 |
| | Lone Star Notification Center | 800-669-8344 |
| Wyoming | One-Call of Wyoming | 800-849-2476 |
| National | Call 811 | 811 |

### Company Emergency Control Center Numbers

| Entity | Telephone Number |
|---|---|
| Kinder Morgan | 888-763-3690 |
| Kinder Morgan Interstate Gas Transmission Company | 888-763-3690 |
| Kinder Morgan Louisiana Pipeline, LLC | 800-733-2490 |
| Kinder Morgan North Texas Pipeline | 800-633-0184 |
| Kinder Morgan Tejas Pipeline, LLC | 800-568-7512 |
| Kinder Morgan Texas Pipeline, LLC | 800-633-0184 |
| Midcontinent Express Pipeline, LLC | 800-733-2490 |
| Natural Gas Pipeline Company of America | 800-733-2490 |
| Trailblazer Pipeline Company | 800-733-2490 |
| TransColorado Gas Transmission | 800-944-4817 |
| Rockies Express Pipeline, LLC | 877-436-2253 |

# Appendix 6

## Table of Contents



## 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☐ Kinder Morgan Power Company

## 2. Scope

This procedure prescribes methods for evaluating and reporting leaking and non-leaking defects in pipe and equipment and appropriate remedial actions. Imperfections or damage that impair pipe integrity require the pipe section to be removed and replaced or be repaired by a proven method using engineering tests and/or analyses. The operating pressure in the line must be at a safe level during repair conditions.

## 3. Core Information and Requirements

### 3.1. Investigating Leaks and Defects

Any gas loss to the atmosphere at a rate affecting pipeline flow, deliveries to customers, endangering public, or employee safety is an emergency covered in each area's Site-Specific Emergency Response Plan.

Respond promptly to reports of gas odor inside or near buildings and promptly investigate all suspected leaks. When investigating a reported or suspected leak, first determine if there is a hazard.

**In the event that a hazardous condition is discovered, operations personnel shall employ immediate temporary measures to protect the public, employees and property from harm or damage.**

An excavation in a High Consequence Area (HCA) shall be evaluated for the potential of stress corrosion cracking (SCC) by reviewing the existing conditions with the SCC criteria (refer to the **Pipeline Integrity Management Program IMP 06 – Threat Identification, Data Integration and Risk Assessment, Subsection 6.1 – Threat Identification** and **O&M Procedure 917 – Stress Corrosion Cracking**). Collect data on **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report** (shown with an asterisk) so Risk Engineering can perform further analysis.

### 3.2. Hazardous Conditions

A hazard is any situation posing a threat to the safety and well-being of customers, the public, or employees. If a hazardous condition exists, follow the Site-Specific Emergency Response Plan to investigate and secure the area.

3.2.1. Hazardous Leaks (HCA and non-HCA)

Any of the leaks described below represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until conditions are no longer hazardous:

- A leak that operating personnel at the scene regard as an immediate hazard
- A leak where escaping gas has ignited
- A leak resulting from equipment damage
- Confirmed or suspected leaking cracks
- An indication that gas has migrated into or under a building or into a tunnel
- A Lower Explosive Limit (LEL) percent reading at the outside wall of a building or where gas would likely migrate to an outside wall or under a building
- Any type of leaking defect in Class 2, 3, and 4 locations
- A blowing casing vent
- A leak that can be seen, heard or felt and is in a location that may endanger the public or property

See 3.5. Special Requirements within an HCA for other conditions requiring immediate repairs.

3.2.2. Hazardous Non-Leaking Conditions (non-HCA)

The following non-leaking conditions also represent an existing or probable hazard to persons or property and require immediate repair or continuous action until conditions are no longer hazardous:

- Dents containing a gouge, groove or arc burn (if operating at 20% or more of SMYS)
- Dents with a depth exceeding 2% of nominal diameter affecting the longitudinal weld or girth weld (if operating at 20% or more of SMYS)
- Gouges or grooves deeper than 30% of the wall thickness regardless of length (if operating at 40% or more of SMYS)
- Gouges or grooves deeper than 12.5% of the wall thickness with lengths greater than the maximum damage lengths in Table 1 – Maximum Gouge Length for Non-Emergency Replacement or Repair at the end of this procedure (if operating at 40% or more of SMYS)
- Cracks in the pipe body, longitudinal weld or girth weld other than stress corrosion cracks (for stress corrosion cracks, refer to **O&M Procedure 917 – Stress Corrosion Cracking**)
- Metal loss greater than 80%, regardless of dimensions
- An indication or anomaly that in the Regional Technical Manager's judgment requires immediate action

### 3.3. Non-Hazardous Conditions

If a segment of pipeline is determined to be in unsatisfactory condition but is not an immediate hazard, regional personnel shall initiate a program to recondition or phase out the segment involved. If the segment cannot be reconditioned or removed from service, contact the Regional Technical Manager, who will work with the Engineering Department to review the established MAOP and determine if it should be reduced.

3.3.1. Non-Hazardous Leaks

Non-hazardous leaks are those determined not to pose an immediate hazard to the public, customers or company facilities, including:

- Any leak that under frozen or adverse soil conditions would likely migrate to the outside wall of a building
- Any leak under a sidewalk in a wall-to-wall paved area that does not qualify for immediate action
- Any leak under a street in a wall-to-wall paved area that has significant gas migration and does not qualify for immediate action
- Any leak in a valve box from which gas would likely migrate, creating a probable future hazard that does not qualify for immediate action
- Any leak in a confined space that does not qualify for immediate action

As soon as practical, schedule action to address non-hazardous leaks. Escaping gas which can be remedied immediately upon discovery by measures such as lubrication of valves or tightening of packing nuts on valves with seal leaks are considered to be routine maintenance work and are not considered to be non-hazardous leaks.

**3.4. HCA Location - General**

Discovery of a condition occurs when company personnel obtain adequate information to determine that the condition presents a potential threat to the integrity of the pipeline. Sufficient information must be obtained promptly, but no later than 180 days after conducting an integrity assessment; otherwise, the 180-day period must be demonstrated to be impracticable. Field Operations will notify the Codes and Standards Department if the 180-day schedule cannot be met and safety cannot be provided through a temporary reduction in the operating pressure or other action.

Any reduction in operating pressure in an HCA as a result of condition(s) as defined in (IMP Section 8 – Remediation) cannot exceed 365 days without notifying PHMSA in accordance with 192.949. The notice must explain the reasons for the delay and provide technical justification that the continued pressure restriction will not jeopardize pipeline integrity. Notify Risk Engineering and Coordinate with Code and Standards to notify appropriate regulatory agencies in accordance with CFR 192.949. Agencies requiring notification include OPS (PHMSA) and state or local pipeline safety authorities when a segment is located in a state where OPS (PHMSA) has an interstate agent agreement or that state regulates an intrastate-covered segment. See IMP Section 17.1 for additional notification details.

**3.5. Special Requirements within an HCA**

The following are considered immediate repair conditions. Immediately reduce the operating pressure to a level not exceeding 80% of the maximum recent pressure (during past 3 months) from the time the condition was discovered. and maintain this pressure restriction until repairs can be promptly completed:

- Any condition with a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure (this condition applies predominately to pitting corrosion or general corrosion, where the predicted burst pressure can be calculated per **O&M Procedure 915 – Maximum Corrosion Limits and MAOP of Corroded Pipe**)
- A dent with any indication of metal loss, cracking or a stress riser
- Any defect listed under Hazardous Leaks above
- Any defect listed under Hazardous Non-Leaking Conditions above

Any of the following conditions will be repaired as provided herein within one year of the condition's discovery:

- A smooth dent with a depth greater than 6% of the pipeline diameter (greater than 0.5-inches in depth for a pipeline diameter less than NPS 12)
- A dent with a depth greater than 2% of the pipeline's diameter (0.25-inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld

### 3.6. Post-repair Inspections

A leak is considered to be effectively repaired when a 0% reading is obtained. A complete re-evaluation of the leak area will be done after repairs of all leaks. Any reading requires immediate action be taken if the leak presents a hazardous condition or a schedule of action be developed if the leak presents a non-hazardous condition and not repaired immediately.. A schedule of action must be followed for any repaired leak that presents a non-hazardous condition until the leak is repaired or cleared.

### 3.7. Reporting Requirements

For all Company assets report all gas lost through **Online Field Ticketing – Unmeasured Gas** within the production month the leak occurred, if known, in conformance with **O&M Procedure 1030 – Unmeasured Gas Use/Loss Reporting**.

Any damage on a transmission line caused by a third party will require a pipeline incident report to be completed using the **STARS Incident Management System**. Each region shall maintain a list of leaks and pipe damage located and actions taken to repair them. Use this list to supply data for the Company's annual report required by DOT, Part 191. Leak and damage lists shall contain at a minimum the information the annual reports (RSPA F7100.1-1 and F7100.2-1) require.

### 3.8. Texas Intrastate Pipelines Leak Grading and Repair

Leaks[1] found on intrastate pipelines within the State of Texas if not fixed immediately must be graded according to the degree or extent of the potential hazard the leak presents and to prescribe remedial actions. Leak grading may be done only by those individuals who possess training, experience and knowledge in the field of leak classification and investigation. Use **O&M Form OM200-05 – Facility Maintenance and Damage Report** to document leak grading.

3.8.1. Grade 1 Leaks

Grade 1 leaks require immediate action be taken to eliminate the hazard and make repairs. Grade 1 leaks are the same as Hazardous Leaks (HCA and non HCA) and include the following:

- Any reading of 80% lower explosive limit (LEL) or greater in a confined space or in small substructures, other than gas associated substructures, from which gas would likely migrate to the outside wall of a building.

3.8.2. Grade 2 Leaks

Grade 2 leaks are the same as Non-Hazardous Leaks. Grade 2 leaks must be scheduled for repair based on probable future hazard and must be re-evaluated at least once every 30 days until repaired or cleared. Document the scheduled repair and subsequent re-evaluation (if necessary) using **O&M Form OM200-05 – Facility Maintenance and Damage Report**.

All Grade 2 leaks must be repaired within six (6) months of discovery:

**[1] For intrastate pipelines within the State of Texas a leak is defined as gas escaping from line pipe or components attached directly to the line pipe. This does not include compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies within areas over which the Company controls access.**

3.8.3. Grade 3 Leaks

Grade 3 leaks are non-hazardous at the time of detection and reasonably can be expected to remain non-hazardous. Grade 3 leaks must be re-evaluated during the next scheduled leak survey or within 15 months of discovery, whichever occurs first, until the leak is repaired, cleared or re-graded.

All Grade 3 leaks must be repaired within 36 months of discovery.

### 3.9. Evaluating Leaks and Damage

Table 2 – Leak Evaluation Procedures below lists methods to evaluate and repair common types of leaks. Table 3 – Non-Leaking Defect Evaluation Procedure lists methods to evaluate and repair common non-leaking defects. Refer to the appropriate part of this procedure or contact your supervisor for additional assistance.

While excavating and inspecting known defects that may threaten the pipeline's integrity, lower the pipeline pressure to the lower of 80% MAOP or 90% of existing (recent) pressure unless the tables below indicate requirements that are more stringent. Alternately, for pipelines with known or indicated metal loss, use the RSTRENG effective area method maximum safe pressure calculated pressure (using a design factor F in conformance with 192.111) unless Table 2 – Leak Evaluation Procedures or Table 3 – Non-Leaking Defect Evaluation Procedure indicates more stringent requirements.

**Note:** Table 1 – Maximum Gouge Length for Non-Emergency Replacement or Repair is located at the end of this procedure.

| Leak Description | Comments | Repair Instructions Refer to Part |
|---|---|---|
| Pinhole leak due to flash weld penetrator, ERW non-fusion, girth weld pinhole or corrosion pinhole | First, determine whether a leak is hazardous and requires immediate action | A |
| Leaking crack | Considered hazardous | B |
| Leaks in navigable waters | Contact the Regional Technical Manager to determine a repair plan | C |
| Dresser coupling leak | Do not tighten a leaking Dresser coupling under pressure. Review **O&M Procedure 237 – Dresser-Coupled Pipelines** before working on Dresser-coupled pipelines. | |
| Flange gasket leak | Initially, try to stop a flange leak by tightening the flange bolts while the pipeline is under pressure. If unsuccessful, remove pipeline pressure and replace the gasket. | |
| Plastic pipe leak | Remove leaking pipe or install patch or saddle | D |

**Table 2 – Leak Evaluation Procedures**

| Defect Description | Comments | Repair Instructions Refer to Part |
|---|---|---|
| Crack (other than SCC) | Considered hazardous | B |
| Stress corrosion cracks (SCC) | Refer to **O&M Procedure 917 – Stress Corrosion Cracking** | E |
| Groove or gouge | If operating at 40% of more of SMYS, grooves or gouges deeper than 30% of the wall thickness or deeper than 12.5% of nominal wall thickness with lengths exceeding the maximum damage lengths in Table 1 – Maximum Gouge Length for Non-Emergency Replacement or Repair are considered hazardous. | F |
| Dent with gouge, groove, arc burn or other stress concentrator/ equipment damage | Before evaluating, reduce the pressure to 80% of existing (recent) pressure. | G |
| Dent – smooth bottom | Refer to Part H for dents affecting the pipe body, longitudinal weld or girth weld. | H |
| General corrosion and pits | Refer to **O&M Procedure 915 – Maximum Corrosion Limits and MAOP of Corroded Pipe** | I |
| Arc burn (including fault current discharges) or contact marks | If operating at 40% of more of SMYS, arc burns are considered defects | J |
| Girth weld defect other than crack | | K |
| Lamination | Determine extent and notify Regional Technical Manager | L |
| Hard spots | Evaluate hardness | M |
| Wrinkle bends | | N |
| Damage in navigable waters | Contact the Regional Technical Manager to determine a repair plan | C |
| Plastic pipe damage | Remove damaged pipe or install patch or saddle | D |

**Table 3 – Non-Leaking Defect Evaluation Procedure**

**Note:** Numbered items below represent steps to take; bullet points are informational.

## A. Flash Weld Penetrator Leaks, ERW Non-Fusion Pinhole Leaks, Girth Weld Pinhole Leaks and Corrosion Pinholes

A flash weld penetrator is a short zone of weld-line non-fusion usually no longer than 3/4-inch found in A. O. Smith flash welded pipe. It may be visible in the weld centerline as an abruptly ending black line.

An electric resistance weld (ERW) non-fusion pinhole leak is seldom longer than 1/4-inch and is located at the weld centerline.

For nominal pipe size (NPS) 6 and larger, identify penetrators, ERW weld seam non-fusion and girth weld pinholes by radiographic examination.

A1. Reduce the pipeline pressure to the lower of 80% of MAOP or 90% of the existing (recent) pressure. Visually locate the flash weld penetrator, ERW non-fusion or weld pinhole or corrosion pinhole. It may be necessary to sand or buff the external weld reinforcement to facilitate locating the leak.

A2. Install a Dresser Style 75 Permaclamp or equivalent bolt-on clamp as a temporary repair except in an HCA, where only permanent repairs are permissible.

A3. Make a permanent repair as soon as feasible. Replace the pipe with pre-tested pipe or install a full-encirclement split sleeve with full fillet weld side seams. The replacement pipe must be equal to or greater than the strength of pipe being replaced.

A4. With the Regional Technical Manager's approval, a girth weld pinhole leak may be permanently repaired by blowing down the pipeline segment, excavating the pinhole area by grinding, preheating and repairing the weld.

**B. Cracks**

For SCC, refer to **O&M Procedure 917 – Stress Corrosion Cracking**. Leaking and non-leaking cracks are considered hazardous and require immediate action to investigate and secure the area in conformance with the Site-Specific Emergency Response Plan. Remove pressure from the line as soon as possible.

- Remove a crack in a circumferential weld or pipe body by removing a cylinder of pipe that includes the length of the crack. Do not attempt to repair the crack in place.
- For longitudinal seam cracks, the entire joint of pipe will normally be replaced. For partial joint replacement, consult with the Regional Technical Manager to determine the length of pipe to remove.
  - Use magnetic particle inspection to examine the entire weld seam of the pipe joint containing the crack
  - Ultrasonic inspection, along with visual, radiographic or magnetic particle inspection may be used to define the crack further
- The Regional Technical Manager may authorize repairing a girth weld crack. The maximum length of a crack in a girth weld that may be considered for repair is less than 8% of the total weld length. Contact the **Codes and Standards Department** for a qualified crack removal procedure.

**C. Leaks or Damage on Pipe in Navigable Waters**

Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of the appropriate design over the leak. Before attempting any repair, notify the Regional Technical Manager and the Engineering Department so an investigation and repair plan can be developed. In an HCA, a mechanical leak clamp is permitted only for external corrosion repairs.

**D. Plastic Pipe**

Repair leaks or damage to plastic pipe by patching, saddling or removing the section. Workers repairing plastic pipe should wear personal protective equipment per the MSDS. Keep a fire extinguisher available at the work site. Review **O&M Procedure 451/C1241 – Plastic Pipe Joining** for additional information.

**E. Stress Corrosion Cracks**

For SCC, refer to **O&M Procedure 917 – Stress Corrosion Cracking**.

**F. Grooves and Gouges**

F1. For gouges with no dent or leak, reduce the pipeline pressure to the lower of 80% of MAOP or 90% of the existing (recent) pressure.

F2. Measure the remaining wall thickness of the gouge with a UT thickness gauge. It may be necessary to determine the remaining thickness under the gouge by measuring the wall thickness adjacent to the gouge with a UT thickness gauge and subtracting the gouge depth measured with a pit gauge

F3. If the remaining wall thickness under the gouge is greater than or equal to the minimum wall tolerance in the original pipe manufacturing specification or the remaining wall thickness under the gouge meets pipe design requirements, neither pipe replacement nor sleeving is required. Table 4 – Minimum Wall Thickness Tolerance in API 5L Pipe Specification below indicates the minimum wall thickness in the original pipe manufacturing specification.

F3a. Sand or buff the rough gouge edges smooth and blend the area into the surrounding pipe material. A flexible back-sanding disk with 80- to 100-grit paper is recommended. Do not use a hard grinding wheel due to the potential to remove excessive material.

F3b. After sanding and buffing, conduct a magnetic particle inspection of the area to check for surface tears at the base of the gouge. Examine the area once with the yoke transverse to the gouge and once with the yoke along the axis of the gouge.

i) If the remaining wall thickness satisfies the requirements in step F3 above and there are no surface tears, only external coating repair is required.

ii) If there are surface tears, it will be necessary to sand or buff off up to 0.010-inch additional metal from the base of the gouge. Reduce the pipeline pressure commensurate with the remaining wall thickness under the gouge before proceeding.

iii) If the remaining wall thickness under the gouge does not satisfy one of the two criteria in step F3, it will be necessary to replace the damaged pipe with pre-tested pipe or to install a full encirclement welded sleeve or a composite sleeve. A composite sleeve is not permitted for a gouge repair in an HCA.

| Year of Pipe Manufacture | Minimum Wall Thickness (% of Nominal Thickness) | | | | | | |
|---|---|---|---|---|---|---|---|
| | NPS 18 and Smaller | | NPS 20 and Larger Seamless | | NPS 20 and Larger Welded | | |
| | B | X42- X80 | B | X42- X80 | B | X42- X56 | X60- X80 |
| 1966 to present | 87.5% | 87.5% | 87.5% | 90.0% | 90.0% | 92.0% | 92.0% |
| 1953 - 1965 | 87.5% | 87.5% | 87.5% | 90.0% | 90.0% | 90.0% | 92.0% |
| Before 1953 | 87.5% | 87.5% | 87.5% | 87.5% | 87.5% | 87.5% | - |

**Table 4 – Minimum Wall Thickness Tolerance in API 5L Pipe Specification**

## G. Dents Containing a Stress Concentrator or Metal Loss

G1. For a dented pipe with a stress concentrator such as a gouge, groove, arc burn or metal loss, reduce the pipeline pressure to 80% or less of the recent pressure before evaluating the damage.

G2. In an HCA, a dent with any indication of metal loss, cracking or a stress riser is considered an immediate repair condition. immediately reduce the operating pressure to a level not exceeding 80% of the maximum recent pressure (during past 3 months) from the time the condition was discovered and maintain this pressure restriction until the damaged pipe can be replaced with pre-tested pipe or a full-encirclement welded sleeve can be installed.

G3. If the remaining wall thickness under the stress concentrator is less than the minimum wall tolerance permitted in the original pipe manufacturing specification or the dent depth exceeds 6% of the pipe diameter, replace the damaged pipe with pre-tested pipe or install a full encirclement welded sleeve. If the dent depth is more than 2% of the pipe diameter, it may be necessary to replace the pipe to permit pigging. Table 4 – Minimum Wall Thickness Tolerance in API 5L Pipe Specification indicates the minimum wall thickness in the original pipe manufacturing specification.

G4. Sand or buff the rough edges of the stress concentrator smooth and blend the area into the surrounding pipe material. A flexible back-sanding disk with 80- to 100-grit paper is recommended. Do not use a hard grinding wheel due to the potential to remove excessive material.

G5. For a gouge, after sanding and buffing, conduct a magnetic particle inspection of the area to check for surface tears at the base of the gouge. Examine the area once with the yoke transverse to the gouge and once with the yoke along the axis of the gouge.

**H. Smooth Bottom Dent**

In a pipeline operating at 20% or more of SMYS or in an HCA (all pressures), a smooth bottom dent that affects the curvature at the longitudinal weld or girth weld requires repair if one of the following is true:

- The dent depth exceeds 2% of nominal pipe diameter in pipe NPS 12 or larger
- The dent depth exceeds 0.250-inch in pipe smaller than NPS 12

In an HCA, these dents must be repaired or removed within one year of discovery of the condition.

In a pipeline operating at 40% or more of SMYS or in an HCA (all pressures), a smooth bottom dent in the pipe body requires repair if one of the following is true:

- The dent depth exceeds 6% of nominal pipe diameter in pipe NPS 12 or larger
- The dent depth exceeds 0.500-inch in pipe smaller than NPS 12
- The dent would obstruct the passage of a pigging device

If a dent is outside an HCA and a repair is required, repair the dent by either:

- Removing by cutting out a cylindrical piece of pipe and replacing with pretested pipe of similar or greater design strength
- Filling the dent with hardenable filler and installing a full encirclement welded sleeve or a composite sleeve

Inside an HCA, a dent exceeding the above dimensional tolerances must be repaired or removed within one year of discovery of the condition. If a repair is required, repair the dent by either:

- Remove by cutting out a cylindrical piece of pipe and replacing with pretested pipe of similar or greater design strength
- Filling the dent with hardenable filler and installing a full encirclement welded sleeve.

**I. General Corrosion and Corrosion Pitting**

Use the limits defined in **O&M Procedure 915 – Maximum Corrosion Limits and MAOP of Corroded Pipe** as acceptance criteria for general corrosion and corrosion pitting in the pipe body, girth welds and longitudinal seam welds. A non-leaking corrosion pit or general corrosion area that is unacceptable can be repaired with a split sleeve or composite sleeve. A corrosion pinhole leak can be repaired as described in Part A, above.

**J. Arc Burns**

An arc burn is a discontinuity consisting of any localized remelted metal, heat-affected metal or change in the surface profile of any part of a weld or base metal resulting from an arc. In a pipeline operating at 40% or more of SMYS, an arc burn must be repaired or removed. For an arc burn or contact mark, replacing the pipe with pre-tested pipe is the preferred remediation method.

Repairing an arc burn or contact mark is permitted only with the Regional Technical Manager's approval.

J1. Reduce the pipeline pressure to the lower of 80% of MAOP or 90% of the existing (recent) pressure.
J2. Sand the arc burn with a flexible back-sanding disk and blend the area into the surrounding pipe material within the wall thickness tolerance for the pipe (refer to Table 4 – Minimum Wall Thickness Tolerance in API 5L Pipe Specification).
J3. Verify the arc burn has been removed by swabbing the area with a cotton ball or Q-tip saturated with 10% ammonium persulfate in water or 5% nital (5% concentrated nitric acid in methyl or ethyl alcohol).
J4. A person knowledgeable of the necessary safety precautions for handling the concentrated chemicals must prepare the etchant.

J5. Etchants can be absorbed into the body by inhalation and ingestion and are corrosive to the eyes, skin and respiratory system. Always wear personal protective equipment required by the MSDS sheet when mixing and handling etchants. Be sure to have an eyewash station or kit available in the work area. Contact EHS for more information.

J6. If the etchant reveals a darkened area, the arc burn has not been completely removed. If further grinding will not reduce the wall thickness below the tolerance, sand an additional 0.010 to 0.020-inch from the area and etch the area again.

J7. When the arc burn has been removed, clean the pipe surface to remove residue from the etchant. The area can be cleaned by scrubbing with soap and water or by using an acid wash such as Oakite 33.

**K. Defects in Girth Welds (Other than Cracks)**

A defect in a girth weld can be determined visually and/or by nondestructive testing as described in **O&M Procedure 406/C1066 – Weld Inspection and Testing**.

If it is feasible to take the pipeline out of service, repair or replace the weld using the welding procedure applicable to the pipe material (refer to **O&M Procedure 407/C1067 – Welding Procedures and Selection Guide**).

If the weld is not leaking and it is not feasible to take the pipeline out of service, the weld may be repaired as follows:

1. Reduce the operating pressure to not more than 20% of the pipe's SMYS.
2. Remove the girth weld defect (other than a crack) down to sound metal. If required, grind the defective area so at least 1/8-inch thickness remains in the pipe weld.
3. Preheat the weld area and repair the weld using the welding procedure applicable to the pipe material.
4. Inspect the repair by visual and radiographic examination (refer to **O&M Procedure 406/C1066 – Weld Inspection and Testing**).

A defective weld that cannot be repaired by this method must either be removed as a cylinder of pipe that includes the weld or be repaired by installing a full encirclement welded split sleeve of appropriate design.

A second repair to a previously repaired area requires Regional Technical Manager approval.

**L. Lamination**

A lamination is a planar, sub-surface discontinuity in the pipe body parallel to the surface, typically located near mid-wall and covering a wide area. A lamination may be found during a magnetic flux leakage metal loss smart tool survey or a wall thickness survey.

- When necessary, the length and width of a lamination may be determined by conducting a wall thickness survey with a UT thickness gauge
- Do not weld on a lamination
- Contact the Regional Technical Manager to determine whether further remedial action is necessary

**M. Hard Spots**

Hard spots appear as flat areas on the pipe caused by quenching the plate during hot rolling. Hard spots could potentially fail by hydrogen stress cracking.

Evaluate a hard spot by reducing the pressure to the lower of 80% of MAOP or 90% of the existing (recent) pressure and determining the hardness with an Equotip® or similar portable rebound-type hardness tester. If the Equotip® hardness exceeds 570 (30 HRC) or its equivalent, replace the affected area with pre-tested pipe.

**N. Wrinkle Bends**

Wrinkle bends are not permitted in a pipeline constructed after 1970 operating at 30% or more of SMYS. For lower pressure pipelines constructed after 1970, wrinkle bends must meet the following requirements:

- The bend must not have any sharp kinks
- When measured along the crotch of the bend, the wrinkles must be at a distance of at least one pipe diameter
- On pipe NPS 16 or larger, the bend may not have a deflection of more than 1.5 degrees for any wrinkle
- On pipe containing a longitudinal weld, the longitudinal seam must be as near as practicable to the neutral axis of the bend
- In an HCA, schedule wrinkle bends for replacement as soon as practical but not to exceed the response time provided in the **Pipeline Integrity Management Program IMP 08 – Remediation, Figure 8-1 – Timing for Scheduled Responses – Time Dependent Threats**.

**3.10. Repair Methods**

3.10.1. Pipe Replacement

**When pipe replacement is required the pipe shall be removed as a cylinder and replaced with pipe that has design strength of greater than or equal to the design strength of the pipeline.**

Pretest all pipe for replacement sections in conformance with **O&M Procedure 1600/C1135 – Strength and Leak Testing**. Perform all welding on pressure-containing piping in conformance with **O&M Procedure 402/C1062 – General Welding Specifications**. Radiograph all tie-in welds in conformance with **O&M Procedure 406/C1066 – Weld Inspection and Testing**.

3.10.2. Full Encirclement Sleeve Repair

Do not attempt to install a split sleeve if damage is severe enough that a tight fit cannot be achieved.

- To repair a leaking defect, use a sleeve with pressure vessel- type construction. The sleeve side seams must be full penetration butt welds and the circumferential seams must be full fillet welds.
- A pressure vessel-type sleeve is preferred for repairing a non-leaking defect. The Engineering Department may approve other types of full encirclement sleeve construction.
- In an HCA, only a pressure vessel-type sleeve is permitted for repairing internal corrosion.

If a pressure vessel-type construction is used, fabricated encirclement sleeves shall be obtained from pre-tested pipe. The following manufactured sleeves for pressurized applications are permitted with prior approval from the Regional Technical Manager or designee if appropriate pressure ratings are met:

| Manufactured Sleeve | Application |
|---|---|
| Dresser Style 110 | Defects on or adjacent to girth welds. The Dresser Style 110 must meet or exceed the current design pressure of the carrier pipe. The sleeve can be no thicker than 0.125" greater than the wall thickness of the carrier pipe. |
| Dresser Style 220 | Installation over Dresser Couplings or previously installed leak clamps that cannot be removed for the installation of split weld reinforcement sleeve. The sleeve can be no thicker than 0.125" greater than the wall thickness of the carrier pipe. |
| Plidco Split+Sleeve | Leak repairs on corrosion pinhole leaks. Primary application is for lines that cannot be realistically welded on. The side seams shall be seal welded. |

**Table 5 – Manufactured Sleeves**

Manufactured sleeves, used in a pressurized repair, shall have the weep-hole sealed by welding on a 1-inch coupling per **Engineering Standard E1100 Subsection 4.8.3.7 – Couplings** and installing an extra-heavy pipe plug. The plug shall be seal welded into the coupling after the sleeve is welded to the pipeline.

Encirclement sleeves for non-pressure vessel-type construction may be made from untested pipe; however, tested pipe is preferred. Manufactured sleeves are permitted with prior approval from the Regional Technical Manager or designee.

Before welding, conduct a pipe wall thickness survey following **O&M Procedure 403/C1063 – Pipe Wall Thickness Survey**. Follow pressure restrictions in **O&M Procedure 404/C1064 – Welding Pressure Limitations** during welding.

Fill pipe surface depressions including corrosion pits, gouges, grooves and dents with a suitable material (Bondo, epoxy filler, etc.) to restore the original pipe surface contour and ensure a tight fit against the sleeve. Filler material may also be required to provide a less abrupt contour adjacent to external weld reinforcement from a girth weld or longitudinal seam.

Follow sleeve installation methods in **O&M Procedure 405/C1065 – Welding on a Pressurized Line**. Refer to **Standard Drawing STD-P-0100-A095 – Standard Full Encirclement Split Sleeve for Anchors, Supports and Repair** for more details.

3.10.3. Composite Material Pipe Wrap

A composite material pipe wrap repair may be installed on non-leaking Company-owned facilities if the following conditions are met:

- The Regional Technical Manager approves the composite sleeve repair
- The remaining pipe wall thickness is 20% or more of nominal thickness
- The pipeline operating temperature does not exceed 120° F

In an HCA, the composite sleeve is only permitted for repairing external corrosion.

The only approved composite repair sleeves are: ClockSpring®, Armor Plate® Pipe Wrap or StrongBack® Composite Reinforcement System. ClockSpring® is approved as a permanent repair method. Armor Plate® and StrongBack® are approved as temporary repairs not to exceed 18 months.

- Only vendor personnel or vendor-certified personnel may install pipe wrap
- Install pipe wrap using the manufacturer's recommended procedures
- Install external circumferential steel bands around both ends of the repair sleeve as markers for subsequent smart pigging

## 4. Training

Review preceding information as necessary before performing repairs. Document reviews in employee's training file.

## 5. Documentation

Properly document all leaks and pipe repairs on **O&M Form OM200-05 – Facility Maintenance and Damage Report**

For a pipeline incident report, document the findings in the **STARS Incident Management System**. Also complete **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report**.

Report all gas lost through **Online Field Ticketing – Unmeasured Gas** for all Company assets.

## 6. References

- 49 CFR 192.613(b), 192.225, 192.309, 192.703(c), 192.929(b)(1); 192.917(b), (e); 192.933a, c, (d)(1), (d)(2)
- **API** Standard 1104 - Welding of Pipelines and Related Facilities (CFR 49 Part 192 referenced edition)
- **ASME** Guide Appendix G-6 and G-7
- ASME B31.8S
- RSPA –98-4733 – Gas & Hazardous Liquid Pipeline Repair
- **O&M Procedure 120 – Personal Protective Equipment**
- **O&M Procedure 122 – Respiratory Protection**
- **O&M Procedure 159 – Incident Reporting and Investigation**
- **O&M Procedure 211 – Reporting Construction and Major Revisions**
- **O&M Procedure 214 – Reporting Pipeline Safety-Related Conditions**
- **O&M Procedure 237 – Dresser-Coupled Pipelines**
- **O&M Procedure 402/C1062 – General Welding Specifications**
- **O&M Procedure 403/C1063 – Pipe Wall Thickness Survey**
- **O&M Procedure 404/C1064 – Welding Pressure Limitations**
- **O&M Procedure 405/C1065 – Welding on a Pressurized Line**
- **O&M Procedure 406/C1066 – Weld Inspection and Testing**
- **O&M Procedure 407/C1067 – Welding Procedures and Selection Guide**
- **O&M Procedure 451/C1241 – Plastic Pipe Joining**
- **O&M Procedure 915 – Maximum Corrosion Limits and MAOP of Corroded Pipe**
- **O&M Procedure 917 – Stress Corrosion Cracking**
- **O&M Procedure 1030 – Unmeasured Gas Use/Loss Reporting**
- **O&M Procedure 1600/C1135 – Strength and Leak Testing**
- **O&M Form OM200-02 – Transmission Buried Pipeline Inspection Report**
- **O&M Form OM200-05 – Facility Maintenance and Damage Report**
- **O&M Form OM200-08 – Pipeline Incident Report**
- **Standard Drawing STD-P-0100-A095 – Standard Full Encirclement Split Sleeve for Anchors, Supports and Repair**
- **Online Field Ticketing – Unmeasured Gas**
- **Pipeline Integrity Management Program**
- **STARS Incident Management System**
- Site-Specific Emergency Response Plan

## Attachment – Table 1 – Maximum Gouge Length for Non-Emergency Replacement or Repair

**Pipe Diameter NPS 2 through NPS 6**

| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 0.083 | 0.109 | 0.125 | 0.141 | 0.154 | 0.172 | 0.188 | 0.218 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.01 | 1.9 | | | | | | | |
| 0.02 | 1.1 | 2.3 | 2.4 | 2.6 | 2.7 | 2.8 | 2.9 | |
| 0.03 | | 0.9 | 1.3 | 1.9 | 2.6 | 2.8 | 2.9 | 3.2 |
| 0.04 | | | 0.8 | 1.0 | 1.3 | 1.6 | 2.1 | 3.2 |
| 0.05 | | | | | 0.9 | 1.1 | 1.3 | 1.9 |
| 0.06 | | | | | | 0.9 | 1.0 | 1.4 |
| 0.07 | | | | | | | | 1.1 |

**Pipe Diameter NPS 8 through NPS 10**

| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 0.083 | 0.125 | 0.156 | 0.188 | 0.203 | 0.219 | 0.250 | 0.312 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.01 | 3.3 | | | | | | | |
| 0.02 | 1.8 | 4.1 | 4.5 | 4.9 | | | | |
| 0.03 | | 2.2 | 4.5 | 4.9 | 5.2 | 5.4 | 5.8 | |
| 0.04 | | 1.4 | 2.2 | 3.6 | 4.8 | 5.4 | 5.8 | 6.4 |
| 0.05 | | | 1.5 | 2.3 | 2.7 | 3.3 | 5.0 | 6.4 |
| 0.06 | | | | 1.7 | 1.9 | 2.3 | 3.1 | 6.4 |
| 0.07 | | | | | | 1.8 | 2.4 | 4.1 |
| 0.08 | | | | | | | 1.9 | 3.1 |
| 0.09 | | | | | | | | 2.6 |
| 0.10 | | | | | | | | 2.2 |

**Pipe Diameter NPS 12 through NPS 16**

| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 0.156 | 0.219 | 0.250 | 0.307 | 0.344 | 0.365 | 0.438 | 0.500 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.02 | 5.8 | | | | | | | |
| 0.03 | 5.8 | 6.8 | 7.3 | | | | | |
| 0.04 | 2.8 | 6.8 | 7.3 | 8.1 | 8.6 | 8.8 | | |
| 0.05 | 1.9 | 4.2 | 6.4 | 8.1 | 8.6 | 8.8 | 9.7 | 10.4 |
| 0.06 | | 2.9 | 4.0 | 7.7 | 8.6 | 8.8 | 9.7 | 10.4 |
| 0.07 | | 2.3 | 3.1 | 4.9 | 7.1 | 8.8 | 9.7 | 10.4 |
| 0.08 | | | 2.5 | 3.8 | 5.0 | 5.9 | 9.7 | 10.4 |
| 0.09 | | | | 3.1 | 4.0 | 4.6 | 7.8 | 10.4 |
| 0.10 | | | | 2.7 | 3.4 | 3.8 | 5.9 | 9.1 |
| 0.11 | | | | | 2.9 | 3.4 | 4.9 | 6.9 |
| 0.12 | | | | | | 2.9 | 4.2 | 5.7 |
| 0.13 | | | | | | | 3.7 | 4.9 |
| 0.14 | | | | | | | 3.3 | 4.3 |
| 0.15 | | | | | | | | 3.9 |
| 0.16 | | | | | | | | 3.6 |

**Table 1 - Maximum Gouge Length for Non-Emergency Replacement or Repair (continued)**

| Pipe Diameter NPS 18 through NPS 20 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Maximum Depth (inches)** | **Nominal Pipe Wall Thickness (inches)** | | | | | | | |
| | **0.188** | **0.250** | **0.312** | **0.344** | **0.375** | **0.438** | **0.500** | **0.625** |
| | **Maximum Gouge Length (inches)** | | | | | | | |
| 0.02 | 7.8 | | | | | | | |
| 0.03 | 7.8 | 8.9 | | | | | | |
| 0.04 | 5.6 | 8.9 | 10.0 | 10.5 | 10.9 | | | |
| 0.05 | 3.5 | 7.8 | 10.0 | 10.5 | 10.9 | 11.8 | 12.6 | |
| 0.06 | 2.6 | 4.9 | 10.0 | 10.5 | 10.9 | 11.8 | 12.6 | |
| 0.07 | | 3.7 | 6.3 | 10.5 | 10.9 | 11.8 | 12.6 | 14.3 |
| 0.08 | | 3.1 | 4.8 | 8.7 | 7.9 | 11.8 | 12.6 | 14.3 |
| 0.09 | | | 3.9 | 6.1 | 6.0 | 9.5 | 12.6 | 14.3 |
| 0.10 | | | 3.4 | 4.9 | 4.9 | 7.2 | 11.1 | 14.3 |
| 0.11 | | | | 4.5 | 4.3 | 5.9 | 8.4 | 14.3 |
| 0.12 | | | | 3.6 | 3.8 | 5.1 | 6.9 | 14.3 |
| 0.13 | | | | | | 4.5 | 5.9 | 10.9 |
| 0.14 | | | | | | 4.1 | 5.3 | 9.0 |
| 0.15 | | | | | | | 4.8 | 7.8 |
| 0.16 | | | | | | | 4.3 | 6.9 |
| 0.17 | | | | | | | | 6.2 |
| 0.18 | | | | | | | | 5.6 |
| 0.19 | | | | | | | | 5.2 |
| 0.20 | | | | | | | | 4.9 |

| Pipe Diameter NPS 22 through NPS 24 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Maximum Depth (inches)** | **Nominal Pipe Wall Thickness (inches)** | | | | | | | |
| | **0.219** | **0.250** | **0.344** | **0.406** | **0.469** | **0.500** | **0.562** | **0.625** |
| | **Maximum Gouge Length (inches)** | | | | | | | |
| 0.03 | 9.4 | 10.0 | | | | | | |
| 0.04 | 9.4 | 10.0 | 11.8 | | | | | |
| 0.05 | 5.7 | 8.8 | 11.8 | 12.8 | 13.7 | 14.1 | | |
| 0.06 | 4.0 | 5.5 | 11.8 | 12.8 | 13.7 | 14.1 | 15.0 | |
| 0.07 | 3.2 | 4.1 | 9.7 | 12.8 | 13.7 | 14.1 | 15.0 | 15.8 |
| 0.08 | | 3.4 | 6.9 | 11.7 | 13.7 | 14.1 | 15.0 | 15.8 |
| 0.09 | | | 5.4 | 8.3 | 13.7 | 14.1 | 15.0 | 15.8 |
| 0.10 | | | 4.6 | 6.6 | 9.9 | 12.4 | 15.0 | 15.8 |
| 0.11 | | | 4.0 | 5.6 | 7.9 | 9.4 | 14.1 | 15.8 |
| 0.12 | | | | 4.9 | 6.6 | 7.8 | 10.8 | 15.8 |
| 0.13 | | | | 4.4 | 5.8 | 6.7 | 8.9 | 12.3 |
| 0.14 | | | | | 5.2 | 5.6 | 7.6 | 10.1 |
| 0.15 | | | | | 4.7 | 5.3 | 6.8 | 3.7 |
| 0.16 | | | | | | 4.8 | 6.1 | 7.7 |
| 0.17 | | | | | | | 5.6 | 6.9 |
| 0.18 | | | | | | | 5.1 | 6.3 |
| 0.19 | | | | | | | | 5.8 |
| 0.20 | | | | | | | | 5.4 |

**Table 1 - Maximum Gouge Length for Non-Emergency Replacement or Repair (continued)**

| Pipe Diameter NPS 26 through NPS 30 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
| | 0.250 | 0.312 | 0.375 | 0.438 | 0.469 | 0.500 | 0.562 | 0.625 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.03 | 10.9 | | | | | | | |
| 0.04 | 10.9 | 12.3 | 13.4 | | | | | |
| 0.05 | 9.6 | 12.3 | 13.4 | 14.5 | 15.0 | 15.5 | | |
| 0.06 | 6.0 | 12.3 | 13.4 | 14.5 | 15.0 | 15.5 | 16.4 | |
| 0.07 | 4.6 | 7.8 | 13.4 | 14.5 | 15.0 | 15.5 | 16.4 | 17.3 |
| 0.08 | 3.8 | 5.9 | 9.7 | 14.5 | 15.0 | 15.5 | 16.4 | 17.3 |
| 0.09 | | 4.9 | 7.4 | 11.6 | 15.0 | 15.5 | 16.4 | 17.3 |
| 0.10 | | 4.2 | 6.1 | 8.9 | 10.8 | 13.6 | 16.4 | 17.3 |
| 0.11 | | | 5.2 | 7.3 | 8.6 | 10.3 | 15.4 | 17.3 |
| 0.12 | | | 4.6 | 6.3 | 7.3 | 8.5 | 11.8 | 17.3 |
| 0.13 | | | | 5.5 | 6.4 | 7.3 | 9.8 | 13.4 |
| 0.14 | | | | 5.0 | 5.7 | 6.4 | 8.4 | 11.1 |
| 0.15 | | | | | 5.1 | 5.8 | 7.4 | 9.5 |
| 0.16 | | | | | | 5.3 | 6.7 | 8.4 |
| 0.17 | | | | | | | 6.1 | 7.6 |
| 0.18 | | | | | | | 5.6 | 6.9 |
| 0.19 | | | | | | | | 6.4 |
| 0.20 | | | | | | | | 5.9 |

| Pipe Diameter NPS 32 through NPS 36 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | |
| | 0.250 | 0.312 | 0.375 | 0.438 | 0.500 | 0.625 | 0.688 |
| | Maximum Gouge Length (inches) | | | | | | |
| 0.03 | 12.3 | | | | | | |
| 0.04 | 12.3 | 13.7 | 15.0 | | | | |
| 0.05 | 10.7 | 13.7 | 15.0 | 16.2 | 17.3 | | |
| 0.06 | 6.7 | 13.7 | 15.0 | 16.2 | 17.3 | | |
| 0.07 | 5.1 | 8.7 | 15.0 | 16.2 | 17.3 | 19.4 | 20.3 |
| 0.08 | 4.2 | 6.6 | 10.8 | 16.2 | 17.3 | 19.4 | 20.3 |
| 0.09 | | 5.4 | 8.3 | 13.0 | 17.3 | 19.4 | 20.3 |
| 0.10 | | 4.7 | 6.8 | 9.9 | 15.1 | 19.4 | 20.3 |
| 0.11 | | | 5.8 | 8.1 | 11.6 | 19.4 | 20.3 |
| 0.12 | | | 5.1 | 7.0 | 9.5 | 19.4 | 20.3 |
| 0.13 | | | | 6.2 | 8.2 | 15.0 | 20.3 |
| 0.14 | | | | 5.6 | 7.2 | 12.4 | 16.8 |
| 0.15 | | | | | 6.5 | 10.6 | 13.9 |
| 0.16 | | | | | 5.9 | 9.4 | 11.9 |
| 0.17 | | | | | | 8.4 | 10.5 |
| 0.18 | | | | | | 7.8 | 9.5 |
| 0.19 | | | | | | 7.1 | 8.7 |
| 0.20 | | | | | | 6.6 | 8.0 |
| 0.21 | | | | | | | 7.4 |
| 0.22 | | | | | | | 7.0 |

**Table 1 - Maximum Gouge Length for Non-Emergency Replacement or Repair (continued)**

| Pipe Diameter NPS 38 through NPS 42 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
| | 0.250 | 0.281 | 0.312 | 0.375 | 0.438 | 0.500 | 0.625 | 0.688 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.03 | 13.4 | 14.2 | | | | | | |
| 0.04 | 13.4 | 14.2 | 15.0 | 16.4 | | | | |
| 0.05 | 11.7 | 14.2 | 15.0 | 16.4 | 17.1 | 18.4 | | |
| 0.06 | 7.4 | 10.3 | 15.0 | 16.4 | 17.1 | 18.4 | 20.1 | |
| 0.07 | 5.6 | 7.3 | 9.5 | 16.4 | 17.1 | 18.4 | 20.1 | 22.3 |
| 0.08 | 4.6 | 5.8 | 7.3 | 11.9 | 15.7 | 18.4 | 20.1 | 22.3 |
| 0.09 | | 4.9 | 5.8 | 9.0 | 11.2 | 18.4 | 20.1 | 22.3 |
| 0.10 | | | 4.9 | 7.4 | 8.9 | 13.3 | 20.1 | 22.3 |
| 0.11 | | | | 6.4 | 7.5 | 10.6 | 18.9 | 22.3 |
| 0.12 | | | | 5.3 | 6.6 | 8.9 | 14.5 | 22.3 |
| 0.13 | | | | | 5.8 | 7.8 | 11.9 | 22.3 |
| 0.14 | | | | | | 6.9 | 10.3 | 18.4 |
| 0.15 | | | | | | 6.3 | 9.1 | 15.2 |
| 0.16 | | | | | | | 8.2 | 13.1 |
| 0.17 | | | | | | | 7.4 | 11.6 |
| 0.18 | | | | | | | 6.9 | 10.4 |
| 0.19 | | | | | | | | 9.5 |
| 0.20 | | | | | | | | 8.8 |
| 0.21 | | | | | | | | 8.1 |
| 0.22 | | | | | | | | 7.6 |

| Pipe Diameter NPS 44 through NPS 48 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Maximum Depth (inches) | Nominal Pipe Wall Thickness (inches) | | | | | | | |
| | 0.344 | 0.406 | 0.438 | 0.479 | 0.500 | 0.562 | 0.625 | 0.688 |
| | Maximum Gouge Length (inches) | | | | | | | |
| 0.04 | 17.0 | | | | | | | |
| 0.05 | 17.0 | 18.4 | 19.2 | 19.9 | 20.5 | | | |
| 0.06 | 17.0 | 18.4 | 19.2 | 19.9 | 20.5 | 21.8 | | |
| 0.07 | 14.1 | 18.4 | 19.2 | 19.9 | 20.5 | 21.8 | 22.9 | 24.1 |
| 0.08 | 9.9 | 17.0 | 19.2 | 19.9 | 20.5 | 21.8 | 22.9 | 24.1 |
| 0.09 | 7.9 | 12.1 | 15.4 | 19.9 | 20.5 | 21.8 | 22.9 | 24.1 |
| 0.10 | 6.7 | 9.6 | 11.7 | 14.4 | 17.9 | 21.8 | 22.9 | 24.1 |
| 0.11 | 5.8 | 8.1 | 9.6 | 11.4 | 13.7 | 20.4 | 22.9 | 24.1 |
| 0.12 | | 7.1 | 8.3 | 9.6 | 11.3 | 15.6 | 22.9 | 24.1 |
| 0.13 | | 6.3 | 7.3 | 8.4 | 9.7 | 12.9 | 17.8 | 24.1 |
| 0.14 | | | 6.6 | 7.5 | 8.6 | 11.1 | 14.6 | 19.9 |
| 0.15 | | | | 6.8 | 7.7 | 9.8 | 12.6 | 16.4 |
| 0.16 | | | | | 7.0 | 8.8 | 11.1 | 14.1 |
| 0.17 | | | | | | 8.1 | 10.0 | 12.4 |
| 0.18 | | | | | | 7.4 | 9.1 | 11.3 |
| 0.19 | | | | | | | 8.4 | 10.3 |
| 0.20 | | | | | | | 7.9 | 9.4 |
| 0.21 | | | | | | | | 8.8 |
| 0.22 | | | | | | | | 8.3 |

**Table 1 - Maximum Gouge Length for Non-Emergency Replacement or Repair**

# Appendix 7

## Table of Contents



# 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☐ Kinder Morgan Power Company

# 2. Scope

The Welding Procedure Selection Guide lists qualified welding procedures for welding on the Company's natural gas pipeline facilities. All work will be done in conformance with 49 CFR Part 192 and 195, API Standard 1104 or ASME Section IX, whichever code is applicable to the work being performed.

# 3. Core Information and Requirements

Perform all welding in conformance with the qualified welding procedure established for pipe size, wall thickness and material as provided in the Welding Procedure Selection Guide. When welding materials of two separate material groups, use the procedure for the higher strength group.

## 3.1. Procedure Qualification

Each pipeline welding procedure or portion thereof shall be qualified in accordance with API 1104 or ASME Section IX. Only destructive testing performed in accordance with the applicable welding standard may be used to qualify the test welds for the proposed welding procedure. The Lakewood Codes and Standards Department will provide assistance with the qualification process. Welding procedures will be developed, qualified and published as necessary.

A non-standard welding procedure may be developed, qualified, recorded and used on specific projects when no standard welding procedure is available that meets the project needs or when, with the Company's approval, the contractor elects to furnish its own qualified welding procedures. The Lakewood Codes and Standards Department shall be consulted whenever a non-standard welding procedure is to be qualified and used on the Company's pressurized facilities.

The Project Manager shall be responsible for assuring the proper welding procedure qualification and for maintaining proper records of such at the construction site during construction. The non-standard qualified procedure, along with the supporting procedure qualification records shall be included in the project as-built documents and a copy sent to the Lakewood Codes and Standards Department.

## 3.2. Multiple Procedures

Many of the welding procedures will include a choice of welding options to join a specific range of O.D., wall thickness and pipe grade using different rod types and welding parameters. The options are indicated within the procedure by subsections A, B, C, etc. The project manager must direct the welder(s) to follow the specific procedure and subsection (if applicable) prior to the start of work. The welding inspector must indicate on any written document the specific procedure and subsection (if applicable) used during the welder testing and project. The welding inspector will verify that the welder(s) is/are following the appropriate welding parameters (volts, amps, travel speed, rod type and size) while performing any welding. Any desired change of an essential variable as detailed in the governing welding code will require a new procedure qualification.

## 4. Training

Review this information and the applicable welding procedures as necessary before performing the work.

## 5. Documentation

The Lakewood Codes and Standards Department will maintain welding procedure qualification records for welding procedures.

## 6. References

- 49 CFR 192 – Transportation of Natural or Other Gas by Pipeline
- 49 CFR 195 – Transportation of Hazardous Liquids by Pipeline
- API 1104 Welding of Pipelines and Related Facilities (CFR 49 Part 192 referenced edition)
- ASME Code – Section IX - Welding and Brazing Qualifications (CFR 49 Part 192 referenced edition)
- Welding Procedure Selection Guide

# Attachment 1 – Welding Procedures Selection Guide

| Welding Code | Material | Welding Process | Filler Metal | Welding Direction | API Material Grade/Group | Joint Design | Nom. Wall Thickness | Nom. Pipe Diameter in inches | Proc. No. 407.xxx |
|---|---|---|---|---|---|---|---|---|---|
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | ≤X-42 | Butt | < 0.188" | 0 to 12 | .010 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | ≤X-42 | Butt | 0.188 - 0.750" | 2 - 12 | .011 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | ≤X-42 | Butt | 0.188 - 0.750" | > 12 | .012 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | ≤X-42 | Butt | 0.751 - 1.000" | > 12 | .013 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | ≤X-42 | Butt w/backing | 0.188 - 0.750" | > 12 | .014 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | ≤X-42 | Butt w/backing | 0.188 - 0.750" | ≥2 | .015 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | ≤X-42 | Branch or Fillet | < 0.188" | < 2 | .016 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | ≤X-42 | Branch or Fillet | 0.188 - 0.750" | All | .017 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | ≤X-42 | Branch or Fillet | ≤ 0.750" | All | .018 |
| | | | | | | | | | |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | > X-42 & < X-65 | Butt | < 0.188" | 2 - 12 | .020 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | > X-42 & < X-65 | Butt | 0.188 - 0.750" | 2 -12 | .021 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | > X-42 & < X-65 | Butt | 0.188 - 0.750" | > 12 | .022 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | > X-42 & < X-65 | Butt | >0.750" | > 12 | .028 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | > X-42 & < X-65 | Butt w/backing | 0.188 - 0.750" | > 12 | .023 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | > X-42 & < X-65 | Butt w/backing | 0.188 - 0.750" | ≥2 | .024 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | > X-42 & < X-65 | Branch or Fillet | < 0.188" | < 2 | .025 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | > X-42 & < X-65 | Branch or Fillet | 0.188 - 0.750" | All | .026 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | > X-42 & < X-65 | Branch or Fillet | ≤ 0.750" | All | .027 |
| | | | | | | | | | |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | X-65 | Butt | 0.188 - 0.750" | ≥2 | .040 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | X-65 | Butt | > 0.750" | > 12 | .046 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | X-65 | Butt w/backing | 0.188 - 0.750" | > 12 | .041 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | X-65 | Butt w/backing | 0.188 - 0.750" | > 12 | .042 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | X-65 | Branch or Fillet | < 0.188" | < 2 | .043 |
| API 1104 | Carbon Steel | SMAW | Group 1 | Down | X-65 | Branch or Fillet | 0.188 - 0.750" | All | .044 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | X-65 | Branch or Fillet | 0.188 - 0.750" | ≥2 | .045 |
| | | | | | | | | | |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | X-70 | Butt | ≥0.188 | > 12 | .060 |
| API 1104 | Carbon Steel | SMAW | Group 2 | Down | X-70 | Butt w/backing | 0.188 - 0.750" | > 12 | .061 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | X-70 | Butt w/backing | 0.188 - 0.750" | > 12 | .062 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | X-70 | Branch or Fillet | < 0.188" | < 2 | .063 |
| API 1104 | Carbon Steel | SMAW | Groups 1 & 2 | Down | X-70 | Branch or Fillet | 0.188 - 0.750" | All | .064 |
| API 1104 | Carbon Steel | SMAW | Group 3 | Up | X-70 | Branch or Fillet | 0.188 - 0.750" | ≥2" | .065 |
| | | | | | | | | | |
| **API 1104** | **Carbon Steel** | **SMAW** | **Groups 1 & 3** | **Down/Up** | **X-80** | **Butt** | **0.188 - 0.750"** | **>12** | **.070** |

| Grade | Welding Process | ASME Group | API 5L Filler Metal Group |
|---|---|---|---|
| < Less than<br>> Greater than<br>≥ Greater than or equal to<br>≤ Less than or equal to | SMAW - shielded metal arc welding<br>GTAW - gas tungsten arc welding | P1 – Carbon Steel<br>P8 – Austenitic stainless steel | Group 1 - E6010 & E7010<br>Group 2 - E8010<br>Group 3 - E7018, 8018-C3, 9018M |

| Welding Code | Material | Welding Process | Filler Metal | Welding Direction | API Material Grade/Group | Joint Design | Nom. Wall Thickness | Nom Pipe Diameter in inches | Proc. No. 407.xxx |
|---|---|---|---|---|---|---|---|---|---|
| API 1104 Appendix B | Carbon Steel | SMAW | Group 3 | Up | ≤X-80 C ≤0.10, Pcm ≤0.22 | Branch Weld With Flow | 0.188-0.750" | ≥12 | .095 |
| API 1104 Appendix B | Carbon Steel | SMAW | Group 3 | Up | ≤X-80 C ≤0.10, Pcm ≤0.22 | Sleeve Butt Weld With Backing & Flow | 0.188-0.750" | ≥12 | .096 |
| API 1104 Appendix B | Carbon Steel | SMAW | Group 3 | Up | ≤X-80 C ≤0.10, Pcm ≤0.22 | Sleeve Fillet Weld With Flow | 0.188-0.750" | ≥12 | .097 |
| API 1104 | High Yield Steel | SMAW | Group 3 | Down | ASTM A829 | Fillet | 0.188 - 0.750 | 5" OD | .099 |
| | | | | | | | | | |
| ASME | Carbon Steel (P1) | SMAW | E6010 | Down | P No. 1 | Groove & Fillet | 0.100 - 1.700" | ≥1 | .100 |
| ASME | Carbon Steel (P1) | SMAW | E6010/E7010 | Down | P No. 1 | Groove & Fillet | 0.100 - 1.750" | ≥1 | .101 |
| ASME | Carbon Steel (P1) | SMAW | E6010/E8010 | Down | P No. 1 | Groove & Fillet | 0.109 - 1.750" | ≥1 | .102 |
| ASME | Carbon Steel (P1) | SMAW | E6010/E7018 | Down/Up | P No. 1 | Groove & Fillet | 0.109 - 1.124" | ≥1 | .103 |
| ASME | Stainless Stl. (P8) | SMAW | ER 308 | Uphill | P No. 8 | Groove & Fillet | 0.188 - 0.474" | ≥2 | .104 |
| | | | | | | | | | |
| ASME | Stainless Stl. (P8) | GTAW | F No. 6 | Uphill | P No. 8 | Groove & Fillet | 0.063"-0.308" | ≥1 | .205 |
| **ASME** | **Carbon Steel (P1)** | **GTAW/ SMAW** | **ER70S-6/ E8010** | **Up/Down** | **P No. 1** | **Groove & Fillet** | **0.063"-0.436"** | **≥1** | **.206** |

| Grade | Welding Process | ASME Group | API 5L Filler Metal Group |
|---|---|---|---|
| < Less than<br>> Greater than<br>≥ Greater than or equal to<br>≤ Less than or equal to | SMAW - shielded metal arc welding<br>GTAW - gas tungsten arc welding | P1 – Carbon Steel<br>P8 – Austenitic stainless steel | Group 1 - E6010 & E7010<br>Group 2 - E8010<br>Group 3 - E7018, 8018-C3, 9018M |

**PROCESS/CODE:** **SMAW - Shielded metal arc (manual)/API 1104**

**PIPE AND FITTING MATERIAL:**

- Specified minimum yield strength (SMYS) - **70,000 psi**
- Low carbon or low alloy carbon steel pipe, fittings or flanges
- API 5L Grade X70 or specifications with similar mechanical properties or chemical compositions.

**PIPE DIAMETER GROUP:** **Greater than 12-3/4 inches**

**WALL THICKNESS GROUP:** **0.188 inch and thicker**

**JOINT DESIGN:** Butt - see figure on next page

**FILLER METAL AND NUMBER OF PASSES:** Filler metal (**cellulosic electrodes**) selection shall be based on the pipe or fitting material with the highest SMYS. See Tables 1 and 2 (A-C).

**ELECTRICAL CHARACTERISTICS:** See Table 3 (A-C).

**POSITION:** Fixed

**DIRECTION OF WELDING:** Downhill

**TIME LAPSE BETWEEN PASSES:** The time lapse between root and second passes should be as soon as practical but shall not be more than 9 minutes and as soon as practical between the second and next pass.

**TYPE OF LINE-UP CLAMP AND REMOVAL:** An external clamp or internal clamp shall be used as determined by Company. The external clamp shall be held in place until a maximum practical amount of the root pass is completed (minimum of 50 percent) in equally spaced increments around the pipe and the pipe has been properly rested. The internal clamp shall be held in place until a minimum of 90 percent of the root pass is completed and the pipe has been properly rested. No pipe movement shall be permitted on tie-ins before the entire weld is completed.

**CLEANING:** Rust, dirt, moisture and foreign matter shall be removed from the bevel surface before welding. Slag or flux remaining on any bead shall be removed from each pass with a power grinder or wire brush before the next pass is applied. The finished weld shall be cleaned and any spatter removed from the adjacent pipe surface.

**PREHEAT/POST HEAT:** A minimum 200° F preheat or inter-pass temperature may be required when the ambient temperature is below 50° F or when completing previously unfinished welds. A minimum 200° F preheat and inter-pass temperature shall be required for pipe, valves or fittings having a nominal wall thickness greater than or equal to 0.450 inch. Heating may be required to remove moisture from the bevel region before welding.

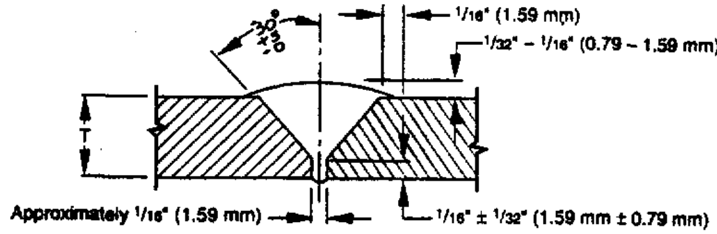
Pipe heating can be done with a propane torch and a wide area heating head or similar Company representative-approved method. The weld area will be adequately heated for at least 3 inches on either side of the weld area. The temperature shall be verified with a hand held pyrometer, tempstick or similar indicator approved by Company representative.

**SHIELDING GAS AND FLOW RATE:** Not applicable.

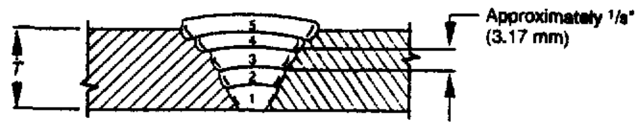
**SPEED OF TRAVEL:** See Table 3 (A-C).

**OTHER:** None

## JOINT DESIGN




Standard V-Bevel Butt Junt




Sequence of Beads

*Note: Dimensions are for example only.*

## A. FILLER METAL – <u>E-7010 Welding Rod (all passes)</u>

| TABLE 1-A: ELECTRODE SELECTION | | | | | |
|---|---|---|---|---|---|
| **NOM. PIPE DIAMETER** | **NOM. WALL THICKNESS** | **ROOT PASS** | **HOT PASS** | **FILLER PASS** | **COVER PASS** |
| Greater than 12" | 0.188" through 0.750" | 1/8 - 5/32"<br>E-7010<br>AWS A5.5 | 1/8-5/32"<br>E-7010<br>AWS A5.5 | 5/32-3/16"<br>E-7010<br>AWS A5.5 | 5/32-3/16"<br>E-7010<br>AWS A5.5 |

| TABLE 2-A: MINIMUM NO. OF PASSES | |
|---|---|
| **NOM. WALL THICKNESS RANGE (inches)** | **MIN. NO. OF PASSES** |
| 0.188 through 0.250 | 3 |
| 0.251 through 0.375 | 4 |
| 0.376 through 0.500 | 5 |
| 0.501 through 0.625 | 7 |
| 0.626 through 0.750 | 9 |

| TABLE 3-A: ELECTRODE ELECTRICAL CHARACTERISTICS AND TRAVEL SPEED (INCHES PER MIN. / I.P.M.) | | | | | | |
|---|---|---|---|---|---|---|
| **ELECTRODE DIAMETER >** | **1/8"** | **5/32"** | **3/16"** | | | |
| **PASS** | **AMPS-VOLTS** | **AMPS-VOLTS** | **AMPS-VOLTS** | **ELEC. POLARITY** | **CURRENT** | **I.P.M.** |
| Root | 50/200-20/37 | 50/200-20/37 | --- | Positive | DC | 3-14 |
| Hot | 50/215-20/40 | 50/215-20/40 | --- | Positive | DC | 3-19 |
| Filler | --- | 60/220-20/40 | 60/220-20/40 | Positive | DC | 3-15 |
| Cover | --- | 50/215-20/38 | 50/215-20/38 | Positive | DC | 3-14 |

## B. FILLER METAL – E-6010 & E-8010 Welding Rod Combination

| TABLE 1-B: ELECTRODE SELECTION | | | | | |
|---|---|---|---|---|---|
| NOM. PIPE DIAMETER | NOM. WALL THICKNESS | ROOT PASS | HOT PASS | FILLER PASS | COVER PASS |
| Greater than 12" | 0.188" and thicker | 1/8 - 5/32" E-6010 AWS A5.1 | 5/32-3/16" E-8010 AWS A5.5 | 3/16" E-8010 AWS A5.5 | 3/16" E-8010 AWS A5.5 |

| TABLE 2-B: MINIMUM NO. OF PASSES | |
|---|---|
| NOM. WALL THICKNESS RANGE (inches) | MIN. NO. OF PASSES |
| 0.188 through 0.250 | 3 |
| 0.251 through 0.375 | 4 |
| 0.376 through 0.500 | 5 |
| 0.501 through 0.625 | 7 |
| 0.626 through 0.750 | 9 |
| Greater than 0.750 | 9 |

| TABLE 3-B: ELECTRODE ELECTRICAL CHARACTERISTICS AND TRAVEL SPEED (INCHES PER MIN. / I.P.M.) | | | | | | |
|---|---|---|---|---|---|---|
| ELECTRODE DIAMETER > | 1/8" | 5/32" | 3/16" | | | |
| PASS | AMPS-VOLTS | AMPS-VOLTS | AMPS-VOLTS | ELEC. POLARITY | CURRENT | I.P.M. |
| Root | 50/200-20/37 | 50/200-20/37 | --- | Positive | DC | 3-14 |
| Hot | --- | 50/215-20/40 | 50/215-20/40 | Positive | DC | 3-19 |
| Filler | --- | --- | 60/220-20/40 | Positive | DC | 3-15 |
| Cover | --- | --- | 50/215-20/38 | Positive | DC | 3-14 |

## C. FILLER METAL - E-8010 Welding Rod (all passes)

| TABLE 1-C: ELECTRODE SELECTION | | | | | |
|---|---|---|---|---|---|
| NOM. PIPE DIAMETER | NOM. WALL THICKNESS | ROOT PASS | HOT PASS | FILLER PASS | COVER PASS |
| Greater than 12" | 0.188" through 0.750" | 1/8 - 5/32" E-8010 AWS A5.5 | 5/32" E-8010 AWS A5.5 | 3/16" E-8010 AWS A5.5 | 3/16" E-8010 AWS A5.5 |

| TABLE 2-C: MINIMUM NO. OF PASSES | |
|---|---|
| NOM. WALL THICKNESS RANGE (inches) | MIN. NO. OF PASSES |
| 0.188 through 0.250 | 3 |
| 0.251 through 0.375 | 4 |
| 0.376 through 0.500 | 5 |
| 0.501 through 0.625 | 7 |
| 0.626 through 0.750 | 9 |

| TABLE 3-C: ELECTRODE ELECTRICAL CHARACTERISTICS AND TRAVEL SPEED (INCHES PER MIN. / I.P.M.) | | | | | | |
|---|---|---|---|---|---|---|
| ELECTRODE DIAMETER > | 1/8" | 5/32" | 3/16" | | | |
| PASS | AMPS-VOLTS | AMPS-VOLTS | AMPS-VOLTS | ELEC. POLARITY | CURRENT | I.P.M. |
| Root | 50/200-20/37 | 50/200-20/37 | --- | Positive | DC | 3-14 |
| Hot | --- | 50/215-20/40 | --- | Positive | DC | 3-19 |
| Filler | --- | --- | 60/220-20/40 | Positive | DC | 3-15 |
| Cover | --- | --- | 50/215-20/38 | Positive | DC | 3-14 |

## Table of Contents



## 1. Applicability

- ☒ Gathering
- ☒ Processing
- ☒ Transmission/Regulated Onshore Gathering
- ☐ Kinder Morgan Power Company

## 2. Scope

This procedure specifies welding standards for all welders working on natural gas pipelines and associated facilities. It includes special procedures for welding on pipes of different dimensions and specifications. Do all work in conformance with 49 CFR Part 192, the latest DOT-approved edition of API Standard 1104 or ASME Section IX, whichever code is applicable to the work being performed.

## 3. Core Information and Requirements

Make all welds in conformance with the qualified welding procedure established for pipe size, wall thickness and material. Refer to **O&M Procedure 407/C1067 – Welding Procedures and Selection Guide**.

Perform all welding and cutting in a well-ventilated area when possible. Review **O&M Procedure 103 – Hot Work** and take all precautionary steps before starting to weld in a hazardous area. Protect welding operations from weather conditions that would impair the completed weld's quality.

### 3.1. Weld Acceptance on Arkansas Facilities Owned by Others

For Arkansas pipeline facilities owned by others and operated on their behalf by the Company, determine the acceptability of welds that are non-destructively tested or visually inspected according to the standards in API 1104.

**Exception:** The standards in API 1104 for undercutting depth adjacent to the root bead will apply only if:

- The depth is visually determined using a depth measuring device on all undercutting along the entire circumference of the weld
- Internal undercutting is visually determined in all pipe of the same diameter in a pipeline, except where impractical at tie-in welds

### 3.2. Distance Between Welds

On a pipeline, the minimum distance between edges of adjacent girth welds shall be one pipe diameter or 24-inches, whichever is less. Request an exception from the Regional Technical Manager if conditions require a variation from this minimum distance.

At compressor stations, the minimum distance between sleeves, braces, etc. and girth welds shall be 6-inches. The minimum distance between two full encirclement sleeves not connected shall be one pipe diameter or 6-inches, whichever is greater.

### 3.3. Sleeve Material

The weld sleeve used for a hot tap or reinforcement shall have the same wall thickness or greater (up to 0.125-inch thicker) and be of the same grade as or higher than the line pipe. Reinforcement sleeves shall be a minimum of 12-inches in length and shall have a minimum of 3-inches on either side of any anomaly outside the minimum wall thickness tolerance as specified in Table 4 – Minimum Wall Thickness Tolerance in API 5L Pipe Specification of **O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage**. Reinforcement sleeves shall be a minimum of 6-inches in length for a doubler plate.

### 3.4. Multiple Repair Sleeve Installation

The minimum distance between sleeves, braces, etc. and girth welds shall be 6-inches for pipelines and 6-inches for compressor station piping.

When repair sleeve ends will be located within 6-inches of a girth weld or the required sleeve is too long to be reasonably or practically fabricated and installed, a short doubler plate (refer to Attachment 1 – Pipe Sleeve and Doubler Plate) can be used to install multiple sleeves or sleeves adjacent to girth welds. Install girth ends of repair sleeves under the doubler plate as close as practical to one another or to the carrier pipe girth weld edges. Do not use fillet welds for sleeve ends under the doubler plate. Fillet-weld doubler plate ends.

### 3.5. Check for Combustible Atmosphere

Before welding, welder shall take steps to minimize the danger of accidental gas ignition in any structure or area where the presence of gas constitutes a fire or explosion hazard. For appropriate levels of LEL, refer to **O&M Procedure 103 – Hot Work**. Do not weld or cut on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work. Follow **O&M Procedure 103 – Hot Work** when working in a potentially combustible atmosphere.

### 3.6. Grinding

Clean the root pass and condition the remaining weld by grinding. Grind with a general-purpose, raised hub disc 1/8- to 3/16-inch thick. Use a disc with a maximum RPM rating higher than the maximum RPM of the grinder being used.

### 3.7. Weld Metal Strength

When the Specified Minimum Yield Strengths (SMYS) of the pipe sections to be joined are unequal, the deposited weld metal shall have mechanical properties at least equal to the section with the higher strength.

### 3.8. Welding Rod Care and Storage

Take proper care of welding rods. External contaminants can dramatically affect the welding process and produce welds with undesirable properties.

3.8.1. E6010, 7010 and 8010 Rod: Keep these rods in a dry location after opening the container. For long-term storage, place electrodes in a rod oven as the welding rod Manufacturer recommends. Discard wet rods.

3.8.2. E7018, **E8018 and E9018** Rod: After opening the original rod container, take all practical precautions to minimize the flux coating's moisture absorption. Store rods in a rod oven. Do not use refrigerators or makeshift storage cabinets. **Ovens shall be energized when storing welding rods and periodically inspected to ensure proper operation.** Follow the Manufacturer's directions for storing and drying. Discard wet rods. Rod can be taken from the oven and placed in a hermetically sealed plastic rod holder. Rod containers for day use shall have an 'O' ring seal to prevent humidity from entering the container.

3.8.3. Other Welding Consumables: Follow the Manufacturer's directions for storing and drying.

### 3.9. Miter Joints

On pipe operated at 30% of SMYS or greater, do not install miter joints greater than 3 degrees. For a larger directional change, the pipe must be bent or install factory-formed elbows.

On pipe operated at greater than 10% but less than 30% of SMYS, a miter joint cannot deflect the pipe more than 12.5 degrees and must be at least one pipe diameter from any other miter joint weld.

On pipe that will be operated at 10% of SMYS or less, a miter joint cannot deflect the pipe more than 90 degrees.

### 3.10. End Preparation for Butt Welding

3.10.1. Any Size Pipe, Hoop Stress <20% and <1/8-Inch Offset

No special treatment is necessary as long as the weld provides adequate penetration and bond is accomplished in welding.

3.10.2. Pipe ≥12-3/4-Inch OD with Unequal Wall Thickness

- Wall thickness variation of 3/32-inch (<0.094 inch) or less: No special preparation is necessary. Refer to Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (a).
- Wall thickness variation greater than 3/32-inch (>0.094 inch) but less than 1/8- inch (<0.125 inch): Refer to the second bullet in Subsection 3.10.6 – Internal and External Diameters Unequal.
- Wall thickness variation of more than 1/8-inch (>0.125 inch): Use a transition piece or the method described in the third bullet in Subsection 3.10.6 – Internal and External Diameters Unequal.

3.10.3. Pipe <12-3/4-Inch OD and any Size Fabricated Assembly with Unequal Wall Thickness and Equal or Unequal Yield Strengths

When the SMYS of sections being joined are unequal, the deposited weld metal shall have mechanical properties at least equal to the section with the higher strength. Use one of the following transition methods between ends of unequal thickness:

- Taper boring (the taper angle should not be less than 14 degrees unless pipes are of equal SMYS)
- A prefabricated transition ring
- Welding as discussed in Subsection 3.10.4 – Internal Diameters Unequal, 3.10.5 – External Diameters Unequal or 3.10.6 – Internal and External Diameters Unequal.

3.10.4. Internal Diameters Unequal

If the piping is operating at hoop stresses of 20% percent or more of SMYS:

- If the nominal wall thicknesses of adjoining ends vary less than 3/32-inch (<0.094 inch), no special treatment is necessary as long as the weld provides full penetration and bond (Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (a)).

- Where the nominal internal offset is equal to or more than 3/32-inch (≥0.094 inch) and the pipe inside is not accessible for welding, transition must be made by a taper cut on the inside end of the thicker section (Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (b)). The taper angle shall not be steeper than 30 degrees.
- Where the nominal internal offset is more than 3/32-inch (>0.094 inch) but does not exceed one-half of the thinner section and the pipe inside is accessible for welding, transition may be made with a tapered weld (Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (c)). The land on the thicker section must be equal to the offset plus the land on abutting section.
- Where the nominal internal offset is more than one-half of the thinner section and the pipe inside is accessible for welding, transition may be made with a combination taper weld to one-half the thinner section and a taper cut from that point (Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (d)).

3.10.5. External Diameters Unequal

- Where the external offset does not exceed one-half the thinner section, transition may be made by welding as in Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (e), provided the weld surface angle of rise does not exceed 30 degrees and both bevel edges are properly fused
- Where an external offset exceeds one-half the thinner section, taper that portion of the offset over one-half t as shown in Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (f)

3.10.6. Internal and External Diameters Unequal

- Where there are both internal and external offsets, joint design shall be as shown in Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness (g). Internal back welding is preferred as shown in Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (d).
  **Note:** Maximum wall thickness difference is limited to 1/8-inch.
- On 12-3/4-inch and larger OD pipe with the difference in wall thickness greater than 3/32-inch (0.094 inch) but no more than one-half of thinner pipe thickness and the pipe inside is accessible for welding, transition may be made with a tapered weld as shown in Attachment 3 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (h).
  **Note:** Maximum wall thickness difference is limited to 1/8-inch.
- On 12-3/4-inch and larger OD pipe with the difference in wall thickness greater than 3/32-inch (0.094-inch) but no more than one-half of thinner pipe thickness and the pipe inside is not accessible for welding, transition may be made with a buildup weld as in Attachment 3 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness Figure (i).

3.10.7. Backing Material

Standard backing material requirements for welding are shown in **Standard Drawings Section STD-P-0100-A095 – Standard Full Encirclement Split Sleeve for Anchors, Supports, and Repair** and **Standard Drawings Section STD-P-0100-B120 – Full Encirclement Split Sleeve Hot Line Tap**. The material should be AISI SAE 1008 hot rolled mild steel. Steel banding strap material is not allowed.

## 4. Training

Review this information as necessary before performing the work.

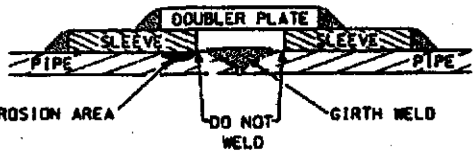
## 5. Documentation

None

## 6. References

- 49 CFR 192
- API Standard 1104 (latest DOT approved edition)
- ASME B 31.8 Appendix I
- **O&M Procedure 103 – Hot Work**
- **O&M Procedure 109 – Excavating, Trenching and Shoring**
- **O&M Procedure 120 – Personal Protective Equipment**
- **O&M Procedure 407/C1067 – Welding Procedures and Selection Guide**
- **Standard Drawings Section STD-P-0100-A095 – Standard Full Encirclement Split Sleeve for Anchors, Supports, and Repair**
- **Standard Drawings Section STD-P-0100-B120 – Full Encirclement Split Sleeve Hot Line Tap**

## Attachment 1 – Pipe Sleeve and Doubler Plate

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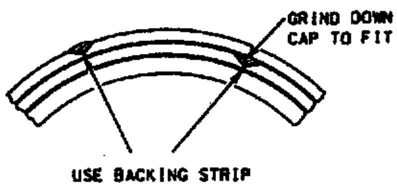
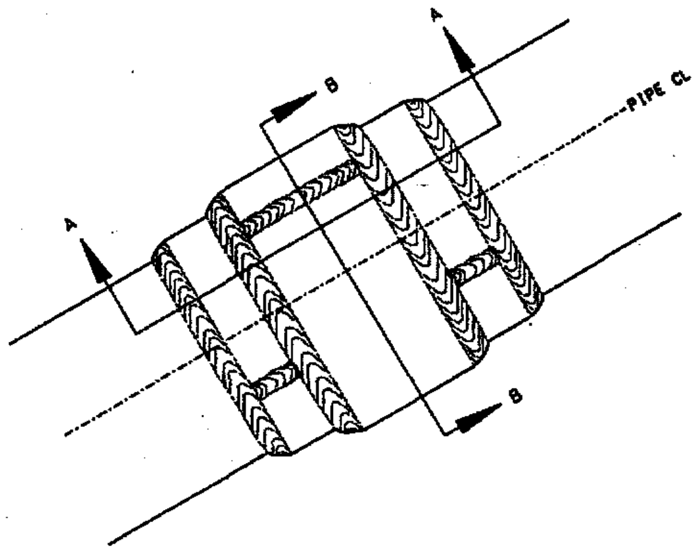



**VIEW 'B'**

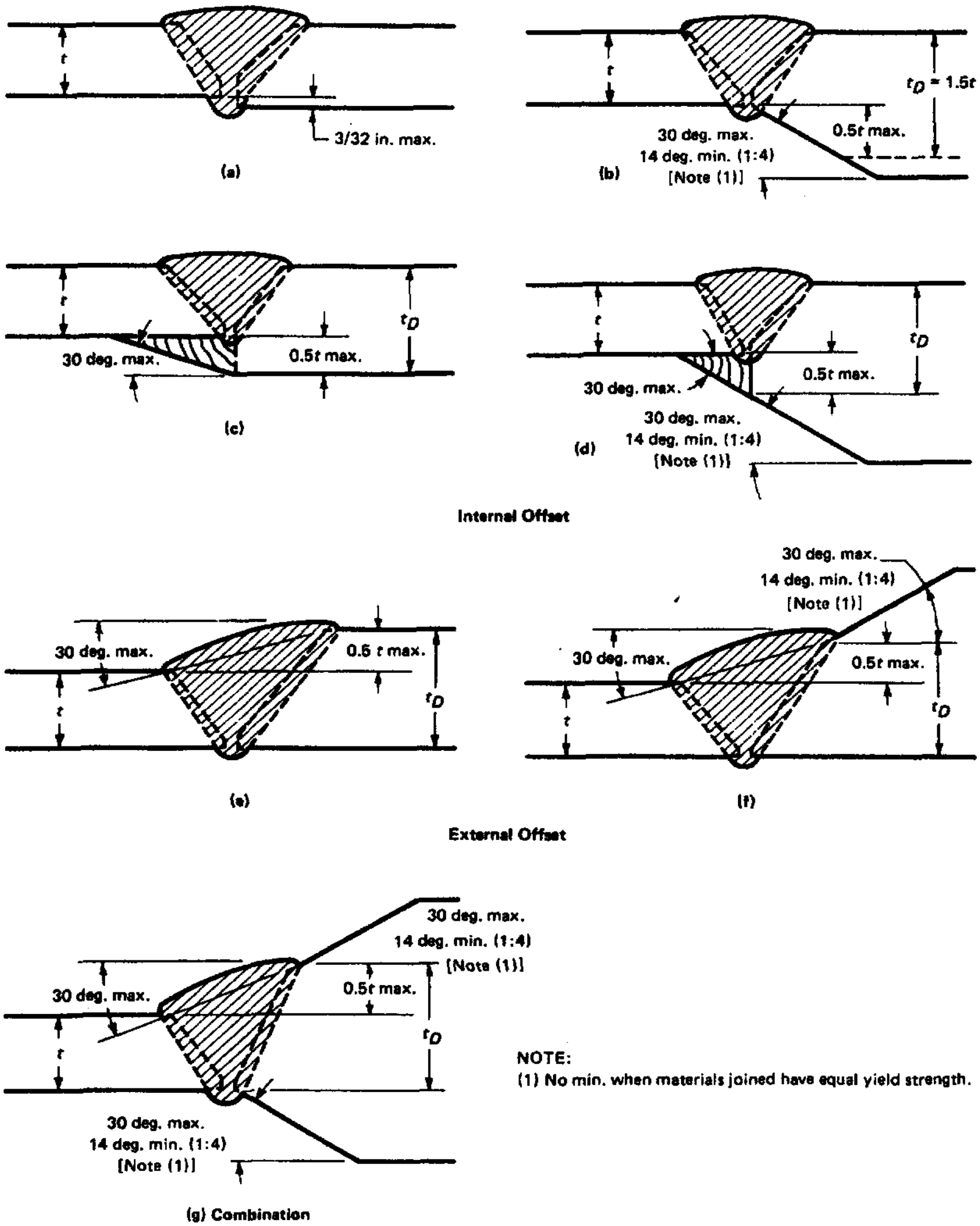



**NOTE:**

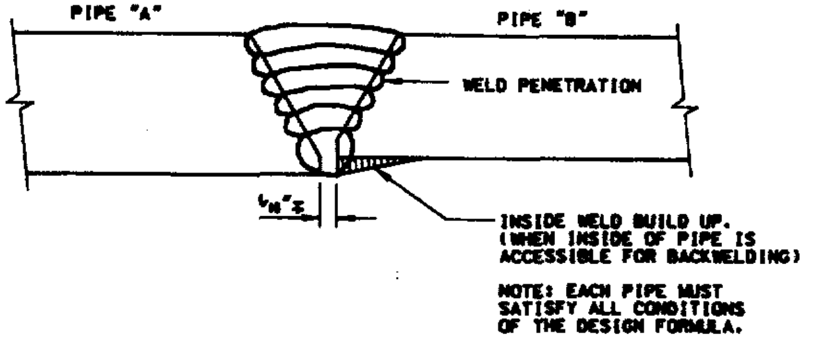
1) ENCIRCLEMENT SLEEVE MAY CONSIST OF A FABRICATED FITTING OR MAY BE FIELD FABRICATED. IF FIELD FABRICATED, THE W.T. AND GRADE OF THE ENCIRCLEMENT SLEEVE AND DOUBLER PLATE MUST BE APPROVED BY ENGINEERING. THE FULL ENCIRCLEMENT SLEEVE SHOULD BE FIELD CUT FROM TWO (2) SEPARATE SECTIONS OF PIPE LARGE ENOUGH TO PERMIT THE TWO HALVES TO FIT OUTSIDE OF AND ENCLOSE THE CARRIER PIPE. THE PORTION OF SLEEVE STOCK CONTAINING THE LONGITUDINAL SEAM WELD MUST BE REMOVED.
2) USE 1/16" A151-1008 HOT ROLLED MILLED STEEL BACKING STRIPS. STEEL BANDING STRAPS ARE NOT ACCEPTABLE.
   ON 12-3/4" O.D. AND LARGER PIPE, USE 1-1/2" WIDE BACKING STRIP
   ON 10-3/4" O.D. AND SMALLER PIPE, USE 1" WIDE BACKING STRIP
3) ALL SLEEVE AND FILLET GIRTH WELDS TO THE CARRIER PIPE WILL BE MADE WITH LOW HYDROGEN WELDING ROD (AWS E7018)
   LONGITUDINAL SEAMS MAY BE WELDED USING AWS E6010, E7010 OR E8010 WELDING ROD (PER PROCEDURE)
4) REFER TO O&M STANDARDS 402, 403, 404 AND 405 BEFORE INSTALLING ANY SLEEVE OR HOT TAP.
5) INSPECTION OF THE COMPLETED WELDMENT SHALL COMPLY WITH O&M STANDARD 406

**PIPE SLEEVE &**
**DOUBLER PLATE**

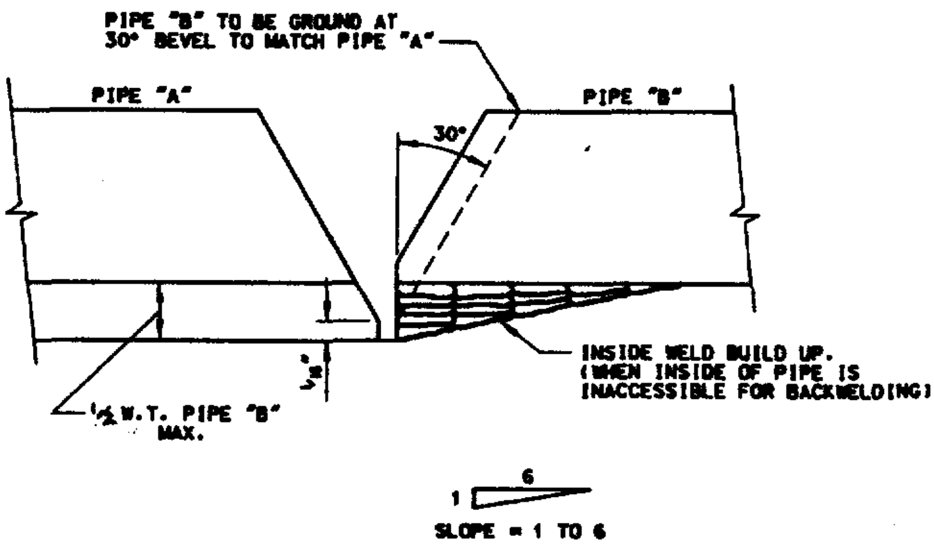
## Attachment 2 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness (a-g)



## Attachment 3 – Acceptable End Preparations for Butt Welding Pipe with Unequal Wall Thickness (h, i)




(h)




TO BE USED ON PIPE 12¾" O.D. AND LARGER WITH DIFFERENCE IN WALL THICKNESS GREATER THAN 3/32" BUT NO MORE THAN ONE HALF OF THINNER PIPE THICKNESS.

(i)

## Table of Contents



## 1. Applicability

☒ Gathering

☒ Processing

☒ Transmission/Regulated Onshore Gathering

☐ Kinder Morgan Power Company

## 2. Scope

This procedure summarizes Company forms and regulatory records retention periods. The retention period is based upon DOT and company requirements. This Operating and Maintenance (O&M) Procedure is intended only for those documents required to operate and maintain pipeline facilities per the 49 CFRs and various state regulations.

An associated procedure, **O&M Procedure 1401 – Records Retention by Form Number**, sorted by form number also provides records retention information.

When this O&M Procedure disagrees with other procedures within the O&M Manual regarding records retention, this procedure will take precedence.

## 3. Core Information and Requirements

This procedure provides the necessary processes and safeguards to satisfy all regulatory requirements pertaining to retaining operating and maintenance records for pipeline facilities.

Table 1 – Retention Schedule of Company Forms and I&M Procedures is sorted by retention period and then O&M Procedure number. Some O&M Procedures may be listed more than once because the procedure references documents that have different retention periods.

Table 1 – Retention Schedule of Company Forms and I&M Procedures contains the following information:

- Retention period
- Record identity from Corporate retention policy
- O&M Procedure number
- Regulatory reference
- Subject
- Company form number(s) or document
- Inspection and Maintenance (I&M) number(s)
- Department responsible for retaining the document and the document's inter-company routing

### 3.1. Retention Requirements

Retention requirements are based upon the following regulations in 49 CFR Part 192. For those documents where a regulation has not been established, the Company has established what it has determined to be an adequate retention time. Where the Corporate retention period based on record identify conflicts with 49 CRF Part 192, follow DOT requirements.

Subpart A – General
192.16(d)(1)(2) Customer Notification
Subpart E – Welding of Steel in Pipelines
192.225(b) Welding – General
192.243(f) Nondestructive Testing
Subpart H – Customer Meters, Service Regulators and Service Lines
192.383(e)(i)(ii) Excess Flow Valve Customer Notification
Subpart I – Requirements for Corrosion Control
192.491(a)-(c) Corrosion Control Records
Subpart J – Test Requirements
192.517(a)-(g) Records
Subpart K – Uprating
192.553(b) General Requirements
Subpart M – Maintenance
192.709(a)-(c) Transmission Lines: Recordkeeping

### 3.2. O&M Sections not Included

The following O&M Manual Sections are not included in this procedure. The **Environmental, Health and Safety Department (EHS)** will research and add them to Table 1 – Retention Schedule of Company Forms and I&M Procedures later:

- 100 – Safety
- 1200 – Environment

### 3.3. I&M Procedures not Included

The following **I&M Procedures** are associated with the O&M Procedures listed in Subsection 3.2 – O&M Sections not Included and are not included in this procedure. **EHS** will research and add them to Table 1 – Retention Schedule of Company Forms and I&M Procedures later.

0102, 0105, 0111.00 through 0115.00, 0118.00, 0120.00 through 0126.00, 0151.00 through 0153.00, 0161, 0162, 0163, 0172, 0190, 0531, 0571, 0571.01, 0572.01, 0813, 1401, 1401.02, 1402, 1404, 1405, 1407.01, 1407.02, 1410, 1411, 1703 through 1706

## 4. Training

N/A

## 5. Documentation

Refer to Table 1 – Retention Schedule of Company Forms and I&M Procedures for retention periods and retention responsibility.

## 6. References

- 33 CFR Parts 140 and 146,
- 46 CFR Part 160
- 49 CFR Parts 191, 192.603(b) and 195
- AGA 7, 8 and 9, AGA Report #3
- API Chapter 21.1
- BLM Onshore Order #5
- Canadian Standard PS-G-06-E
- FAA
- FCC
- FERC Order #609, Section 7 and Blanket Certification
- **O&M Procedure 1401 – Records Retention by Form Number**
- **O&M Procedure 1700 – Inspection and Maintenance Procedures**
- Technical Reference Manual

## Attachment 1 – Retention Schedule Tables

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| A | OP30 | 001 | None | Standards Modification (Variances) | OM000-01 | None | Codes and Standards - ADC Administrator |
| | | 202 | | Lowering in-service pipelines | OM200-28 | | Field Files, Engineering Records after lowering is completed |
| | | 204 | 192.614(a)(c)(3-6), .709 | Construction near Company Facilities | OM200-01 | | District Files, Local Files, Engineering Support |
| | | | | | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | | | OM200-29 | | Local Files |
| | | 208 | 192.553(b) | Uprate (increase) a pipeline's MAOP | OM1600-01, pressure/temp. chart, MOC, any notifications, proposed plan and any deviations, any leaks or repairs per 192.709 and O&M 213 | | Field Operations, Project Closure Package, Project Files, Engineering Records |
| | | 213 | 192.245, 192.709 | Pipe Repair | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | 16 TAC 8.207 | Leak Grading (Texas intrastate pipelines – ONLY) | OM200-05 | | Regulatory Process Owner, ROW. – Lkw., Construction/ Maintenance Owner, Area File |
| | | | | | OM200-08 | | EHS Project Manager, Codes and Standards, Engineering Records |
| | | 214 | 191.9, 191.15, 192.617 | Incident report and pipeline failure investigations | OM200-08 and written investigation report | | |
| | | | 191.23, 191.25 | Regulatory reporting of safety-related conditions | N/A - Written safety-related condition report | | Codes and Standards will file with OPS within 5 working days of discovery and no later than 10 working days. |
| | | 215 | 192.706(b), 192.705(b) | Transmission lines – patrolling and leakage surveys | OM200-21 | 0204,0204.01, 0204.02, 0204.03 0205, 0206, 0206.01, 0240, 0242, 0243, 0244, 0244.01, 0245, 0245.01 | Local Office, Compliance Personnel |
| | | 218 | 192.613 | Continuing surveillance | None | 0203 | Field Operations |
| | | 219 | 191.17; 195.402; 16 TAC 8.210, 8.301, and 8.225; City of Corpus Christi Pipeline Ordinance 021776; PHMSA-2006-23998, PHMSA-2006-25803, PHMSA-2007-27842 | Annual DOT and state pipeline mileage reports | DOT/PHMSA forms RSPA F7100.1-1 and F7100.2-1, TRRC forms PS-81, PS-87, and PS-95 | 0219.11, 0219.12, 0219.13, 0219.14, 0219. 15, 0219.16 | Codes and Standards |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| A | OP30 | 220 | None | Document contacts with public officials regarding HCA identification. | OM200-26 | None | Field Files, PODS/GIS Group if HCA location is identified |
| | | 223 | 192.605(b)(5) | Shutouts, pipeline and pipeline facilities | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | 225 | 192.727 | Assessing facilities for abandonment or deactivation | OM200-22 | | Compression and Process Services, Lkw |
| | | | | | OM200-23 | | FAP Initiator for AFE submission Engineering Support |
| | | | | | OM200-24 (accessed from OM200-23) | | Attach to OM200-23 |
| | | 226 | 192.727, .709 | Abandonment report to NPMS | OM200-05 | | Regulatory Process Owner, ROW. – Lkw., Construction/ Maintenance Owner, Area File |
| | | 237 | | Dresser-coupled pipelines | Local records of Dresser coupling rechains, OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | 403 | 192.627, .709 | Pipe wall thickness survey | OM400-03 | | Local Operations Files<br>Regional Project Records |
| | EG30 | 404 | 192.605(a) | Welding pressure limitation | None | | |
| | OP30 | 405 | 192.605(a) | Welding on a pressurized line | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | EG30 | 406 | 192.241(b), .243(f) | Nondestructive testing records | OM400-02, NDT contractor's daily progress report, NDT contractor's testing results (refer to API 1104 Section 8), Technician's latest certification, radiographic procedure and annual eye exam | | Operating Regional Office, Field Construction Office, Codes & Standards – Lkw. Keep NDT daily progress reports, technician's OM400-02, certification & annual eye exam in project file. |
| | | | 192.241(c) | Visual Weld Inspection Report | OM400-11 | | Project Closure Package<br>Project File |
| | | 407 | 192.225 | Welding Procedures and Selection Guide / **Procedure Qualification Reports** | Welding Procedure Specifications | | Procedures maintained in the O&M Manual |
| | OP30 | 501 | 192.605(b)(5) | Start and stop guidelines – reciprocating compressors | Site-specific start/stop guidelines for each unit type | 0513 | Field Operations |
| | | 502 | | Start and stop guidelines – centrifugal compressors | | | |
| | | 903 | 192.459, .491 | External corrosion control design – casing removal | OM200-02 | 1107 | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | 192.463, .465, .491 | Cathodic protection | Bass program | None | Field Operations |
| | | | 192.459, .491 | Cathodic protection – buried pipe inspection | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| A | OP30 | 903 | 192.467 | AC voltage and fault current mitigation | Bass program | none | Field Operations |
| | | 906 | 192.475(b), .491 | Inspect for internal corrosion when pipe is removed | OM200-02, Written local program | 1101 | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | 192.475 | Internal corrosion control program | | 1106 | Field Operations |
| | | | 192.477, .491 | Internal corrosion monitoring | None | 1101 | |
| | | | 192.467(f), .491 | Reverse current switches | None | None | |
| | | 915 | 192.485 | Maximum corrosion limits and MAOP of corroded pipe | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | | | OM200-08 | | EHS Project Manager, Codes and Standards, Engineering Records |
| | | 916 | 192 Subpart O | Smart pigging | Graded survey log from contractor | | Pipeline Integrity |
| | | | | | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | | Action Plan and Closure Report for each in-line inspection conducted | Action Plan, Closure Report | | Operations Director, Director of Pipeline Integrity, Operations Manager, Technical Manager, Manager of Risk Engineering, whose copies Engineering Records will permanently archive |
| | | 917 | | Action Plan and Closure Report for each SCC inspection conducted in an HCA | | | |
| | | 918 | 192.479, .481, .483, .485. 487, 192 Subpart O | Atmospheric Corrosion Inspection | OM300-03, Bass Program | 1141 | Field Operations |
| | | | 192 Subpart O | Valve Inspection Report (Atmospheric Corrosion Inspection) | OM300-03 | | Business Center Office File, Field Operations – local files |
| | | 920 | | External corrosion direct assessment | Action Plan, Closure Report | None | Operations Director, Director of Pipeline Integrity, Operations Manager, Technical Manager, Manager of Risk Engineering, whose copies Engineering Records will permanently archive |
| | | 921 | | Internal corrosion direct assessment | | | |
| | EG30 | 1014 | AGA Report #3 | Orifice plate inspection | OM1000-02 | 1214 | Field Operations – local files |
| | OP30 | 1600 | 192.505, .507, .517 | Strength and leak testing steel pipe >30% SMYS or <30% SMYS but @ or above 100 psig | OM1600-01, pressure/temp. chart, rechain survey notes | None | Field Operations, Project Closure Package, Project Files |
| | | | | | OM200-02 | | See above |
| | | | 192.719 | Test replacement transmission pipe and welding repairs | OM1600-01, pressure/temp. chart | | Field Operations, Project Closure Package, Project Files |
| | | | 192.605(b) | Gas Loss | OM1000-05 | | See Form |
| | | Throughout O&M Manual | 192.459, .491 | Buried pipeline inspection | OM200-02 | | Field Files, Engineering Records, Risk Engineering – HCA Location Only |
| | | | | | OM200-05 | | Regulatory Process Owner, ROW Dept. – Lkw., Construction/ Maintenance Owner, Area File |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**



A = Sold date or life of facility + 3 years  B = Appropriate maintenance cycle per procedure, refer to Table 2 – Retention Schedule Chart on the last page
C = Current year + 3 years  D = Current year + 5 years  E = Current year + six years  F = As long as need but no longer than 3 years
G = Date superseded or no longer in use + 10 years

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| B1 | OP33 | 515 | 192.605(b)(7) | Crankcase explosion relief valves | None | 0515 | Field Operations |
| B012 | | 804 | N/A | Line heater inspection | | 1032 | |
| B1 | | 804 | N/A | Line heater inspection | | 1034 | |
| B02 | | 1006 | None | Flow computer battery | | 1230 | |
| B1 | | 1007 | AGA 7, API Chapter 21.1 | Turbine meter inspections | Document on approved meter test report or use I&Ms | 1225, 1227 | |
| B04 | | | | | | 1226 | |
| B5 | | | | | | 1229 | |
| B2 | | | | | | 1229.01 | |
| B1 | | 1008 | API Chapter 21.1, AGA | Rotary and positive meter proof check | Document on approved meter test report or use I&Ms | 1228.00 | |
| B10 | | | | Rotary/diaphragm meter 10-year calibration | | 1228.01, 02 | |
| B5 | | | | Diaphragm meter 5-year calibration | | 1228.03 | |
| B3 | | | | Diaphragm meter 3-year calibration | | 1228.04 | |
| B04 | | 1009 | GPS Std. 2145 | Chromatograph standard practices | Cylinder calibration gas certification, normalized concentrations and dew points, configuration reports, chromatograms, response factor plots and use I&Ms | 1232, 1233 | |
| B012 | | | | | | 1234 | |
| B1 | | No Procedure | FCC, FAA | Aerial river crossing | None | 0222 | |
| | | | | | | 0223 | |
| B012 | | | None | Gas detection – water wells and tile lines Station 201 only | | 0532, 0533 | |
| | | | | Air tanks with man-ways for compressor engines | | 0561 | |
| | | | | Separator and accumulator dump valve and high level shutdown | | 0801 | |
| B1 | | | | | | 0802 | |
| B3 | | | | Filter separator elements | | 0803 | |
| B02 | | | 195.428 | Relief valves – liquid lines | | 0904 | |
| B3 | | | None | Pneumatic controller overhaul | | 0914 | |
| B012 | | | | $H_2S$ atmospheric monitors | | 1231 | |
| B012 | | | | Calibrate analyzers - $O_2$, $H_2S$, $CO_2$, moisture content, sulfur and nitrogen | | 1292, 1294, 1295 | |
| B02 | | | | | | 1293, 1294.01 | |
| B12 | | | | Downhole safety valves | | 1501 | |
| B02 | | | | | | 1502 | |
| B12 | | | | Storage – well annuli Sta. 184, 201 through 206 and 388 | | 1541 | |
| B02 | | | | Electrical ground and phase monitor alarms | | 1701 | |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**



A = Sold date or life of facility + 3 years  B = Appropriate maintenance cycle per procedure, refer to Table 2 – Retention Schedule Chart on the last page
C = Current year + 3 years  D = Current year + 5 years  E = Current year + six years  F = As long as need but no longer than 3 years
G = Date superseded or no longer in use + 10 years

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| B1 | OP33 | Technical Ref. 09TR9720 | None | Electronic line break detection | None | 1901.01 | Field Operations |
| C | OP20 | 239 | 192.16 | Customer Notification | None | I-0239.00 | Local District Office, Public Awareness Coordinator |
| | | 401 | 192.227, .229 | Welder qualifications | OM400-01 | None | Codes and Standards Dept., Project File, Project Manager, Local District Office |
| | | | | | OM400-02 | | Local District Office, Field Construction Office, Codes & Standards Dept., Project Manager. Keep NDT daily progress reports, technician's OM400-02, certification & annual eye exam in project file. |
| | | | | | OM400-06 | | Codes and Standards Dept., Project Manager, Project File, Local District Office |
| | | | | | OM400-09 | | Codes and Standards Dept., Project Manager, Project File, Local District Office |
| | | 451 | 192.283(c) | Joining plastic pipe | Written O&M procedure | | Procedure maintained in the O&M Manual |
| | | 452 | 192.285 | Joining plastic pipe - qualification | OM400-04, OM400-05 | | District Office, Project Job Book |
| | | 453 | 192.287 | Plastic pipe joining – visual inspection | Written O&M procedure | | Procedure maintained in the O&M Manual |
| | SH30 | 550 | 192.709, .736 | Compressor station gas and fire detection performance tests | Document in the daily log or use I&M | 0101, 0101.01, 0551 | Field Operations |
| | OP20 | 1104 | 192.605 | Procedures for operations, maintenance and emergencies | OM1100-01 | None | Gas Control |
| E | OP31 | 204 | 192.614(a)(c)(3-6), .709 | Construction near company facilities | OM200-03 | 0265.00 | Local Office |
| | | | | | OM200-31 | | Local Office, Public Awareness Coordinator |
| | LG50 | 207 | FERC Order #609, Section 7 and Blanket Certification | FERC landowner notification | Landowner database maintenance. Refer to O&M 207 for complete list of documentation required | None | Lkw Regulatory Products & Services Dept. |
| | OP31 | 212 | 192.605(b) | Remove freeze or restriction, report gas loss | OM1000-05 | | See Form |
| | | 213 | 192.245, .709 | Pipe Repair | VMA - Unmeasured Gas online form completed by the field | | Lkw Gas Measurement Dept. |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**



A = Sold date or life of facility + 3 years
B = Appropriate maintenance cycle per procedure, refer to Table 2 – Retention Schedule Chart on the last page
C = Current year + 3 years
D = Current year + 5 years
E = Current year + six years
F = As long as need but no longer than 3 years
G = Date superseded or no longer in use + 10 years

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| E | OP31 | 215 | 192.705, .706, .709 | Patrolling and Leak Detection | OM200-10 | 0204, 0204.01, 0204.02, 0205, 0206, 0206.01, 0240, 0241, 0242, 0243, 0244, 0244.01, 0245, 0245.01 | Field Office (Regional DOT Records Location) |
| | | 216 | 192.612, .709 | Gulf of Mexico underwater inspection | Written survey report | 0215.01 | Project Engineering |
| | | 217 | 192.317 | Underwater crossing inspection | | None | Field Operations – send copy to Project Engineering |
| | | 220 | 192.609, .611, .613, .709 | Class location study | N/A – collected electronically | 0220 | Field Operations |
| | | 227 | 192.605(b)(6) | Purging | OM1000-05 | None | See Form |
| | | 232 | 192.16, .614, .615(a)(2)(c), .616, .709, .911(m), .917(b), .935(b)(1)(iii) | Damage prevention and Public Awareness program | OM200-31, OM200-32, local documentation of lists, letters, advertisements, persons contacted, etc. | 0260.00 | Local Office<br>Public Awareness Coordinator |
| | | 234 | 192.605(b)(5) | Pipeline segment blowdowns | Report all gas used/lost via Online Field Ticketing – Unmeasured Gas | None | Field Operations |
| | | 235 | 192.605(a) | Pigging operations | OM200-14 | | |
| | | 236 | | Air movers | OM1000-05 | | See Form |
| | | 301 | 192.709, .745 | Valve maintenance transmission systems | OM300-01, 300-02 | 0306, 1901 | Local Operations Files |
| | | | | | OM300-03 | | Business Center Office, File |
| | | | 195.420 | Valve maintenance liquid hydrocarbon pipelines | None | 0361 | Field Operations |
| | | 310 | 192.709, .745 | Overpressure shut-in valves | OM300-01, 300-02 | 0306, 0310 | Local Operations Files |
| | | | | | OM300-03 | | Business Center Office, File |
| | | 702 | 192.709, .731, .739, .743 | Rupture disc assembly | OM700-02 | None | Field Operations |
| | | 703 | | Pressure regulating, limiting and compressor station relief device and remote control shutdown and capacities inspection and testing | OM700-01, OM700-02 | 0310, 0511, 0521, 0522, 0901, 0902, 0906, 0907, 0911, 0912, 1911, 1932 | Local Operations Files |
| | | | N/A | Station temperature shut-down operation and set point | None | 1922 | Field Operations |
| | | 801 | | Boilers – startup checks and shutdown devices, annual and biennial insurance inspection | | 0901, 1001, 1002, 1006, 1007 | |
| | | 903 | 192.467(a), .491 | Shorted casings | OM900-01 | None | Corrosion Coordinator<br>Local Operations Files |
| | | | 192.465(b), .491 | Rectifier, impressed current inspection | OM900-02 | 1130 | Local Operations Files |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**



A = Sold date or life of facility + 3 years B = Appropriate maintenance cycle per procedure, refer to Table 2 – Retention Schedule Chart on the last page
C = Current year + 3 years D = Current year + 5 years E = Current year + six years F = As long as need but no longer than 3 years
G = Date superseded or no longer in use + 10 years

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| E | OP31 | 918 | 192.481, .491 | Atmospheric corrosion control monitoring | Bass Program | 1141 | Field Operations |
| | | | | | OM300-03 | | Business Center Office, File |
| | | 1008 | API Chapter 21.1 | Positive displacement meter installation, inspection, testing | Document on approved meter test report or use I&Ms | 1228, 1228.01-.04 | Field Operations |
| | | 1026 | 192.625, .709<br>16 TAC 8.215 | Inspect domestic gas odorizers and farm taps, Annual Odorant Concentration Insp, Monthly Odorant Injection Rate Insp | None, OM1000-12, OM1000-13 | 1211, 1212, 1213 | Field Operations. |
| | AC30 | 1030 | 192.605(b) | Unmeasured Gas Use/Loss Reporting | Component 1, Component 2 | | Corporate Measurement Department, which may forward to Pipeline Accounting if necessary |
| | OP31 | 1600 | N/A | Strength and Leak Testing | OM1600-01 | None | Field Operations, Project Closure Package, Project Files |
| F | AD99 | 001 | | Standards modification | OM000-01 | | Codes and Standards - ADC Administrator |
| | | 211 | Report construction and major revisions | Notify state commissions of construction or scheduled repairs | EHS notified by field via email or telephone. EHS will write letter to state | | EHS – send copy of letter to Operations Manager and Regional Director |
| | | 219 | 191.17, 16 TAC 8.210 | Annual leak report | OM200-17 | 0219.02 | Field Operations/Codes and Standards |
| | OP99 | 223 | None | Pipeline and pipeline facility shutouts | OM200-25 | | Pipeline Management, Facility Supervisor, District Manager, affected locations retain until work completion |
| | | PM-89-006 | | Reboilers and reclaimers | None | 1011, 1013 | Field Operations |
| G | SH21 | 500 | 192.605(a) | Remote control blowdown – verify ESD procedure | | 1933 | |
| | | 512 | 192.615(a)(3)(iv) | Severe weather operating plan | Part of site-specific emergency plan | None | Field Operations, plan is part of site-specific emergency plan |
| | | 1900 | 192.615, .709 | Abnormal operating conditions and emergency plan program | OM1900-01 through OM1900-17, SPCC Plan, plot plan or pipeline map | 1711 | Area/Facility Emergency Response Plan |
| | | Emergency Plan | 192.615(c) | Contact law enforcement, fire and public officials | None | | Field Operations |
| | | 2000 | N/A | Site-specific procedures | OM2000-01 | None | Local Operations Files – O&M Manual Section 2000 |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures (continued)**

| Reten. Period | Record ID | O&M Proc. | Regulatory Reference | Subject | Company Form(s) | I&M Procedure(s) | Retention Department/Routing |
|---|---|---|---|---|---|---|---|
| **Non-Standard Retention Times or Maintenance Cycles** | | | | | | | |
| Deter-mined by facility manager | OP33 | 1503 | None | Electrical insulation and testing | OM1500-01 | 1702, 1702.01, 1702.02 | Field Operations |
| Not to exceed 12 months | | No Procedure | 33 Part 140.103, .105 | Outer continental shelf facility | None | 0150 | |
| | | | 46 Part 160.051 | Inflatable life raft | | 0150.01 | |
| At least once each mo. | | | 33 Part 146 | Offshore emergency drill | | 0150.02 | |
| At least 26 times each calendar year, not to exceed 3 weeks | | | FCC, FAA | Aerial river crossing | | 0221 | |

**Table 1 – Retention Schedule of Company Forms and I&M Procedures**

| Record ID | Description | Type | Retention Period |
|---|---|---|---|
| OP33 | Non-DOT Serviceability Inspections, Testing & Maintenance Records | B | Appropriate maintenance cycle – see below |
| | | B1 | At least once each calendar year, not to exceed 15 months. |
| | | B2 | At least once each two calendar years, not to exceed 27 months. |
| | | B3 | At least once each three calendar years, not to exceed 39 months. |
| | | B5 | At least once each five calendar years, not to exceed 63 months. |
| | | B10 | At least once each ten calendar years, not to exceed 123 months. |
| | | B02 | At least twice per calendar year, not to exceed 7.5 months. |
| | | B04 | At least 4 times each calendar year, not to exceed 4.5 months. |
| | | B012 | At least 12 times each calendar year, not to exceed 1.5 months. |

**Table 2 – Retention Schedule Chart**



A = Sold date or life of facility + 3 years
B = Appropriate maintenance cycle per procedure, refer to Table 2 – Retention Schedule Chart on the last page
C = Current year + 3 years
D = Current year + 5 years
E = Current year + six years
F = As long as need but no longer than 3 years
G = Date superseded or no longer in use + 10 years

# Appendix 8

## Table of Contents



## 1. Applicability

☒ Gathering

☒ Processing

☒ Transmission/Regulated Onshore Gathering

☒ Kinder Morgan Power Company

## 2. Scope

This procedure applies to all underground metallic structures (gas piping, water piping, air piping, oil piping, etc.) that must be installed with protective coatings. Ground rods are exempt from coating requirements.

## 3. Core Information and Requirements

Only the pipeline coatings listed in Tables 1 through 4 of this procedure are approved for use. Number designations for coatings and primers are important and should not be substituted.

**Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must:**

- **Be applied on a properly prepared surface;**
- **Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;**
- **Be sufficiently ductile to resist cracking;**
- **Have sufficient strength to resist damage due to handling and soil stress**; and,
- **Have properties compatible with any supplemental cathodic protection.**

Pipeline coatings and repair materials are listed in Table 1 – Pipeline Coating Names and Generic Specifications and Table 2 – Compatible Repair Coatings for Joining Same or Dissimilar Coatings by both their product name and generic description. Coatings listed by brand name may be on Company records and no longer available. The Generic Specification column in Table 1 identifies the associated generic coating type.

The coating repair shall be made with a protective coating compatible with the original protective coating as detailed in the appropriate table in this procedure.

### 3.1. Special Applications

Coatings for special applications may not be listed in this procedure. Contact the Corrosion Process Manager or Regional Corrosion Supervisors for information before using coatings not on this list. Submit new coatings for evaluation to the Corrosion Process Manager.

### 3.2. Applying Coatings

Make all practical efforts to dry the pipe before applying coatings or primers. Never apply coatings when the steel surface is wet unless the coating is designed to be applied to wet surfaces as specified in the coating Manufacturer's application instructions. Review the recommended cleaning and surface preparation requirements for each coating before applying. All coatings have improved performance based on the quality of surface preparation. Abrasive grit blasting is the preferred surface preparation method. If abrasive grit blasting is not feasible, use methods such as hand tools or power equipment with 80-grit abrasive disk pads, air driven needle scalers or non-woven abrasive pads to remove corrosion rust products, old coating products and to prepare the surface for coating.

Apply all protective coatings according to the latest recommended practices. Allow time for the coating to sufficiently cure and inspect coatings prior to backfilling. Provide additional protection to the coating where needed during backfilling by using clean earth padding, rock shield or pipeline felt.

### 3.3. Above-Grade Pipe Coatings

Buried pipe that extends above grade should be coated with an approved underground coating at least one-foot above grade. Coating application may be less than one-foot if applying coating limits proper operation of control valves or other appurtenances. Paint over the aboveground coating to match the paint color applied for atmospheric corrosion and to protect the below grade coating from ultraviolet rays from the sun.

### 3.4. Safety

Apply all coatings to Manufacturer's specifications and follow the Manufacturer's safety procedures. Use personal protective equipment (PPE) as indicated on the MSDS. Refer to **O&M Procedure 120 – Personal Protective Equipment** and **O&M Procedure 122 – Respiratory Protection** for additional safety procedures.

### 3.5. Inspection

The coating on new or replacement pipeline installations and large-scale coating repairs (> 20 feet in length) shall be inspected over the entire surface area for coating holidays with an electronic holiday detector prior to lowering in the ditch and backfilling. Repair all coating holidays detected with a compatible approved coating prior to backfill.

All small-scale coating repairs (< 20ft in length) or patch coating repairs shall be visually inspected for coating holidays and repaired prior to backfill.

The necessary holiday detector voltage will vary with the type of coating and thickness. The application tables include guidance voltage for holiday detector settings. As a rule, detector voltage setting should be 125 times the coating mil thickness. Example for 30 mil coating: 125 x 30 = 3,750 volts.

Holiday detectors for higher voltage ranges are available with metal coils, metal brushes or conductive rubber wands for contact. Low voltage types using a wet sponge wand are available for small, irregular painted surfaces up to l0 mils thick (or on painted surfaces up to 20 mils thick with suitable wetting agent).

### 3.6. Operating Temperature Limitations

The Company limits (without gas cooling and/or thermal stress evaluation) the pipeline operating gas temperature to 135° F before the pipeline goes below grade, regardless of the coating type. Some older coating systems, such as asphalt enamels, have test results that indicate serious coating damage at 110° F. Newer thin film powder epoxy coatings can perform with operating temperatures equal to or greater than 200° F. Review the operating temperature range for the pipeline segment prior to selecting a repair coating from the appropriate tables in this procedure.

#### 3.6.1. Midcontinent Express Waiver Pipelines

**If gas temperatures exceed 120 degrees F the District will implement the site specific procedure that has been developed to address this condition.**

### 3.7. Coating Performance Considerations

**Tape coatings** do not perform well on large diameter pipelines or pipelines that experience high operating temperatures (e.g. downstream of compressor stations and treating facilities). Cold applied tapes tend to disbond and shield pipe from cathodic protection current, which may contribute to stress corrosion cracking on higher specified minimum yield strength grades of pipeline steel.

- Hot applied tapes can be used on pipelines 16-inches or less in diameter with an operating temperature ≤ 120° F.
- Use only the tapes listed in the tables in this procedure. Do not substitute tape and primer numbers.

**Heat shrink materials** generally do not perform well on large diameter pipelines and are limited to 12-inch and smaller pipelines. Heat shrink materials should be selectively used on transmission piping after considering all alternative coating products available for the application. Heat shrink materials require preheating the pipe to temperatures that can damage the adjacent coating. Without preheating correctly, the heat shrink materials will not bond adequately to the pipeline.

**Liquid epoxy product coatings** provide excellent coating performance but require surface preparation to a near white cleanliness and 2 mils or more anchor pattern for best results. Prepare the surface by blasting with appropriate abrasive grit media to a white metal surface, use 80-grit abrasive sandpaper or hand power equipment with an 80-grit disk to roughen the surface to a white metal finish. Apply to a thickness specified by the Manufacturer and listed in the tables in this procedure. Correct mixing ratios are necessary for proper reaction. Apply by pouring, brushing, rolling, spraying or daubing as specified by the Manufacturer. Liquid epoxies specified in the tables have a wide range of operating temperature limitations and various cure times for cold or warm weather application.

## 4. Training

Review preceding information as necessary before performing the procedure. Document reviews in employee's training file.

## 5. Documentation

Not applicable.

## 6. References

- **O&M Procedure 120 – Personal Protective Equipment**
- **O&M Procedure 122 – Respiratory Protection**
- **O&M Procedure 213 – Leaks, Pipe and Weld Defects and Equipment Damage**

| Pipeline Coatings | Generic Specification |
|---|---|
| Barretts (All designations) (no longer available) | Coal Tar Enamel |
| Bitumastic 70B (no longer available) | Coal Tar Enamel |
| Buton (Enjay Chemical Company coating no longer available) - used on segments of KM Tejas 36-inch | Modified Butadiene-Styrene Copolymer |
| Enamel "X" (no longer available) | Coal Tar Enamel |
| Flakeline (251 or 252) | Polyester Resin Epoxy |
| Gulf States #434 (no longer available) | Asphalt |
| Hevicote | Concrete over hot applied asphalt mastic coating |
| Hot-Service Enamel (no longer available) | Coal Tar Enamel |
| Koppers Bitumastic No. 300M | Coal Tar Epoxy |
| Koppers (All other designations) | Coal Tar Enamel |
| Lilly or Pipeclad (All designations) | Fusion Bonded Epoxy (thin film powder coatings) |
| Lilly 20/40 (Topcoat Abrasive Coating) | Thermoset Polymer |
| Lions (All designations and no longer available) | Asphalt Enamels |
| Nap-Gard (All designations) | Fusion Bonded Epoxy (thin film powder coatings) |
| P/W | Painted with coal tar enamel and felt wrap |
| PP&F | Coal Tar Enamel (primer, paint and felt) |
| Pittsburg (All designations) | Coal Tar Enamel |
| Plicoflex Tape | Tape |
| Polyguard Tape | Tape |
| Polyken Tape | Tape |
| Powercrete (Overcoat Abrasive Coating) | Epoxy Based Polymer Concrete |
| Powercrete J (Joint Coating with or without FBE) | Epoxy Based Polymer Concrete |
| Pritel 20/40 | Extruded Polyethylene |
| Protegol UT Coating | Polyurethane/Tar |
| Regular Enamel | Coal Tar Enamel |
| Reilly 230A | Coal Tar Enamel |
| TGF | Coal Tar Enamel with glass and felt wrap |
| TGP | Coal Tar Enamel with glass and perforated polyethylene tape |
| Scotchkote (3M Company - all designations) | Fusion Bonded Epoxy |
| Servi-Wrap | Tape |
| Tapecoat | Tape |
| Valpipe 100 | Urethane |
| Whitcolite A-303E (no longer available) | Asphalt Enamel |
| X-Tru Coat | Extruded Polyethylene |
| XXH Enamel (no longer available) | Coal Tar Enamel |

If the coating name or generic specification cannot be determined or is not listed in this table, contact the Corrosion Process Manager for assistance.

**Table 1 - Pipeline Coating Names and Generic Specifications**

| Original Coating | Joining Coating | Repair Coatings (in order of preference) |
|---|---|---|
| Coal Tar Enamel | Coal Tar Enamel | 1) Epoxy, 2) Heat Shrink Material[d], 3) Tape[c] |
| | Fusion Bond Epoxy | 1) Epoxy, 2) Heat Shrink Material[d] , 3)Tape[c] |
| | Extruded Polyethylene[a] | 1) Powercrete JP, 2) Heat Shrink Material[d], 3) Tape[c] |
| | Asphalt Enamel | 1) Epoxy, 2) Tape[c] |
| | Polyester Epoxy | 1) Epoxy, 2) Heat Shrink Material[d], 3) Tape[c] |
| | Tape[c] | 1) Tape[c], 2) Epoxy |
| | Polyurethane/Tar | 1) Epoxy, 2) Heat Shrink Material, 3) Tape[c] |
| Asphalt Enamel | Fusion Bond Epoxy | 1) Epoxy, 2) Heat Shrink Material[d] , 3)Tape[c] |
| | Extruded Polyethylene[a] | 1) Powercrete JP, 2) Tape[c] |
| | Polyester Epoxy | 1) Epoxy, 2) Tape[c] |
| | Tape[c] | 1) Epoxy, 2) Tape[c] |
| | Polyurethane/Tar | 1) Epoxy, 2) Tape[c] |
| Fusion Bond Epoxy | Fusion Bond Epoxy | Pinholes: 1) Epoxy, 2) Heat Stick, 3) Powercrete J<br>Large Repairs: 1) Epoxy |
| | Extruded Polyethylene[a] | 1)Powercrete JP, 2) Tape[c] |
| | Polyester Epoxy | 1) Epoxy, 2) Polyester Epoxy[b], 3) Tape[c], 4) Powercrete J |
| | Tape[c] | 1) Epoxy, 2) Tape[c] |
| | Polyurethane/Tar | 1) Epoxy, 2) Heat-Shrink Material[d], 3) Tape[c] |
| Extruded Polyethylene[a] | Extruded Polyethylene[a] | 1) Powercrete JP, 2) Tape[c] |
| | Polyester Epoxy | 1) Epoxy, 2) Powercrete JP, 3) Tape[c] |
| | Tape[c] | 1) Powercrete JP, 2) Tape[c] |
| | Polyurethane/Tar | 1) Powercrete JP, 2) Epoxy, 3) Tape[c] |
| Tape | Tape[c] | 1) Tape[c] |

**Table 2 - Compatible Repair Coatings for Joining Same or Dissimilar Coatings**

**Table 2 Footnotes:**

[a] Includes coatings such as Pritec and X-Tru-Coat. Does not include polyethylene-backing tapes.

[b] Can be used to overlap original coating during field application of polyester epoxy.

[c] Tapes are easily damaged by impact. Use a protective wrap in soil-stress areas and when backfill contains rock or other material that can cut through the tape. Hot applied tape is limited to repairing pipe 16-inches or less in diameter, operating at temperatures less than 120° F..

[d] Limit heat-shrink material to 12-inches or less diameter pipelines.

**For use on underwater structures of limited surface areas, wet pipe surfaces and splash zones**

| Manufacturer | Coating Name | Generic Type | Foot-notes | Remarks |
|---|---|---|---|---|
| Tyco Adhesives - Power Lone Star | Powerdur | Liquid epoxy polymer | a | For repairs in splash zones or pipelines subjected to wet surfaces from condensation. Minimum surface preparation aboveground using hand power tools such as needle guns or grinders, water blasting or dry abrasive blasting to yield a firm, granular surface free of loose contamination. Apply with putty knives or straight edge spreaders underwater or aboveground to yield 40 mils film thickness. Cures to a hard film within 14 hrs. at ambient temperatures. Cures underwater with retarded cure time. |
| Royston Laboratories, Inc. | Royston Wet-Set B-822 | Epoxy-Amide | a | Smear on surface by hand. Pot life is 1 hr. below 100 ° F. Cure time is 2 hrs. @ 80° F, 6 hrs. @ 60° F. Thickness 1/8" to 1/4" required. Cures underwater with retarded cure time. |
| Ameron International | Devoe Devclad 182 Splash Zone Barrier Coating | 100% solids epoxy | a, b | Smear on surface by hand. Pot life is 1 hr. at 77° F. Cure time is relative to thickness and moisture conditions. Minimum time 30 minutes. Thickness 1/8" to 1/4" required. Cures underwater with retarded cure time. |
| International Protective Coatings | Interzone® 1000 Glass Flake Epoxy | 92% glass flake solids, high build epoxy. Primers Intergard 269 or 982 recommended. | | All surfaces to be coated should be clean, dry and free from contamination. Abrasive blast to SSPC-SP10, surface profile should be 3 to 4 mils. Airless spray equipment preferred. Aggregate can be added for non-slip applications on decks. Cure time (touch dry) 5 hrs. @ 77° F, 30 minutes cure time for immersion underwater. |
| International Protective Coatings | Interzone® 954 Modified Epoxy | 85% solids. Primers Intergard 269 or 982 recommended for underwater applications. | | May be applied to reoxidized and slightly damp surfaces. All surfaces to be coated should be clean, dry and free from contamination. Abrasive blast to SSPC-SP6, surface profile should be 2 to 3 mils. Airless spray equipment preferred. Aggregate can be added for non-slip applications on decks. Cure time (touch dry) 4 hrs@ 77° F, 30 minutes cure time for immersion. |

**Table 3 - Coating Repair Material for Underwater Structures**

**Table 3 Footnotes:**

a. Abrasion grit blasted surface preparation recommended if practical.

b. In rough weather, apply a spiral wrap of polyethylene, glass fiber, burlap, cheesecloth or similar material over the freshly applied coating to help hold the coating during the initial curing operation.

| Generic Type | Manufacturer | Coating Name | Max. Serv. Temp. | Holiday Detector Voltage | Foot-notes | Remarks |
|---|---|---|---|---|---|---|
| Epoxy | Denso North America | Protal 7200 Fast Cure Epoxy - Brush Grade<br>Protal 7250 Fast Cure Epoxy - Spray Grade | 185° F | 2000V | a, b, d, e | Two-part mixture. High build fast cure liquid epoxy brush-applied in one coat to 25 to 30 mils dry film thickness (D.F.T.) High moisture tolerance. Surface temperatures below 50° F must be preheated. Pot life @77° F is 6 minutes; handling time @77° F is 60 minutes. Interfaces and bonds to coal tar enamels and asphalts. Shelf life is 24 mos. |
| | Denso North America | Protal 7125 Epoxy Fast Cure Low Temperature | 150° F | 2000V | a, b, d, e | Specifically designed for cold pipe surface and ambient conditions. Fast cures at -4° F. Two-part mixture. One coat brush, roller or spray application to 25 to 30 mils D.F.T. Cure time varies from 7 minutes to 120 minutes with various substrate and ambient temperatures. Trace amount of styrene in product limit bonding strength to coal tar asphalt enamels. Shelf life is 6 mos. |
| | 3M Company | Scotchkote #323 Brush and Spray | 230° F | 125V/mil | a, b, d, e | For repair to all fusion bond epoxy coatings, bare girth welds or pipe rehabilitation projects. Application to 45 mils D.F.T. in one application using cartridge, brush, roller or plural component spray equipment. Dry to handle time 2 hours; pot life is 39 minutes @ 75° F. Preheat pipe if below 50° F. Shelf life is 18 mos. |
| | Dupont Nap-Gard | NAP-GARD Patch Compound #7-1847 | 180° F | 125V/mil | a, b, e | For repair to all fusion bond epoxy coatings, field coating girth welds and wet pipe surfaces. Rough surface with 80- or 100-grit sandpaper or power disk and brush- apply one coat at 25 mils thickness by trowel, knife, etc. Pot life is 60 minutes @ 77° F, cure time 5 hours to handle. |
| | Jotun Powder Coatings | Valspar Fast Cure Epoxy Patching Compound, Grey #46F640 | 200° F | | a, b, d, e | For small coating repair and at test lead/rectifier terminal connections to pipe. Clean area to bright metal with 80-grit sandpaper or other means. Cartridge – Squeeze out desired amount near point of patch location. Mix well with stiff spatula or knife. Allow the patch to heat to the same temperature as the pipe. Spread the patch out to the desired thickness. |
| Epoxy Based Polymer Concrete | Tyco Power Lone Star | Powercrete J-Fast Cure | 130° F | 125V/mil | a, b, e | Two-part epoxy applied at temperatures as low as 40° F without requiring heat during the application and cure. Apply using hot, airless equipment or manual application. Yellow color. Minimum 20 to 25 mils D.F.T. Bonds well to coal tar and asphalt enamels. |
| | Tyco Power Lone Star | Powercrete J | 130° F | 4000V | a, b, e | Coating can be used as a joint coating or also as a repair or joint coating for Powercrete applications. Coating should be applied in two 15-mil coats at least 20 minutes apart to achieve a D.F.T of 30 mils. Bonds well to coal tar and asphalt enamels. Preheat if pipe temperature is ≤ 50° F. |
| Polyester Epoxy | Ceilcote Co. | Flakeline 251 (Spray)<br>Flakeline 252 (Brush) | 250° F | 4000V | a, b | Use primer P-370 for immersion service or if over 8-hr. time lag following surface preparation. Shelf life is 6 months. Spray formulation requires special spray equipment. Pot life is 35 minutes @ 70° F. Apply 2 to 3 coats to obtain 35 to 40 mils D.F.T. Cure time is 4 to 48 hrs. Requires grit blasting to white finish and 3 to 4 mil surface profile. Contains substantial amounts of styrene - does not bond to coal tar and asphalt enamels. Do not apply when pipe temperature is below 50° F or over 110° F. |

**Table 4 - Approved Repair Coatings for Underground Structures (continued)**

| | | | | | | |
|---|---|---|---|---|---|---|
| Epoxy Heat Stick | 3M Company | Heat Stick #206P and 226P | 250° F | 125V/mil | b | Single component, stick-applied with heat for pinhole repairs on all fusion bond epoxy coatings. Roughen surface and preheat pipe sufficiently to melt stick on contact. Apply heat until patch is smooth and glossy. Apply thickness of 25 mils. |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Dupont Nap-Gard | Heat Stick #7-1631S<br>Heat Stick #7-1677 | 250° F | 125V/mil | b | Single component stick applied with heat for pinhole repairs on all fusion bond epoxy coatings. Roughen surface, preheat pipe sufficiently to melt stick. Apply heat until patch is smooth and glossy to 25 mils thick. |
| Epoxy/ Butyl Rubber | Tyco Power Lone Star | Powercrete JP | 130° F | 485 Volts per mil | a | Coating for girth welds on polyethylene and polypropylene coated pipe. Two-part application: 1) Apply the butyl rubber adhesive as a tape, overlapping the abraded mainline coating and the clean, bare steel. 2) Apply Powercrete J over the butyl rubber adhesive manually or spray to a minimum total D.F.T. of 25 to 30 mils. |
| Rubberized Mastic | Royston Laboratories Inc. | Roskote Mastic R28 | 250° F | 125V/mil | a, c | For small repairs of coal tar and asphalt enamel coatings. Thin with toluene for application below 60° F. No primer needed. Clean area to bright metal with 80-grit sandpaper or other means. Stir thoroughly before using. Apply by brush, spray, spatula or rubber glove. Apply two coats, allowing the first coat to touch dry before applying second coat. Dries to touch in 1/2 hr, sufficient for backfilling in 1 1/2 hrs. Shelf life is one year. |
| Heat Shrink Material | Canusa | KLON | 150° F | 10,000V | a, c | Wrapid Sleeve Material (105 mils) is shrunk onto pipe or weld joint with a special propane torch. Different sized sleeves are used for different sized pipes. Pipe must be preheated to 160° F before applying sleeve. Limited to ≤12-inch pipe. Compatible with PE, PP, FBE, PU, Coal Tar, Bitumen coatings. Not recommended for bends, tees, fittings, etc. |
| | Canusa | KLA Rapid Sleeve | 125° F | 10,000V | a, c | This sleeve is to be used where more soil-stress conditions exist. Wrapid Sleeve Material is shrunk onto pipe or weld joint with a special propane torch. Different sized sleeves are used for different sized pipes. Pipe must be preheated to 150° F (hot to touch) before applying sleeve. Preferably should be used with Canusa C Primer. Limited to ≤ 12-inch pipe and restricted operating temperatures. Compatible with PE and FBE coatings. Not recommended for bends, tees, fittings, etc. |
| Tape - Hot Applied | Tapecoat Co. | Tapecoat 20 Hot Applied | 120° F | 8000V | a, c | Use Tapecoat Omniprime, Tapecoat 7000 Primer or Reilly #122 Black Synthetic Primer. Limit to ≤ 16-inch pipelines and restricted operating temperatures. Will soften and allow penetration at 77° F. Use rock shield or other padding to prevent environment from penetrating softened coating due to pipe temperature. |

**Table 4 - Approved Repair Coatings for Underground Structures**

**Table 4 Footnotes:**

a. Abrasion grit blasted surface preparation to NACE near white and 2 to 3 mil anchor pattern recommended if practical.
b. Roughen the exposed steel and coating around pinholes and small repair areas with Carborundum cloth or 80-grit sandpaper prior to application.
c. Use a protective wrap to protect tape from impact in soil-stress areas when backfill contains rock, caliche, hardened clay or other material that can cut through the tape.
d. Available in repair cartridges.
e. Use Mesa Corrosion Control Thermite Weld Caps (#Weld 50000) or similar product with epoxy products for pipeline test lead or rectifier connections. The Weld Cap is 3" x 3" square of 20 mil thick, high density polyethylene formed as an igloo. The dome of the cap is filled with epoxy and placed over the thermite weld. The cap is pressed down until epoxy fills the gap between the cap and the pipe surface. The igloo tunnel portion permits the lead wire to exit so the cap surface remains flush to the connected structure.