BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms	R.11-02-019 (Filed February 24, 2011)

CENTRAL VALLEY GAS STORAGE, LLC'S (U 915 G)
REVISED NATURAL GAS SYSTEM OPERATOR SAFETY PLAN

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Dated: June 28, 2013

BEFORE THE
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REVISED NATURAL GAS SYSTEM OPERATOR SAFETY PLAN

Central Valley Gas Storage, LLC (Central Valley) respectfully submits its Revised Natural Gas System Operator Safety Plan (Safety Plan). On June 29, 2012, Central Valley submitted its initial Safety Plan. Pursuant to the California Public Utility Commission's (Commission or CPUC) issued Decision D.12-12-009, and the Commission's letter to Central Valley dated June 27, 2013 authorizing Central Valley to file its revised Safety Plan (Attached as Exhibit A), Central Valley now submits its Revised Safety Plan with changes to resolve deficiencies in accordance with the Decision. The Revised Safety Plan is attached hereto as Exhibit B.

Central Valley requests the Commission accept and approve this Revised Natural Gas System Operator Safety Plan.

Dated this 28th of June, 2013, at Washington, D.C.

Respectfully Submitted by,

CENTRAL VALLEY GAS STORAGE, LLC

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Exhibit A

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

June 27, 2013

Subject: Filing of Gas Safety Plans

Dear Mr. Hermann,

The Safety and Enforcement Division, Gas Safety and Reliability Branch (GSRB) has reviewed the revisions made to Central Valley Gas Storage's (CVGS) Safety Plan to resolve all deficiencies per the requirements of Ordering Paragraph 3 (OP.3) of Commission Decision 12-12-009.

Based on its review, GSRB believes the revisions adequately address the deficiencies and that CVGS may now file its revised Safety Plan with all the required company official's and management signatures. As a reminder, a separate table summarizing the changes made with the following information must be included in the final filing:

PU Code section	Requirement	GSRB's initial review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section

Should you have any questions related to this matter, please contact at Aimee Cauguiran at (415) 703-2055 or by e-mail at (aimee.cauguiran@cpuc.ca.gov).

Sincerely,

Michael Robertson, Program Manager
Gas Safety and Reliability Branch

Exhibit B

CENTRAL VALLEY GAS STORAGE, LLC

REVISED NATURAL GAS SYSTEM OPERATOR SAFETY PLAN

Pursuant to Rulemaking 11-02-019

6/28/2013

Central Valley Gas Storage
An AGL Resources Company

Central Valley Gas Storage, LLC
3333 Warrenville Road
Suite 300
Lisle, IL 60532

Phone 630 245-6150
Fax 630 245-7835
Internet www.cvgasstorage.com

June 28, 2013

California Public Utilities Commission
505 Van Ness Ave
San Francisco, CA 94610

Subject: REVISED Central Valley Gas Storage Operator Safety Plan

Central Valley Gas Storage, LLC (CVGS) hereby submits updated documents comprising its Operator Safety Plan (the Plan) with changes made to resolve deficiencies in accordance with Decision 12-12-009. CVGS has attached a table summarizing changes made to the Plan.

Along with the summary table, CVGS is submitting the contents of the Plan as follows:

- Central Valley Gas Storage Policy #1. This Policy, signed by the officers responsible for CVGS, illustrates the priority CVGS places on safety and demonstrates the commitment by CVGS management to updating its Plan and proactively securing workforce participation in developing and implementing the Plan. The policy has been revised to specify frequency for reviewing and updating the Plan, to describe CVGS's processes for staying informed on industry best practices and evaluate how CVGS's operations and processes conform with or differ from trends for similar operations, to state that CVGS will meet or exceed required standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities, and to state that CVGS will ensure an adequately sized, qualified and properly trained workforce to carry out the Plan based on a demonstrable analysis.

- Current versions of elements that ensure that CVGS is complying with federal pipeline safety statues and Section 961 (c), including:

    - The CVGS Operations and Maintenance (O&M) plan
    - The CVGS Operator Qualification (OQ) plan
    - The CVGS Emergency Response plan (ERP)
    - The CVGS Integrity Management (IM) plan

- Additional Safety-related plans adopted by CVGS in compliance with the Mitigation Monitoring Compliance and Reporting Program implemented per its Certificate issued by the California Public Utilities Commission in D 10-10-001, including:

    - The CVGS Hazardous Substances Control plan
    - The CVGS Worker Health and Safety plan
    - The CVGS Fire Prevention and Management plan

  These plans were submitted to the Commission during CVGS project construction.

- Appendices documenting CVGS practices and design features for quick reference in reviewing compliance with the requirements of Section 961 subdivision (d):
    - Appendix I. - Measures CVGS has undertaken to identify and minimize risks. The Process Hazard Analysis referenced in the Appendix has been attached.
    - Appendix II. - CVGS safety-related systems.
    - Appendix III. - CVGS' MAOP determination.
    - Appendix IV. - Overview of CVGS design standards.
    - Appendix V. - CVGS Staffing, Qualifications and Training

- The Valve Location Plan that CVGS filed with the CPUC in December of 2012

In addition to the elements of the Plan, CVGS is submitting its current process for ensuring adequate capacity and injection/withdrawal capability to satisfy its customer commitments and to match up nominations from its customers with operating conditions at CVGS and its connection with PG&E.

The objectives of AGL Resources Inc., and of CVGS, are to operate their businesses in a safe and reliable manner and in compliance with applicable laws, rules and regulations. If there are any questions concerning this Plan, please contact me at (630) 245-7825 or e-mail me at jboehme@aglresources.com.

Sincerely,

John Boehme

John Boehme
Manager Regulatory Affairs
Storage and Fuels (North/West)
AGL Resources

Attachment 1

Central Valley Gas Storage
Summary Table

Summary Table - Changes made to the REVISED CVGS Operator Safety Plan to address deficiencies

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
Sec. 961 Subdivision (b)					
-3	Each gas corporation shall implement its approved plan	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.
-4	The commission shall require each gas corporation to periodically review and update the plan	N	CVGS safety plan did not provide a specific frequency or time interval for reviews and updates.	CVGS Policy #1	CVGS Policy #1 is modified to specify timeframe for review and modification of the Safety Plan.
Sec. 961 Subdivision (c)					

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
Sec. 961 Subdivision (c)	The plan developed, approved, and implemented pursuant to subdivision (b) shall be consistent with best practices in the gas industry and with federal pipeline safety statutes as set forth in Chapter 601 (commencing with Section 60101) of Subtitle VIII of Title 49 of the United States Code and the regulations adopted by the United States Department of Transportation pursuant to those statutes.	**N**	CVGS safety plan did not detail CVGS's processes for staying informed on industry best practices or for evaluating how CVGS's operations and processes conform with or differ from national and statewide trends for similar operations.	CVGS Policy #1	CVGS Policy #1 is modified to specify measures that CVGS shall include in its scheduled Safety Plan review to ensure that the Safety Plan reflects updated versions of safety regulations and industry best practices. CVGS will evaluate its plan using the findings from these measures to determine if its processes, procedures and standards conform with or differ from industry trends for similar operations.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
Sec. 961 Subdivision (d)					

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-1	Identify and minimize hazards and systemic risks in order to minimize accidents, explosions, fires, and dangerous conditions, and protect the public and the gas corporation workforce.	N	CVGS did not provide PHA and PSSR for review with its filing	Appendix I and attached PHA	Appendix I has been revised to refer to the PHA as an attachment and the PHA is included in the revised Safety Plan.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-2	Identify the safety-related systems that will be deployed to minimize hazards, including adequate documentation of the commission-regulated gas pipeline facility history and capability.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-3	Provide adequate storage and transportation capacity to reliably and safely deliver gas to all customers consistent with rules authorized by the commission governing core and noncore replacement, preventive maintenance, and reactive maintenance and repair of its commission-regulated gas pipeline facility.	N	CVGS safety plan did not detail or provide reference to its process for confirming adequate pressure and capacity under peak load conditions	CVGS has supplied its current process for ensuring adequate capacity and injection/withdrawal capability to satisfy its customer commitments as an attachment to the Safety Plan cover letter.	The procedure documents the process that CVGS uses to ensure adequate capacity and injection/withdrawal capability to satisfy its customer commitments and to match up nominations from its customers with operating conditions at CVGS and its connection with PG&E.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-4	Provide for effective patrol and inspection of the commission-regulated gas pipeline facility to detect leaks and other compromised facility conditions and to effect timely repairs.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-5	Provide for appropriate and effective system controls, with respect to both equipment and personnel procedures, to limit the damage from accidents, explosions, fires, and dangerous conditions.	N	Appendix III & MAOP worksheets detail the MAOP criteria and calculations used to establish initial MAOP for pipeline facilities. CVGS safety plan did not detail or reference a process for monitoring MAOP. Specific procedures to limit the flow of gas in an unsafe situation could not be identified.	O&M Plan Section 17.08; Operator Qualification (OQ) plan	The procedure for abnormal operations is in the O&M plan and the CVGS OQ plan includes qualifying the CVGS workforce on abnormal operations.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-6	Provide timely response to customer and employee reports of leaks and other hazardous conditions and emergency events, including disconnection, reconnection, and pilot-lighting procedures.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-7	Include appropriate protocols for determining maximum allowable operating pressures on relevant pipeline segments, including all necessary documentation affecting the calculation of maximum allowable operating pressures.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.
-8	Prepare for, or minimize damage from, and respond to, earthquakes and other major events.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-9	Meet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations issued by the United States Department of Transportation in Part 192 (commencing with Section 192.1) of Title 49 of the Code of Federal Regulations.	N	CVGS safety plan did not provide a statement signed by an officer of the corporation.	CVGS Policy #1	Language has been added to Policy #1 stating that CVGS endeavors to design, construct, install, operate, and maintain its gas pipeline facilities at standards that meet or exceed the requirements of CPUC General Order 112-E , which references and adopts regulations issued by the United States Department of Transportation in part 192 of Title 49 of the Code of Federal Regulations. Policy #1 is signed by the officers responbsible for CVGS.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
-10 and Sec. 963 Subdivision (b)(3)	Ensure an adequately sized, qualified, and properly trained gas corporation workforce to carry out the plan.	N	CVGS safety plan did not provide a statement signed by an officer of the corporation related to the adequacy of its workforce, including training based on demonstrable analysis.	CVGS Policy #1	Language has been added to Policy #1 stating that CVGS will ensure an adequately sized, trained, and qualified workforce, to comply with the Plan and other regulatory requirements, and shall retain records that can be utilized to perform an analysis that evaluates resources dedicated to employee safety training and operational training. Policy #1 is signed by the officers responpbsible for CVGS.
-11	Any additional matter that the commission determines should be included in the plan.	N	Did not meet criterion	CVGS Hazardous Substances Control plan, CVGS Worker Health and Safety plan, and CVGS Fire Prevention and Management plan	The Commission has not indicated additional matters for CVGS to include.

PU Code Section	Requirement	GECS's initial Review of Safety Plan if it complies with this Section of the PU Code (Y or N)	GSRB Reviewer's Comments during the initial review	Specific section in the REVISED Safety Plan that addresses revisions made to meet the PU Code Section	Summary of the REVISED Safety Plan that addresses this PU Code Section
Sec. 961 Subdivision (e)					
Section 961 Subdivision (e)	The commission and gas corporation shall provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industry wide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce.	Y	No issue identified at this time	Not applicable	No revisions addressing this Section were necessary.

Attachment 2

Central Valley Gas Storage Policy #1

Central Valley Gas Storage
An AGL Resources Company

POLICY AND PROCEDURE

Policy # 1 Revision #1 **Prepared by: John Boehme**

Effective Date: June 28, 2013 **Approved by:**
AGL Resources V.P. Storage and Peaking Operations

Approved by:
CVGS President

Title: OPERATOR SAFETY PLAN

Purpose:

The objective of Central Valley Gas Storage, LLC, ('Company') is to operate the business in a safe and reliable manner and in compliance with applicable laws, rules and regulations. The purpose of this policy is:

(1) to clearly state that the safety of the public and the Company workforce is the top priority,
(2) to ensure that the Company Operator Safety Plan ("Plan") is fully understood by its employees and is reviewed and updated at regular intervals, and
(3) to provide opportunities for meaningful, substantial, and ongoing participation by Company employees in the development and implementation of the Plan, with the objective of developing a culture of safety that strives to prevent accidents, explosions, fires, and dangerous conditions for the protection of the public and the Company workforce.

Scope:

This policy and procedure applies to the Company.

Policy:

The Company places the safety of the public and its workforce as its top priority. The Company endeavors to design, construct, install, operate, and maintain its gas pipeline facilities at standards that meet or exceed the requirements of California Public Utility Commission General Order 112-E ("G.O. 112-E"), which references and adopts regulations issued by the United States Department of Transportation in part 192 of Title 49 of the Code of Federal Regulations ("part 192"). The Company will implement the following measures with respect to complying with and maintaining this Plan:

- The Company shall ensure an adequately sized, trained, and qualified workforce, to comply with the Plan and other regulatory requirements, and shall retain records that can be utilized to perform an analysis that evaluates resources dedicated to employee safety training and operational training. The analysis shall demonstrate the priority placed by the Company on the safety of the public, its workforce, and the surrounding environment.
- The Company will compare Company's Operations, training, and staffing requirements to other affiliated AGL Resources storage companies. Incidents and/or near misses encountered at any affiliated AGL Resources storage company facility will be investigated and reports will be distributed to all the other facilities to minimize the potential for similar events occurring at the other facilities.
- Upon employment, each Company employee shall be provided access to the Plan documents.
- Each Company employee shall have access to the annual safety report filed by the Company.
- The Company shall accept and appropriately evaluate workforce suggestions to revise the Plan. The Company shall retain a log of employee suggestions with respect to the Plan including the disposition of the suggestion and the rationale for the disposition.
- The Company shall hold meetings on a planned and scheduled basis with its workforce to review the Plan and discuss appropriate modifications.
- The Company shall review and make an update with appropriate modifications to its Plan at least once each calendar year. The Company shall maintain a record of revisions documenting changes made to the Plan.
- As part of its calendar year Plan review, the Company shall include the following measures to ensure that the Plan reflects updated versions of safety regulations and industry best practices:
    - A full review of G.O. 112-E requirements in effect at the time of the calendar year Plan review, including part 192 regulations, to make certain that the Company's Plan is updated to reflect any changes in regulatory requirements.
    - A review of United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) advisory bulletins since the most recent Plan review to determine additional items that should be changed.
    - Inclusion of any industry best practices discovered through AGL Resources' participation in American Gas Association committees related to safe operation of gas storage facilities since the most recent Plan review.
    - A review of California Public Utility Commission Orders for which the Company has been notified by the CPUC that revise or update pipeline safety regulatory requirements since the most recent Plan review to determine additional items that should be changed.

  To ensure that CVGS evaluates its Plan to determine whether it conforms with or differs from industry trends for similar operations, the findings from these measures will be evaluated against current operations, maintenance, and emergency response processes, procedures, and standards documented in the Plan. Based on the evaluation, CVGS will either modify its Plan to conform with the findings, or in cases where Company processes or procedures shall differ, CVGS will document why they differ.
- The Company shall inform its employees that any employee who perceives a breach of safety requirements may inform the CPUC of the breach on a confidential basis and the

Company shall provide information on how to contact the CPUC with a confidential safety breach notification.

- Modified versions of the Plan shall be filed with the CPUC as appropriate unless otherwise directed by the CPUC.

Revision History: *(Document policy amendments using a revision history chart)*

Revision	Date	Description of changes	Requested By
1	06/28/13	Added measures for workforce analysis. Specified timing for review and update. Added measures for reviewing industry best practices and regulation updates and evaluating whether the Plan conforms to industry trends.	John Boehme

Attachment 3

Central Valley Gas Storage Operations and Maintenance Plan

Central Valley Gas Storage

An AGL Resources Company

Operations and Maintenance Manual

June 2013

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SECTION 17 – PIPELINE SPECIFIC O&M (PSOM)

FORWARD

The United States Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) requires that the accident reporting, design, installation, operation, and maintenance of regulated pipeline facilities conform to the requirements of Title 49 of the Code of Federal Regulations (49 CFR) parts 191 and 192.

The Company policies mandate compliance with all applicable legal requirements wherever we conduct business and providence of an environment where employees and contractors work safely. This manual contains procedures, information, references, and forms that provide guidance for Company employees and contractors to comply with the aforementioned Federal regulations, California regulations, and company policies.

The information contained in this manual should be applied to all regulated pipelines and facilities. State and local regulations, as well as specific information about individual pipeline systems/segments, are included in the pipeline specific section O&M (PSOM) of this manual.
This manual is to be used in conjunction with a Pipeline Specific Operations Manual (PSOM) and a pipeline specific Emergency Response Plan (ERP). The PSOM and ERP must be developed by the local facility personnel.

This manual shall be prepared before initial operations and of a pipeline system commence. Appropriate parts shall be kept at locations where operations and maintenance activities are conducted. This manual shall be <u>reviewed once per calendar year, not to exceed 15 months</u>. Appropriate changes will be made as necessary to insure that the manual is effective.

This manual shall be made available to any authorized representative of the DOT/PHMSA or state agency upon request.

Gas O&M Record of Revisions: Sept 2012
Updated procedure #1.02, Reporting of SRCs: 5.1 Safety Related Conditions The following conditions are defined as safety related conditions and must be reported per 5.2 below: Use Figure #1.02A for assistance in making SRC reporting determination. 5.2.6 Information Resources Manager Office of Pipeline Safety Pipeline and Hazardous Material Safety Administration (PHMSA) PHP-20 1200 New Jersey Ave, SE Washington, DC 20590 Added Figure #1.02A, Determination of SRCs
Updated procedure #1.03, Investigation of Failures and Incidents: 7. RECORDS 7.1 Complete Form 1.01B and DOT Form PHMSA form #11 (at the end of Procedure 1.01), as required. Complete the Company's "Accident and Near Miss Investigation Report", Form 2055.
Updated procedures #1.07, PHSMA Registration and OPID: 1. REFERENCE 49 CFR 191.22, PHMSA Advisory ADB-12-04 • Removed section #5.2 because it is already covered in procedure #1.06, HCA survey

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #3.01, Damage Prevention: 5.6.12 The locator shall notify the appropriate pipeline operator person when the pipeline alignment and as-built drawings need updates. 5.6.20 When there are reports of third party damage on the pipeline, the company will check the TPD against One-Call tickets and document this review. [PHMSA protocol 195.442] 5.6.21 The company will review "One-Call" reports and generate a list of third parties who actually conducted excavation activities along the pipelines. These companies who conducted excavation activities will be included in the public awareness education program either by mailing of materials or onsite visit. This excavation activities list will be documented once per year including how excavation companies were contacted. [PHMSA protocol 195.442]
Updated procedure #3.03, Public Awareness: Many changes due to internal company review and recommendations from (8) PHMSA public awareness audits in early 2012. See changes in red. Government liaison form was also updated for face to face meeting with emergency responders. PA measures worksheet, form #3.03-3, updated with additional measures. PA enhanced program review worksheet, form #3.03-4, and was added to documents section #9.2 reviews. Reference to this worksheet was added to team charter, agenda and procedure #3.03.
Updated procedure #3.04, Preparation of Emergency Plan: • Updated formatting, font, and file name

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #5.01, Continuing Surveillance: 4.1 Surveillance procedures and instructions are to be reviewed with employee(s) and/or contract personnel at the time of a specific inspection, and on an intermittent basis such as safety, tailgate, and operations meetings. Normally the continuing surveillance review will be conducted on annual bases for class 3 & 4 and minimum once per two years for class 1 & 2. If continuing surveillance reviews are not conducted at these frequencies, the Pipeline Engineer and/or Compliance Manager will document that no pipeline safety issues are pending. Use form #5.01A or equivalent to conduct this review.
Updated procedure #5.03, Patrols: <u>RECORDS</u> 7.1 Record each item found during a patrol that requires further investigation to provide a permanent record on the Gas Leak Survey/Pipeline Patrol (Form 5.02B/5.03B), Navigable Waterway Crossing Inspection Form (Form 5.03C), Critical Crossing Form (Form 5.03D) or equivalent form. This record will ultimately indicate the actual situation and its disposition.
Updated procedure #5.04, Line Markers: 1. <u>REFERENCE</u> 49 CFR, Section 192.707, and API #1109 Marking Liquid Petroleum Facilities
Updated procedure #6.01, Atmospheric Corrosion: 4.7.1 Exception to cleaning and coating of pipelines: Except offshore splash zones or soil-to-air interfaces, the operator does NOT have to clean and coat the pipeline if the operator can demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will;

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #6.02, Internal Corrosion: 6.1 Internal Inspections 6.1.1 Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion. If internal corrosion is noted visually, further investigation including NDT techniques, shall be used to quantify the extent of the corrosion. Use form #6.02A (Internal Pipe Inspection) or equivalent to documents this review. 6.2 Gas Analysis and Evaluation 6.2.1 If there is a reasonable possibility that potentially corrosive gas could occur in a pipeline system, gas samples shall be taken at applicable locations and tested for the presence and concentration of corrosive components. Testing shall be done at least once each year or when new gas stream is introduced into the pipeline system. Use form #6.02B-1 (gas analysis sampling) and form #6.02B-2 (Evaluation of Gas Analysis) or equivalent to documents this review. Gas samples shall be tested by “Gas Analysis by Chromatography” - ASTM D1945/D 3588 or other ASTM standard that provides component data in both mole percent and weight percent. Total sulfur (ASTM D3246) and hydrogen sulfide (ASTM D4810) shall also be noted in the testing. 6.2.2 Dew point analysis shall be performed on gas sources at a minimum of once each year or when new gas stream is introduced into the pipeline system. If the gas is considered potentially highly corrosive, more frequent dew point tests should be considered.

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #6.02, Internal Corrosion: (cont.) 6.2.5 Monitoring and Detection 6.2.5.1 Monitor checkpoints and record the results at least twice each calendar year with intervals not exceeding 7½ months. Monitor more frequently if the level of the corrosive component increases or the effectiveness of the anti-corrosion measures needs to be confirmed. Use form #6.02C (Coupon Monitoring) or equivalent to documents this review. 6.2.5.2 If liquids are present, collect and analyze liquid samples once each year or when new gas stream is introduced into the pipeline system. Special attention should be given to drips, blow downs, and low spots in the pipeline.
Updated procedure #6.11, Remedial Measures: 4. GENERAL The (228) ________________ will have one individual qualified by experience and training in pipeline corrosion control methods to carry out the corrosion control program. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly or the pipeline must be shut down until the repair is made. The company may not operate a segment of pipeline, unless it is maintained in accordance with this subpart M, Maintenance, 192.701-755.

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #7.01m, Valve Inspections: 5.7 Ensure the valve environment will not interfere with the operation of the valve or prevent safe personnel access at any time of the year. 5.8 Notify the control room and/or the appropriate person when the valve inspection is complete.
Updated procedure #7.03, Valve Vaults with Regulators, revised header name: **VALVE VAULTS with REGULATORS**
Updated procedure #8.01, MAOP: 1. REFERENCE 49 CFR, Sections 192.103, 192.105, 192.107, 192.109, 192.111, 192.113, 192.115, 192.485, 192.611, 192.613, and 192.619, and PHMSA "Determination of MAOP in Natural Gas Pipelines" 4. GENERAL 4.1 The maximum allowable operating pressure (MAOP) of a steel pipeline segment may not exceed the lowest of the following: [192.619(a)-(4)] 1) The design pressure of the weakest element in the segment (see 4.1.1) 2) The pressure obtained by dividing the pressure to which the segment was tested after construction (see 4.1.2) 3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date (see 4.1.3) 4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure (see 4.1.4) 4.1.1 The design pressure of the weakest element in the segment. [192.619(a)(1)] 4.1.1.1 For steel pipe, the design pressure is defined by the following: [192.105(a)(1)]

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #8.01, MAOP: (cont.) 4.1.2 Pressure Test Requirements [192.619(a)(2)] This regulation applies not only to tests made after initial construction of the pipeline or system, but also to tests of pipe used for extensions, laterals, or services connected to the original pipe, and to any replacement pipe. Any single piece of pipe tested to a lower pressure than the rest of the system will set the MAOP for the entire system. If more than one pressure test has been conducted, the most recent test controls. 4.1.3 Operating History Requirements [192.619(a)(3)] If the design pressure rating for system components cannot be determined due to lack of information, setting the MAOP based on Part 192.619(a)(4) or Part 192.619(a)(5) may be considered. This decision shall be cleared through the appropriate regulatory agency. Approval from regulatory agency shall be in writing. The highest actual operating pressure to which the segment was subjected during the 5 years, preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested per 4.1.2 above after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated per Procedure 12.01. For onshore pipelines, review records for the highest operating pressure between July 1, 1965, and July 1, 1970, such as pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc. If no records are available, a notarized statement by a person in charge of pipeline operations during that time period, attesting to the operating pressure during that period, may be acceptable at the discretion of regulatory agencies. The historic operating pressure limit can be overridden in two ways: by a pressure test under Part 192.619(a)(2) conducted after July 1, 1965, or by an uprating in compliance with Part 192, Subpart K. The most recent test or uprating would control.

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #8.01, MAOP: (cont.) 4.1.4 Maximum Safe Operating After Review of the Pipeline [192.619(a)(4)] If pipeline records are missing or incomplete, it may be impossible to conclusively determine what the MAOP should be under this criteria. In this situation the operator must consult with the Regulatory Agency, and should look at the normal operating pressures over the last 5 years, and select the highest pressure which did not cause unusual safety or operational problems. This pressure must have applied for a long enough period of time for any problems to become evident. The operator could then conclude that this pressure represents the maximum known safe operating pressure, and determine that it should be the MAOP. Use of Part 192.619(a)(4) to establish the MAOP will require that the pipeline or system have overpressure protection to prevent the MAOP from being exceeded should a regulator failure occur. Any previous "grandfather" exemption from overpressure protection requirements is overruled. The concept is that if higher than normal pressures could cause a safety problem, or if the safety risk of a higher pressure cannot be determined because of lack of information, then measures must be taken to prevent that higher pressure from occurring.

Gas O&M Record of Revisions: Sept 2012 (cont.)

Updated procedure #8.01, MAOP: (cont.)

5. PROCEDURE

5.1 After determining the appropriate pressure limit in each category which applies to the pipeline or pipeline system involved (see sections #4.1.1-4.1.4 above), select the lowest value as the MAOP. Use form #8.01A and form #8.01B to aid in MAOP determination and attach all support documents. These support documents should be for all categories reviewed, not just the one which controlled. This file should be maintained for the life of the pipeline or system involved.

5.2 Establish the maximum allowable operating pressure (MAOP) for each distinct segment of all existing and new pipeline facilities. Records must be available to substantiate any value determined. Form #8.01A and #8.01B can be used to document the MAOP determination. The (253) ________________ shall communicate the MAOP to the appropriate parties.

Updated procedure #9.01, Repairs:

4.2 Operating pressure must be at a safe level during repair operations. Considering the above items, the individual shall make a recommendation for pressure reduction with safety as a primary element. Immediate temporary measures should be taken to protect life and property from hazards resulting from a leaking, defective or damaged pipeline with an injurious damage condition. See section 5.3.1 of these procedures for methods used in determining the remaining strength of pipe.

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

5.6.7 All repairs must meet API 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999) or equivalent welding procedures.

5.8.2.1 Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure and the requirements of Section 9 of API Standard 1104, "Welding of Pipelines and Related Facilities" (Welding of Pipelines and Related Facilities, 19th edition, 1999).

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #9.06, Welding: 5. QUALIFICATION OF WELDING PROCEDURES AND WELDERS 5.1 All welding performed on gas pipeline systems shall be completed using welding procedures qualified in accordance with the API Standard 1104 section #5 (19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008, or Section IX "Welding and Brazing Qualifications" of the ASME Boiler and Pressure Vessel Code (incorporated by reference, 49 CFR192.7 currently referenced editions).
Updated procedure #12.02, Conversion of Service: 1. REFERENCE 49 CFR, Sections 192.14 and 192.452. GPTC – Guide for Gas Transmission and Distribution Piping Systems ASME B31.8 – Gas Transmission and Distribution Piping Systems, section #856

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #12.02, Conversion of Service: (cont.)

5. PROCEDURE

5.1 Conduct historical records study by reviewing design, construction, operation, and maintenance history of the pipeline. If available, particular attention should be paid to welding procedures used and other joining methods, internal and external coating, pipe material, and other material descriptions. Study available operating and maintenance data including leak surveys, leak records, inspections, failures, cathodic protection, and internal corrosion control practices. Use form #12.02A and form #12.02B (pipeline fact sheet template) or equivalent to document this review. If sufficient historical records are not available, then appropriate tests must be conducted to determine if the pipeline is safe to operate.

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient historical records are not available [192.14(a)(1)]:

- Corrosion surveys including one or more of the processes used in the integrity management program:
  1) External Corrosion Direct Assessment (ECDA) evaluations. These normally include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM)
  2) In line inspection (ILI) tools
  3) Guided wave
- Ultrasonic inspections for corrosion and wall thickness determinations
- Positive material identification inspection using portable XRF analyzers
- Acoustic emissions inspection
- Tensile tests
- Internals inspections in accordance with O&M procedure #6.02
- Radiographic inspections

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #12.02, Conversion of Service: (cont.)

5.2 Visually inspect the pipeline right-of-way, all aboveground segments, and appropriate underground segments of the pipeline for physical defects or other conditions which could impair the strength or tightness of the line.

Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites:

- Corrosion surveys
- Segments with coating damage or deterioration due to soil stresses and/or internal or external temperature extremes
- Pipeline component locations
- Locations subject to mechanical damage
- Foreign pipeline crossings
- Locations subject to damage due to chemicals such as acid
- Population density (document class location study per 192.5)

5.4 Determine new MAOP for the line in accordance with 192.619 and Procedure 8.01.

5.5 Conduct class location survey in accordance with 192.5 and compare the proposed MAOP and operating stress levels with those allowed for the location class. Replace pipe and/or facilities to make sure the operating stress levels is commensurate the location class.

5.5 Conduct a pressure test the line to substantiate the new line MAOP in accordance with 192 subpart J and procedure #15.01.

5.6 Within one year of the date that the converted line is placed in gas service, provide cathodic protection as required by 192.455.

7. RECORDS

7.2 Document investigations, repairs, replacements, and alternations on Form 12.02A or equivalent.
7.3 Document pressure tests on suitable or third party forms.
7.4 Maintain all conversion of service records for life of the pipeline.

Gas O&M Record of Revisions: Sept 2012 (cont.)
Updated procedure #13.01, Abandonment or Inactivation of Facilities: 2. PURPOSE The purpose of this procedure is to establish minimum requirements for the abandonment of natural gas pipeline facilities.
Updated procedure #15.02, Visual Inspection and Non-Destructive Testing: 4.4 The acceptability of a weld that is nondestructively tested or visually inspected, is determined according to the standards in Section 9 of API Standard 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999). Only level II or III qualified under SNT-TC-1A will be allowed to intrepet test results. Recommended Practice No. SNT-TC-1A: Personnel Qualification and Certification in Nondestructive Testing (2011) provides guidelines for employers wishing to establish in-house certification programs. Personnel qualification records under SNT-TC-1a will be maintained the company. 8.6 Personnel qualification records for personnel reading and intrepeting test result will be qualified under SNT-TC-1a and all records of these qualification will be maintained the company.

Signature & Date of Person Who Conducted Annual Review of O&M Manual:

____
Signature

____
Date

Gas O&M Record of Revisions: June 2013
Updated procedure #17 – Pipeline Specific O&M General Changes: • Updated identification of responsibilities in various sections to conform to the Assignment Table (in Red) • Removed references to the Temporary Compressor and associated piping, equipment and materials. • Updated 17.05.11, PG&E Valve Location Chart, to reflect current use of 24" pipeline and connection at PG&E's 401 interconnect.
Updated Procedure 1.06 – HCA Survey. • In Section 5.3 changed requirement to incorporate newly-identified HCAs to within one calendar year. • In Section 7 changed requirement to integrate inherited pipeline segments with HCAs to within one calendar year.

Signature

Date

USE OF NUMBERED BLANKS

1. What are all of the blanks for?

   The blanks serve as place holders for specific task/responsibility assignments.

2. How are these task/responsibility assignments determined?

   Since job descriptions and workloads vary from location to location, this manual does not attempt to assign tasks/responsibilities to individual job classifications. The local pipeline management must determine which job positions are best suited for each assignment. This determination should be done on a case by case basis.

3. Why are the blanks numbered?

   The blanks are numbered to eliminate the need to fill in every blank by hand. After the tasks/responsibility assignments are determined, simply fill in the Blank Assignment Table in this section of the manual. This table can be copied and distributed to all users of the manual. This eliminates the need to fill in every blank in every copy by hand. In addition, changes to personnel or responsibilities can be easily updated without the need to revise and redistribute the entire manual.

4. Should the blanks be filled in?

   With the addition of the Blank Assignment Table, filling in the blanks within the procedures is not necessary. The blanks can be filled in if desired, however this will make updating the manuals more difficult.

5. When should the Blank Assignment Table be filled in?

   The Blank Assignment Table <u>must</u> be filled in prior to the manual being distributed to the work place. Until the blanks are assigned, the manual is incomplete and does not satisfy the intent of the regulation.

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Reporting and Control of Incidents			
1	Facility Manager	1.01	3.0
2	Dir, Stg & Peaking Ops – West	1.01	4.1.2
3	Dir, Stg & Peaking Ops – West	1.01	4.4
4	Managing Director, Fed & MS Gov Affairs	1.01	5.3
5	Dir, Stg & Peaking Ops – West	1.01	6.1.2
6	Facility Manager	1.01	6.2
7	Facility Manager	1.01	6.3
8	Facility Manager	1.01	6.4
9	Dir, Stg & Peaking Ops – West	1.01	6.4.1
10	Facility Manager	1.01	6.5
11	Facility Manager	1.01	6.5.1
11B	Facility Manager	1.01	6.6
12	Facility Manager	1.01	6.7
13	Facility Manager	1.01	6.7.6
14	Dir, Stg & Peaking Ops – West	1.01	6.7.6
15	VP Storage & Peaking Ops	1.01	6.7.6
16	VP Storage & Peaking Ops	1.01	6.7.6
17	Facility Manager	1.01	6.7.7
18	Facility Manager	1.01	8.1
Reporting of Safety Related Conditions			
22	Facility Manager	1.02	3.0
23	Facility Manager	1.02	3.0
24	Facility Manager	1.02	4.2
25	Dir, Stg & Peaking Ops – West	1.02	4.2
26	Facility Manager	1.02	4.3
27	Facility Manager	1.02	5.2.3
28	Facility Manager	1.02	5.2.4
29	Facility Manager	1.02	5.2.4
30	Facility Manager	1.02	5.2.4
31	Facility Manager	1.02	5.2.6
32	Facility Manager	1.02	5.2.6
33	Facility Manager	1.02	5.2.6

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Investigation of Failures and Accidents			
42	Facility Manager	1.03	3.0
43	Facility Manager	1.03	4.1
44	Facility Manager	1.03	4.2
45	Facility Manager	1.03	4.2
46	Company Personnel	1.03	4.4
47	Facility Manager	1.03	5.1
48	Facility Manager	1.03	5.2
49	Dir, Stg & Peaking Ops – West	1.03	5.2.2
50A	Dir, Stg & Peaking Ops – West	1.03	5.2.5
50B	VP Storage & Peaking Ops	1.03	5.2.5
50C	Dir, Stg & Peaking Ops – West	1.03	5.2.6
51	Administrative Assistant	1.03	7.20
Pipeline Annual Reports			
58	Facility Manager	1.04	3.0
59	Dir, Compliance Assurance	1.04	3.0
60	Dir, Compliance Assurance	1.04	5.1
61	Facility Manager	1.04	6.2
62	Dir, Stg & Peaking Ops – West	1.04	6.2
63	Dir, Compliance Assurance	1.04	6.2
64	Dir, Compliance Assurance	1.04	6.2
65	Facility Manager	1.04	6.3
66	Dir, Compliance Assurance	1.04	6.3
NPMS Submittal			
67	Facility Manager	1.05	3.0
High Consequence Area Survey			
68	Facility Manager	1.06	3.0
PHMSA Operator ID			
69	Facility Manager	1.07	3.0
Record Keeping			
72	Facility Manager	2.01	3.0
Marking and Documentation of Materials			
78	Facility Manager	2.02	3.0

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Damage Prevention Program			
84	Facility Manager	3.01	3.0
85	Facility Manager	3.01	5.7.1
Telephone Answering Service			
91	Facility Manager	3.02	3.0
Public Education Program			
97	Facility Manager	3.03	3.0
97B	Corporation	3.03	3.0
98	Dir, Compliance Assurance	3.03	4.2
Preparation of an Emergency Response Plan			
105	Facility Manager	3.04	3.0
Crossing of Company Pipelines			
111	Facility Manager	3.05	3.0
112	GIS Mapping Dept.	3.05	7.3
Preparation of a Pipeline Specific O&M Manual (PSOM)			
118	Facility Manager	3.06	3.0
119	Facility Manager	3.06	3.0
Class Location Survey and Documentation			
125	Facility Manager	4.01	3.0
126	Dir, Compliance Assurance	4.01	6.4
127	Dir, Compliance Assurance	4.01	6.5
128	Dir, Compliance Assurance	4.01	6.6
129	Facility Manager	4.01	6.6
Onshore Gas Gathering Determination			
130	N/A	4.02	3.0
Continuing Surveillance			
135	Facility Manager	5.01	3.0
136	Facility Manager	5.01	3.0
Gas Leak Survey			
142	Facility Manager	5.02	3.0
Pipeline Patrols			
148	Facility Manager	5.03	3.0
Pipeline Markers and Signs			
154	Facility Manager	5.04	3.0

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Atmospheric Corrosion			
160	Facility Manager	6.01	3.0
161	Facility Manager	6.01	3.0
Internal Corrosion			
167	Managing Dir, System Integrity	6.02	3.0
168	Facility Manager	6.02	3.0
External Protective Coating			
174	Facility Manager	6.03	3.0
Internal & External Examination of Buried Pipe			
181	Facility Manager	6.04	3.0
Cathodic Protection & External Corrosion Control			
187	Facility Manager	6.05	3.0
188	Managing Dir, System Integrity	6.05	4.10
189	Managing Dir, System Integrity	6.05	5.4
Electrical Isolation			
195	Sr Mgr, Ops Programs	6.06	3.0
Impressed Current Power Source Inspection			
201	Sr Mgr, Ops Programs	6.07	3.0
202	Sr Mgr, Ops Programs	6.07	5.3.2
203	Sr Mgr, Ops Programs	6.07	5.3.3
Cathodic Protection Maps and Records			
210	Sr Mgr, Ops Programs	6.08	3.0
Evaluation of Bare, Buried, or Submerged Unprotected Lines			
216	Facility Manager	6.09	3.0
District Office Review			
222	Facility Manager	6.10	2.0
223	Managing Dir, System Integrity	6.10	3.0
224	Sr Mgr, Ops Programs	6.10	4.0
225	Sr Mgr, Ops Programs	6.10	5.0
Remedial Measures			
226	Sr Mgr, Ops Programs	6.11	2.0
227	Facility Manager	6.11	3.0
228	Sr Mgr, Ops Programs	6.11	4.0
229	Sr Mgr, Ops Programs	6.11	5.0

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Emergency Valve Maintenance			
231	Facility Manager	7.01	3.0
232	Facility Manager	7.01	4.2
233	Facility Manager	7.01	4.4
Pressure Regulators and Relief Devices			
239	Facility Manager	7.02	3.0
Valve Vaults			
245	Facility Manager	7.03	3.0
Maximum Allowable Operating Pressure (MAOP)			
251	Design Engineer	8.01	3.0
252	Facility Manager	8.01	3.0
253	Facility Manager	8.01	5.1
254	Managing Dir, System Integrity	8.01	7.2
Operating Pressure Limits – Maintenance and Repair			
260	Facility Manager	8.02	3.0
Pipeline Repair Procedures			
269	Facility Manager	9.01	3.0
270	Office of Corporate Engineering	9.01	7.2
Purging and Blowdown			
282	Facility Manager	9.03	3.0
Air Movers			
288	Facility Manager	9.04	3.0
Tapping Pipelines			
294	Facility Engineer	9.05	3.0
295	Office of Corporate Engineering	9.05	7.1
Pipeline Welding			
301	Facility Manager	9.06	3.0
302	Office of Corporate Engineering	9.06	3.0
303	Facility Manager	9.06	3.0

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.
Compressor Station ESD			
309	Facility Manager	10.01	3.0
310	Facility Manager	10.01	3.0
Compressor Station Storage of Combustibles			
311	Facility Manager	10.02	3.0
Compressor Stations Gas Detection and Alarm			
316	Office of Corporate Engineering	10.03	3.0
317	Facility Manager	10.03	3.0
Odorization of Gas			
323	Office of Corporate Engineering	11.01	3.0
324	Office of Corporate Engineering	11.01	6.3
Pipeline Uprating			
330	Managing Dir, System Integrity	12.01	3.0
331	Facility Manager	12.01	3.0
332	O&M Procedures Manual	12.01	4.0
Conversion of Service			
338	Facility Manager	12.02	3.0
Abandonment			
344	Facility Manager	13.01	3.0
345	Facility Manager	13.01	6.4
346	Facility Manager	13.01	9.1
Valve Security			
352	Facility Manager	14.01	3.0
353	Facility Manager	14.01	4.3
354	Facility Manager	14.01	5.1
Pipeline Isolation Lock and Tag			
360	Facility Manager	14.02	3.0
Prevention of Accidental Ignition			
366	Facility Manager	14.03	3.0
Excavations			
372	Facility Manager	14.04	3.0
Pressure Testing			
378	Facility Manager	15.01	3.0
Visual Inspection and Nondestructive Testing			
384	Facility Manager	15.02	3.0

Assignment Table - CVGS
Operations and Maintenance Manual

BLANK NO.	RESPONSIBILITY	PROC. NO.	SEC. NO.

Design of Plastic Pipe– N/A to CVGS			
390	N/A to CVGS	16.01	3.0
Plastic Pipe Materials– N/A to CVGS			
396	N/A to CVGS	16.02	3.0
Joining of Plastic Pipe– N/A to CVGS			
402	N/A to CVGS	16.03	3.0
Plastic Pipe Construction Requirements– N/A to CVGS			
408	N/A to CVGS	16.04	3.0
Test Requirements for Plastic Pipe			
414	N/A to CVGS	16.05	3.0
MAOP of Plastic Facilities – N/A to CVGS			
420	N/A to CVGS	16.06	3.0
421	N/A to CVGS	16.06	3.0
422	N/A to CVGS	16.06	4.1
423	N/A to CVGS	16.06	7.2

Pipeline Specific O&M (PSOM)

Purpose, Scope, and Annual Review			
500	Facility Manager	17.01	3.0
501	Facility Manager	17.01	5.0
502	Facility Manager	17.01	5.0
503	Facility Manager	17.01	6.0
Distribution Log			
NA	NA	17.02	Na
Pipeline Fact Sheet			
NA	NA	17.03	NA
Updating Maps and Records			
530	Facility Manager	17.04	4.0
Startup and Shutdown			
540	Facility Manager	17.05	3.0
Pigging			
550	Facility Manager	17.06	3.0
DOT Inspection and Report Schedule			
560	Facility Manager	17.07	4.0
Abnormal Operations			
570	Facility Manager	17.08	3.0
Management of Change			
580	Facility Manager	17.09	3.0
Agency Specific Requirements			
590	Facility Manager	17.10	3.0
Control Room Management			
600	Facility Manager	17.11	3.0

CVGS O&M Cross Reference Table

FN: Gas O&M x-ref, v2012-1
Updated: Sept 2012

Line #	192 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
1	191.1	191	NA	Scope	1.01		1.04
2	191.3	191	NA	Definitions	1.01		1.04
3	191.5	191	NA	Telephonic Notice of Certain Incidents	1.01		
4	191.7	191	NA	Address For Written Reports	1.01		1.04
5	191.15(a)	191	NA	Transmission and Gathering Systems: Incident Report - 30-day follow-up written report	1.01		
6	191.15(b)	191	NA	Transmission and Gathering Systems: Incident Report - Supplemental report (to 30-day follow-up)	1.01		
7	191.16	191	NA	Customer Notification	1.02		
8	191.17	191	NA	Transmission and Gathering Systems: Annual Report	1.04		
9	191.19	191	NA	Report Forms	1.01		1.04
10	191.23	191	NA	Reporting Safety-Related Conditions	1.02		
11	191.25	191	NA	Filing Safety-Related Condition Reports	1.02		
12	191.27	191	NA	Offshore pipeline condition reports – filed within 60 days after the inspections per 192.612(a)	NA		
13	192.1	A	General				
14	192.3	A	General	Scope of Part	1.04		
15	192.5	A	General	Definitions			
16	192.7	A	General	Class Locations			
17	192.8	A	General	Incorporation by Reference			
18	192.9	A	General	How Are Onshore Gathering Lines Determined	4.02		
19	192.1	A	General	What Requirements Apply to Gathering Lines	4.02		
20	192.11	A	General	Outer Continental Shelf Pipelines			
21	192.13	A	General	Pipeline Gas Systems			
22	192.14	A	General	General			
23	192.15	A	General	Conversion to Service Subject to this Part	12.02		
24	192.16	A	General	Rules of Regulatory Construction			
25	192.17	A	General	Customer Notification	NA		
26	192.51	B	Materials	Scope			
27	192.53	B	Materials	General			
28	192.55	B	Materials	Steel Pipe			
29	192.57	B	Materials	Reserved			
30	192.59	B	Materials	Plastic Pipe	16.02		
31	192.61	B	Materials	Reserved			
32	192.63	B	Materials	Marking of Materials	2.02		16.02
33	192.65	B	Materials	Transportation of Pipe	15.01		
34	192.101	C	Pipe Design	Scope			
35	192.103	C	Pipe Design	General	8.01		
36	192.105	C	Pipe Design	Design Formula for Steel Pipe	8.01		
37	192.107	C	Pipe Design	Yield Strength (S) for Steel Pipe	8.01		
38	192.109	C	Pipe Design	Nominal wall thickness (t) for Steel Pipe	8.01		
39	192.111	C	Pipe Design	Design Factor (F) for Steel Pipe	8.01		
40	192.113	C	Pipe Design	Longitudinal Joint Factor (E) for Steel Pipe	8.01		
41	192.115	C	Pipe Design	Temperature Derating Factor (T) for Steel Pipe	8.01		
42	192.117	C	Pipe Design	Reserved			
43	192.119	C	Pipe Design	Reserved			
44	192.121	C	Pipe Design	Design of Plastic Pie	16.01		16.06
45	192.123	C	Pipe Design	Design Limitations for Plastic Pipe	16.01		16.06
46	192.125	C	Pipe Design	Design of Copper Pipe			
47	192.141	D	Design of Pipeline Components	Scope			
48	192.143	D	Design of Pipeline Components	General Requirements			
49	192.144	D	Design of Pipeline Components	Qualifying Metallic Components			
50	192.145	D	Design of Pipeline Components	Valves	7.01 & 7.02		
51	192.147	D	Design of Pipeline Components	Flanges and Flange Accessories			
52	192.149	D	Design of Pipeline Components	Standard Fittings			

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53	192.15	D	Design of Pipeline Components	Passage of Internal Inspection Devices	9.01		
54	192.151	D	Design of Pipeline Components	Tapping	9.05		
55	192.153	D	Design of Pipeline Components	Components Fabricated by Welding			
56	192.155	D	Design of Pipeline Components	Welded Branch Connections	9.05		
57	192.157	D	Design of Pipeline Components	Extruded Outlets			
58	192.159	D	Design of Pipeline Components	Flexibility			
59	192.161	D	Design of Pipeline Components	Supports and Anchors			
60	192.163	D	Design of Pipeline Components	Compressor Stations: Design and Construction	10.01		
61	192.165	D	Design of Pipeline Components	Compressor Stations: Liquid Removal	10.01		
62	192.167	D	Design of Pipeline Components	Compressor Stations: Emergency Shutdown	10.01		
63	192.169	D	Design of Pipeline Components	Compressor Stations: Pressure Limiting Devices	7.02		
64	192.171	D	Design of Pipeline Components	Compressor Stations: Additional Safety Equipment	10.01		
65	192.173	D	Design of Pipeline Components	Compressor Stations: Ventilation			
66	192.175	D	Design of Pipeline Components	Pipe-Type and Bottle-Type Holders			
67	192.177	D	Design of Pipeline Components	Additional Provisions for Bottle-Type Holders			
68	192.179	D	Design of Pipeline Components	Transmission Line Valves	7.01		4.01, 9.03, 14.01
69	192.181	D	Design of Pipeline Components	Distribution Line Valves			
70	192.183	D	Design of Pipeline Components	Vaults: Structural Design Requirements	7.03		
71	192.185	D	Design of Pipeline Components	Vaults: Accessibility	7.03		
72	192.187	D	Design of Pipeline Components	Sealing, Venting, and Ventilation	7.03		
73	192.189	D	Design of Pipeline Components	Vaults: Drainage and Waterproofing	7.03		
74	192.191	D	Design of Pipeline Components	Design Pressure of Plastic Fittings	16.01		16.06
75	192.193	D	Design of Pipeline Components	Valve Installation in Plastic Pipe	16.01		
76	192.195	D	Design of Pipeline Components	Protection Against Accidental Over Pressuring	7.02		
77	192.197	D	Design of Pipeline Components	Control of the Pressure of Gas Delivered From High- Pressure Distribution systems			
78	192.199	D	Design of Pipeline Components	Requirements for Design Pressure Relief and Limiting Devices	7.02		
79	192.201	D	Design of Pipeline Components	Required Capacity of Pressure Relieving and Limiting Stations	7.02		
80	192.203	D	Design of Pipeline Components	Instrument, Control, and Sampling Pipe and Components			
81	192.221	E	Welding of Steel of Steel in Pipelines	Scope	9.06		
82	192.225(a)	E	Welding of Steel of Steel in Pipelines	Welding Procedures - Welding procedures must be qualifed under Section #5 API 1104, 19th edition, or section IX of the ASME Boiler and Pressure Code, 2004 edition	9.06		

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83	192.225(b)	E	Welding of Steel of Steel in Pipelines	Welding Procedures - Retention of welding procedures, details and test	9.06		
84	192.227(a)	E	Welding of Steel of Steel in Pipelines	Qualification of Welders - Welders must be qualified under section #6 of API 1104, 19th edition, or section IX of ASME Boiler and Pressure Code, 2004 edition	9.06		
85	192.227(b)	E	Welding of Steel of Steel in Pipelines	Qualification of Welders - Welders must be qualified under section #1 of appendix C to weld on lines that operate at <20% SMYS	9.06		
86	192.229(a)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - To weld on compressor station piping and components, a welder must successfully complete a destructive test	9.06		
87	192.229(b)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - Welder must have used welding process within the preceding 6 months	9.06		
88	192.229(c)(1)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - A welder qualified under 227(a)	9.06		
89	192.229(c)(2)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - A welder qualified under 227(a)	9.06		
90	192.229(d)(1)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - A welder qualified under 227(b)	9.06		
91	192.229(d)(2)	E	Welding of Steel of Steel in Pipelines	Limitations on Welders - A welder qualified under 227(b)	9.06		
92	192.231	E	Welding of Steel of Steel in Pipelines	Protection From Weather	9.06		
93	192.233	E	Welding of Steel of Steel in Pipelines	Miter Joints	9.06		
94	192.235	E	Welding of Steel of Steel in Pipelines	Preparation for Welding	9.06		
95	192.241(a)	E	Welding of Steel of Steel in Pipelines	Inspection and Test of Welds - Visual inspection must be conducted by an individual qualified by approriate training and experience to ensure 1) Compliance with welding procedure 2) Weld is accepatible in accordance with Section #9, API 1104.	9.06		
96	192.241(b)	E	Welding of Steel of Steel in Pipelines	Inspection and Test of Welds - Welds on pipelines to be operated at 20% or mor of SYMS must be non destructively tested in accordance with 192.243.	15.02		9.06
97	192.241(c)	E	Welding of Steel of Steel in Pipelines	Inspection and Test of Welds - Acceptability based on visual inspection or NDT is determined according to Section 9 of API 1104.	15.02		9.01, 9.06
98	192.243(a)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing - Nondestructive testing of welds must be performed by any process, other than trepanning, that indicates defects that may affect the integrity of the weld	15.02		9.01, 9.06
99	192.243(b)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing - Nondestructive testing of welds must be performed 1) In accordance with a written procedure 2) By persons trained and qualified in the established procedures and with test equipment used	15.02		9.01, 9.06
100	192.243(c)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing - Procedures established for proper interpretation of each nondestructive test of a weld to ensure acceptability of the weld under 192.241(c)	15.02		9.01, 9.06
101	192.243(d)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing - % of field welds that need to be tested	15.02		9.01, 9.06
102	192.243(e)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing - daily non destructive testing	15.02		9.01, 9.06
103	192.243(f)	E	Welding of Steel of Steel in Pipelines	Nondestructive Testing- Records must be maintained for the life of the pipeline	15.02		9.01, 9.06
104	192.245(a)	E	Welding of Steel of Steel in Pipelines	Repair or Removal of Defects - Each weld that is unacceptable must be repaired or removed	15.02		9.01, 9.06
105	192.245(b)	E	Welding of Steel of Steel in Pipelines	Repair or Removal of Defects - Each weld that is repaired must have the defect removed down to sound metal	15.02		9.01, 9.06
106	192.245(c)	E	Welding of Steel of Steel in Pipelines	Repair or Removal of Defects - Repair of any crack or any other defect in a previously repaired area must be in accordance with a written weld procedure, qualified under 192.225	15.02		9.06
107	192.271	F	Joining of Materials Other Than By Welding	Scope	16.03		
108	192. 273	F	Joining of Materials Other Than By Welding	General	16.03		
109	192. 275	F	Joining of Materials Other Than By Welding	Cast Iron Pipe			
110	192. 277	F	Joining of Materials Other Than By Welding	Ductile Iron Pipe			

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111	192. 279	F	Joining of Materials Other Than By Welding	Copper Pipe			
112	192. 281	F	Joining of Materials Other Than By Welding	Plastic Pipe	16.03		
113	192. 283	F	Joining of Materials Other Than By Welding	Plastic Pipe: Qualifying Joining Procedures	16.03		
114	192. 285	F	Joining of Materials Other Than By Welding	Plastic Pipe: Qualifying Persons to Make Joints	16.03		
115	192. 287	F	Joining of Materials Other Than By Welding	Plastic Pipe: Inspection of Joints	16.03		
116	192.301	G	General Construction for Transmission Lines and Mains	Scope			
117	192.303	G	General Construction for Transmission Lines and Mains	Compliance With Specifications or Standards			
118	192.305	G	General Construction for Transmission Lines and Mains	Inspection: General			
119	192.307	G	General Construction for Transmission Lines and Mains	Inspection of Materials			
120	192.309	G	General Construction for Transmission Lines and Mains	Repair of Steel Pipe	9.01		
121	192.311	G	General Construction for Transmission Lines and Mains	Repair of Plastic Pipe	16.04		
122	192.313	G	General Construction for Transmission Lines and Mains	Vends and Elbows			
123	192.315	G	General Construction for Transmission Lines and Mains	Wrinkle Bends in Steel Pipe			
124	192.317	G	General Construction for Transmission Lines and Mains	Protection From Hazards			
125	192.319	G	General Construction for Transmission Lines and Mains	Installation of Pipe in a Ditch			
126	192.321	G	General Construction for Transmission Lines and Mains	Installation of Plastic Pipe	16.04		
127	192.323	G	General Construction for Transmission Lines and Mains	Casing			
128	192.325	G	General Construction for Transmission Lines and Mains	Underground Clearance	3.05		16.04
129	192.327	G	General Construction for Transmission Lines and Mains	Cover	16.04		
130	192.351	H	Customer Meters, Service Regulators, and Serviced Lines	Scope	NA		
131	192.353	H	Customer Meters, Service Regulators, and Serviced Lines	Customer Meters and Regulators: Location	NA		

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132	192.355	H	Customer Meters, Service Regulators, and Serviced Lines	Customer Meters and Regulators: Protection From Damage	NA		
133	192.357	H	Customer Meters, Service Regulators, and Serviced Lines	Customer Meters and Regulators: Installation	NA		
134	192.359	H	Customer Meters, Service Regulators, and Serviced Lines	Customer Meter Installations: Operating Pressure	NA		
135	192.361	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Installation	NA		
136	192.363	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Valve Requirements	NA		
137	192.365	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Location of Valves	NA		
138	192.367	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: General Requirements for Connections to Main Piping	NA		
139	192.369	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Connections to Cast Iron or Ductile Iron Mains	NA		
140	192.371	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Steel	NA		
141	192.373	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Cast Iron and Ductile Iron	NA		
142	192.375	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Plastic	NA		
143	192.377	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Copper	NA		
144	192.379	H	Customer Meters, Service Regulators, and Serviced Lines	New Service Lines Not in Use	NA		
145	192.381	H	Customer Meters, Service Regulators, and Serviced Lines	Service Lines: Excess Flow Valve Perf. Stds.	NA		
146	192.383	H	Customer Meters, Service Regulators, and Serviced Lines	Excess Flow Valve Customer Notification	NA		
147	192.501	J	Test Requirements	Scope	15.01		
148	192.503	J	Test Requirements	General Requirements	15.01		
149	192.505	J	Test Requirements	Strength Test Requirements For Steel Pipeline to Operator at a Hoop Stress of 30% or More of SMYS	15.01		
150	192.507	J	Test Requirements	Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30% of SMYS and Above 100 psig	15.01		
151	192.509	J	Test Requirements	Test Requirements for Pipelines to Operate below 100 psig	15.01		
152	192.511	J	Test Requirements	Test Requirements for Service Lines			
153	192.513	J	Test Requirements	Test Requirements for Plastic Pipelines	16.05		
154	192.515	J	Test Requirements	Environmental Protection and Safety Requirements	15.01		
155	192.517	J	Test Requirements	Records	15.01		
156	192.451	I	Requirements for Corrosion Control	Scope			
157	192.452	I	Requirements for Corrosion Control	Applicability to Converted Pipelines	12.02		

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158	192.453	I	Requirements for Corrosion Control	General	6.01 – 6.10		
159	192.455	I	Requirements for Corrosion Control	External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971	6.05		6.03, 6.09
160	192.457	I	Requirements for Corrosion Control	External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971	6.05		6.03, 6.09
161	192.459	I	Requirements for Corrosion Control	External Corrosion Control: Examination of Buried Pipeline When Exposed	6.04		6.03
162	192.461	I	Requirements for Corrosion Control	External Corrosion Control: Protective Coating	6.03		
163	192.463	I	Requirements for Corrosion Control	External Corrosion Control: Cathodic Protection	6.05		6.03
164	192.465(a)	I	Requirements for Corrosion Control	External Corrosion Control: Monitoring - Pipe to soil monitoring	6.05		6.03
165	192.465(b)	I	Requirements for Corrosion Control	External Corrosion Control: Monitoring - Rectifier monitoring	6.05		6.03
166	192.465(c)	I	Requirements for Corrosion Control	External Corrosion Control: Monitoring - Interferance bond monitoring	6.05		6.03
167	192.465(d)	I	Requirements for Corrosion Control	External Corrosion Control: Monitoring - Remedial action	6.05		6.03
168	192.465(e)	I	Requirements for Corrosion Control	External Corrosion Control: Monitoring - Electrical surveys	6.05		6.07, 6.09
169	192.467	I	Requirements for Corrosion Control	External Corrosion Control: Electrical Isolation	6.06	5.4.2	
170	192.479	I	Requirements for Corrosion Control	External Corrosion Control: Test Stations	6.05		
171	192.471	I	Requirements for Corrosion Control	External Corrosion Control: Test Leads	6.05		
172	192.473	I	Requirements for Corrosion Control	External Corrosion Control: Interference Currents	6.05		
173	192.475(a)	I	Requirements for Corrosion Control	Internal Corrosion Control: General - Proper procedures for transporting corrosive gas	6.05		
174	192.475(b)	I	Requirements for Corrosion Control	Internal Corrosion Control: General - Exceptions	6.02		6.04
175	192.476(a)	I	Requirements for Corrosion Control	Internal Corrosion Control: General - New construction	6.02		
176	192.476(b)	I	Requirements for Corrosion Control	Internal Corrosion Control: General - Exceptions	6.02		
177	192.476(c)	I	Requirements for Corrosion Control	Internal Corrosion Control: General - Evaluate impact of configuration changes to existing system	6.02		
178	192.477	I	Requirements for Corrosion Control	Internal Corrosion Control: Monitoring - Coupon Monitoring	6.02		
179	192.479(a)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: General - Each exposed pipe must be cleaned and coated	6.02		
180	192.479(b)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: General - Suitable coating material	6.02		
181	192.479(c)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: General - Light surface oxide	6.01		
182	192.481(a)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: Monitoring Frequency	6.01		
183	192.481(b)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: Monitoring - Special attention to soil/air surfaces	6.01		
184	192.481(c)	I	Requirements for Corrosion Control	Atmospheric Corrosion Control: Monitoring - Protection if atm corrosion found	6.01		
185	192.483	I	Requirements for Corrosion Control	Remedial Measures: General	6.11		6.03
186	192.485(a)	I	Requirements for Corrosion Control	Remedial Measures: General - Procedures to replace pipe or lower MAOP for general corrosion	6.11		6.03
187	192.485(b)	I	Requirements for Corrosion Control	Remedial Measures: General - Procedures to replace pipe or lower MAOP for localized corrosion	6.11		6.03

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188	192.485(c)	I	Requirements for Corrosion Control	Remedial Measures: Transmission Lines - Procedure to use R-strent of ASME B31G	6.11		1.02, 5.01, 6.01, 6.02, 6.04, 8.01, 9.01
189	192.487	I	Requirements for Corrosion Control	Remedial Measures: Distribution Lines Other Than Cast Iron Or Ductile Iron Pipelines			
190	192.489	I	Requirements for Corrosion Control	Remedial Measures: Cast Iron and Ductile Iron Pipelines			
191	192.491	I	Requirements for Corrosion Control	Corrosion Control Records	6.08		2.01, 6.01, 6.02.
192	192.501	J	Test Requirements	Scope	15.01		
193	192.503	J	Test Requirements	General Requirements	15.01		
194	192.505	J	Test Requirements	Strength Test Requirements For Steel Pipeline to Operator at a Hoop Stress of 30% or More of SMYS	15.01		
195	192.507	J	Test Requirements	Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30% of SMYS and Above 100 psig	15.01		
196	192.509	J	Test Requirements	Test Requirements for Pipelines to Operate below 100 psig	15.01		
197	192.511	J	Test Requirements	Test Requirements for Service Lines			
198	192.513	J	Test Requirements	Test Requirements for Plastic Pipelines	16.05		
199	192.515	J	Test Requirements	Environmental Protection and Safety Requirements	15.01		
200	192.517	J	Test Requirements	Records	15.01		
201	192.551	K	Uprating	Scope	12.01		
202	192.553	K	Uprating	General Requirements	12.01		
203	192.555	K	Uprating	Uprating to a Pressure that Will Produce a Hoop Stress of 30% or More of SMYS in Steel Pipelines	12.01		
204	192.557	K	Uprating	Uprating: Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 % of SMYS; Plastic, Cast Iron, and Ductile Iron Pipelines	12.01		
205	192.605	L	Operations	Procedure Manual for Operations, Maintenance, and Emergencies	Forward		
206	192.605(a)	L	Operations	Annual review of O&M and emergency procedures	Forward		
207	192.605(b)	L	Operations	Specific Procedure Requirements for O&M Manual			
208	192.605(b)(1)	L	Operations	Procedure for Operating, Maintaining, and Repairing Pipeline	9.06		
209	192.605(b)(2)	L	Operations	Procedure for Controlling Corrosion	6.01-6.11		
210	192.605(b)(3)	L	Operations	Procedure for Making Construction Maps, Records, and Operating History Available	PSOM		
211	192.605(b)(4)	L	Operations	Procedure for Gathering Data for Reporting Incidents under 191	1.01		
212	192.605(b)(5)	L	Operations	Procedure for Starting and Shutting Down Any Part of the Pipeline	PSOM		
213	192.605(b)(6)	L	Operations	Procedure for Maintaining Compressor Stations Including Isolation	PSOM		10.01 - 10.03
214	192.605(b)(7)	L	Operations	Procedure for Startup, Shutdown, and Operation of Compressors	PSOM		10.01 - 10.04
215	192.605(b)(8)	L	Operations	Procedure for Periodically Reviewing Work Performed by Operator	PSOM		
216	192.605(b)(9)	L	Operations	Procedure for Taking Adequate Precautions in Excavated Trenches	14.04		
217	192.605(b)(10)	L	Operations	Procedure for Testing and Inspection of Bottle Type Holders	NA		
218	192.605(b)(11)	L	Operations	Procedure for Periodic Testing and Sampling of Gas in Storage	NA		
219	192.605(c)	L	Operations	Abnormal Operations	PSOM		
220	192.605(d)	L	Operations	Safety Related Condition	1.02		
221	192.605(e)	L	Operations	Procedures for Surveillance, Emergency Response, and Accident Investigation	5.01, Em Plan, & 1.03		
222	192.609	L	Operations	Change in Class Location Required Study	4.01		
223	192.611	L	Operations	Change in Class Location Confirmation or Revision of MAOP	4.01		
224	192.613	L	Operations	Continuing Surveillance Review	5.01		
225	193.614	L	Operations	Damage Prevention	3.01		3.03
226	615(a)(1)	L	Operations	Em. Plan - Receiving, identifying, and classifying notices of events which require immediate response by the operator	Em Plan		3.04, 3.02
227	615(a)(2)	L	Operations	Em. Plan - Establish and maintain communication with appropriate public officials regarding possible emergency	Em Plan		3.04, 3.03
228	615(a)(3)(i)	L	Operations	Em. Plan - Prompt response to the following emergency: Gas detected inside a building	Em Plan		3.04, 3.04
229	615(a)(3)(ii)	L	Operations	Em. Plan - Prompt response to the following emergency: Fire located near a pipeline	Em Plan		3.04, 3.05
230	615(a)(3)(iii)	L	Operations	Em. Plan - Prompt response to the following emergency: Explosion near a pipeline	Em Plan		3.04, 3.06
231	615(a)(3)(iv)	L	Operations	Em. Plan - Prompt response to the following emergency: Natural disaster	Em Plan		3.04, 3.07
232	615(a)(4)	L	Operations	7.01]	Em Plan		3.04, 3.08
233	615(a)(5)	L	Operations	Em. Plan - Actions directed towards protecting people first, then property	Em Plan		3.04, 3.09
234	615(a)(6)	L	Operations	Em. Plan - Emergency shutdown or pressure reduction to minimize hazards to life or property	Em Plan		3.04, 3.10
235	615(a)(7)	L	Operations	Em. Plan - Making safe any actual or potential hazard to life or property	Em Plan		3.04, 3.11

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236	615(a)(8)	L	Operations	Em. Plan - Notifying appropriate public officials required at the emergency scene and coordinating planned and actual responses with these officials	Em Plan		3.04, 3.12
237	615(a)(9)	L	Operations	Em. Plan - Instructions for restoring service outages after the emergency has been rendered safe	Em Plan		3.04, 3.13
238	615(a)(10)	L	Operations	Em. Plan - Investigating accidents and failures as soon as possible after the emergency	Em Plan		3.04, 3.14
239	615(b)(1)	L	Operations	Em. Plan - Furnishing applicable portions of the emergency plan to supervisory personnel who are responsible for emergency action	Em Plan		3.04, 3.15
240	615(b)(2)	L	Operations	Em. Plan - Training appropriate employees as to the requirements of the emergency plan and verifying effectiveness of training	Em Plan		3.04, 3.16
241	615(b)(3)	L	Operations	Em. Plan - Reviewing activities following emergencies to determine if the procedures were effective	Em Plan		3.04, 3.17
242	615(c)	L	Operations	Em. Plan - Establish and maintain liaison with appropriate public officials, such that both the operator and public officials are aware of each other's resources and capabilities in dealing with gas emergencies	Em Plan		3.04, 3.18
243	616(d)(1)	L	Operations	PA program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: (1) Use of a one-call notification system prior to excavation and other damage prevention activities	3.03		
244	616(d)(2)	L	Operations	PA program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: (2) Possible hazards associated with unintended releases from a gas pipeline facility	3.03		
245	616(d)(3)	L	Operations	PA program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: (3) Physical indications of a possible release	3.03		
246	616(d)(4)	L	Operations	PA program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: (4) Steps to be taken for public safety in the event of a gas pipeline release	3.03		
247	616(d)(5)	L	Operations	PA program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on: (5) Procedures to report such an event (to the operator).	3.03		
248	616(e)	L	Operations	The operator's program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.	3.03		
249	616(f)	L	Operations	The operator's program and the media used must be comprehensive enough to reach all areas in which the operator transports gas	3.03		
250	616(g)	L	Operations	The program conducted in English and any other languages commonly understood by a significant number of the population in the operator's area?	3.03		
251	617	L	Operations	Analyzing accidents and failures including laboratory analysis where appropriate to determine cause and prevention of recurrence	1.03		
252	619(a)(1)	L	Operations	Establishing MAOP so that it is commensurate with the class location MAOP cannot exceed the lowest of the following: (a)(1) Design pressure of the weakest element	8.01		12.01, 5.01
253	619(a)(2)	L	Operations	Establishing MAOP so that it is commensurate with the class location MAOP cannot exceed the lowest of the following: (a)(2) Test pressure divided by applicable factor	8.01		12.01, 5.01
254	619(a)(3)	L	Operations	Establishing MAOP so that it is commensurate with the class location MAOP cannot exceed the lowest of the following: (a)(3) The highest actual operating pressure to which the segment of line was subjected during the 5 years preceding the applicable date in second column, unless the segment was tested according to .619(a)(2) after the applicable date in the third column or the segment was uprated according to subpart K.	8.01		12.01, 5.01

CVGS O&M Cross Reference Table

FN: Gas O&M x-ref, v2012-1
Updated: Sept 2012

Line #	192 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
255	619(a)(4)	L	Operations	Establishing MAOP so that it is commensurate with the class location MAOP cannot exceed the lowest of the following: (a)(4) Maximum safe pressure determined by operator.	8.01		12.01, 5.01
256	619(b)	L	Operations	Overpressure protective devices must be installed if .619(a)(4) is applicable	7.02		
257	619(c)	L	Operations	The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.	8.01		
258	620	L	Operations	Use of alternate MAOP (greater than 72% SMYS)	NA		
259	625(b)	L	Operations	Odorized gas in Class 3 or 4 locations (if applicable) – must be readily detectable by person with normal sense of smell at 1/5 of the LEL	11.01		
260	625(f)	L	Operations	Periodic gas sampling, using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.	11.01		
261	627	L	Operations	Hot taps must be made by a qualified crew NDT testing is suggested prior to tapping the pipe. Reference API RP 2201 for Best Practices	9.05		
262	629(a)	L	Operations	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the pipeline (a) Lines containing air must be properly purged	9.03		9.04
263	629(b)	L	Operations	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the pipeline (b) Lines containing gas must be properly purged	9.03		9.04
264	703(b)	M	Maintenance	Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service	9.01		1.02, 5.01, 5.02, 5.03, 6.11,8.02
265	703(c)	M	Maintenance	Hazardous leaks must be repaired promptly	9.01		1.02, 5.01, 5.02, 5.03, 6.11,8.02
266	705(a)	M	Maintenance	Patrolling ROW conditions	5.03		
267	705(b)	M	Maintenance	Intervals between patrols	5.03		
268	706	M	Maintenance	Leakage surveys	5.02		
269	707	M	Maintenance	Line markers installed and labeled as required	5.04		
270	709	M	Maintenance	Records must be maintained (a) Repairs to the pipe – life of system	2.01		
271	709	M	Maintenance	Records must be maintained (b) Repairs to "other than pipe" – 5 years	2.01		
272	709	M	Maintenance	Records must be maintained (c) Operation (Sub L) and Maintenance (Sub M) patrols, surveys, tests – 5 years or until next one	2.01		
273	711	M	Maintenance	General requirements for repair procedures	9.01		8.02
274	713(a)(1)	M	Maintenance	Repairs of imperfections and damages on pipelines operating above 40% SMYS (1) Cut out a cylindrical piece of pipe and replace with pipe of $ design strength	9.01		8.02
275	713(a)(2)	M	Maintenance	Repairs of imperfections and damages on pipelines operating above 40% SMYS (2) Use of a reliable engineering method	9.01		8.02
276	713(b)	M	Maintenance	Reduce operating pressure to a safe level during the repair	9.01		8.02
277	715(a)	M	Maintenance	Welds found to be unacceptable under §192.241(c) must be repaired by: (a) If feasible, taking the line out of service and repairing the weld in accordance with the applicable requirements of §192.245.	9.01		8.02, 15.02
278	715(b)(1)	M	Maintenance	Welds found to be unacceptable under §192.241(c) must be repaired by: (b) If the line remains in service, the weld may be repaired in accordance with §192.245 if: (1) The weld is not leaking	9.01		8.02, 15.02
279	715(b)(2)	M	Maintenance	Welds found to be unacceptable under §192.241(c) must be repaired by: (b) If the line remains in service, the weld may be repaired in accordance with §192.245 if: (2) The pressure is reduced to produce a stress that is 20% of SMYS or less	9.01		8.02, 15.02
280	715(b)(3)	M	Maintenance	Welds found to be unacceptable under §192.241(c) must be repaired by: (b) If the line remains in service, the weld may be repaired in accordance with §192.245 if: (3) Grinding is limited so that ⅛ inch of pipe weld remains	9.01		8.02, 15.02
281	715(c)	M	Maintenance	If the weld cannot be repaired in accordance with (a) or (b) above, a full encirclement welded split sleeve must be installed	9.01		8.02, 15.02
282	717(a)	M	Maintenance	Field repairs of leaks must be made as follows: (a) Replace by cutting out a cylinder and replace with pipe similar or of greater design	9.01		8.02
283	717(b)(1)	M	Maintenance	Field repairs of leaks must be made as follows: (b)(1) Install a full encirclement welded split sleeve of an appropriate design unless the pipe is joined by mechanical couplings and operates at less than 40% SMYS	9.01		8.02

CVGS O&M Cross Reference Table
FN: Gas O&M x-ref, v2012-1
Updated: Sept 2012

Line #	192 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
284	717(b)(2)	M	Maintenance	Field repairs of leaks must be made as follows: (b)(2) A leak due to a corrosion pit may be repaired by installing a bolt on leak clamp	9.01		8.02

CVGS O&M Cross Reference Table

FN: Gas O&M x-ref, v2012-1
Updated: Sept 2012

Line #	192 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
285	717(b)(3)	M	Maintenance	Field repairs of leaks must be made as follows: (b)(3) For a corrosion pit leak, if a pipe is not more than 40,000 psi SMYS, the pits may be repaired by fillet welding a steel plate. The plate must have rounded corners and the same thickness or greater than the pipe, and not more than ½D of the pipe size	9.01		8.02
286	717(b)(4)	M	Maintenance	Field repairs of leaks must be made as follows: (b)(4) Submerged offshore pipe or pipe in inland navigable waterways may be repaired with a mechanically applied full encirclement split sleeve of appropriate design	9.01		8.02
287	717(b)(5)	M	Maintenance	Field repairs of leaks must be made as follows: (b)(5) Apply reliable engineering method	9.01		8.02
288	719(a)	M	Maintenance	Replacement pipe must be pressure tested to meet the requirements of a new pipeline	9.01		15.01, 15.02
289	719(b)	M	Maintenance	For lines of 6-inch diameter or larger and that operate at 20% of more of SMYS, the repair must be nondestructively tested in accordance with §192.241(c)	9.01		15.01, 15.02
290	727(b)	M	Maintenance	Operator must disconnect both ends, purge, and seal each end before abandonment or a period of deactivation where the pipeline is not being maintained. Offshore abandoned pipelines must be filled with water or an inert material, with the ends sealed	13.01		
291	727(c)	M	Maintenance	Except for service lines, each inactive pipeline that is not being maintained under Part 192 must be disconnected from all gas sources/supplies, purged, and sealed at each end.	13.01		
292	727(d)(1)	M	Maintenance	Whenever service to a customer is discontinued, do the procedures indicate one of the following: (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator	13.01		
293	727(d)(2)	M	Maintenance	Whenever service to a customer is discontinued, do the procedures indicate one of the following: (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly	13.01		
294	727(d)(3)	M	Maintenance	Whenever service to a customer is discontinued, do the procedures indicate one of the following: (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed	13.01		
295	727(e)	M	Maintenance	If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging	13.01		
296	727(g)	M	Maintenance	Operator must file reports upon abandoning underwater facilities crossing navigable waterways, including offshore facilities.	13.01		
297	731	M	Maintenance	Inspection and testing procedures for remote control shutdowns and pressure relieving devices (1 per yr/15 months), prompt repair or replacement	10.01		7.02

CVGS O&M Cross Reference Table

FN: Gas O&M x-ref, v2012-1
Updated: Sept 2012

Line #	192 Regulation	Subpart	Subpart Title	Description of Regulation:	Primary Procedure #	Primary Procedure Section #	Secondary Procedure(s) #
298	737(a)	M	Maintenance	(a) Storage of excess flammable or combustible materials at a safe distance from the compressor buildings	10.02		14.03
299	737(b)	M	Maintenance	(b) Tank must be protected according to NFPA #30	10.02		14.03
300	736	M	Maintenance	Compressor buildings in a compressor station must have fixed gas detection and alarm systems (must be performance tested), unless: - 50% of the upright side areas are permanently open, or - It is an unattended field compressor station of 1000 hp or less	10.03		
301	739(a)(1)	M	Maintenance	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (1 per yr/15 months) (1) In good mechanical condition	7.02		
302	739(a)(2)	M	Maintenance	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (1 per yr/15 months): (2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed	7.02		
303	739(a)(3)	M	Maintenance	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (1 per yr/15 months): (3) Set to control or relieve at correct pressures consistent with .201(a), except for .739(b).	7.02		
304	739(a)(4)	M	Maintenance	Inspection and testing procedures for pressure limiting stations, relief devices, pressure regulating stations and equipment (1 per yr/15 months): (4) Properly installed and protected from dirt, liquids, other conditions that may prevent proper oper.	7.02		
305	739(b)	M	Maintenance	For steel lines if MAOP is determined per .619(c) and the MAOP is 60 psi (414 kPa) gage or more . . .:If MAOP produces hoop stress that is greater than 72 percent of SMYS, then pressure limit is MAOP plu 4%.....If unknown as a percent of SMYS a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP	7.02		
306	743(a)	M	Maintenance	Testing of Relief Devices: (a) Capacity must be consistent with .201(a) except for .739(b), and be determined 1 per yr/15 mo.	7.02		
307	743(b)	M	Maintenance	Testing of Relief Devices: (b) If calculated, capacities must be compared; annual review and documentation are required.	7.02		
308	743(c)	M	Maintenance	Testing of Relief Devices: (c) If insufficient capacity, new or additional devices must be installed to provide required capacity.	7.02		
309	745(a)	M	Maintenance	(a) Inspect and partially operate each transmission valve that might be required during an emergency (1 per yr/15 months)	7.01		
310	745(b)	M	Maintenance	(b) Prompt remedial action required, or designate alternative valve.	7.01		
311	749	M	Maintenance	Inspection of vaults greater than 200 cubic feet (1 per yr/15 months)	7.03		
312	751(a)	M	Maintenance	Prevention of Accidental Ignition; Reduce the hazard of fire or explosion by: (a) Removal of ignition sources in presence of gas and providing for a fire extinguisher	14.03		9.03, 9.04
313	751(b)	M	Maintenance	Prevention of Accidental Ignition; Reduce the hazard of fire or explosion by: (b) Prevent welding or cutting on a pipeline containing a combustible mixture	14.03		9.03, 9.05
314	751(c)	M	Maintenance	Prevention of Accidental Ignition; Reduce the hazard of fire or explosion by: (c) Post warning signs	14.03		9.03, 9.06

Gas Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

PROCEDURE	FORM	TITLE	Frequency
1.01	Chart 1.01A	Accident Reporting Criteria	AR
1.01	Form 1.01B	Incident and Service Interruption Report	AR
1.01	RSPA F7100.2 (FEDERAL)	Incident Report – Gas Transmission and Gathering Systems	AR
1.01	Chart 1.02A	Safety Related Condition Reporting Criteria	AR
1.02	Form 1.02B	Safety Related Condition Report	AR
1.03	Form 2055	Accident & Near Miss Investigation Report	AR
1.03	Form 1.03	Failure Investigation Form (PHMSA form #11)	AR
1.04	RSPA F7100.2-1(FEDERAL) & instructions	Annual Report for Calendar Year 20__ -Gas Trans. and Gathering Systems	1x/yr
3.01	Form 3.01B	Pipeline Maintenance and Surveillance Form	Various
3.03	Form 3.03A	Government Liaison Record of Face to Face Meeting	1x/yr
3.03	Form 3.03B	Damage Prevention Program List of Contacts	1x/yr
3.03	3.03-1	Public Awareness Annual Review for Implementation and Supplemental Efforts	1x/yr
3.03	3.03-2	Public Awareness Evaluation of Effectiveness	1x/4yr
3.03	3.03-3	Public Awareness Agenda and Action Items	1x/yr
3.03	3.03-4	Public Awareness Team Charter template	1x/yr
3.03	3.03-5	Public Awareness Government Liaison	1x/yr
3.03	3.03A - PA Agenda	Public Awareness Agenda	1x/yr
3.03	3.03B - PA Team Charter	Public Awareness Team Charter	1x/yr
4.01	Form 4.01A	Class Location Survey Form	1x/yr
4.02	Form 4.02A	Gas Gathering Determination	AR
5.01	Form 5.01	Continuing Surveillance Review	1x/yr
5.02/5.03	Form 5.02B/5.03B	Gas Leak Survey/Pipeline Patrol	Various
5.03	Form 5.03C	Navigable Waterway Crossing Inspection Form	Various
5.03D	Form 5.03D	Critical Crossing Inspection	Various
6.01	Form 6.01A	External Corrosion Test for Above Ground Facilities (Atmospheric Corrosion)	Various

Gas Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

PROCEDURE	FORM	TITLE	Frequency
6.02	Form 6.02A	Internal Pipe Inspection	AR
6.02	Form 6.02B-1	Gas Analysis Sampling	1x/yr or AR
6.02	Form 6.02B-2	Gas Analysis Review and Evaluation	AR
6.02	Form 6.02C	Internal Corrosion Coupon Monitoring	2x/yr
6.05	Form 6.05A	CP System Record	1x/yr
6.05	Form 6.05B	Critical Bonds	6x/yr
6.07	Form 6.07A	Rectifier Inspection	6x/yr
6.09	Form 6.09A	Unprotected Pipeline Inspection Report	1x/yr
7.01	Form 7.01A	Emergency Valve Inspection Report	1x/yr
7.02	Form 7.02A	Relief Valve Report	1x/yr
7.02	Form 7.02B	Regulator Report	1x/yr
7.02	Form 7.02C	Relief Valve and Regulator Capacity Review	1x/yr
7.03	Form 7.03A	Vault With Regulator Inspection Form	1x/yr
8.01	Form 8.01A	Pipeline Qualification Record	AR
8.01	Form 8.01B	MAOP Pipeline Calculation template	AR
10.01	Form 10.01A	Compressor Station Remote Control Shutdown Device Test Form	1x/yr
10.03	Form 10.03A	Compressor Station Gas Detection and Alarm System Test and Evaluation	1x/yr
11.01	Form 11.01B	Odorant Sampling Report	Periodic
12.02	Form 12.02A	Conversion of Service Form	AR
12.02	Template Form 12.02B	Conversion of Service Form – Fact Sheet Info Template	AR
12.02	Template Form 12.02C	Conversion of Service Form – Step by Step Template	AR
13.01	Form 13.01A	Facility Abandonment Record	AR

Gas Pipelines - LIST OF FORMS REQUIRED BY STANDARD PROCEDURES

PROCEDURE	FORM	TITLE	Frequency
PSOM		Abnormal Operations Report	
PSOM		DOT Pre-Audit Form	
PSOM		Miscellaneous CRM	
PSOM		Review Work Performed by Operator Tracking Form	
PSOM		Pipeline Management of Change (MOC)	
PSOM		Training Registration	

REPORTING AND CONTROL OF INCIDENTS

1. REFERENCE

   49 CFR, Sections 191.1, 191.3, 191.5, 191.7, 191.15, 191.19 and 192.605(b)(4).
   PHMSA Advisory ADB 10-04, April 29, 2010

2. PURPOSE

   The purpose of this procedure is to establish responsibilities for activities associated with certain pipeline facility incidents. These activities include, but are not limited to, incident control, repair, reporting, investigation and documentation.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (1)__________________ is responsible for reporting and documentation of pipeline facilities incidents.

4. INCIDENT CRITERIA [191.3]

   Incidents which meet the Criteria listed below shall be reported and controlled under this procedure.

   4.1 "Incident" means any of the following events:

   An event that involves a release of gas from a pipeline or pipeline facility and that results in one or more of the following consequences:

   4.1.1 A death or personal injury requiring in-patient hospitalization of an employee or member or the public.

   4.1.2 Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost; If in doubt, report the incident to the (2) _________.

   4.1.3 Unintentional estimated gas loss of three million cubic feet or more;

   4.2 An event that is significant in the judgment of the operator, even though it did not meet the criteria list above.

5. IMMEDIATE NOTICE OF CERTAIN INCIDENTS [191.5]

5.1 At the earliest practicable moment following discovery, the company shall give notice to the NRC as shown below.

5.2 Each "incident" notification required by this procedure must be made to the National Response Center either by telephone to 800–424–8802 (in Washington, DC, 202 267–2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

5.3 The Incident and Service Interruption Report from (Form 1.01B) is a check list intended to assure accurate conveying and recording of information transmitted by telephone. Copies should be made readily available to personnel who may report or receive reports of incidents. It is recognized that only limited details will probably be available when the initial call on an incident is made.

6. REPORT SUBMISSION REQUIREMENTS [191.7]

6.1 The company must submit each report required by this procedure electronically to the Pipeline and Hazardous Materials Safety Administration at *http://opsweb.phmsa.dot.gov* unless an alternative reporting method is authorized in accordance with requirements below.

6.2 ***Alternative Reporting Method***. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

7. WRITTEN REPORT SUBMISSION DEADLINE [191.15(a)]

7.1 Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

8. SUPPLEMENTAL REPORT REQUIREMENTS [191.15(c)]

8.1 Where additional related information is obtained after a report is submitted under this procedure, the company must make a supplemental report as soon as practicable with a clear reference by date to the original report.

9. INTRASTATE PIPELINES IN STATES WHERE STATE IS AN AGENT FOR PHMSA

9.1 For intrastate pipelines and in states where the state is an Agent for PHMSA, a report shall be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports. Also, provide a copy of the report to the DOT under the regulated time constraints stated within this procedure.

10. FIRST RESPONDER RESPONSIBILITIES

10.1 Company First Responder responsibilities include the following:

10.1.1 Establish initial control of each incident.

10.1.2 Immediately after initial control is established and a preliminary assessment or conditions can be made, call the (5)___________________, if not present at the location, and report those incidents meeting one of the Incident Criteria.

10.1.3 Coordinate all on-site activities including such things as repair, preservation of evidence and materials, internal reporting and documentation of events and actions.

10.1.4 Secure the site and maintain undisturbed if possible, until the appropriate Company representative is on site. If the site cannot be left undisturbed, document the site and incident details and preserve the site and details as indicated in the appropriate system specific

Emergency Plan or in Investigation of Failure and Accidents (Procedure 1.03).

10.1.5 Documentation and/or investigation of incidents as necessary to meet operational requirements. Use the Incident and Service Interruption Report form as a reference for the information to be reported (Form 1.01B). Submit Form 1.01B to the (9) __________________ as soon as possible (see 6.7.6).

11. PIPELINE SUPERVISOR RESPONSIBILITIES

11.1 Arrange for interviews of employees as required.

11.2 Arrange for the shipment or materials or evidence to specified locations.

11.3 Arrange for outside professional services to assist in an investigation (e.g., corrosion specialist, land surveyor, metallurgist, or welding engineer) if deemed necessary.

11.4 Analyze field data collected, operating history of facility and results of lab testing to establish cause of failure or condition and write reports as necessary.

11.5 Provide recommendations for operational changes or facility modifications as appropriate.

11.6 Recommend and review written recommendations for operational procedure changes prior to issuing for field use.

12. EHS ADVISOR RESPONSIBILITIES

12.1 Evaluate the reportability in conjunction with legal staff, if appropriate.

12.2 Report incidents to Federal and State safety and regulatory agencies within one to two hours of discovery. The report shall be made by telephone to (800) 424-8802 (National Response Center - NRC) and shall include the following information.

CAUTION: Anything that is said or written to the NRC becomes evidence in an "incident".

- Name(s) of person(s) making report and their telephone numbers.
- The location of incident.

- The time of the incident.
- The number of fatalities and personal injuries, if any.
- All other significant facts that are known to be relevant to the cause of the incident or extent of the damages.

12.3 Obtain an incident identification number from the NRC, and complete all required forms.

12.4 Receive requests for data, information or on-site investigation and respond to those requests after collaboration with other persons (Operations, Safety, Security, and Legal staff) as determined necessary or appropriate.

12.5 Submit copies of all incident reports (including supplemental reports) to other agencies, as required, and to the District Office.

13. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
1.03 Investigation of Failures and Accidents
3.04 Preparation of an Emergency Plan System Specific Emergency Plan

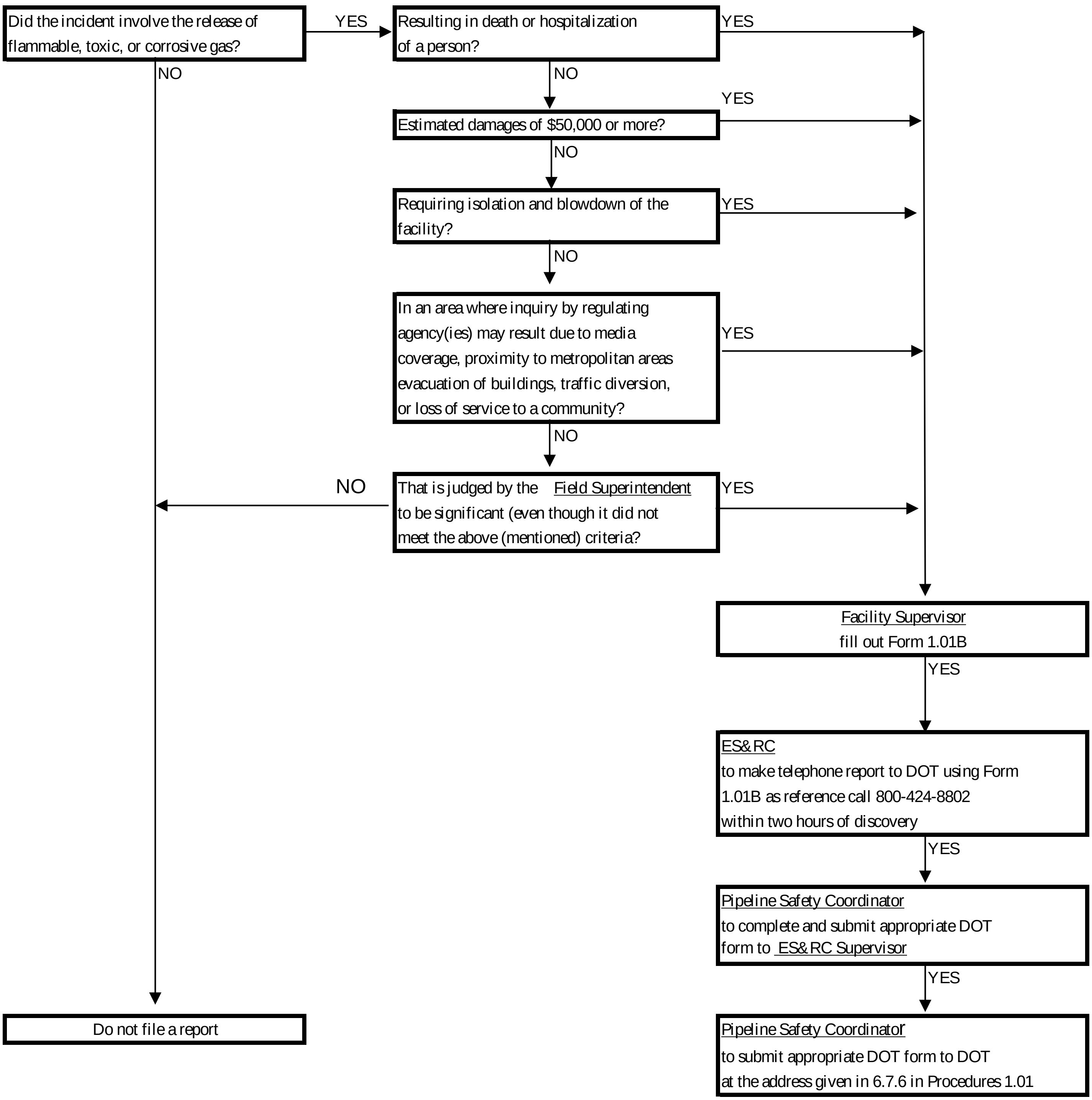
14. RECORDS

14.1 The (18) __________________ will maintain the official files on incidents meeting one of the Incident Criteria that are reported to outside agencies.

14.2 Each file will be kept for the life of the pipeline. Legal department shall be contacted prior to destroying a file.

EXTERNAL REPORTING OF INCIDENTS

CHART 1.01A (GAS) [191.3]



See Procedure 1.01, Section 6 for Internal Reporting of Incidents and for more details on External Reporting of Incidents.

INCIDENT AND SERVICE INTERRUPTION REPORT

FORM 1.01B [191.5]

REPORTED BY:	REPORTED TO:	TIME:	DATE: ______ M0-DAY-YR
PHONE No.:	PHONE No.:		
COMPANY:	DISTRICT/LOCATION:	MEDIA ATTENTION	YES NO

Time/Location

PLANT:	PIPELINE NAME: ☐ Rural ☐ Non Rural ☐ Offshore						
STATE:	COUNTY/ PARISH:	SEC.-TWN-RANGE: ☐ Gas ☐ Haz Liq					
PIPELINE DATA	☐ Transmission ☐ Gathering	GATHERING: ☐ D.O.T. Juris ☐ Non Juris	Size	Wall	Grade	MAOP	OP Pressure

Incident

		Yes	No		Yes	No
Release and Fatality	Employee ☐ Public ☐			Fire or Explosion		
Release and Injury	Employee ☐ Public ☐			Other significant Event		
Gas Release and Property Damage > $50,000 Haz Liquid Release > 50 bbls				Total Estimated Property Damage to Company and others $		

System Interruption

System Interruption ☐ Yes ☐ No	Estimated Length of System interruption		Hours		Minutes
System or Customer affected:					
	DATE & TIME COMPLETED	EST. ACT.			

Description & Apparent Cause

☐ Outside Force ☐ Corrosion ☐ Material Failure ☐ Construction Defect ☐ Other

DESCRIPTION AND APPARENT CAUSE: ______

Action Taken

Temporary measures to protect the public or maintain the system:	DATE & TIME SYSTEM COMPLETED	EST. ACT.
Repair: ______	DATE & TIME REPAIR COMPLETED	EST. ACT.

Report Activity

Telephone Report	To ☐ DOT ☐ STATE ☐ OTHERS:		
	Reported By:	Date Reported:	Time Reported:
☐ Form RSPA F 7100.2 ☐ Form DOT 7000-1	Reported By:		Date:

Distribution:

______

______

______

Signatures:

Completed By: ______

Supervisor: ______

INSTRUCTIONS FOR FORM PHMSA F 7100.2 (Rev. 01-2010) INCIDENT REPORT – GAS TRANSMISSION AND GATHERING SYSTEMS

Revised (11/2010)

GENERAL INSTRUCTIONS

Each gas transmission or gathering system operator shall file Form PHMSA F 7100.2 for an incident that meets the criteria in 49 CFR §191.3 as soon as practicable but not more than 30 days after the incident. Requirements for submitting reports are in §191.7.

Release of gas, for the purpose of maintenance or other routine activities, need not be reported if the only reportable criterion is loss of gas of $50,000 or more as described in 49 CFR §191.3 under "Incident" (1)(ii). Damage from secondary ignition need not be reported unless the damage to facilities subject to Part 191 exceeds $50,000. Secondary ignition is a fire where the origin is unrelated to the gas facilities, such as electrical fires, arson, etc.

If you need copies of Form PHMSA F 7100.2 and/or instructions they can be found on the Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking the Library hyperlink and then the Forms hyperlink under the "Mini Menu" on the right of the web page. The applicable forms are listed in the section titled Accidents/Incidents/Annual Reporting Forms. If you have questions about this report or these instructions, please call (202) 366-8075. Please type or print all entries when submitting forms by mail or Fax.

§191.3 Definitions.

* * * * *

***Incident* means any of the following events:**

(1) An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and

(i) A death, or personal injury necessitating in-patient hospitalization; or

(ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

(2) An event that results in an emergency shutdown of an LNG facility.

(3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2).

§191.5 Telephonic notice of certain incidents.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

(b) Each notice required by paragraph (a) of this section shall be made by telephone to 800-424-8802(in Washington, DC, 267-2675) and shall include the following information:

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

(5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

§ 191.15 Transmission and gathering systems: Incident report.

(a) Except as provided in paragraph (c) of this section, each operator of a transmission or a gathering pipeline system shall submit Department of Transportation Form RSPA[1] F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under Sec. 191.5.

(b) Where additional related information is obtained after a report is submitted under paragraph (a) of this section, the operator shall make a supplemental report as soon as practicable with a clear reference by date and subject to the original report.

(c) The incident report required by paragraph (a) of this section need not be submitted with respect to LNG facilities.

REPORTING METHODS

Use one of the following methods to submit your report. We strongly encourage online reporting over hardcopy submissions. If you prefer, you can mail or fax your completed reports to DOT/PHMSA.

[1] RSPA, the Research and Special Projects Administration, was a predecessor agency to PHMSA. The revised form is now designated PHMSA F 7100.2. This reference will be changed in the Code of Federal Regulations by rulemaking.

1. Online

a. Navigate to the new **Electronic Incident Accident (EIA) System** at the following URL http://pipelineonlinereporting.phmsa.dot.gov/.
b. Enter Operator ID and PIN (*the name that appears is the operator name assigned to the operator ID and PIN and is automatically populated by our database and cannot be changed by the operator at the time of filing*).
c. Under "**Create Reports**" on the left side of the screen, select the type of report you would like to create (i.e., gas transmission or gas distribution incident, or hazardous liquid accident) and proceed with entering your data. **Note**: *Data fields marked with a single asterisk are considered required fields that must be completed before the system will accept your initial filing.*
d. Click "**Submit**" when finished with your filing to have your report uploaded to our database; or click "**Save**" which doesn't submit the report to PHMSA but stores it in a draft status to allow you to come back to complete your filing at a later time. **Note**: *The "Save" feature will allow you to start a report and save a draft of it which you can print out to gather additional information and then come back to accurately complete your data entry before submitting it to PHMSA.*
e. Once you hit [Submit], the system will return you to the initial view of the screen that lists your [Saved Incident/Accident Reports] in the top portion of the screen and your [Submitted Incident/Accident Reports] in the bottom portion of the screen. **Note**: *To confirm that your report was successfully submitted to PHMSA, look for it in the bottom portion of the screen where you can also view a PDF of what you submitted.*

Note: **Supplemental Report Filing –** follow steps 1.a and 1.b above and then select a report from the [Submitted Incident/Accident Reports] lists as described in step 1.e. The report will default to supplemental and pre-populate data fields with data you previously submitted. At this point, you can amend your data and re-submit the report to PHMSA.

If you submit your report online, <u>PLEASE DO NOT MAIL OR FAX</u> the completed report to DOT as this may result in duplicate entries.

2. Mail to:

DOT/PHMSA Office of Pipeline Safety
Information Resources Manager,
1200 New Jersey Ave., SE
East Building, 2nd Floor, (PHP-20)
Room Number E22-321
Washington, DC 20590

3. Fax to: Information Resources Manager at (202) 366-4566.

30-DAY WRITTEN REPORT RETRACTION

An operator who submits a 30-day written report for an incident and upon subsequent investigation determines the incident did not meet the criteria in 49 CFR 191.3 should request to have the report retracted. Requests to retract a 30-day written report should be submitted on company letterhead and mailed or faxed to the Information Resources Manager at the address/fax number above. Letters to request retraction may also be submitted as email attachments to InformationResourcesManager@dot.gov. Requests should include the following information:

a. The Report ID, the unique 8-digit identifier assigned by PHMSA,
b. Operator name,
c. PHMSA-issued operator ID number,
d. Date of the incident,
e. Location of the incident (e.g., for onshore incidents: city, county, state), and
f. A brief statement as to why the 30-day written report should be retracted.

SPECIAL INSTRUCTIONS

1. Certain data fields must be completed before an Original Report will be accepted. The data fields that must be completed for an Original Report to be accepted are indicated on the form by a single asterisk (*). If filing a hardcopy of this report, the report will not be accepted by PHMSA unless all of these fields have been completed. If filing on-line, your Original Report will not be able to be submitted until the required information has been provided, although your partially completed form can be saved on-line so that you can return at a later time to provide the missing information.

2. An entry should be made in each applicable space or check box, unless otherwise directed by the section instructions.

3. If the data is unavailable, enter "unknown" for text fields and leave numeric fields and fields using check boxes or "radio" buttons blank.

4. If possible**,** provide an **estimate** in lieu of answering a question with "unknown" or leaving the field blank. Estimates should be based on best-available information and reasonable effort.

5. For unknown or estimated data entries, the operator should file a supplemental report when additional information becomes available to finalize the report.

6. If the question is not applicable, please enter "N/A" for text fields and leave numeric fields and fields using check boxes or "radio" buttons blank.

7. For questions requiring numeric answers, all data fields should be filled in using zeroes when appropriate. When decimal points are required, **the decimal point should be placed**

in a separate block in the data field.

Examples:

(Part C, item 3.a,) Nominal diameter of pipe (in):	/0/0/2/4/	(24 inches)
	/3/./5/	(3.5 inches)
(Part C, item 3.b), Wall thickness (in)	/0/./3/1/2/	(0.312 inches)
(Part C, item 3.c), SMYS	/0/5/2/,/0/0/0/	(52,000 psi)

8. If **OTHER** is checked for any answer to a question, please include an explanation or description on the line provided next to the item checked.

9. Pay close attention to each question for the phrase:
   a. ***(select all that apply)***
   b. ***(select only one)***

   If the phrase does not exist for a given question, then "select only one" is the default instruction. "Select all that apply" means that you should choose all answers that are applicable. "Select only one" means that you should select the single, primary or most applicable answer. DO NOT SELECT MORE ANSWERS THAN REQUESTED.

10. **Date format** = mm/dd/yy or for year = /yyyy/

11. **Time format:** All times are reported as a 24-hour clock:

    Time format Examples:

    a. (0000) = midnight = /0/0/0/0/
    b. (0800) = 8:00 a.m. = /0/8/0/0/
    c. (1200) = Noon = /1/2/0/0/
    d. (1715) = 5:15 p.m. = /1/7/1/5/
    e. (2200) = 10:00 p.m. = /2/2/0/0/

12. **Local time** always refers to time at the site of the incident.

SPECIFIC INSTRUCTIONS

PART A – GENERAL REPORT INFORMATION

Report Type: *(select all that apply)*

Check the appropriate report box or boxes to indicate the type of report being filed. Depending on the descriptions below, the following combinations of boxes may be selected:

- Original Report only
- Original Report plus Final Report

- Supplemental Report only
- Supplemental Report plus Final Report

☐ **Original Report**
Select this type of report if this is the FIRST report filed for this incident.

If all of the information requested is known and provided at the time the initial report is filed, including final property damages and failure cause information, check the box for "Final Report" as well as the box for "Original Report," indicating that no further information will be forthcoming.

☐ **Supplemental Report**
Select this type of report only if you have already filed an "Original Report" AND you are now providing new, updated, and/or corrected information. Multiple supplements are to be submitted, as necessary, in order to provide new, updated, and/or corrected information as it becomes available.

For Supplemental Reports filed by fax or mail, please check the **Supplemental Report** box, complete Part A, Items 1 through 6, and then enter information that has changed or is being added. Please do not enter previously submitted information that has not changed other than Items 1-6, which is needed to provide a way to identify previously filed reports.

For Supplemental Reports filed online, all data previously submitted will automatically populate in the form. Page through the form to make edits and additions where needed.

Operators are encouraged to file supplemental reports within one year in those instances where the supplemental report is used to update information from investigations that were still ongoing when the prior report was filed.

☐ **Final Report**
Select this type of report if you are filing an "Original Report" for which no further information will be forthcoming (as described under "Original Report" above) or if you have already filed an "Original Report" AND you are now providing new, updated, and/or corrected information via a "Supplemental Report" AND you are reasonably certain that no further information will be forthcoming. (Note: If an Operator files one of the two types of "Final" Reports and then subsequently finds that new information needs to be provided, it should submit another "Supplemental Report" and select the appropriate box or boxes – "Supplemental + Final" (if appropriate) – for the newly submitted report and include an explanation in the PART H Narrative.)

Supplemental reports must be filed as soon as practicable following the Operator's awareness of new, additional, or updated information. Failure to comply with these requirements can result in enforcement actions, including the assessment of civil penalties not to exceed $100,000 for each violation for each day that such violation persists up to a maximum of $1,000,000.

In Part A, answer questions from 1 thru 19 by providing the requested information or by checking the appropriate box.

1. Operator's OPS -Issued Operator Identification Number (OPID):

The Pipeline and Hazardous Materials Safety Administration (PHMSA) assigns the operator's identification number. Most OPIDs are 5 digits. Older OPIDs may contain fewer digits. If your OPID contains fewer than 5 digits, insert leading zeros to fill all blanks. Contact us at (202) 366-8075 if you need assistance with an identification number during our business hours of 8:30 AM to 5:00 PM Eastern Time.

2. Name of Operator

This is the company name used when registering for an Operator ID and PIN in the Online Data Entry System. For online entries, the Name of Operator should be automatically filled in based on the Operator Identification Number entered in question 1. If the name that appears does not coincide with the Operator ID, contact PHMSA at the number provided in Question 1.

3. Address of Operator

Enter the address of the operator's business office to which any correspondence related to the incident report should be sent.

4. Local time (24-hour clock) and date of the Incident.

For pipeline systems crossing multiple time zones, enter the time at the location of the Incident.

> See page 5 for examples of **Date format** and **Time format** expressed as a 24-hour clock

5. Location of Incident:

The latitude and longitude of the incident are to be reported as Decimal Degrees with a minimum of 5 decimal places (e.g. Lat: 38.89664 Long: -77.04327), using the NAD83 or WGS84 datums.

If you have coordinates in degrees/minutes or degrees/minutes/seconds use the formula below to convert to decimal degrees:

degrees + (minutes/60) + (seconds/3600) = decimal degrees

e.g. 38° 53' 47.904" = 38 + (53/60) + (47.904/3600) = 38.89664°

All locations in the United States will have a negative longitude coordinate**, which has already been printed on the form**.

If you cannot locate the incident with a GPS or some other means, the U.S. Census Bureau provides a tool for determining latitude and longitude, (http://tiger.census.gov/cgi-bin/mapbrowse-tbl). You can use the online tool to identify the geographic location of the incident. The tool displays the latitude and longitude in decimal degrees below the map. Any questions regarding the required format, conversion or how to use the tool noted above can be directed to Amy Nelson (202.493.0591 or amy.nelson@dot.gov).

6. National Response Center (NRC) Report Number

§ 191.5 requires that incidents meeting the criteria outlined in §191.3 be reported directly to the **24-hour National Response Center (NRC): at 1-800-424-8802** at the earliest practicable moment (generally within 2 hours). The NRC assigns numbers to each call. The number of that telephonic report is to be entered in Question 6.

7. Local time (24-hr clock) and date of initial telephonic report to the National Response Center:

Enter the time (local time at site of the Incident) and date of the telephonic report of Incident. The time should be shown by 24-hour clock notation (see page 5 for examples).

8. Incident resulted from:

Indicate whether the incident resulted from intentional or unintentional release of gas or from reasons other than release of gas.

9. Gas released:

Report the type of gas released. Examples of **synthetic gas** include landfill gas, biogas, and manufactured gas based on naptha.

10. Estimated volume of gas released unintentionally:

Estimate the amount of gas that was released (in thousands of cubic feet) from the beginning of the incident until such time as gas is no longer being released from the pipeline system or intentional and controlled blowdown has commenced. Estimates should be based on best-available information.

11. Estimated volume of intentional and controlled release/blowdown :

Estimate the amount of gas that was released (in thousands of cubic feet) during any intentional release or controlled blowdown conducted as part of responding to or recovering from the incident. Intentional and controlled blowdown implies a level of control of the site and situation by the Operator such that the area and the public are protected during the controlled release.

12. Estimated volume of accompanying liquid released

If any accompanying liquid was released as a result of the incident, estimate the quantity released, in barrels. **Barrel** means a unit of measurement equal to **42 U.S. standard gallons**. The table below converts gallons to barrels.

If estimated volume is		Report		If estimated volume is		Report	
5	gallons	**0.12**	barrels	24		**0.57**	barrels
6	gallons	**0.14**	barrels	25	gallons	**0.60**	barrels
7	gallons	**0.17**	barrels	26	gallons	**0.62**	barrels
8	gallons	**0.19**	barrels	27	gallons	**0.64**	barrels
9	gallons	**0.21**	barrels	28	gallons	**0.67**	barrels
10	gallons	**0.24**	barrels	29	gallons	**0.69**	barrels
11	gallons	**0.26**	barrels	30	gallons	**0.71**	barrels
12	gallons	**0.29**	barrels	31	gallons	**0.74**	barrels
13	gallons	**0.31**	barrels	32	gallons	**0.76**	barrels
14	gallons	**0.33**	barrels	33	gallons	**0.79**	barrels
15	gallons	**0.36**	barrels	34	gallons	**0.81**	barrels
16	gallons	**0.38**	barrels	35	gallons	**0.83**	barrels
17	gallons	**0.41**	barrels	36	gallons	**0.86**	barrels
18	gallons	**0.43**	barrels	37	gallons	**0.88**	barrels
19	gallons	**0.45**	barrels	38	gallons	**0.91**	barrels
20	gallons	**0.48**	barrels	39	gallons	**0.93**	barrels
21	gallons	**0.50**	barrels	40	gallons	**0.95**	barrels
22	gallons	**0.52**	barrels	41	gallons	**0.98**	barrels
23	gallons	**0.55**	barrels	42	gallons	**1.000**	barrels

13. Were there fatalities?

If a person dies at the time of the incident or within 30 days of the initial incident date due to injuries sustained as a result of the incident, report as a fatality. If a person dies subsequent to an injury more than 30 days past the incident date, report as an injury. This aligns with the Department of Transportation's general guidelines for all modes for reporting deaths and injuries.

Contractor employees working for the operator means people hired to work for or on behalf of the operator of the pipeline.

Non-operator emergency responders means people responding to render professional aid at the incident scene including on-duty fire fighters, rescue workers, EMTs, police officers, etc. "Good Samaritans" that stop to assist should be reported as "General public."

Workers Working on the Right of Way, but NOT Associated with this Operator means people authorized to work in or near the right-of-way, but not hired by or working on behalf of the operator of the pipeline. This includes all work conducted within the right of way including work associated with other underground facilities sharing the right of way, building/road construction in or across the right of way, or farming. This category most often includes employees of other pipelines or underground facilities operators, or their contractors, working in or near a shared right-of-way.

Workers performing work near, but not on, the right of way and who are affected should be reported as general public.

14. Were there injuries requiring inpatient hospitalization?
Injuries requiring inpatient hospitalization means injuries sustained as a result of the incident and which require both hospital admission *and* at least one overnight stay.

15. Was the pipeline/facility shut down due to the incident?
Report any shutdowns that occur because of damage incurred during the incident or to make repairs necessitated by the incident. Instances in which an incident was caused by a release that did not involve damage to the pipeline (e.g., incorrect operations) and in which no need for repairs resulted need not be reported as being shutdown, even though the pipeline may have been shutdown as a precautionary measure to inspect for damages.

If No is selected, explain the reason that no shutdown was needed in the blank provided.

If Yes is selected, complete questions 15.a and 15.b.

15.a. Local time (24hr clock) and date of shutdown
For pipeline systems crossing multiple time zones, enter the time at the location of the incident.

15.b. Local time pipeline/facility restarted
Report the time the pipeline/facility was restarted (if applicable). If the pipeline or facility has not been restarted at the time of reporting, check "Still shut down" and then include the restart time in a future Supplemental Report.

16. Did the gas Ignite?
Ignite means the gas caught fire**.**

17. Did the gas Explode?
Explode means the ignition of the gas with a sudden and violent release of energy.

18. Number of General Public Evacuated:
The number of people evacuated should be estimated based on operator knowledge, or police, fire or other emergency responder reports. If there was no evacuation involving the general public, report "0." If an estimate is not possible for some reason, leave blank but include an explanation of why it was not possible in the Part H Narrative.

19. Time sequence (use local time, 24-hour clock)

Enter the time the operator became aware that an event constituted an incident (i.e., identified the incident) and the time operator personnel or contract resources (i.e., personnel or equipment) arrived on site. All times should be local times at the location of the incident.

PART B – ADDITIONAL LOCATION INFORMATION

1. Was the origin of the incident onshore?
Answer Yes or No as appropriate and complete only the designated questions.

<u>For onshore pipelines</u>

2 – 5. Incident Location
Provide the state, zip code, city, and county/parish in which the incident occurred.

6. Operator Designated Location:

This is intended to be the designation that the operator would use to identify the location of the Incident on its pipeline system. Enter the appropriate milepost/valve station or survey station number. This designator is intended to allow PHMSA personnel to both return to the physical location of the Incident using the operator's own maps and identification systems as well as to identify the "paper" location of the Incident when reviewing operator maps and records.

7. Pipeline/Facility Name

Multiple pipeline systems and/or facilities are often operated by a single operator. This information identifies the particular pipeline system or pipeline facility name commonly used by the operator on which the Incident occurred, for example, the "West Line 24" Pipeline", or "Gulf Coast Pipeline".

8. Segment name/ID

Within a given pipeline system and/or facility, there are typically multiple segment or station identifiers, names, or ID's which are commonly used by the operator. The information to be reported here helps locate and/or record the more precise incident location, for example, "Segment 4-32", or "MP 4.5 to Wayne County Line", or "Dublin Compressor Station", or "Witte Reducing Station".

9. Was the incident on Federal Lands other than the Outer Continental Shelf?

Federal Lands other than Outer Continental Shelf means all lands the United States owns, including military reservations, except lands in National Parks and lands held in trust for Native Americans. Incidents at Federal buildings, such as Federal Court Houses, Custom Houses, and other Federal office buildings and warehouses, are not to be reported as being on Federal Lands.

10. Location of incident

Operator-controlled Property would normally apply to an operator's facility, which may or may not have controlled access, but which is often fenced or otherwise marked with discernible boundaries. This "operator-controlled property" does not refer to the pipeline right-of-way, which is a separate choice for this question.

11. Area of Incident (as found)

Underground means pipe, components or other facilities installed below the natural ground level, road bed, or below the underwater natural bottom.

Under pavement includes under streets, sidewalks, paved roads, driveways and parking lots.

Exposed due to Excavation means that a normally buried pipeline had been exposed by any party (operator, operator's contractor, or third party) preparatory to or as a result of excavation. The cause of the release, however, may or may not necessarily be related to excavation damage. This category could include a corrosion leak not previously evidenced by stained vegetation, but found during an ILI dig, or a release caused by a non-excavation vehicle where contact happened to occur while the pipeline was exposed for a repair or examination. Natural forces might also damage a pipeline that happened to be temporarily exposed. In each case, the cause should be appropriately reported in section G of this form.

Aboveground means pipe, components or other facilities that are above the natural grade.

Typical aboveground facility piping includes any pipe or components installed aboveground such as those at compressor stations, valve sites, and reducing stations.

Transition area means the junction of differing material or media between pipes, components, or facilities such as those installed at a belowground-aboveground junction (soil/air interface), another environmental interface, or in close contact to supporting elements such as those at water crossings, pump stations and break out tank farms.

12. Did Incident occur in a crossing?

Use **Bridge Crossing** if the pipeline is suspended above a body of water or roadway, railroad right-of-way, etc. either on a separately designed pipeline bridge or as a part of or connected to a road, railroad, or passenger bridge.

Use **Railroad Crossing** or **Road Crossing**, as appropriate, if the pipeline is buried beneath rail bed or road bed.

Use **Water Crossing** if the pipeline is in the water, beneath the water, in contact with the natural ground of the lake bed, etc., or buried beneath the bed of a lake, reservoir, stream or creek, whether the crossing happens to be flowing water at the time of the incident or not. The name of the body of water should be provided if it is commonly known and understood among the local population. (The purpose of this information is to allow persons familiar with the area in which the incident occurred to identify the location and understand it in its local context. Research to identify names that are not commonly used is not necessary since such names would not fulfill the intended purpose. If a body of water does not have a name that is commonly used and understood in the local area, this field should be left blank).

For **Approximate water Depth (ft)** of the lake, reservoir, etc., estimate the typical water depth at the location and time of the incident, allowing for seasonal, weather-related and other factors which may affect the water depth from time to time.

<u>For offshore</u> pipelines

13. Approximate water depth (ft.):
This should be the estimated depth from the surface of the water to the seabed at the point of the incident regardless of whether the pipeline is below/on the bottom, underwater but suspended above the bottom, or above the surface (e.g., on a platform).

14. Origin of Incident

Area and Tract/Block numbers should be provided for either State or OCS waters, whichever is applicable.

For Nearest County/Parish, as with the name of an onshore body of water (see question 12 above), the data collected is intended to allow persons familiar with the area in which the incident occurred to identify the location and understand it in its local context. Accordingly, it is not necessary to take measurements to determine which county/parish is "nearest" in cases where the incident location is approximately equidistant from two (or more). In such cases, the name of one of the nearby counties/parishes should be provided.

PART C – ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility [Interstate or Intrastate]?

Interstate gas pipeline facility means a gas pipeline facility used to transport gas and subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act (15 U.S.C. 717 et seq.).

Intrastate gas pipeline facility means a gas pipeline facility within a State not subject to the jurisdiction of the FERC under the Natural Gas Act (15 U.S.C. 717 et seq.

3. Item involved in Incident

Pipe (whether pipe body or pipe seam) means the pipe through which product is transported, not including auxiliary piping, tubing or instrumentation

Nominal diameter of pipe is also called **Nominal pipe size.** It is the diameter in whole number inches (except for pipe less than 4") used to describe the pipe size; for example, 8-5/8 pipe has a nominal pipe size of 8". Decimals are unnecessary for this measure (except for pipe less than 4").

Enter **pipe wall thickness** in inches. Wall thickness is typically less than an inch, and is standard among different pipeline types and manufacturers. Accordingly, use three decimal places to report wall thickness: 0.312, 0.281, etc.

SMYS means specified minimum yield strength and is the yield strength prescribed by the specification under which the material is purchased from the manufacturer.

Pipe Specification is the specification to which the pipe was manufactured, such as API 5L or ASTM A106.

Pipe seam means the longitudinal seam (longitudinal weld) created during manufacture of the joint of pipe.

Pipe Seam Type Abbreviations
SAW means submerged arc weld
ERW means electric-resistance weld
DSAW means double submerged arc weld

Auxiliary piping means piping, usually small in diameter that supports the operation of the mainline or facility piping and does not include tubing. Examples of auxiliary piping include discharge and drain lines, etc.

If the incident occurred on an item not provided in this section, check the OTHER box and specify in the space provided the item that failed.

6. Type of release Involved (*select only one*):

Mechanical puncture means a puncture of the pipeline, typically by a piece of equipment such as would occur if the pipeline were pierced by directional drilling or a backhoe bucket tooth. Not all excavation-related damage will be a "mechanical puncture." (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and one decimal.)

Leak means a failure resulting in an unintentional release of gas that is often small in size, usually resulting a low volume release, although large volume leaks can and do occur on occasion.

Rupture means a loss of containment event that immediately impairs the operation of the pipeline. Pipeline ruptures have the potential to be severely detrimental to safety and the environment. The terms "circumferential" and "longitudinal" refer to the general direction or orientation of the rupture relative the pipe's axis. They do not exclusively refer to a failure involving a circumferential weld such as a girth weld, or to a failure involving a longitudinal weld such as a pipe seam. (Precise measurement of size – e.g., micrometer – is not needed. Approximate measurements can be provided in inches and decimals.)

PART D – ADDITIONAL CONSEQUENCE INFORMATION

§192.903 What definitions apply to this subpart?

*   *   *   *   *

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:
(1) An area defined as--
(i) A Class 3 location under Sec. 192.5; or
(ii) A Class 4 location under Sec. 192.5; or
(iii) 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; or
(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
(2) The area within a potential impact circle containing--
(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
(ii) An identified site.
(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See figure E.I.A. in appendix E.)

2. Did this Incident occur in a High Consequence Area (HCA)?

This question should be answered based on the classification of the involved segment in the operator’s integrity management (IM) program at the time of the incident.

2.a. Specify the Method used to identify the HCA:

Answer this question only if the incident occurred in an HCA.

As defined in §192.903, HCAs are determined by one of two methods: Method (1) uses class locations, and Method (2) uses potential impact circles. The operator should identify the method used within its IM program to determine that the location at which the incident occurred was an HCA.

3. What is the PIR (Potential Impact Radius) for the location of this Incident?

An operator should answer this question for all incidents, regardless of whether or not the incident occurred in a high consequence area (HCA) or of the method used to identify an HCA. A PIR is one of the two methods for identifying an HCA, and this question and those immediately following are intended to collect data from actual incidents as part of a continuing effort to assure that the definition of a PIR is appropriate for that purpose.

PIR is defined in §191.903 as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula:

$$r = 0.69 * \sqrt{p * d^2}$$

where `r' is the radius of a circular area in feet surrounding the point of failure,
`p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and
`d' is the nominal diameter of the pipeline in inches.

(0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; incorporated into the regulations by reference, see Sec. 192.7) to calculate the impact radius formula.)

4. Were any structures outside the PIR impacted or otherwise damaged by heat/fire resulting from the incident?

Report any damage to structures further from the point of failure than the PIR distance that resulted from heat radiation or fires started as a result of the incident.

5**. Were any structures outside the PIR impacted or otherwise damaged NOT due to heat/fire resulting from the incident?**

This would include damage by blast effects, impact from missiles dislodged by a pipeline rupture, etc.

6. Were any of the fatalities or injuries reported for persons located outside the PIR?

This refers to the fatalities and injuries reported in Part A, questions 13 and 14.

7. Estimated cost to Operator:

All relevant costs to the operator must be included on the initial written incident report as well as supplemental reports. This includes (but is not limited to) costs due to property damage to the operator's facilities and to the property of others, gas lost, facility repair and replacement, and environmental cleanup and damage. Do not report costs incurred for facility repair, replacement, or change that are not related to the incident done solely for convenience. An example of doing work solely for convenience is working on non-leaking facilities unearthed because of the incident. Litigation and other legal expenses related to the Incident are not reportable.

Operators should report costs based on the best estimate available at the time a report is submitted. It is likely that an estimate of final repair costs may not be available when the initial report must be submitted (30 days, per § 191.15). The best available estimate of these costs should be included in the initial report. For convenience, this estimate can be revised, if needed, when supplemental reports are filed for other reasons, however, when no other changes are forthcoming, supplemental reports should be filed as new cost information becomes available. If supplemental reports are not submitted for other reasons, a supplemental report should be filed for the purpose of correcting the estimated cost if these costs differ from those already reported by 20 percent or $20,000, whichever is greater.

Public and Non-operator private property damage estimates generally include physical damage to the property of others, the cost of investigation and remediation of a site not owned or operated by the Operator, laboratory costs, third party expenses such as engineers or scientists, and other reasonable costs, excluding litigation and other legal expenses related to the incident.

Paid/reimbursed means that the entity experiencing the property damage was compensated by the operator or operator's representative for the damage or the cost to repair the damage.

Cost of gas released unintentionally should be based on the volume reported in Part A, Question 10.

Cost of gas released during intentional and controlled blowdown should be based on the volume reported in Part A, Question 11.

Operator's property damage estimates generally include physical damage to the property of Operator or Owner Company such as the estimated installed value of the damaged pipe, coating, component, materials or equipment due to the Incident, excluding litigation and other legal expenses related to the incident.

When estimating the **Cost of repairs** to company facilities, the standard shall be the cost necessary to safely restore property to its predefined level of service. Property damage estimates include the cost to access, excavate and repair the pipeline using methods, materials, and labor necessary to re-establish operations at a predetermined level. These costs may include the cost of repair sleeves or clamps, re-routing of piping, or the removal from service of an appurtenance or pipeline component. When more comprehensive repairs or improvements are justified but not required for continued operation, the cost of such repairs or replacement is not attributable to the incident. Costs associated with improvements to the pipeline to mitigate the risk of future failures are not included.

Estimated cost of **Operator's emergency response** includes emergency response operations necessary to return the incident site to a safe state, actions to minimize the volume of gas released, conduct reconnaissance, and to identify the extent of incident impacts. They include materials, supplies, labor, and benefits. Costs related to stakeholder outreach, media response, etc. should not be included.

Other costs should not include estimated cost categories separately listed above.

Costs should be reported in only one category and should not be double-counted. Costs can be split between two or more categories when they overlap more than one reporting category.

PART E – ADDITIONAL OPERATING INFORMATION

4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP ?

Consider both voluntary and mandated pressure restrictions. A pressure restriction should be considered mandated by PHMSA or a state regulator if it was directed by an order or other formal correspondence. Pressure reductions imposed by the operator as a result of regulatory requirements, e.g., a pressure reduction taken because an anomaly identified during an IM assessment could not be repaired within the required schedule (192.933(d)), should not be considered mandated by PHMSA.

5.a. Type of upstream valve used to initially isolate release source
Identify the type of valve used to initially isolate the release on the upstream side. In general, this will be the first upstream valve selected by the Operator to minimize the release volume but may not be the closest to the incident site.

5.b. Type of downstream valve used to initially isolate release source
Identify the type of valve used to initially isolate the release on the downstream side. In general, this will be the first downstream valve selected by the Operator to minimize the release volume but may not be the closest to the incident site.

5.c. Length of segment isolated between valves (ft):
Identify the length in feet between the valves identified in item 5.a and 5.b that were initially used to isolate the incident area.

5.f. Function of pipeline system

Transmission System means pipelines that are part of a system whose principal purpose is transmission of gas.

Transmission Line of Distribution System means a pipeline that meets the definition of “transmission line” in §192.3 but which is operated as part of a distribution pipeline system. Typically, this includes portions of the distribution pipeline system for which the operating stress level exceeds 20 percent SMYS.

SMYS means specified minimum yield strength and is the yield strength prescribed by the specification under which the material is purchased from the manufacturer.

Type A and Type B Gathering means a pipeline that transports gas from a current production facility to a transmission line or main and that meets the criteria for either Type A or Type B in §192.8.

6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?

This does not mean a system exclusively for leak detection.

6.a. Was it operating at the time of the Incident?
Was the SCADA system in operation at the time of the Incident?

6.b. Was it fully functional at the time of the Incident?
Was the SCADA system capable of performing all of its functions, whether or not it was actually in operation at the time of the incident? If no, describe functions that were not operational in the Narrative Part H

6.c and d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection or confirmation of the Incident?

Check yes if SCADA-based information was used to confirm the incident even if the initial report or identification may have come from other sources. Use of SCADA data for subsequent estimation of amount of gas lost, etc. is not considered use to confirm the incident.

Check No if data from SCADA was not used to assist with identification of the incident.

7. How was the incident initially identified for the Operator? (*select only one*)

Controller per the definition in API RP 1168 means a qualified individual whose function within a shift is to remotely monitor and/or control the operations of entire or multiple sections of pipeline systems via a SCADA system from a pipeline control room, and who has operational authority and accountability for the daily remote operational functions of pipeline systems.

Local Operating Personnel including contractors means employees or contractors working on behalf of the operator outside the control room.

8. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the incident?

Check only one of the boxes to indicate whether an investigation was/is being conducted (Yes) or was not conducted (No). If an investigation has been completed, select all the factors that apply in describing the results of the investigation.

Cause means an action or lack of action that directly led to or resulted in the pipeline incident.

Contributing factor means an action or lack of action that when added to the existing pipeline circumstances heightened the likelihood of the release or added to the impact of the release.

Controller Error means that the controller failed to identify a circumstance indicative of a release event, such as an abnormal operating condition, alarm, pressure drop, change in flow rate, or other similar event.

Incorrect Controller action means that the controller errantly operated the means for controlling an event. Examples include opening or closing the wrong valve, or hitting the wrong switch or button.

PART F – DRUG & ALCOHOL TESTING INFORMATION

Requirements for post-incident drug and alcohol tests are in 49 CFR 199.105 and 225 respectively. If the incident circumstances were such that tests were not required by these sections, and if no tests were conducted, check no. If tests were administered, report separately the number of operator employees and contractors working for the operator who were tested and who failed.

PART G – APPARENT CAUSE

In PART G – Apparent Cause
Complete only one of the eight sections listed under G1 thru G8

After identifying the main cause category as designated by G1 thru G8, select the one, single sub-cause that best describes the apparent cause of the incident in the shaded column on the left. Answer the corresponding questions that accompany your selected sub-cause, and describe any secondary, contributing, or root causes of the incident in the narrative (PART H).

G1 – Corrosion Failure

Corrosion includes a leak or failure caused by galvanic, atmospheric, stray current, microbiological, or other corrosive action, and, for the purposes of this reporting, includes selective seam corrosion. A corrosion leak is not limited to a hole in the pipe. If the bonnet or packing gland on a valve or flange on piping deteriorates or becomes loose and leaks due to corrosion and failure of bolts, it is classified as Corrosion. (If the bonnet, packing, or other gasket has deteriorated before the end of its expected life but not due to corrosive action, the failure should be classified as a Equipment Failure – G6.)

External Corrosion

4.a. Under cathodic protection means cathodic protection in accordance with Sections 192.455, 192.457, and 192.463. Recognizing that older pipelines may have had cathodic protection added over a number of years, provide an estimate if the exact year cathodic protection started is unknown.

Internal Corrosion

12. Were cleaning/dewatering pigs (or other operations) routinely utilized?
13. Were corrosion coupons routinely utilized?

For purposes of these questions, "routinely" refers to an action that is performed on more than a sporadic or one-time basis as part of a regular program with the intent to ensure that water build-up and/or settling and internal corrosion do not occur.

Either External or Internal Corrosion

14.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

Magnetic Flux Leakage Tool is an in-line inspection tool using an imposed magnetic flux to detect instances of pipe wall loss from corrosion. This includes low- and high-resolution MFL tools. It does not include transverse flux MFL tools, which are a separate choice in this question.

Ultrasonic refers to an in-line inspection tool that uses ultrasonic technology to measure wall thickness and detect instances of wall loss.

Transverse Field/Triaxial tools are specialized magnetic flux leakage tools that use a flux oriented to improve ability to detect crack anomalies.

Combination Tool refers to any in-line inspection tool that uses a combination of these inspection technologies in a single tool.

15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the incident?
Information from the initial post-construction hydrostatic test need not be reported.

16. Has one or more Direct Assessment been conducted on this segment?

This refers to direct assessment as defined in 49 CFR 195.553. Instances in which one or more indirect monitoring tools (e.g., close interval survey, DCVG) have been used that might be used as part of direct assessment but which have not been used as part of the direct assessment process defined in 195.553 do not constitute a Direct Assessment for purposes of this question.

G2 – Natural Force Damage

This category includes all outside forces attributable to causes NOT involving humans.

Earth Movement NOT due to Heavy Rains/Floods refers to incidents caused by land shifts such as earthquakes, landslides, or subsidence, but not mudslides which are presumed to be initiated by heavy rains or floods.

Heavy Rains/Floods refer to all water related incident causes. While mudslides involve earth movement, report them here since typically they are an effect of heavy rains or floods.

Lightning includes both damage and/or fire caused by a direct lighting strike and damage and/or fire as a secondary effect from a lightning strike in the area. An example of such a secondary effect would be a forest fire started by lightning that results in damage to a pipeline system asset which results in an incident.

Temperature refers to those causes that are related to ambient temperature effects, either heat or cold, where temperature was the initial cause.

Thermal stress refers to mechanical stress induced in a pipe or component when some or all of its parts are not free to expand or contract in response to changes in temperature.

Frozen components would include incidents where components are inoperable because of freezing and those due to cracking of a piece of equipment due to expansion of water during a freeze cycle.

High Winds includes damage caused by wind-induced forces. Select this category if the damage is due to the force of the wind itself. Damage caused by impact from objects blown by wind would be reported as section G4 "Other Outside Force Damage".

G3 – Excavation Damage

This section covers damage inflicted by the operator, operator's contractor, or entities unrelated to the operator during excavation that results in an immediate release of gas. For damage from outside forces OTHER than excavation which results in an immediate release, use G2 "Natural Force Damage" or G4 "Other Outside Force," as appropriate. For a strike or other damage to a pipeline or facility that results in a later release, report the incident in Section G4 as "Rupture or Failure Due to Previous Mechanical Damage."

Excavation Damage by Operator (First Party)
Check this sub-cause if the incident was caused as a result of excavation by a direct employee of the operator.

Excavation Damage by Operator's Contractor (Second Party)
Check this sub-cause if the incident was caused as a result of excavation by the operator's contractor or agent or other party working for the operator.

Excavation Damage by Third Party

Check this sub-cause if the incident was caused by excavation damage resulting from actions by personnel or other third parties not working for or acting on behalf of the operator or its agent.

Previous Damage due to Excavation Activity

1.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

Magnetic Flux Leakage Tool is an in-line inspection tool using an imposed magnetic flux to detect instances of pipe wall loss from corrosion. Includes low- and high-resolution MFL tools. Does not include transverse flux MFL tools, which are a separate choice in this question.

Ultrasonic refers to an in-line inspection tool that uses ultrasonic technology to measure wall thickness and detect instances of wall loss.

Transverse Field/Triaxial tools are specialized magnetic flux leakage tools that use a flux oriented to improve ability to detect crack anomalies.

Combination Tool refers to any in-line inspection tool that uses a combination of these inspection technologies in a single tool.

3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?
Information from the initial post-construction hydrostatic test need not be reported.

4. Has one or more Direct Assessment been conducted on this segment?

This refers to direct assessment as defined in 49 CFR 195.553. Instances in which one or more indirect monitoring tools (e.g., close interval survey, DCVG) have been used that might be used as part of direct assessment but which were not used as part of the direct assessment process defined in 195.553 do not constitute a Direct Assessment for purposes of this question.

7. – 17. Complete these questions for any excavation damage sub-cause. Instructions for answering these questions can be found at CGA's web site, https://www.damagereporting.org/dr/control/userGuide.do.

G4 – Other Outside Force Damage

This section covers incidents caused by outside force damage, other than excavation damage or natural forces. Check the most appropriate one sub-cause in this section that applies and answer any questions.

Nearby Industrial, Man-made or other Fire/Explosion as Primary Cause of Incident applies to situations where the fire occurred before and caused the release**.** An example of such a failure would be an explosion/fire at a neighboring facility or installation (chemical plant, tank farm, other industrial facility) that results in a release at the operator's facility. (Note that an incident report is required only if damage to facilities subject to Part 192 exceeded $50,000). This section should not be used if the release occurred first and then the gas ignited. If the fire is known to have been started as a result of a lightning strike, the incident's cause should be classified under Section G2, "Natural Force Damage." Arson events directed at harming the pipeline or the operator should be reported as "Intentional Damage" in this section. Forest fires that are caused by human activity and result in a release should be reported in this section.

Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation. An example of this sub-cause would be a stopple tee that releases gas when damaged by a pickup truck maneuvering near the pipeline. Other motorized vehicles or equipment include tractors, backhoes, bulldozers and other tracked vehicles, and heavy equipment that can move. Include under this sub-cause incidents caused by vehicles operated by the pipeline operator, the pipeline operator's contractor, or a third party and specify the vehicle/equipment operator's affiliation. Pipeline incidents resulting from vehicular traffic loading or other contact should also be reported in this category. If the activity involved digging, drilling, boring, grading, cultivation or similar activities, report in Section G3 "Excavation Damage".

Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring. This sub-cause includes impacts by maritime equipment or vessels (including their anchors or anchor chains or other attached equipment) that have lost their moorings and are carried into the pipeline facility by the current. This sub-cause also includes maritime equipment or vessels set adrift as a result of severe weather events and carried into the pipeline facility by waves, currents, or high winds. In such cases, also indicate the type of severe weather event. Do not report in this sub-cause incidents which are caused by the impact of maritime equipment or vessels while they are engaged in their normal or routine activities; such incidents should be reported as "Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation" so long as those activities are not excavation activities. If those activities are excavation activities such as dredging or bank stabilization or renewal, the incident should be reported in Section G3, "Excavation Damage".

Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation. This sub-cause includes incidents due to shrimping, purseining, oil drilling, or oilfield workover rigs, including anchor strikes, and other routine or normal maritime-related activities UNLESS the movement of the maritime asset was due to a severe weather event (this type of incident should be reported under "Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring") or the incident was caused by excavation activity such as **dredging** of waterways or bodies of water (this type of incident should be reported under Section G3, "Excavation Damage.").

Previous Mechanical Damage NOT Related to Excavation. This sub-cause covers incidents where damage occurred at some time prior to the release, and would include prior excavation damage, prior outside force damage of an unknown nature, prior natural force damage, and prior damage from other outside forces. Incidents resulting from damage sustained during construction, installation, or fabrication of the pipe or a weld should be reported under Section G5, "Material Failure of Pipe or Weld."

Intentional Damage

Vandalism means willful or malicious destruction of the operator's pipeline facility or equipment. This category would include pranks, systematic damage inflicted to harass the operator, motor vehicle damage that was inflicted intentionally, and a variety of other intentional acts.

Terrorism, per 28 C.F.R. § 0.85 General functions, includes the unlawful use of force and violence against persons or property to intimidate or coerce a government, the civilian population, or any segment thereof, in furtherance of political or social objectives. Operators selecting this item are encouraged to also notify the FBI.

Theft means damage by any individual or entity, by any mechanism, specifically to steal, or attempt to steal, the transported gas or pipeline equipment.

Other
Describe in the space provided and, if necessary, provide additional explanation in Part H.

G5 – Material Failure of Pipe or Weld

Use this section to report material failures only if "Item Involved in Incident" (Part C, Question 3) is "**Pipe**" (whether pipe body or pipe seam) or "**Weld**."

This section includes leaks, ruptures or other failures from defects within the material of the pipe body or within the pipe seam or other weld due to faulty manufacturing procedures, defects resulting from poor construction/installation practices, and in-service stresses such as vibration, fatigue and environmental cracking.

Construction-, Installation-, or Fabrication-related includes leaks in or failures of originally sound material due to force being applied during construction or installation that caused a dent, gouge, excessive stress, or some other defect that eventually failed resulting in an incident. Included are leaks in or failures of wrinkle bends, field welds, and damage sustained in transportation to the construction or fabrication site.

Original Manufacturing-related (NOT girth weld or other welds formed in the field) means an inherent flaw in the material or weld that occurred in the manufacture or at a point prior to construction, fabrication or installation. Therefore, this option is not appropriate for wrinkle bends, field welds, girth welds, or other joints fabricated in the field. Use this option for failures such as those due to defects of the longitudinal weld or inclusions in the pipe body.

If **Construction, Installation, Fabrication-related** or **Original Manufacturing-related** is selected, then select the failure mechanism.

Examples of Mechanical Stress include failures related to overburden or loss of support.

G6 – Equipment Failure

This section applies to failures of items **other than** Pipe Body, Pipe Seam, or Welds.

Malfunction of Control/Relief Equipment
Examples of this type of incident cause include: overpressurization resulting from malfunction of control or alarm device; relief valve malfunction: valves failing to open or close on command; or valves which opened or closed when not commanded to do so. If overpressurization or some other aspect of this incident was caused by incorrect operation, the incident should be reported under Section G7, "Incorrect Operation."

ESD System Failure means failure of an emergency shutdown system.

G7 – Incorrect Operation

These types of incidents most often occur during operating, maintenance or repair activities. Some examples of this type of failure are improper valve selection or operation, inadvertent overpressurization, or improper selection or installation of equipment. The unintentional ignition of the transported gas during a welding or maintenance activity would also be included in this sub-cause. These types of incidents often involve training or judgment errors.

G8 – Other Incident Cause

This section is provided for incident causes that do not fit in any of the main cause categories listed in Sections G1 through G7.

If the incident cause is known but doesn't fit in any category in sections G1 through G7, check the **Miscellaneous** box and enter a description of the incident and continue in Part H, Narrative Description of the Incident, if more space is needed.

If the incident cause is unknown at time of filing this report, check the **Unknown** box in this section and select one reason from the accompanying two choices. If the investigation is not completed and the cause of the incident is thus still to be determined, file a supplemental report once the investigation is completed to report the apparent cause.

PART H – NARRATIVE DESCRIPTION OF THE INCIDENT

(Attach additional sheets as necessary)

Concisely describe the incident, including the facts, circumstances, and conditions that may have contributed directly or indirectly to causing the incident. Include secondary and contributing causes when possible, or any other factors associated with the cause that are deemed pertinent. Use this section to clarify or explain unusual conditions, to provide sketches or drawings, and to explain any estimated data. Operators submitting reports on-line will be afforded the opportunity to attach/upload files containing sketches, drawings, or additional data.

If you checked the Miscellaneous block in Section G8, the narrative should describe the incident in detail, including all known or suspected causes and possible contributing factors.

Operators should use the narrative to describe any secondary causes that they consider important but which could not be reported in section G since only the primary cause is reported there.

PART I – PREPARER AND AUTHORIZED SIGNATURE

The Preparer is the person who compiled the data and prepared the responses to the report and who is to be contacted for more information (preferably the person most knowledgeable about the information in the report or who knows how to contact the person most knowledgeable). Please enter the Preparer's e-mail address if the Preparer has one, and the phone and fax numbers used by the Preparer.

An Authorized Signature must be obtained from an officer, manager, or other person whom the operator has designated to review and approve (and sign and date) the report. This individual is responsible for assuring the accuracy and completeness of the reported data. In addition to their title, a phone number and email address are to be provided for the individual signing as the Authorized Signature.

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.

OMB NO: 2137-0522

EXPIRATION DATE: 01/31/2013

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

INCIDENT REPORT – GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS

Report Date ______________

No. ______________________
(DOT Use Only)

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 10 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A – KEY REPORT INFORMATION

*Report Type: *(select all that apply)* ☐ Original ☐ Supplemental ☐ Final

*1. Operator's OPS-issued Operator Identification Number (OPID): /__/__/__/__/__/

*2. Name of Operator: ____

*3. Address of Operator:

*3.a ____
(Street Address)

*3.b ____
(City)

*3.c State: /__/__/

*3.d Zip Code: /__/__/__/__/__/ - /__/__/__/__/

*4. Local time *(24-hr clock)* and date of the Incident:

/__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

*5. Location of Incident:

Latitude: /__/__/ . /__/__/__/__/__/

Longitude: - /__/__/__/ . /__/__/__/__/__/

6. National Response Center Report Number:

/__/__/__/__/__/__/

7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):

/__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

*8. Incident resulted from:

☐ Unintentional release of gas
☐ Intentional release of gas
☐ Reasons other than release of gas

*9. Gas released: *(select only one, based on predominant volume released)*

☐ Natural Gas
☐ Propane Gas
☐ Synthetic Gas
☐ Hydrogen Gas
☐ Other Gas ⇨ Name: ______________________

*10. Estimated volume of gas released unintentionally: /__/__/,/__/__/__/ Thousand Cubic Feet (MCF)

11. Estimated volume of intentional and controlled release/blowdown : /__/__/,/__/__/__/ Thousand Cubic Feet (MCF)

12. Estimated volume of accompanying liquid released: /__/__/,/__/__/__/ Barrels

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*13. Were there fatalities? ○ Yes ○ No If Yes, specify the number in each category: *13.a Operator employees /__/__/__/__/ *13.b Contractor employees working for the Operator /__/__/__/__/ *13.c Non-Operator emergency responders /__/__/__/__/ *13.d Workers working on the right-of-way, but NOT associated with this Operator /__/__/__/__/ *13.e General public /__/__/__/__/ 13.f Total fatalities (sum of above) /__/__/__/__/	*14. Were there injuries requiring inpatient hospitalization? ○ Yes ○ No If Yes, specify the number in each category: *14.a Operator employees /__/__/__/__/ *14.b Contractor employees working for the Operator /__/__/__/__/ *14.c Non-Operator emergency responders /__/__/__/__/ *14.d Workers working on the right-of-way, but NOT associated with this Operator /__/__/__/__/ *14.e General public /__/__/__/__/ 14.f Total injuries (sum of above) /__/__/__/__/

15. Was the pipeline/facility shut down due to the incident?
○ Yes ○ No ⇨ Explain: ____________________

If Yes, complete Questions 15.a and 15.b: *(use local time, 24-hr clock)*

15.a Local time and date of shutdown /__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

15.b Local time pipeline/facility restarted /__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year ○ Still shut down* *(*Supplemental Report required)*

*16. Did the gas ignite? ○ Yes ○ No

*17. Did the gas explode? ○ Yes ○ No

18. Number of general public evacuated: /__/__/__/,/__/__/__/

19. Time sequence: *(use local time, 24-hour clock)*

19.a Local time operator identified Incident /__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

19.b Local time operator resources arrived on site /__/__/__/__/ Hour /__/__/ Month /__/__/ Day /__/__/ Year

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PART B – ADDITIONAL LOCATION INFORMATION

*1. Was the origin of the Incident onshore?
○ Yes *(Complete Questions 2-12)* ○ No *(Complete Questions 13-15)*

If **Onshore**:

*2. State: /__/__/

*3. Zip Code: /__/__/__/__/__/ - /__/__/__/__/

4 ______________________ 5 ______________________
City County or Parish

6. Operator designated location: *(select only one)*
☐ Milepost/Valve Station *(specify in shaded area below)*
☐ Survey Station No. *(specify in shaded area below)*

/__/__/__/__/__/__/__/__/__/__/__/__/__/

7. Pipeline/Facility name: ______________________

8. Segment name/ID: ______________________

*9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)? ○ Yes ○ No

*10. Location of Incident: *(select only one)*
☐ Operator-controlled property
☐ Pipeline right-of-way

*11. Area of Incident (as found): *(select only one)*
☐ Belowground storage or aboveground storage vessel, including attached appurtenances
☐ Underground ⇨ Specify: ○ Under soil
○ Under a building ○ Under pavement
○ Exposed due to excavation
○ In underground enclosed space (e.g., vault)
○ Other ______________________
Depth-of-Cover (in): /__/,/__/__/__/
☐ Aboveground ⇨ Specify:
○ Typical aboveground facility piping or appurtenance
○ Overhead crossing
○ In or spanning an open ditch
○ Inside a building ○ Inside other enclosed space
○ Other ______________________
☐ Transition Area ⇨ Specify: ○ Soil/air interface ○ Wall sleeve ○ Pipe support or other close contact area
○ Other ______________________

*12. Did Incident occur in a crossing? ○ Yes ○ No
If Yes, specify type below:
☐ Bridge crossing ⇨ Specify: ○ Cased ○ Uncased
☐ Railroad crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Road crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Water crossing
⇨ Specify: ○ Cased ○ Uncased
Name of body of water, if commonly known:
____
Approx. water depth (ft) at the point of the Incident:
/__/,/__/__/__/
(select only one of the following)
○ Shoreline/Bank crossing
○ Below water, pipe in bored/drilled crossing
○ Below water, pipe buried below bottom (NOT in bored/drilled crossing)
○ Below water, pipe on or above bottom

If **Offshore**:

*13. Approximate water depth (ft.) at the point of the Incident:
/__/,/__/__/__/

*14. Origin of Incident:
☐ In State waters
⇨ Specify: State: /__/__/
Area: ______________________
Block/Tract #: /__/__/__/__/
Nearest County/Parish: ______________________
☐ On the Outer Continental Shelf (OCS)
⇨ Specify: Area: ______________________
Block #: /__/__/__/__/

*15. Area of Incident: *(select only one)*
☐ Shoreline/Bank crossing or shore approach
☐ Below water, pipe buried or jetted below seabed
☐ Below water, pipe on or above seabed
☐ Splash Zone of riser
☐ Portion of riser outside of Splash Zone, including riser bend
☐ Platform

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PART C – ADDITIONAL FACILITY INFORMATION

*1. Is the pipeline or facility:
- ☐ Interstate
- ☐ Intrastate

*2. Part of system involved in Incident: *(select only one)*
- ☐ Belowground Storage, Including Associated Equipment and Piping
- ☐ Aboveground Storage, Including Associated Equipment and Piping
- ☐ Onshore Compressor Station Equipment and Piping
- ☐ Onshore Regulator/Metering Station Equipment and Piping
- ☐ Onshore Pipeline, Including Valve Sites
- ☐ Offshore Platform, Including Platform-mounted Equipment and Piping
- ☐ Offshore Pipeline, Including Riser and Riser Bend

*3. Item involved in Incident: *(select only one)*

☐ Pipe ⇨ Specify: ○ Pipe Body ○ Pipe Seam

3.a Nominal diameter of pipe (in): /___/___/./___/___/___/

3.b Wall thickness (in): /___/./___/___/___/

3.c SMYS (Specified Minimum Yield Strength) of pipe (psi): /___/___/___/,/___/___/___/

3.d Pipe specification: ______________________________

3.e Pipe Seam ⇨ Specify: ○ Longitudinal ERW - High Frequency ○ Single SAW ○ Flash Welded ○ Longitudinal ERW - Low Frequency ○ DSAW ○ Continuous Welded ○ Longitudinal ERW – Unknown Frequency ○ Furnace Butt Welded ○ Spiral Welded ERW ○ Spiral Welded SAW ○ Spiral Welded DSAW ○ Lap Welded ○ Seamless ○ Other ________________________

3.f Pipe manufacturer: ________________________________

3.g Year of manufacture: /___/___/___/___/

3.h Pipeline coating type at point of Incident

⇨ Specify: ○ Fusion Bonded Epoxy ○ Coal Tar ○ Asphalt ○ Polyolefin ○ Extruded Polyethylene ○ Field Applied Epoxy ○ Cold Applied Tape ○ Paint ○ Composite ○ None ○ Other ______________________________

☐ Weld, including heat-affected zone ⇨ Specify: ○ Pipe Girth Weld ○ Other Butt Weld ○ Fillet Weld ○ Other____________

☐ Valve ○ Mainline ⇨ Specify: ○ Butterfly ○ Check ○ Gate ○ Plug ○ Ball ○ Globe ○ Other ______________________

3.i Mainline valve manufacturer: ______________________________

3.j Year of manufacture: /___/___/___/___/

○ Relief Valve
○ Auxiliary or Other Valve

- ☐ Compressor
- ☐ Meter
- ☐ Scraper/Pig Trap
- ☐ Separator/Separator Filter
- ☐ Strainer/Filter
- ☐ Dehydrator/Drier/Treater
- ☐ Regulator/Control Valve
- ☐ Drip/Drip Collection Device
- ☐ Pulsation Bottle
- ☐ Cooler
- ☐ Repair Sleeve or Clamp
- ☐ Hot Tap Equipment
- ☐ Stopple Fitting
- ☐ Flange
- ☐ Relief Line
- ☐ Auxiliary Piping (e.g. drain lines)
- ☐ Tubing
- ☐ Instrumentation
- ☐ Underground Gas Storage or Cavern
- ☐ Pressure Vessel
- ☐ Other ________________________________

4. Year item involved in Incident was installed: /___/___/___/___/

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*5. Material involved in Incident: *(select only one)*

☐ Carbon Steel
☐ Plastic
☐ Material other than Carbon Steel or Plastic ⇨ Specify: ____

*6. Type of Incident involved: *(select only one)*

☐ Mechanical Puncture ⇨ Approx. size: /__/__/__/__/./__/in. (axial) by /__/__/__/__/./__/in. (circumferential)

☐ Leak ⇨ Select Type: ○ Pinhole ○ Crack ○ Connection Failure ○ Seal or Packing ○ Other

☐ Rupture ⇨ Select Orientation: ○ Circumferential ○ Longitudinal ○ Other ________________________________

Approx. size: /__/__/__/__/./__/ in. (widest opening) by /__/__/__/__/__/./__/in. (length circumferentially or axially)

☐ Other ⇨ Describe: ____

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PART D – ADDITIONAL CONSEQUENCE INFORMATION

*1. Class Location of Incident: *(select only one)*
- ☐ Class 1 Location
- ☐ Class 2 Location
- ☐ Class 3 Location
- ☐ Class 4 Location

*2. Did this Incident occur in a High Consequence Area (HCA)?
- ☐ No
- ☐ Yes ➪ 2.a Specify the Method used to identify the HCA: ○ Method 1 ○ Method 2

*3. What is the PIR (Potential Impact Radius) for the location of this Incident? /__/,/__/__/__/ feet

*4. Were any structures outside the PIR impacted or otherwise damaged by heat/fire resulting from the Incident? ○ Yes ○ No

*5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident? ○ Yes ○ No

*6. Were any of the fatalities or injuries reported for persons located outside the PIR? ○ Yes ○ No

*7. Estimated cost to Operator:

7.a Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator $ /__/__/__/,/__/__/__/,/__/__/__/

7.b Estimated cost of gas released unintentionally $ /__/__/__/,/__/__/__/,/__/__/__/

7.c Estimated cost of gas released during intentional and controlled blowdown $ /__/__/__/,/__/__/__/,/__/__/__/

7.d Estimated cost of Operator's property damage & repairs $ /__/__/__/,/__/__/__/,/__/__/__/

7.e Estimated cost of Operator's emergency response $ /__/__/__/,/__/__/__/,/__/__/__/

7.f Estimated other costs $ /__/__/__/,/__/__/__/,/__/__/__/

Describe ____

7.g Estimated total costs (sum of above) $ /__/__/__/,/__/__/__/,/__/__/__/

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PART E – ADDITIONAL OPERATING INFORMATION

*1. Estimated pressure at the point and time of the Incident (psig): /___/___/,/___/___/___/

*2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig) : /___/___/,/___/___/___/

*3. Describe the pressure on the system or facility relating to the Incident: *(select only one)*
- ☐ Pressure did not exceed MAOP
- ☐ Pressure exceeded MAOP, but did not exceed 110% of MAOP
- ☐ Pressure exceeded 110% of MAOP

*4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP ?
- ☐ No
- ☐ Yes ⇨ *(Complete 4.a and 4.b below)*

*4.a Did the pressure exceed this established pressure restriction? ○ Yes ○ No

*4.b Was this pressure restriction mandated by PHMSA or the State? ○ PHMSA ○ State ○ Not mandated

*5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?
- ☐ No
- ☐ Yes ⇨ *(Complete 5.a – 5.f below)*

5.a Type of upstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled

5.b Type of downstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled ○ Check Valve

5.c Length of segment isolated between valves (ft): /___/___/___/,/___/___/___/

5.d Is the pipeline configured to accommodate internal inspection tools?
- ☐ Yes
- ☐ No ⇨ Which physical features limit tool accommodation? *(select all that apply)*
  - ○ Changes in line pipe diameter
  - ○ Presence of unsuitable mainline valves
  - ○ Tight or mitered pipe bends
  - ○ Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)
  - ○ Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)
  - ○ Other ⇨ Describe:______________________________

5.e For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?
- ☐ No
- ☐ Yes ⇨ Which operational factors complicate execution? *(select all that apply)*
  - ○ Excessive debris or scale, wax, or other wall build-up
  - ○ Low operating pressure(s)
  - ○ Low flow or absence of flow
  - ○ Incompatible commodity
  - ○ Other ⇨ Describe:______________________________

5.f Function of pipeline system: *(select only one)*
- ☐ Transmission System
- ☐ Transmission Line of Distribution System
- ☐ Type A Gathering
- ☐ Type B Gathering
- ☐ Storage Gathering

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*6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?

☐ No

☐ Yes ⇨ 6.a Was it operating at the time of the Incident? ○ Yes ○ No

6.b Was it fully functional at the time of the Incident? ○ Yes ○ No

6.c Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident? ○ Yes ○ No

6.d Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident? ○ Yes ○ No

*7. How was the Incident initially identified for the Operator? *(select only one)*

☐ SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)

☐ Static Shut-in Test or Other Pressure or Leak Test

☐ Controller

☐ Air Patrol

☐ Notification from Public

☐ Notification from Third Party that caused the Incident

☐ Local Operating Personnel, including contractors

☐ Ground Patrol by Operator or its contractor

☐ Notification from Emergency Responder

☐ Other ______________________________

*7.a If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 7, specify the following: *(select only one)*

○ Operator employee ○ Contractor working for the Operator

*8. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Incident? *(select only one)*

☐ Yes, but the investigation of the control room and/or controller actions has not yet been completed by the operator *(Supplemental Report required)*

☐ No, the facility was not monitored by a controller(s) at the time of the Incident

☐ No, the operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*

____

____

____

☐ Yes, specify investigation result(s): *(select all that apply)*

○ Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue

○ Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue *(provide an explanation for why not)*

____

____

____

○ Investigation identified no control room issues

○ Investigation identified no controller issues

○ Investigation identified incorrect controller action or controller error

○ Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response

○ Investigation identified incorrect procedures

○ Investigation identified incorrect control room equipment operation

○ Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response

○ Investigation identified areas other than those above ⇨ Describe: ______________________________

____

____

____

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PART F – DRUG & ALCOHOL TESTING INFORMATION	

*1. As a result of this Incident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

O No

O Yes ⇨ *1.a Specify how many were tested: /___/___/

*1.b Specify how many failed: /___/___/

*2. As a result of this Incident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

O No

O Yes ⇨ *2.a Specify how many were tested: /___/___/

*2.b Specify how many failed: /___/___/

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PART G – APPARENT CAUSE	***Select only one box from PART G in the shaded column on the left representing the APPARENT Cause of the Incident, and answer the questions on the right. Describe secondary, contributing, or root causes of the Incident in the narrative (PART H).***

G1 - Corrosion Failure – *only one **sub-cause** can be picked from shaded left-hand column

☐ **External Corrosion**	*1. Results of visual examination: O Localized Pitting O General Corrosion O Other ______ *2. Type of corrosion: *(select all that apply)* O Galvanic O Atmospheric O Stray Current O Microbiological O Selective Seam O Other ______ *3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)* O Field examination O Determined by metallurgical analysis O Other ______ *4. Was the failed item buried under the ground? O Yes ⇨ *4.a Was failed item considered to be under cathodic protection at the time of the incident? O Yes ⇨ Year protection started: /__/__/__/__/ O No *4.b Was shielding, tenting, or disbonding of coating evident at the point of the incident? O Yes O No *4.c Has one or more Cathodic Protection Survey been conducted at the point of the incident? O Yes, CP Annual Survey ⇨ Most recent year conducted: /__/__/__/__/ O Yes, Close Interval Survey ⇨ Most recent year conducted: /__/__/__/__/ O Yes, Other CP Survey ⇨ Most recent year conducted: /__/__/__/__/ O No O No ⇨ 4.d Was the failed item externally coated or painted? O Yes O No *5. Was there observable damage to the coating or paint in the vicinity of the corrosion? O Yes O No
☐ **Internal Corrosion**	*6. Results of visual examination: O Localized Pitting O General Corrosion O Not cut open O Other ______ *7. Cause of corrosion: *(select all that apply)* O Corrosive Commodity O Water drop-out/Acid O Microbiological O Erosion O Other ______ ______ *8. The cause(s) of corrosion selected in Question 7 is based on the following: *(select all that apply)* O Field examination O Determined by metallurgical analysis O Other ______ *9. Location of corrosion: *(select all that apply)* O Low point in pipe O Elbow O Drop-out O Other ______ *10. Was the gas/fluid treated with corrosion inhibitors or biocides? O Yes O No 11. Was the interior coated or lined with protective coating? O Yes O No 12. Were cleaning/dewatering pigs (or other operations) routinely utilized? O Not applicable - Not mainline pipe O Yes O No 13. Were corrosion coupons routinely utilized? O Not applicable - Not mainline pipe O Yes O No

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Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.

14. Has one or more internal inspection tool collected data at the point of the Incident?
    - ○ Yes ○ No

    14.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

    - ○ Magnetic Flux Leakage Tool /___/___/___/___/
    - ○ Ultrasonic /___/___/___/___/
    - ○ Geometry /___/___/___/___/
    - ○ Caliper /___/___/___/___/
    - ○ Crack /___/___/___/___/
    - ○ Hard Spot /___/___/___/___/
    - ○ Combination Tool /___/___/___/___/
    - ○ Transverse Field/Triaxial /___/___/___/___/
    - ○ Other ________________________ /___/___/___/___/

15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?
    - ○ Yes ➪ Most recent year tested: /___/___/___/___/ Test pressure (psig): /___/___/___/___/___/
    - ○ No

16. Has one or more Direct Assessment been conducted on this segment?
    - ○ Yes, and an investigative dig was conducted at the point of the Incident ➪ Most recent year conducted: /___/___/___/___/
    - ○ Yes, but the point of the Incident was not identified as a dig site ➪ Most recent year conducted: /___/___/___/___/
    - ○ No

17. Has one or more non-destructive examination been conducted at the point of the Incident since January 21, 2002?
    - ○ Yes ○ No

    17.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

    - ○ Radiography /___/___/___/___/
    - ○ Guided Wave Ultrasonic /___/___/___/___/
    - ○ Handheld Ultrasonic Tool /___/___/___/___/
    - ○ Wet Magnetic Particle Test /___/___/___/___/
    - ○ Dry Magnetic Particle Test /___/___/___/___/
    - ○ Other ________________________ /___/___/___/___/

G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Earth Movement, NOT due to Heavy Rains/Floods**	1. Specify: ○ Earthquake ○ Subsidence ○ Landslide ○ Other ________________
☐ **Heavy Rains/Floods**	2. Specify: ○ Washout/Scouring ○ Flotation ○ Mudslide ○ Other ______________
☐ **Lightning**	3. Specify: ○ Direct hit ○ Secondary impact such as resulting nearby fires
☐ **Temperature**	4. Specify: ○ Thermal Stress ○ Frost Heave ○ Frozen Components ○ Other ____________________________
☐ **High Winds**	
☐ **Other Natural Force Damage**	*5. Describe: ____

Complete the following if any Natural Force Damage sub-cause is selected.

*6. Were the natural forces causing the Incident generated in conjunction with an extreme weather event? ○ Yes ○ No

*6.a If Yes, specify: (*select all that apply*) ○ Hurricane ○ Tropical Storm ○ Tornado ○ Other ___________________________

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G3 – Excavation Damage - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Excavation Damage by Operator (First Party)**

☐ **Excavation Damage by Operator's Contractor (Second Party)**

☐ **Excavation Damage by Third Party**

☐ **Previous Damage due to Excavation Activity**

Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.

1. Has one or more internal inspection tool collected data at the point of the Incident?
   ○ Yes ○ No

   1.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

   - ○ Magnetic Flux Leakage /__/__/__/__/
   - ○ Ultrasonic /__/__/__/__/
   - ○ Geometry /__/__/__/__/
   - ○ Caliper /__/__/__/__/
   - ○ Crack /__/__/__/__/
   - ○ Hard Spot /__/__/__/__/
   - ○ Combination Tool /__/__/__/__/
   - ○ Transverse Field/Triaxial /__/__/__/__/
   - ○ Other ____________________ /__/__/__/__/

2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? ○ Yes ○ No

3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?

   ○ Yes ⇨ Most recent year tested: /__/__/__/__/
   Test pressure (psig): /__/__/,/__/__/__/

   ○ No

4. Has one or more Direct Assessment been conducted on the pipeline segment?

   ○ Yes, and an investigative dig was conducted at the point of the Incident
   ⇨ Most recent year conducted: /__/__/__/__/

   ○ Yes, but the point of the Incident was not identified as a dig site
   ⇨ Most recent year conducted: /__/__/__/__/

   ○ No

5. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?
   ○ Yes ○ No

   5.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

   - ○ Radiography /__/__/__/__/
   - ○ Guided Wave Ultrasonic /__/__/__/__/
   - ○ Handheld Ultrasonic Tool /__/__/__/__/
   - ○ Wet Magnetic Particle Test /__/__/__/__/
   - ○ Dry Magnetic Particle Test /__/__/__/__/
   - ○ Other ________________________ /__/__/__/__/

Complete the following if Excavation Damage by Third Party is selected as the sub-cause.

6. Did the operator get prior notification of the excavation activity? ○ Yes ○ No

   *6.a If Yes, Notification received from: *(select all that apply)* ○ One-Call System ○ Excavator ○ Contractor ○ Landowner

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Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.

7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)? ○Yes ○ No

*8. Right-of-Way where event occurred: *(select all that apply)*

☐ Public ⇨ Specify: ○ City Street ○ State Highway ○ County Road ○ Interstate Highway ○ Other

☐ Private ⇨ Specify: ○ Private Landowner ○ Private Business ○ Private Easement

☐ Pipeline Property/Easement
☐ Power/Transmission Line
☐ Railroad
☐ Dedicated Public Utility Easement
☐ Federal Land
☐ Data not collected
☐ Unknown/Other

*9. Type of excavator: *(select only one)*

○ Contractor ○ County ○ Developer ○ Farmer ○ Municipality ○ Occupant
○ Railroad ○ State ○ Utility ○ Data not collected ○ Unknown/Other

*10. Type of excavation equipment: *(select only one)*

○ Auger ○ Backhoe/Trackhoe ○ Boring ○ Drilling ○ Directional Drilling
○ Explosives ○ Farm Equipment ○ Grader/Scraper ○ Hand Tools ○ Milling Equipment
○ Probing Device ○ Trencher ○ Vacuum Equipment ○ Data not collected ○ Unknown/Other

*11. Type of work performed: *(select only one)*

○ Agriculture ○ Cable TV ○ Curb/Sidewalk ○ Building Construction ○ Building Demolition
○ Drainage ○ Driveway ○ Electric ○ Engineering/Surveying ○ Fencing
○ Grading ○ Irrigation ○ Landscaping ○ Liquid Pipeline ○ Milling
○ Natural Gas ○ Pole ○ Public Transit Authority ○ Railroad Maintenance ○ Road Work
○ Sewer (Sanitary/Storm) ○ Site Development ○ Steam ○ Storm Drain/Culvert ○Street Light
○ Telecommunications ○Traffic Signal ○ Traffic Sign ○ Water ○ Waterway Improvement
○ Data not collected ○ Unknown/Other

*12. Was the One-Call Center notified? ○ Yes ○ No

*12.a If Yes, specify ticket number: /__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/

*12.b If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:

____

*13. Type of Locator: ○ Utility Owner ○ Contract Locator ○ Data not collected ○ Unknown/Other

*14. Were facility locate marks visible in the area of excavation? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*15. Were facilities marked correctly? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16. Did the damage cause an interruption in service? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16.a If Yes, specify duration of the interruption: /___/___/___/___/ hours

(This CGA-DIRT section continued on next page with Question 17.)

*17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*:

☐ One-Call Notification Practices Not Sufficient: *(select only one)*
- ○ No notification made to the One-Call Center
- ○ Notification to One-Call Center made, but not sufficient
- ○ Wrong information provided

☐ Locating Practices Not Sufficient: *(select only one)*
- ○ Facility could not be found/located
- ○ Facility marking or location not sufficient
- ○ Facility was not located or marked
- ○ Incorrect facility records/maps

☐ Excavation Practices Not Sufficient: *(select only one)*
- ○ Excavation practices not sufficient (other)
- ○ Failure to maintain clearance
- ○ Failure to maintain the marks
- ○ Failure to support exposed facilities
- ○ Failure to use hand tools where required
- ○ Failure to verify location by test-hole (pot-holing)
- ○ Improper backfilling

☐ One-Call Notification Center Error

☐ Abandoned Facility

☐ Deteriorated Facility

☐ Previous Damage

☐ Data Not Collected

☐ Other / None of the Above *(explain)*____

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G4 - Other Outside Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident**	
☐ **Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation**	1. Vehicle/Equipment operated by: *(select only one)* O Operator O Operator's Contractor O Third Party
☐ **Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring**	2. Select one or more of the following IF an extreme weather event was a factor: O Hurricane O Tropical Storm O Tornado O Heavy Rains/Flood O Other ______________________________
☐ **Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation**	
☐ **Electrical Arcing from Other Equipment or Facility**	
☐ **Previous Mechanical Damage NOT Related to Excavation**	**Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.** 3. Has one or more internal inspection tool collected data at the point of the Incident? O Yes O No 3.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: O Magnetic Flux Leakage /__/__/__/__/ O Ultrasonic /__/__/__/__/ O Geometry /__/__/__/__/ O Caliper /__/__/__/__/ O Crack /__/__/__/__/ O Hard Spot /__/__/__/__/ O Combination Tool /__/__/__/__/ O Transverse Field/Triaxial /__/__/__/__/ O Other /__/__/__/__/ 4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? O Yes O No 5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident? O Yes ⇨ Most recent year tested: /__/__/__/__/ Test pressure (psig): /__/__/,/__/__/__/ O No 6. Has one or more Direct Assessment been conducted on the pipeline segment? O Yes, and an investigative dig was conducted at the point of the Incident ⇨ Most recent year conducted: /__/__/__/__/ O Yes, but the point of the Incident was not identified as a dig site ⇨ Most recent year conducted: /__/__/__/__/ O No *(This section continued on next page with Question 7.)*

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	7. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002? ○ Yes ○ No 7.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: ○ Radiography /___/___/___/___/ ○ Guided Wave Ultrasonic /___/___/___/___/ ○ Handheld Ultrasonic Tool /___/___/___/___/ ○ Wet Magnetic Particle Test /___/___/___/___/ ○ Dry Magnetic Particle Test /___/___/___/___/ ○ Other ________________________ /___/___/___/___/
☐ **Intentional Damage**	8. Specify: ○ Vandalism ○ Terrorism ○ Theft of transported commodity ○ Theft of equipment ○ Other ____________________________________
☐ **Other Outside Force Damage**	*9. Describe: ____

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G5 - Material Failure of Pipe or Weld	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is "Pipe" or "Weld."** *Only one **sub-cause** can be picked from shaded left-hand column

1. The sub-cause selected below is based on the following: *(select all that apply)*

☐ Field Examination ☐ Determined by Metallurgical Analysis ☐ Other Analysis________________________

☐ Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*

☐ **Construction-, Installation-, or Fabrication-related** ☐ **Original Manufacturing-related (NOT girth weld or other welds formed in the field)**	2. List contributing factors: *(select all that apply)* ☐ Fatigue- or Vibration-related: ○ Mechanically-induced prior to installation (such as during transport of pipe) ○ Mechanical Vibration ○ Pressure-related ○ Thermal ○ Other ________________________________ ☐ Mechanical Stress ☐ Other ________________________________
☐ **Environmental Cracking-related**	3. Specify: ○ Stress Corrosion Cracking ○ Sulfide Stress Cracking ○ Hydrogen Stress Cracking ○ Other __________________________________

Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.

*4. Additional factors (*select all that apply*): ○ Dent ○ Gouge ○ Pipe Bend ○ Arc Burn ○ Crack ○ Lack of Fusion
○ Lamination ○ Buckle ○ Wrinkle ○ Misalignment ○ Burnt Steel
○ Other ________________________________

*5. Has one or more internal inspection tool collected data at the point of the Incident? ○ Yes ○ No

*5.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

○ Magnetic Flux Leakage Tool /___/___/___/___/
○ Ultrasonic /___/___/___/___/
○ Geometry /___/___/___/___/
○ Caliper /___/___/___/___/
○ Crack /___/___/___/___/
○ Hard Spot /___/___/___/___/
○ Combination Tool /___/___/___/___/
○ Transverse Field/Triaxial /___/___/___/___/
○ Other ________________________ /___/___/___/___/

*6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?
○ Yes ⇨ *Most recent year tested: /___/___/___/___/ *Test pressure (psig): /___/___/,/___/___/___/
○ No

*7. Has one or more Direct Assessment been conducted on the pipeline segment?
○ Yes, and an investigative dig was conducted at the point of the Incident ⇨ Most recent year conducted: /___/___/___/___/
○ Yes, but the point of the incident was not identified as a dig site ⇨ Most recent year conducted: /___/___/___/___/
○ No

*8. Has one or more non-destructive examination(s) been conducted at the point of the Incident since January 1, 2002?
○ Yes ○ No

*8.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

○ Radiography /___/___/___/___/
○ Guided Wave Ultrasonic /___/___/___/___/
○ Handheld Ultrasonic Tool /___/___/___/___/
○ Wet Magnetic Particle Test /___/___/___/___/
○ Dry Magnetic Particle Test /___/___/___/___/
○ Other ______________________________ /___/___/___/___/

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G6 - Equipment Failure - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Malfunction of Control/Relief Equipment**	1. Specify: *(select all that apply)* ○ Control Valve ○ Instrumentation ○ SCADA ○ Communications ○ Block Valve ○ Check Valve ○ Relief Valve ○ Power Failure ○ Stopple/Control Fitting ○ Pressure Regulator ○ ESD System Failure ○ Other ___
☐ **Compressor or Compressor-related Equipment**	2. Specify: ○ Seal/Packing Failure ○ Body Failure ○ Crack in Body ○ Appurtenance Failure ○ Pressure Vessel Failure ○ Other ___
☐ **Threaded Connection/Coupling Failure**	3. Specify: ○ Pipe Nipple ○ Valve Threads ○ Mechanical Coupling ○ Threaded Pipe Collar ○ Threaded Fitting ○ Other ___
☐ **Non-threaded Connection Failure**	4. Specify: ○ O-Ring ○ Gasket ○ Seal (NOT compressor seal) or Packing ○ Other___
☐ **Defective or Loose Tubing or Fitting**	
☐ **Failure of Equipment Body (except Compressor), Vessel Plate, or other Material**	
☐ **Other Equipment Failure**	*5. Describe: ___ ___

Complete the following if any Equipment Failure sub-cause is selected.

*6. Additional factors that contributed to the equipment failure: *(select all that apply)*

- ○ Excessive vibration
- ○ Overpressurization
- ○ No support or loss of support
- ○ Manufacturing defect
- ○ Loss of electricity
- ○ Improper installation
- ○ Mismatched items (different manufacturer for tubing and tubing fittings)
- ○ Dissimilar metals
- ○ Breakdown of soft goods due to compatibility issues with transported gas/fluid
- ○ Valve vault or valve can contributed to the release
- ○ Alarm/status failure
- ○ Misalignment
- ○ Thermal stress
- ○ Other ___

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G7 - Incorrect Operation - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage**	
☐ **Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure**	1. Specify: ○ Valve Misalignment ○ Incorrect Reference Data/Calculation ○ Miscommunication ○ Inadequate Monitoring ○ Other ______________________
☐ **Valve Left or Placed in Wrong Position, but NOT Resulting in an Overpressure**	
☐ **Pipeline or Equipment Overpressured**	
☐ **Equipment Not Installed Properly**	
☐ **Wrong Equipment Specified or Installed**	
☐ **Other Incorrect Operation**	*2. Describe: ______________________

Complete the following if any Incorrect Operation sub-cause is selected.

*3. Was this Incident related to: *(select all that apply)*

○ Inadequate procedure
○ No procedure established
○ Failure to follow procedure
○ Other: ______________________

*4. What category type was the activity that caused the Incident:

○ Construction
○ Commissioning
○ Decommissioning
○ Right-of-Way activities
○ Routine maintenance
○ Other maintenance
○ Normal operating conditions
○ Non-routine operating conditions (abnormal operations or emergencies)

*5. Was the task(s) that led to the Incident identified as a covered task in your Operator Qualification Program? ○ Yes ○ No

*5.a If Yes, were the individuals performing the task(s) qualified for the task(s)?

○ Yes, they were qualified for the task(s)
○ No, but they were performing the task(s) under the direction and observation of a qualified individual
○ No, they were not qualified for the task(s) nor were they performing the task(s) under the direction and observation of a qualified individual

G8 – Other Incident Cause - *only one **sub-cause** can be picked from shaded left-hand column

☐ **Miscellaneous**	*1. Describe: ______________________
☐ **Unknown**	*2. Specify: ○ Investigation complete, cause of Incident unknown ○ Still under investigation, cause of Incident to be determined* *(*Supplemental Report required)*

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PART H – NARRATIVE DESCRIPTION OF THE INCIDENT	*(Attach additional sheets as necessary)*

***PART I – PREPARER AND AUTHORIZED SIGNATURE**

*Preparer's Name (type or print)

Preparer's Telephone Number

Preparer's Title (type or print)

Preparer's E-mail Address

Preparer's Facsimile Number

Authorized Signature

*Date

Authorized Signature Telephone Number

*Authorized Signature's Name (type or print)

Authorized Signature's Title (type or print)

Authorized Signature's E-mail Address

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REPORTING OF SAFETY RELATED CONDITIONS

1. REFERENCE

49 CFR, Sections 191.23, 191.25, 192.485, 192.605(d), 192.613, & 192.703.

2. PURPOSE

The purpose of this procedure is to define safety related conditions and establish responsibilities for reporting safety related conditions on Company pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (22) ________________ is responsible for the determination, evaluation, and correction of safety related conditions and reporting of these items to the governing agencies. The (23) ________________ is responsible to train operating personnel to insure that they are capable of properly identifying and interpreting safety related conditions.

4. GENERAL

4.1 Designated operating personnel will look for possible safety related conditions while conducting routine operating functions and when following applicable procedures for inspections and surveillance.

4.2 The (24) __________________ or designated operating personnel will complete the Safety Related Conditions Report (Form 1.02B). If completed by operating personnel, Form 1.02B must be provided to the (25) ______________________ as soon as possible, but not more than five (5) working days after discovery.

4.3 The (26) ______________________ is responsible for evaluating safety related conditions and reporting to governing agencies. Reports must be received by the governing agencies no later than five (5) working days after the day of determination or ten (10) working days after the day of discovery.

4.4 If a possible safety related condition is discovered which results in taking the facility out of service due to an incident before determination, and not more than five (5) working days from discovery, the reporting requirements of this procedure are eliminated.

4.5 "Safety Related Condition," as defined in Item 5.1 below, is a condition which lies within 220 yards (200 meters) of any building intended for human occupancy or outdoor place of assembly, or within the right-of-way of an active railroad, asphalt or concrete paved road, street or highway.

4.6 "Discovery Date" is the date that a condition is identified that may be classified as a safety related condition under this procedure, but requires additional evaluation or analysis.

4.7 "Determination Date" is the date when a condition evaluation results in the conclusion that it is a safety related condition.

4.8 "Working Days" are Monday through Friday, except Federal holidays. (See List of Federal Holidays at the end of this procedure.)

4.9 The company will provide instruction and/or training to pipeline supervisors and pipeline operators who perform operation and maintenance activities to enable them to recognize conditions that potentially may be safety related conditions that are subject to the reporting requirements of 191.23.

5. PROCEDURE

5.1 Safety Related Conditions

The following conditions are defined as safety related conditions and must be reported per 5.2 below: Use Figure #1.02A for assistance in making SRC reporting determination.

5.1.1 On a pipeline operating at a hoop stress of 20% or more of its specified minimum yield strength (SMYS), when:

5.1.1.1 General corrosion has reduced the wall thickness to less than the wall thickness required for the maximum allowable operating pressure (MAOP) of the system.

5.1.1.2 Localized corrosion pitting to a degree where leakage could result.

5.1.2 Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline.

5.1.3 On a pipeline at a hoop stress of 20% or more of its specified minimum yield strength (SMYS) a material defect or physical damage that impairs the serviceability of the pipeline.

5.1.4 Any equipment malfunction or operating error that causes the pressure in a pipeline to exceed the maximum allowable operating pressure (MAOP)
plus the build-up allowed for operation of pressure limiting or control devices.

5.1.5 A leak in a pipeline or facility that is characterized by the need for immediate corrective action to protect the public or property and that constitutes an emergency.

5.1.6 A shutdown or reduction in operating pressure of 20% or more that is made in reaction to a known unsafe condition.

5.1.7 Reduction in pressure as a precaution to avoid an unsafe condition for the following activities is not reportable.

5.1.7.1 Abandonment of pipeline facilities.

5.1.7.2 Routine maintenance or construction.

5.1.7.3 Facilitate inspection for potential problems.

5.1.7.4 Avoid problems related to external loading from blasting or subsidence.

5.1.7.5 Provide for safe line movement.

5.2 Reporting of Safety Related Conditions

The following outlines when a safety related condition is reportable and also defines the reporting process.

5.2.1 <u>Report</u> safety related conditions to regulatory agencies for:

5.2.1.1 All safety related conditions resulting from defects outlined in 5.1.1 above, regardless of when the condition is repaired.

5.2.2 A safety related condition <u>is not reportable</u> if:

5.2.2.1 It becomes an incident before the deadline for filing the safety related condition report. Report the situation per Procedure 1.01 of this manual.

5.2.2.2 It exists on a pipeline that is more than 220 yards from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway.

5.2.2.3 It is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for the conditions in 5.1.1 above, other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

5.2.3 Designated operating personnel shall contact the (27) ______________________ promptly if a possible safety related condition is discovered.

5.2.4 Operating personnel shall provide relevant information on an expedited schedule to support the timely submission of reports to DOT. The Safety Related Condition Report (Form 1.02B) form is to be used as a communication tool by Operating Personnel to provide proper information to the (28) ____________________. If the (29) _________________ determines that a reportable safety related condition exists, then the (30) _________________ shall complete Form 1.02B.

5.2.5 Use Chart 1.02A, as a guide for determination of safety related conditions.

5.2.6 The (31) _________________ will evaluate and confirm the reportability of a condition. If a condition is determined to be reportable, the (32) __________________ will submit the necessary written report to the appropriate agencies.

The (33) _________________ must submit a final report to DOT within five (5) working days of determination, but not later than ten (10) working days after discovery of the condition, at the following address:

Information Resources Manager
Office of Pipeline Safety
Pipeline and Hazardous Material Safety Administration (PHMSA)
PHP-20
1200 New Jersey Ave, SE
Washington, DC 20590

The report may also be submitted by telefacsimile (FAX): (202) 366-7128. Form 1.02B may be used to report a safety related condition to DOT.

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents
1.03 Investigation of Failures and Accidents
5.01 Continuing Surveillance
9.01 Repair Procedures

7. RECORDS

7.1 For intrastate pipelines, and in states where the state is an Agent for DOT, a report copy will be sent to the applicable state agency.

7.2 Copies of Form 1.02B and reports to DOT or other agencies will be sent to the applicable Company Offices.

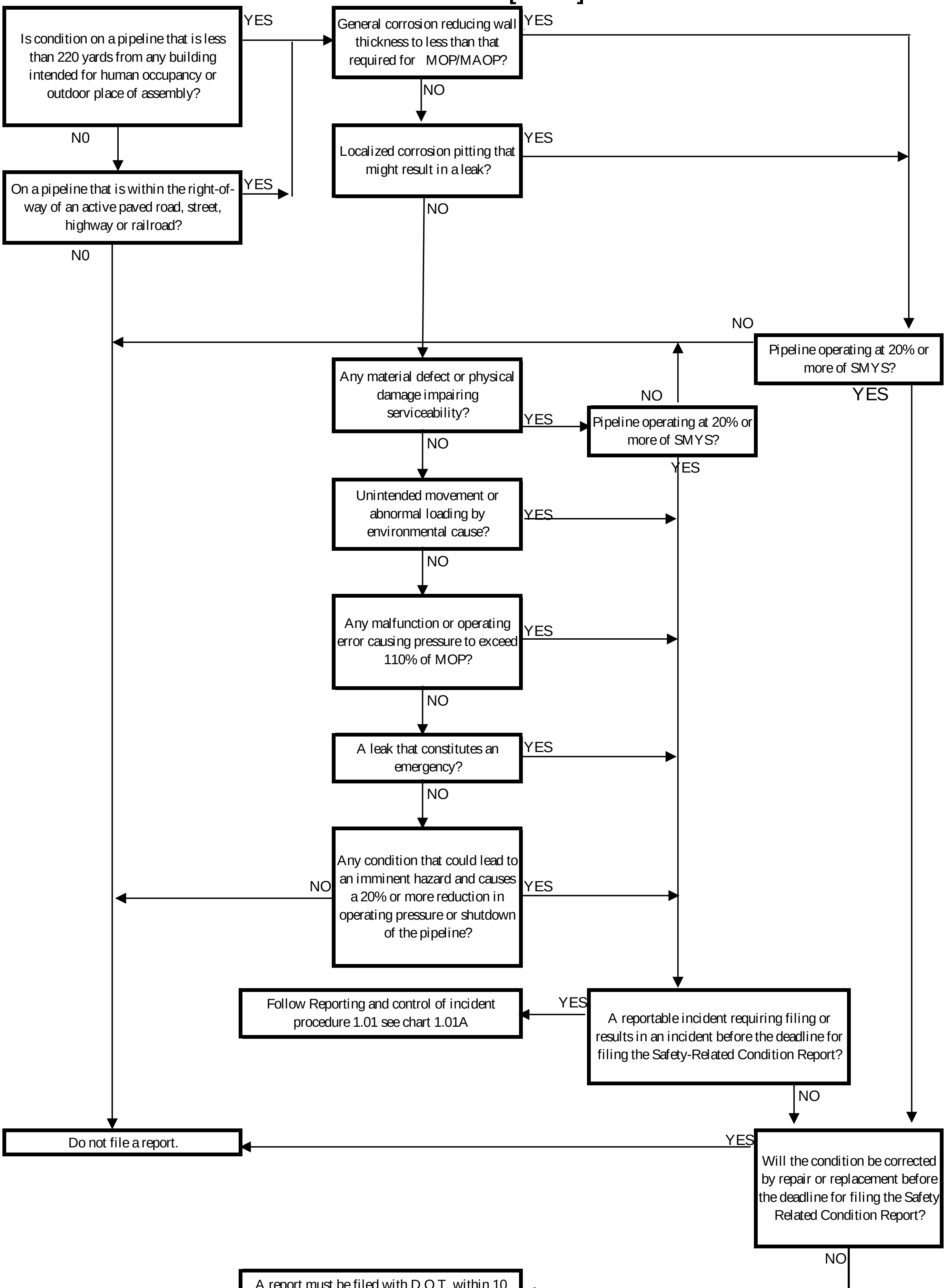
7.3 A copy of all correspondence related to reported conditions will be kept by the District Office for five (5) years.

7.4 Reports on all corrective actions taken will be kept by the District Office for at least five years.

LIST OF FEDERAL HOLIDAYS

New Years Day	January 1
Martin Luther King Day	Third Monday in January
Washington's Birthday	February 22
Memorial Day	Last Monday in May
Independence Day	July 4
Labor Day	First Monday in September
Columbus Day	Second Monday in October
Veterans Day	November 11
Thanksgiving	Fourth Thursday in November
Christmas	December 25

REPORTING OF SAFETY RELATED CONDITIONS
CHART 1.02A [191.23]



DETERMINATION OF REPORTING REQUIREMENTS FOR SAFETY - RELATED CONDITIONS
191.23

<table>
<tr><th>Location</th><th>Time Factor</th><th>Type</th><th colspan="2">Effect on Facility Operation</th><th>Report Required</th></tr>
<tr><td rowspan="20">Within 220 yards of a 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.</td><td rowspan="14">Will not be corrected within 5 working days after determination <u>or</u> 10 working days after discovery, whichever comes first</td><td rowspan="2">General Corrosion</td><td colspan="2">Causes the MAOP to reduced</td><td>Yes</td></tr>
<tr><td colspan="2">Does not cause the MAOP to be reduced</td><td>No</td></tr>
<tr><td rowspan="2">Localized Corrosion Pitting</td><td colspan="2">Leakage might result</td><td>Yes</td></tr>
<tr><td colspan="2">Leakage unlikely to result</td><td>No</td></tr>
<tr><td rowspan="2">Unintended Movement or Loading</td><td colspan="2">Impairs serviceability</td><td>Yes</td></tr>
<tr><td colspan="2">Does not impair serviceability</td><td>No</td></tr>
<tr><td rowspan="2">Material Defect or Damage</td><td colspan="2">Impairs serviceability</td><td>Yes</td></tr>
<tr><td colspan="2">Does not impair serviceability</td><td>No</td></tr>
<tr><td rowspan="2">Malfunction or Operating Error</td><td colspan="2">Causes pressure to increase above MAOP + allowable build-up</td><td>Yes</td></tr>
<tr><td colspan="2">Does not cause pressure to increase above MAOP + allowable build-up</td><td>No</td></tr>
<tr><td rowspan="2">Leak</td><td colspan="2">Creates an emergency</td><td>Yes</td></tr>
<tr><td colspan="2">Does not create an emergency</td><td>No</td></tr>
<tr><td rowspan="2">All Other Conditions</td><td colspan="2">Could lead to an imminent hazard and causes:
a) 20% or more pressure reduction or
b) shutdown</td><td>Yes</td></tr>
<tr><td colspan="2">All others</td><td>No</td></tr>
<tr><td rowspan="6">Will be corrected within 5 working days after determination or 10 working days after discovery, whichever comes first.</td><td rowspan="2">General Corrosion</td><td colspan="2">Causes the MAOP to be reduced</td><td>Yes</td></tr>
<tr><td colspan="2">Does not cause the MAOP to be reduced</td><td>No</td></tr>
<tr><td rowspan="3">Localized Corrosion Pitting</td><td rowspan="2">Leakage might result</td><td>Coated & cathodically protected</td><td>No</td></tr>
<tr><td>Not coated or not cathodically protected</td><td>Yes</td></tr>
<tr><td colspan="2">Leakage unlikely to result</td><td>No</td></tr>
<tr><td>All Other</td><td colspan="2">All</td><td>No</td></tr>
<tr><td>All Other Areas</td><td colspan="5">No Report Required</td></tr>
<tr><td colspan="6">1 An event which has been reported as an incident (191.5) is not reportable as a safety-related condition. Report is not required for any safety-related condition that exists on a master system or a customer-owned service line.
2 Does not pertain to pipelines operating at less than 20% SMYS</td></tr>
</table>

SAFETY RELATED CONDITION REPORT
FORM 1.02B

Company: ____________	Operating Location: ____________	Date: ____________ MO / DAY / YR

Person Submitting Report:	Person Who Determined Condition Exists:
Name: ____________	Name: ____________
Title: ____________	Title: ____________
Telephone: ____________	Telephone: ____________
Date Condition Discovered: ____________	Date Condition Determined: ____________

Location of Condition:

- ☐ Rural
- ☐ Non-Rural
- ☐ Offshore

Pipeline Name and Number: ____________ Class Location:(Gas) ____________

Date(s) of Installation of all Affected Pipeline Segments: ____________

O.D. ____________ Station or Mile Post: ____________

Wall Thickness: ____________ Grade: ____________

Plant Field / Area: ____________

State: ____________ County/Parish: ____________ Sec/Twnship/Rnge: ____________

Name of nearest street or road (where applicable) ____________

Condition Description:

Corrective Action Taken:

[191.25]

Signatures:

Person Completing This Form: ____________

Supervisor: ____________

INVESTIGATION OF FAILURES AND INCIDENTS

1. REFERENCE

   49 CFR, Sections 192.617 and 199.105(b).

2. PURPOSE

   The purpose of this procedure is to establish responsibilities for activities associated with investigation, analysis, and documentation of pipeline facility failures and incidents.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (42) __________________________ is responsible for investigation, analysis, and documentation of pipeline facility failures and incidents.

4. GENERAL

   4.1 The (43) __________________________ is responsible for investigating the cause of incidents reported to State and Federal Agencies.

   4.2 The (44) __________________________ is responsible for documenting and/or investigating those incidents not investigated by the (45) ______________.

   4.3 The investigation shall address at least the following:

   4.3.1 Description and service history of the failed facility or equipment.

   4.3.2 Sequence of events leading up to the accident or failure.

   4.3.3 General data on any systems involved.

   4.3.3.1 Facility specifications.

   4.3.3.2 Operating conditions at the time of failure or accident.

   4.3.3.3 Physical damage to any facilities or equipment.

   4.3.3.4 Physical evidence should be maintained in its original state as much as possible. Consider using “chain-of-custody” if appropriate for critical samples.

   4.3.4 Injury to Company and/or third party individuals.

4.3.5 Cause of accident or failure. Conduct laboratory analysis if appropriate. Laboratory analysis may be performed by independent testing/consulting laboratory services.

4.3.6 Measures to be taken to prevent recurrence, based on final findings.

4.3.7 A review of employee activities to determine whether appropriate procedures were followed.

4.3.8 Procedural changes desirable.

4.4 Any accident investigation by the DOT shall receive full cooperation by the (46) __________________________.

5. <u>PROCEDURE</u>

5.1 (47) _______________________ /Designated Personnel Responsibilities:

5.1.1 In the event of a failure or incident, take appropriate action <u>to protect people first and then property</u> per the applicable emergency plan. (See system specific Emergency Plan if required.)

5.1.2 Secure the site and maintain it undisturbed if possible. If possible, leave failed equipment or portions of failed systems undisturbed, until the appropriate Company representative is on site. If the site or equipment cannot be left undisturbed, thoroughly document the situation prior to disturbing it. Documentation should include such things as taking photographs, making dimensioned sketches and corrosion surveys, collecting soil and liquid samples, as applicable so that the location and orientation of equipment or failed portion can be identified later and other necessary data is not lost by repair work.

5.1.3 Provide for the selecting, collecting, preserving, labeling & handling of metallurgical specimens. Precautions must be exercised to prevent changing <u>any</u> sample from its natural state. See 5.2.2 below.

5.1.4 Arrange for interviews of employees and witnesses as requested.

5.1.5 As soon as practical, but no later than 32 hours after an incident has been reported to DOT, <u>drug test</u> each employee or contractor's employee whose performance contributed to or may have contributed to the incident. All reasonable steps must be taken to test such persons even though injured, unconscious, or otherwise unable to evidence consent.

5.1.6 As soon as practical, but no later than 2 hours after an incident has been reported to DOT, alcohol test employees or contractor's employees whose performance contributed to or may have contributed to the incident. All reasonable steps must be taken to test such persons even though injured, unconscious, or otherwise unable to evidence consent.

5.2 (48) __________________________ Responsibilities for Code Compliance:

5.2.1 On a case by case basis, provide on-site investigation of incidents meeting one of the Accident Criteria in Procedure 1.01.

5.2.2 Arrange for outside professional services to assist in an investigation (e.g., corrosion specialist, land surveyor, metallurgist, welding engineer, etc.) if deemed necessary, or if so directed by Legal staff or (49) __________________________.

5.2.3 Analyze field data collected, operating history of facility and results of lab testing to establish cause of failure or condition and write reports as necessary.

5.2.4 Provide recommendations for operational changes or facility modifications as appropriate to minimize the possibilities of recurrence.

5.2.5 Written recommendations will be reviewed by (50A) ___________ and (50B) ___________ prior to issuance.

5.2.6 Submit copies of reports to other agencies and to the applicable Company (50C) ___________.

5.3 Critique the investigation by completing, the Company's "Accident and Near Miss Investigation Report", Form 2055.

6. RELATED PROCEDURES

1.01 Reporting and Control of Incidents
1.02 Reporting of Safety Related Conditions
3.04 Preparation of an Emergency Plan
5.01 Continuing Surveillance

7. RECORDS

7.1 Complete Form 1.01B and DOT Form PHMSA form #11 (at the end of Procedure 1.01), as required. Complete the Company's "Accident and Near Miss Investigation Report", Form 2055 or equivalent.

7.2 The (51) __________________________ will maintain the official files on incidents that are reported to outside agencies.

7.3 Each file will be kept for the life of the system.

ACCIDENT & NEAR MISS INVESTIGATION REPORT

(Any Accident or Near Miss)

[191]

PERSON(S) INVOLVED	
Name:	Employee or contractor:
Address:	Phone number:
Name:	Employee or contractor:
Address:	Phone number:
EMPLOYER INFORMATION (If contractor)	
Employer name:	Phone number:
Address:	
ACCIDENT / NEAR MISS INFORMATION	
Date of occurrence:	
Exact location of accident:	
Description of accident:	
What unsafe action/condition was the root cause of the accident?	
What corrective action has been taken to prevent reoccurrence?	
Person responsible for corrective action:	
REPORT REVIEW	
Person(s) involved signature(s):	Date:
Operations Supervisor signature:	Date:
Plant Manager signature:	Date:

Form #1.03A

Pipeline Failure Investigation Report

Pipeline System: ______________________ **Operator:** ______________________

Location: ______________________ **Date of Occurrence:** ______________________

Medium Released: ______________________ **Quantity:** ______________________

OPS Arrival Time & Date: ______________________ **Total Damages $:** ______________________

Investigation Responsibility: ☐ State ☐ OPS ☐ NTSB Other ______________________

Company Reported Apparent Cause: ☐ Corrosion ☐ Damage by Outside Force

☐ Damage by Natural Forces ☐ Accidentally Caused by the Operator

☐ Construction/Material Defect ☐ Equipment Malfunction ☐ Other ______________________

Rupture ? ☐ Yes ☐ No

Leak ? ☐ Yes ☐ No

Fire? ☐ Yes ☐ No

Explosion?: ☐ Yes ☐ No

Evacuation?: ☐ Yes ☐ No Number of Persons? __________ Area? __________

Narrative Summary
One paragraph summary description of the Incident/Accident which will give interested persons sufficient information to make them aware of the basic scenario and facts.

Region/State: ______________________ **Reviewed by:** ______________________

Principle Investigator: ______________________ **Title:** ______________________

Date: ______________________ **Date:** ______________________

Failure Location & Response			
Location (City, Township, Range, County/Parish): (Acquire Map)			
Address or M.P. on Pipeline: ρ		Type of Area (Rural, City): ρ	
Date:		Time of Failure:	
Time Detected:		Time Located:	
How Located:			
NRC Report #: (Attach Report)	Time Reported to NRC:		Reported by:

Type of Pipeline:

Gas Distribution	Gas Transmission	Hazardous Liquid	LNG
☐ LP	☐ Interstate Gas	☐ Interstate Liquid	☐ LNG Facility
☐ Municipal	☐ Intrastate Gas	☐ Intrastate Liquid	
☐ Public Utility	☐ Jurisdictional Gas Gathering	☐ Offshore Liquid	
☐ Master Meter	☐ Offshore Gas	☐ Jurisdictional Liquid Gathering	
	☐ Offshore Gas - High H_2S	☐ CO_2	

Pipeline Configuration (Regulator Station, Pump Station, Pipeline, etc.):

Operator/Owner Information			
Owner:		Operator:	
Contact:		Company Official:	
Address:		Title:	
City:	State:	Address:	
Phone No.:	Fax No.:	City:	State:
DRUG TESTING			☐ **N/A**
Contact:		Phone No.:	

Damages	
Product/Gas Loss or Spill(1): Amount Recovered: Estimated Amount $:	Estimated Property Damage $: Associated Damages(2) $:
Description of Property Damage:	

Customers out of Service: ☐ Yes ☐ No Number: ____________

Suppliers out of Service: ☐ Yes ☐ No Number: ____________

(1) Initial Volume Lost or Spilled

(2) Including Cleanup Cost

Fatalities and Injuries

Fatalities:	☐ Yes	☐ No	Company: ______	Contractor: ______	Public: ______
Injuries - Hospitalization:	☐ Yes	☐ No	Company: ______	Contractor: ______	Public: ______
Injuries - Non-Hospitalization:	☐ Yes	☐ No	Company: ______	Contractor: ______	Public: ______
Total Injuries (including Non-Hospitalization):			Company: ______	Contractor: ______	Public: ______

Name	Age	M/F	Job Function	Yrs w/ Comp.	Yrs Exp.	Type of Injury

Drug/Alcohol Testing ☐ *N/A*

Were all employees that could have contributed to the incident, Post Accident tested within the 2 hour time frame for alcohol or the 32 hour time frame for all other drugs?

☐ Yes ☐ No

Job Function	Time of Test	Location	Results Pos.	Results Neg.	Type of Drug

System Description

Describe the Operator's System:

Pipe Failure Description ☐ *N/A*

Length of Failure (inches, feet, miles): ρ

Position (Top, Bottom, include position on pipe, 6 O'clock): ρ	Description of Failure (Corrosion Gouge, Seam Split): ρ

Laboratory Analysis: ☐ Yes ☐ No
Performed by:

Preservation of Failed Section or Component: ☐ Yes ☐ No
If Yes - Method:

In Custody of:

Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Direction of Flow.

Component Failure Description		☐ N/A
Component Failed:		ρ
Manufacturer:	Model:	
Pressure Rating:	Size:	
Other (Breakout Tank, Underground Storage):		

Pipe Data	☐ N/A
Material:	Wall Thickness/SDR:
Diameter (O.D.):	Installation Date:
SMYS:	Manufacturer:
Longitudinal Seam:	Type of Coating:
Pipe Specifications (API 5L, ASTM A53, etc.):	

Joining	☐ N/A
Type:	Procedure:
NDT Method:	Inspected: ☐ Yes ☐ No

Pressure @ Time of Failure @ Failure Site				☐ N/A
Pressure @ Failure Site:		Elevation @ Failure Site:		
Pressure Readings @ Various Locations:			Direction from Failure Site	
Location/M.P./Station #	Pressure	Elevation	Upstream	Downstream

Upstream Pump Station Data	☐ N/A
Type of Product:	API Gravity:
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure(3):	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Upstream Compressor Station Data	☐ N/A
Specific Gravity:	Flow Rate:
Pressure @ Time of Failure(3):	Distance to Failure Site:
High Pressure Set Point:	Low Pressure Set Point:

Operating Pressure	☐ N/A
Max. Allowable Operating Pressure:	Determination of MAOP:
Actual Operating Pressure:	
Method of Over Pressure Protection:	
Relief Valve Set Point:	Capacity Adequate?: ☐ Yes ☐ No

(3) Obtain Event Logs and Pressure Recording Charts

Integrity Test After Failure	☐ ***N/A***
Pressure Test Conducted in place? (Conducted on Failed Components or Associated Piping): ☐ Yes ☐ No	
If NO, Tested after removal?: ☐ Yes ☐ No	
Method?:	
Describe any failures during the test.	

Pressure Test History					☐ ***N/A***
	Date	Test Medium	Pressure	Duration	% SMYS
Installation:					
Last:					
Other:					

Any problems occur during any of the Pressure Tests?:

Soil/water Conditions @ Failure Site	☐ ***N/A***
Condition of and type of Soil around Failure Site (Color, Wet, Dry, Frost Depth):	
Type of Backfill (Size and Description):	
Type of Water (Salt, Brackish):	Water Analysis[4]: ☐ Yes ☐ No

(4) Attach Copy of Water Analysis Report

External Pipe or Component Examination	☐ ***N/A***
External Corrosion?: ☐ Yes ☐ No ρ	Coating Condition (Disbonded, Non-existent): ρ
Description of Corrosion: ρ	
Description of Failure surface (Gouges, Arc Burns, Wrinkle Bends, Cracks, Stress Cracks, Chevrons, Fracture Mode, Point of Origin):	
Above Ground: ☐ Yes ☐ No ρ	Buried: ☐ Yes ☐ No ρ
Stress Inducing Factors: ρ	Depth of Cover: ρ

Cathodic Protection	☐ ***N/A***
P/S (Surface):	P/S (Interface):
Soil Resistivity: pH:	Date of Installation:
Method of Protection?:	
Did the Operator have knowledge of Corrosion before the Incident?: ☐ Yes ☐ No	
How Discovered? (Close Interval Survey, Instrumented Pig, Annual Survey, Rectifier Readings):	

Internal Pipe or Component Examination	☐ ***N/A***
Internal Corrosion: ☐ Yes ☐ No ρ	Injected Inhibitors: ☐ Yes ☐ No
Type of Inhibitors:	Testing: ☐ Yes ☐ No
Results (Coupon Test, Corrosion resistance Probe):	
Description of Failure surface (MIC, Pitting, Wall Thinning, Chevrons, Fracture Mode, Point of Origin):	
Cleaning Pig Program: ☐ Yes ☐ No	Gas and/or Liquid Analysis: ☐ Yes ☐ No
Results of Gas and/or Liquid Analysis(5):	
Internal Inspection Survey: ☐ Yes ☐ No	Results(6):
Did the Operator have knowledge of Corrosion before the Incident?: ☐ Yes ☐ No	
How Discovered? (Instrumented Pig, Coupon Testing):	

(5) Attach Copy of Gas and/or Liquid Analysis Report

(6) Attach Copy of Internal Inspection Survey Report

Outside Force Damage	☐ N/A
Responsible Party:	Telephone No.:
Address:	
Work Being Performed:	
Equipment Involved: ρ	Called One Call System?: ☐ Yes ☐ No
One Call Name:	One Call Report #(7):
Notice Date:	Time:
Response Date:	Time:
Details of Response:	
Was Location Marked According to Procedures: ☐ Yes ☐ No	
Pipeline Marking Type: ρ	Location: ρ
State Law Damage Prevention Program Followed?: ☐ Yes ☐ No ☐ No State Law	
Notice Required: ☐ Yes ☐ No	Response Required: ☐ Yes ☐ No
Was Operator Member of State One Call?: ☐ Yes ☐ No	Was Operator on Site?: ☐ Yes ☐ No
Is OSHA Notification Required?: ☐ Yes ☐ No	

Natural Forces	☐ N/A
Description (Earthquake, Tornado, Flooding, Erosion):	

Failure Isolation	☐ N/A
Squeeze Off/Stopple Location and Method: ρ	
Valve Closed - Upstream: Time:	I.D.: M.P.:
Valve Closed - Downstream: Time:	I.D.: M.P.:
Pipeline Shutdown Method: ☐ Manual ☐ Automatic ☐ SCADA ☐ Controller ☐ ESD	
Failed Section Bypassed or Isolated:	
Performed By:	Valve Spacing:

(7) Attach Copy of One Call Report

Odorization	☐ ***N/A***
Gas Odorized: ☐ Yes ☐ No	Concentration of Odorant (Post Incident at Failure Site):
Method of Determination:	% LEL: % Gas In Air:
	Time Taken:
Was Odorizer Working Prior to the Incident: ☐ Yes ☐ No	Type of Odorizer (Wick, By-Pass):
Odorant Manufacturer: Model:	Type of Odorant:
Amount Injected:	Monitoring Interval (Weekly):
Odorization History (Leaks Complaints, Low Odorant Levels, Monitoring Locations, Distances from Failure Site):	

Weather Conditions	☐ ***N/A***
Temperature:	Wind (Direction & Speed):
Climate (Snow, Rain):	Humidity:
Was Incident preceded by a rapid weather change: ☐ Yes ☐ No	
Weather Conditions Prior to Incident (Cloud Cover, Ceiling Heights, Snow, Rain, Fog):	

Gas Migration Survey	☐ ***N/A***
Bar Hole Test of Area: ☐ Yes ☐ No	Equipment Used:
Method of Survey (Foundations, Curbs, Manholes, Driveways, Mains, Services)(8):	ρ

Environment Sensitivity Impact	☐ ***N/A***
Location (Nearest Rivers, Body of Water, Marshlands, Wildlife Refuge, City Water Supplies that could be or were affected by the medium loss.):	ρ
OPA Contingency Plan Available?: ☐ Yes ☐ No	Followed?: ☐ Yes ☐ No

Class Location	☐ ***N/A***
Class:	Determination:
Odorization Required?: ☐ Yes ☐ No	

(8) Plot on Site Description Page

Maps & Records	☐ N/A
Are Maps and Records Current?[9]: ☐ Yes ☐ No	

Leak Survey History	☐ N/A
Leak Survey History (Trend Analysis, Leak Plots):	

Pipeline Operation History		☐ N/A
Description (Repair or Leak Reports, Exposed Pipe Reports):		
Did a Safety Related Condition Exist Prior to Failure?: ☐ Yes ☐ No	Reported?: ☐ Yes ☐ No	
Unaccounted For Gas:		
Over & Short/Line Balance (24 hr., Weekly, Monthly/Trend):		

Operator/Contractor Error	☐ N/A
Name:	Job Function:
Title:	Years of Experience:
Training (Type of Training, Background):	
Type of Error (Inadvertent Operation of a Valve):	
Procedures that are required:	
Actions that were taken:	
Pre-Job Meeting (Construction, Maintenance, Blow Down, Purging, Isolation):	
Prevention of Accidental Ignition (Tag & Lock Out, Hot Weld Permit):	
Procedures conducted for Accidental Ignition:	
Was a Company Inspector on the Job?: ☐ Yes ☐ No	
Was an Inspection conducted on this portion of the Job?: ☐ Yes ☐ No	
Additional Actions (Contributing factors may include number of hours at work prior to failure or time of day work being conducted):	

(9) Obtain Copies of Maps and Records

Operator/Contractor Error				☐ ***N/A***
Training Procedures:				
Operation Procedures:				
Controller Activities:				
Name	Title	Years Experience	Hours on Duty Prior to Failure	Shift
Alarm Parameters:				
High/Low Pressure Shutdown:				
Flow Rate:				
Procedures for Clearing Alarms:				
Type of Alarm:				
Company Response Procedures for Abnormal Operations:				
Over/Short Line Balance Procedures:				
Frequency of Over/Short Line Balance:				
Additional Actions:				

Additional Actions Taken by the Operator
Make notes regarding the emergency and Failure Investigation Procedures (Pressure reduction, Reinforced Squeeze Off, Clean Up, Use of Evacuators, Line Purging, closing Additional Valves, Double Block and Bleed, Continue Operating downstream Pumps):

Photo Documentation ρ

Overall Area from best possible view.
Pictures from the four points of the compass.
Failed Component.
Operator Actions.
Damages in Area.
Address Markings.

Photo No.	Description	Roll No.	Photo No.	Description	Roll No.
1			1		
2			2		
3			3		
4			4		
5			5		
6			6		
7			7		
8			8		
9			9		
10			10		
11			11		
12			12		
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23			23		
24			24		
25			25		
26			26		
27			27		
28			28		
29			29		
30			30		
31			31		
32			32		
33			33		
34			34		
35			35		
36			36		

Type of Camera:

Film ASA:

Video Counter Log(10):

(10) Attach Copy of Video Counter Log

Additional Information Sources	
Phone Number	Name
Police:	Contact:
Fire Dept.:	Contact:
State Fire Marshall:	Contact:
State Agency:	Contact:
NTSB:	Contact:
EPA:	Contact:
FBI:	Contact:
ATF:	Contact:
OSHA:	Contact:
Insurance Co.:	Contact:
FRA:	Contact:
MMS:	Contact:
Television:	Contact:
Televison	Contact:
Newspaper:	Contact:
Other:	Contact:

Persons Interviewed		
Name	Title	Phone Number

Event Log

Sequence of events prior, during and after the incident by time. (Consider the events of all parties involved in the incident, Fire Department and Police reports, Operator Logs and other government agencies.)

Time	Event

Investigation Contact Log			
Time	Date	Name	Description

Failure Investigation Documentation Log

Operator: Unit #: CPF #: Date:

Appendix Number	Documentation Description	Date Received	FOIA	
			Yes	No

Site Description

Develop a sketch of the area including distances from roads, houses, stress inducing factors, pipe configurations, etc.. Bar Hole Test Survey Plot should be outlined with concentrations at test points. Photos should be taken from all angles with each photo documented. Additional areas may be needed in any area of this guideline.

PIPELINE ANNUAL REPORTS

1. REFERENCE

49 CFR, Sections 191.1, 191.3, 191.7, 191.17, 191.19, and 192.1.

2. PURPOSE

The purpose of this procedure is to establish responsibilities for preparing and submitting of pipeline annual reports.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (58) ____________________ is responsible to provide information required to fill out the pipeline annual report. The (59) _______________________ is responsible for reporting and documentation of pipeline annual reports for pipeline facilities.

4. REGULATED LINES:

4.1 Gas transmission lines, distribution lines, branch lines, sales lines, and associated facilities, such as compressor stations, meter stations, regulator stations, etc.

4.2 Onshore gas gathering lines inside of the following areas:

4.2.1 An area within the limits of any incorporated or unincorporated city, town, or village.

4.2.2 Any designated residential or commercial area such as a subdivision business or shopping center, or community development.

4.3 Offshore gas gathering pipelines downstream of the outlet flange of the structure on which the gas is first produced, separated, dehydrated, or processed.

4.4 On the OCS (Outer Continental Shelf) downstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

5. REPORT SUBMISSION REQUIREMENTS [191.7]

5.1 Except safety-related condition report (§191.25) or an offshore pipeline condition report, the company must submit each report required by this procedure electronically to the Pipeline and Hazardous Materials Safety Administration at *http://opsweb.phmsa.dot.gov* unless an alternative reporting method is authorized in accordance with requirements below.

5.2 ***Exceptions***. The company is not required to submit a safety-related condition report (§191.25) or an offshore pipeline condition report (§191.27) electronically.

5.3 ***Alternative Reporting Method***. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

6. REPORT SUBMISSION DEADLINE [191.17]

6.1 For each transmission or gathering pipeline system the company must submit an annual report for that system on DOT Form PHMSA 7100.2.1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

7. DISTRICT ENGINEERING RESPONSIBILITIES

7.1 Collect data information, such as number and type of leaks, cause of the leaks and their disposition, etc., for preparation and submitting of the Pipeline Annual Reports.

7.2 For intrastate Pipelines, and in states where the state is an Agent for DOT, a report shall be submitted in duplicate to the State agency, if the regulations of that agency require submission of these reports, and provide for further transmittal of one copy no later than March 15, to the Information Resources Manager.

8. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
1.03 Investigation of Failures and Accidents
4.01 Class Location Survey and Determination

9. RECORDS

9.1 The District Office will maintain the official files on Pipeline Annual Reports.

9.2 Each file will be kept for the life of the pipeline facilities.

GENERAL INSTRUCTIONS

All section references are to Title 49 of the Code of Federal Regulations (49 CFR). The Natural and Other Gas Transmission and Gathering Systems Annual Report has been revised as of calendar year 2010 affecting submissions for 2010 and beyond. This Annual Report is required per §191.17 and must be filed per §191.7. Read through the Annual Report and instructions carefully before beginning to complete the Report. Where common data elements exist between this Report and an operator's NPMS submission, the data submitted by the operator on their Annual Report should be the same as the data submitted through NPMS when possible. (Additionally, and in order to align an operator's NPMS submission with their Annual Report data, PHMSA suggests that operators send their NPMS submission to PHMSA by March 15, representing pipeline assets as of December 31 of the previous year.)

Each operator of a transmission or a gathering pipeline system must submit an Annual Report for that system on DOT Form PHMSA 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. In order to improve the accuracy of reported data, operators are requested to review prior years' Reports in order to validate that their reported numbers are accurate, or to identify and correct inconsistencies or errors that are either found or that may exist in any previously reported data. Operators should file Supplemental Reports as necessary, including those supplementing prior years' Reports.

The terms "operator," "distribution line," "gathering line," "Maximum Allowable Operating Pressure (MAOP)," "offshore," "Outer Continental Shelf," "pipe," "pipeline," "pipeline facility," "specified minimum yield strength (SMYS)," and "transmission line" are defined in §192.3. The terms "assessment," and "high consequence area (HCA)" are defined in §192.903. §192.8 describes how to identify onshore gathering lines and to determine if a gathering line is subject to regulation (i.e., is a "regulated gathering line"). If an operator determines that its pipelines fall under the definition for distribution lines, he or she should submit Form PHMSA F 7100.1-1 rather than this Form PHMSA F 7100.2-1.

If you need copies of the Form PHMSA F 7100.2-1 and/or instructions, they can be found on the Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking Data and Statistics and then selecting the Forms hyperlink. If you have questions about this Report or these instructions, call PHMSA's Information Resources Manager at 202-366-8075.

ONLINE REPORTING REQUIREMENTS

Annual Reports must be submitted online unless an alternate method is approved (see Alternate Reporting Methods below).

The following two separate PIN/password requirements must be fulfilled prior to submitting data online:

1. You must have an Office of Pipeline Safety (OPS) provided Operator Identification Number (OPID) and Personal Identification Number (PIN). If you do not have one, complete and submit the form located on the OPS Online Data Entry and Operator Registration System New Operator Registration web site at http://opsweb.phmsa.dot.gov/cfdocs/opsapps/pipes/new_operator.cfm to obtain one.

2. You must ALSO have a Username and Password obtained by registering through the PHMSA Portal. If you have an OPS OPID and PIN, you may obtain a Username and Password through the PHMSA Portal. If you do not have a Username and Password for the PHMSA Portal, go to https://portal.phmsa.dot.gov/pipeline and click on *Create Account* and complete the form as required.

Important: Each operator without an OPID is to plan accordingly and allow for several weeks prior to the due date of the Report to obtain their OPID from PHMSA.

REPORTING METHOD

Use the following procedures to complete an Annual Report:

1. Navigate to the Pipeline Safety Community main page, http://www.phmsa.dot.gov/pipeline, click the **ONLINE DATA ENTRY** link listed.

2. Click on the "**Year 2010 and later**" hyperlink under the *Gas Transmission and Gathering Pipeline Systems* subtitle. This takes you to the PHMSA Portal login screen.

3. Enter your "Username" and "Password and click on "**Login**".

4. Under "**Create Reports**" on the left side of the screen, under *Annual* select "Gas Transmission and Gathering" and proceed with entering your data. *Note: Data fields marked with a single asterisk are considered required fields that must be completed before the system will accept your <u>initial</u> submission.* Also, only one annual report by commodity for an OPID may be submitted per year.

5. To save intermediate work without formally submitting it to PHMSA, click **Save**. To modify a draft of an annual report that you saved, go to **Saved Reports** and click on *Gas Transmission and Gathering*. Locate your saved report by the date, report year, or commodity. Select the record by clicking on it once, and then click **Modify** below the record.

6. Once all sections of the form have been completed, click on **Validate** to ensure all required fields have been completed and data meets all other requirements. A list of errors will be generated that must be fixed prior to submitting an Annual Report.

7. Click **Submit** when you have completed the Report (for either an Initial Report or a Supplemental Report), and are ready to initiate formal submission of your Report to PHMSA.

8. A confirmation message will appear that confirms a record has been successfully submitted. To save or print a copy of your submission, go to **Submitted Reports** on the left hand side, and click on *Gas Transmission and Gathering*. Locate your submitted report by the date, report year, or Commodity Group, and then click on the PDF icon to either open the file and print it, or save an electronic copy.

9. To submit a *Supplemental Report*, go to **Submitted Reports** on the left hand side, and click on *Gas Transmission and Gathering*. Locate your submitted report by the date, report year, or Commodity Group. Select the record by clicking on it once, and then click “Create Supplemental”.

Alternate Reporting Methods

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternative reporting method. Operators must follow the requirements in §191.7(d) to request an alternative reporting method and must comply with any conditions imposed as part of PHMSA’s approval of an alternate reporting method.

SPECIFIC INSTRUCTIONS

Make an entry in each block for which data is available. Estimate data only if necessary. Avoid entering any data as **UNKNOWN or 0 (zero)** except where zero is appropriate to indicate that there were no instances or amounts of the attribute being reported.

Do not report miles of pipe, pipe segments, or pipeline in feet. When reporting mileages that are less than 1 mile or when reporting portions of a mile, convert feet into a decimal notation (e.g. 2,640 feet = .5 miles) and report mileage using decimals rounded to the nearest tenth of a mile. Operators may round all mileages that are greater than 1 mile to the nearest mile. Do not use fractions.

Enter the Calendar Year for which the Report is being filed, bearing in mind that reporting requirements are for the preceding calendar year (i.e., for the March 15, 2011 deadline, the Report should provide information for assets as they existed at the end of the 2010 calendar year).

Select **Initial Report** if this is the original filing for the calendar year. Select **Supplemental Report** if this is a follow-up to a previously filed Report to amend or correct information for that calendar year. On Supplemental Reports, enter all information requested in Parts A and N, and only the new or revised information for the other Parts of the Report, completing Part O as required.

Report miles of pipe, pipe segments, or pipeline in the system at the end of the reporting year, including any additions or deletions to the system occurring during that year. Report other data for the duration of the calendar year as appropriate. Adhere to definitions in 49 CFR 192 when reporting mileage and other data.

For a given OPID, a separate Annual Report is to be completed for each Commodity Group within that OPID. The separate Annual Report is to cover all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within that OPID that serve to transport that Commodity Group. As an example, if an operator uses a single OPID and has one set of facilities and/or pipelines that transport natural gas and another that transports synthetic gas, this operator is to file two Annual Reports – one Annual Report covering all the facilities and/or pipelines that transport natural gas and another Annual Report covering all the facilities and/or pipelines that transport synthetic gas. If another operator utilizes two OPIDs with both natural gas and synthetic gas facilities and/or pipelines within each OPID, that operator must file four separate Annual Reports.

Parts A – E are to be completed once for each Annual Report, namely once for each Commodity Group within an OPID, covering ALL of the pipelines and/or facilities (both Interstate and Intrastate) and combining all states in which those assets exist. Separate reporting by state is not required for these Parts. Parts F – M, however, are to be reported separately for Interstate and for Intrastate facilities, or by state, or both depending on the instructions pertaining to each Part.

PART A – OPERATOR INFORMATION

Complete all 8 sections of Part A before continuing to the next Part.

1. **Operator's 5-digit Identification Number (OPID)**

All operators that meet the definition of an "operator" under §192.3 must have a PHMSA-assigned Operator Identification Number (also known as an OPID). If the person completing the Report does not know the OPID for the system being reported, this information may be requested from PHMSA's Information Resources Manager at -202--366-8075. (See instructions on the ONLINE DATA ENTRY page as described above.)

2. **Name of Company or Establishment**

This is the company name used when registering for an OPID and PIN in the Online Data Entry System. When completing the Report online, the Name of Operator is automatically filled in based on the OPID entered in Part A, Question 1. If the name that appears does not coincide with the OPID, contact PHMSA's Information Resources Manager.

If the company corresponding to the OPID is a subsidiary, enter the name of the parent company.

3. **Individual where additional information may be obtained**

Enter the name, title, email address and telephone number of the individual who should be contacted if additional information regarding this Report submission is needed.

4. **Headquarters address**

Enter the address and phone number of the operator's corporate headquarters.

5. **This Report pertains to the following Commodity Group**

It is a PHMSA requirement that operators submit separate Reports for each Commodity Group within a particular OPID.

File a separate Annual Report for each of the following Commodity Group**s**:

Natural Gas

Synthetic Gas (Examples include landfill gas, biogas, and manufactured gas based on naphtha)

Hydrogen Gas

Propane Gas

Other Gas – If this Commodity Group is selected, report the name of the other gas in the space provided.

Note: When a single pipeline or facility serves to transport two or more of the above Commodity

Groups, that pipeline or facility should be reported only once, reporting within the Commodity Group for the commodity that is transported most predominantly during the year being reported.

6. **Integrity Management Program**

Indicate here whether any portion(s) of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are subject to the integrity management (IM) requirements of 49 CFR 192, Subpart O.

Pipelines and/or pipeline facilities that include high consequence areas (HCAs) are required to be in an IM Program in accordance with Subpart O. For the purposes of this question and, more generally, this Report, do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Select the box indicating that portions of *SOME or ALL* of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are included in an IM Program as required by Subpart O, and complete other Parts of this Report in accordance with Part A, Question 8.

If *NO PORTIONS* of the pipelines and/or pipeline facilities covered under this OPID are included in an IM Program as required by Subpart O, select the box indicating such. In this case, Parts B, F, G, the "HCA" portions of M1, and O need not be completed.

7. **Interstate and/or Intrastate pipeline**

Pipeline assets included within a particular Commodity Group under a single OPID may be either interstate, intrastate, or both. Check the appropriate box or boxes to indicate whether the pipelines and/or pipeline facilities for the OPID and Commodity Group are interstate or intrastate or both. List the two-letter state abbreviation for each state in which reported interstate and intrastate assets are located.

Interstate *gas pipeline* means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act (15 U.S.C. 717 et seq.).

Intrastate *gas pipeline facility* means a gas pipeline facility or that part of a gas pipeline facility that is used to transport gas within a state and is not subject to the jurisdiction of FERC under the Natural Gas Act (15 U.S.C. 717 et seq.).

8. **Does this Report represent a change from last year's final reported information for one or more of the following Parts?**

Select "This Report is for calendar year 2010 reporting or is a first-time Report…" only for the reporting of calendar year 2010 information, including any supplements to that information, or if this is a first-time filing of an Annual Report for these facilities. Because this revision of the

Annual Report will be used for the first time to report information for calendar year 2010, some of the "Parts" of this Report referred to in this question are new and, therefore, no comparable information will have been reported for the prior year. For calendar year 2010 only, respond to this question by selecting the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable. Similarly, if no Annual Report has been previously filed for this operator, OPID, Commodity Group, or pipelines and/or pipeline facilities, or for other reasons, select the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable.

For calendar year submissions beyond 2010, an option has been created to allow the operator to provide information for relevant Parts when certain portions of the information have not changed.

Select "No" if there are no changes in the information reported for the current reporting year compared against the prior calendar year for Parts B, D, E, H, I, J, K, or L for the Commodity Group reported.

It should be noted that PHMSA expects that the data describing volume transported (Part C) and integrity management activity (Parts F and G) will change each year. Therefore, Part C, describing volume transported, must be completed every year. Additionally, those Parts of this Report related to integrity management activity (Parts F, G and O) must be completed every year by every operator with portions of pipelines and/or pipeline facilities subject to PHMSA's IM regulations as indicated in Part A, Question 6.

When there are changes in the information reported for the current reporting year compared against the prior calendar year, these changes can occur for one of the two following reasons:

1) New information or new calculations may have changed the understanding of pipeline and/or pipeline facility data, leading to differences in some data elements reported on the Annual Report in the previous year's Report, even though the physical pipeline(s) and/or pipeline facility(ies) themselves have not changed; or

2) The pipeline(s) and/or pipeline facility(ies) may have changed – either physically or operationally.

Select one or both of the two "Yes" boxes if reported system information has changed. If the change is due to a change in the pipelines and/or pipeline facilities and/or operations (number 2 above), select the appropriate box or boxes to indicate the nature of the change(s). If "Other" is selected, provide a brief description of the change.

- Merger/acquisition involves a change in ownership or operating responsibility that would likely result in increases or other changes in the reported miles of pipeline in most Parts of the Report.

- Divestiture involves a change in ownership or operating responsibility that would likely result in decreases or other changes in the reported miles of pipeline.

- New construction or new installation that would likely result in increases or other changes in the reported miles of pipeline, including rerouting of pipelines.

- Conversion of service, change in commodity transported, or change in MOP (maximum operating pressure).

  - Conversion to service means conversion to transportation of natural or other gas under §192.14 that would likely result in increases or other changes in the reported miles of pipeline. (This is selected if a pipeline that was previously used to transport a commodity or material that was not covered under 49 CFR 191/192, such as water, is being converted to move a commodity that is covered under 49 CFR 191/192, such as a propane gas line.)

  - Change in commodity transported means a change in the commodity predominately transported and thus in the "Commodity Group" reported in Part A, Question 6. (This is selected if the previous commodity moved in a pipeline covered under 49 CFR 191/192 is changed to a different commodity moved under 49 CFR 191/192, for example a natural gas line being changed to a synthetic gas line.)

  - Change in MAOP (maximum allowable operating pressure) could result in changes to the mileage of pipeline operating in different categories of hoop stress (i.e., percent SMYS (Specified Minimum Yield Strength)) as reported in Part K.

- "Abandoned," as defined in §192.3, means permanently removed from service. All pipeline mileage not permanently removed from service should be reported, including pipelines and/or pipeline facilities considered to be idled.

- Change in various aspects of an operator's IM Program may result in changes to information reported in Parts B, F, and/or G.

- Change in an operator's OPID number – or changes in pipelines and/or pipeline facilities covered by a particular OPID number - may result in changes throughout the Annual Report.

For the designated Commodity Group, complete Parts B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate or INTRAstate – included within this OPID. Separate reporting by state is not required for these Parts. Data reported should represent the system in total, including all states in which system assets are located.

PART B – TRANSMISSION PIPELINE HCA MILES

Report in Part B the total miles of Onshore and Offshore pipe that are high consequence areas (HCAs). Do not include miles of pipeline that are not HCAs but which are included in the IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). This Part should be left blank if no portions of the pipelines and/or pipeline facilities covered by this OPID are in an IM Program, as indicated in Part A, Question 6.

PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludes Transmission lines of Gas Distribution systems)

Report the volume transported in transmission pipelines during the calendar year for this Commodity Group, in millions of standard cubic feet (60ºF and 14.73 psia). Include the annual total volume transported for all states and for all pipelines and/or pipeline facilities – both INTERstate or INTRAstate – included within this OPID and for this Commodity Group. Volumes of any Commodity Group transported in addition to the Commodity Group predominately transported through these pipelines and/or pipeline facilities should also be reported in Part C within the proper row.

Note: This Part does not need to be completed if the pipeline system corresponding to the OPID reported in Part A, Question 1, includes only gathering pipelines or if the transmission line is operated by a gas distribution company as an integral part of its distribution pipeline system. Operators whose pipelines are limited to these types should select the box to so indicate.

PART D – MILES OF STEEL PIPE BY CORROSION PROTECTION

For steel pipe only, report the total miles of Onshore and Offshore Transmission and Gathering pipe that is cathodically protected and cathodically unprotected subdivided, in each case, into the amount that is bare and the amount that is coated pipe. **COATED** means pipe coated with an effective hot or cold applied dielectric coating or wrapper. Enter zero (0) in any cell for which the pipeline system includes no mileage. Do not leave any cells blank.

PART E – MILES OF non-STEEL PIPE BY TYPE AND LOCATION

For non-steel pipe only, report the total miles of Onshore and Offshore pipe that is of a material other than steel. Enter zero (0) in any cell for which the pipeline system includes no mileage. Do not leave any cells blank.

OTHER PIPE means a pipe made of a non-steel material not specifically designated on the form, such as copper, aluminum, etc.

For the designated Commodity Group, complete PARTs F and G one time for all INTERstate pipelines and/or pipeline facilities included within this OPID and multiple times as needed for the designated Commodity Group for each State in which INTRAstate pipelines and/or pipeline facilities included within this OPID exist.

For example: Consider a set of natural gas pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts F and G should be completed four times for this set of natural gas pipeline systems – once for all INTERstate assets (combined) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located (separately).

Each time Parts F and G are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities. If INTRAstate, enter in the space provided the two-letter postal abbreviation for the state.

PART F – INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION

This Part incorporates transmission pipeline integrity management performance measure reporting required by §192.945 and ASME/ANSI B31.8S, Section 9.4(b) (incorporated into the regulations by reference), items 1-3. Report all integrity assessments (inspections) required by PHMSA's IM regulations which were conducted and actions which were taken during the calendar year based on inspection results. Include all inspections conducted in the reporting period calendar year including baseline assessments and re-assessments. Do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Part F is subdivided into six (6) sections.

Section 1 - Mileage inspected in calendar year using the following In-Line Inspection (ILI) tools.

Report the mileage inspected using each of the listed tool types. Include total miles inspected, not just the mileage in high consequence areas (HCA). Where multiple ILI tools are used (e.g., a metal loss tool and a deformation tool), report the mileage in both categories. Where a combination tool is used (i.e., a single tool with multiple capabilities), report the mileage separately in each category included as part of the combination. Thus, the total mileage inspected during the calendar year (the sum of the mileage reported for individual tools) may be greater than the actual number of physical pipeline miles on which ILI inspections were run.

Enter zero (0) for any tool which was not used for IM assessments during the year. Leave no rows blank.

Section 2 - Actions taken in calendar year based on In-Line Inspections.

Include all actions taken during the calendar year that resulted from information obtained during an ILI inspection. This should include actions taken as a result of information developed during ILI inspections conducted during the calendar year PLUS actions taken as a result of ILI inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on review of ILI results but which did not actually occur during the reporting year.

Report in items a. and b. the total number of anomalies excavated and repaired based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in HCA pipeline segments. (The operator's criteria for anomalies in HCA pipeline segments must be at least as conservative as those required by the regulations).

Report in a. the total number of anomalies excavated, recognizing that multiple anomalies may be exposed in a single excavation.

Report in b. only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Report in c. only the anomalies in HCA pipeline segments that were repaired because they met one of the repair criteria in the IM regulations. "Scheduled conditions" as used in this section refers to anomalies that are required to be repaired in accordance with the schedule in ASME/ANSI B31.8S, section 7, Figure 4 (see §193.933(c)). (The total of repairs reported in item c. should not exceed the total number of repairs reported in item b.)

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 3 – Mileage inspected and actions taken in calendar year based on Pressure Testing.

Report in a. total miles inspected by pressure testing, including both HCA mileage and mileage outside HCA.

Report in b. the total number of test failures (ruptures and leaks) on all mileage tested during the year.

Report in c. the ruptures and in d. the leaks repaired ONLY in HCA segments.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank. Enter zero (0) in all rows of section 3 if no IM assessments were conducted by pressure test during the year.

Section 4 – Mileage inspected and actions taken in calendar year based on DA (Direct Assessment).

Include all actions taken during the calendar year that resulted from information obtained through external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment inspections. Include all actions taken during the calendar year that resulted from information obtained during a DA inspection. This should include actions taken as a result of information developed during DA inspections conducted during the calendar year PLUS actions taken as a result of DA inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on DA inspection results but which did not actually occur during the reporting year.

Report in b. the total number of anomalies excavated and repaired within an HCA segment and outside an HCA segment based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in HCA pipeline segments. (The operator's criteria for anomalies in HCA pipeline segments must be at least as conservative as those required by the regulations).

Report in c. the number of anomalies identified in HCA pipeline segments that were repaired because when excavated and examined they met one of the repair criteria in the IM regulations.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 5 - Mileage inspected and actions taken in calendar year based on Other Inspection Techniques.

IM regulations allow operators to use other assessment techniques provided that they notify PHMSA (or states exercising regulatory jurisdiction) in advance. Report here the mileage inspected and actions taken as a result of inspections conducted using any technique other than those covered in Sections 1-4 of Part F.

As for the other techniques, include all actions taken during the calendar year that resulted from information obtained during an inspection using another technique. This should include actions taken as a result of information developed as part of inspections conducted during the calendar year PLUS actions taken as a result of inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on inspection results but which did not actually occur during the reporting year.
Report only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

Section 6 - Total Mileage Inspected (all Methods) and Actions Taken.

These entries will be calculated automatically based on data entered in sections 1-5. For operators completing a paper form as a result of PHMSA approval to use alternate reporting measures (see above), report here the total mileage inspected and actions taken as the sum of the indicated elements from other sections.

PART G – MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)

Report the number of miles of pipeline in HCA (as reported in part B) that were assessed during the calendar year pursuant to §192.921 or §192.937. Report separately the number of miles inspected for baseline assessments (e.g., initial baseline assessments and new baseline assessments, including those which occur due to new pipelines or facilities, new HCA, etc.) and miles for which a reassessment was conducted. Do not include pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.).

Report only assessments that were completed during the calendar year. These “completed assessments” are defined consistently with FAQ 34 http://primis.phmsa.dot.gov/gasimp/faqlist.gim. ***The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed***, not including repair activities. That is when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with direct assessment is made, or the date on which "other technology" for which an operator has provided timely notification is conducted.

Operators should report in Part G the total number of miles actually assessed. This differs from Part F where operators report the number of miles inspected by individual inspection methods and where some mileage may be reported multiple times. Operators should note that the mileages reported as completed Assessments in Part G should be a subset of the total miles of onshore/offshore pipe in HCA reported in Part B. Operators should validate the total completed and scheduled assessment mileage in their Assessment Plans with the mileage reported here. The comparison of these two numbers will highlight any discrepancies resulting from new HCA segments being added or deleted, acquired or sold, or idled[1] or converted, and which need to be properly reflected in this Report.

For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities separately for each State in which INTRAstate systems exist within this OPID.

For example: Consider a set of natural gas pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts H, I, J, K, L, and M should be completed ten times for this set of natural gas pipeline systems – seven times for INTERstate assets (once for each state in which INTERstate assets are located) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located.

Each time the remaining Parts are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities, and enter in the space provided the two-letter postal abbreviation for the state.

PART H – MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)

Report the miles of transmission pipe by Nominal Pipe Size (NPS) and location for both onshore and offshore locations. Enter the appropriate mileage in the corresponding nominal size blocks.

Pipe size which does not correspond to NPS measurements should be included in the "Other Pipe Sizes Not Listed" columns. Include both the pipe size and the corresponding mileage.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any

[1] While the regulations do not recognize an intermediate state between operational and abandoned (see instructions for Part A, Question 8 above), PHMSA has acknowledged that operators sometimes maintain some of their pipe in an idle status in which conducting IM assessments is impractical. This consideration of "idle" pipe is discussed in FAQ 7 on the PHMSA Gas IM website (http://primis.phmsa.dot.gov/gasimp/faqlist.gim).

blocks blank.

PART I – MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)

Report the miles of gathering pipe by Nominal Pipe Size (NPS) and location for both Onshore and Offshore locations. Report onshore Type A and Type B gathering lines (§192.8) separately, as shown. Enter the appropriate mileage in the corresponding nominal size blocks.

Pipe size which does not correspond to NPS measurements should be included in the "Other Pipe Sizes Not Listed" columns. Include both the pipe size and the corresponding mileage.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

PART J – MILES OF PIPE BY DECADE INSTALLED

Report the miles of pipe by decade installed. Make an entry in each block including zero (0) when appropriate. Some companies may have pipe for which installation records may not exist. When the decade of construction is unknown, enter estimates of the totals of such mileage in the "Pre-40 or Unknown" section of Part J.

PART K – MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

§192.5 defines class locations as:

§192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

> **(1) A ''class location unit'' is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.**
>
> **(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.**

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

> **(1) A Class 1 location is:**
>
> > **(i) An offshore area; or**

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

Report the total miles of steel transmission pipe by hoop stress (as percent of SMYS) for pipe onshore and offshore by stress range and Class Location. Enter zero (0) in any cell for which the pipeline system includes no mileage. Report pipe for which hoop stress (i.e., percent of SMYS) is unknown and all non-steel pipe, regardless of operating pressure, in the rows indicated. Do not leave any cells blank.

Pay close attention to the classification of each pipeline. Short segments of pipeline operated by distribution systems at less than or equal to 20 percent SMYS have sometimes been inaccurately reported as transmission lines. Unless such pipelines meet the definition of transmission lines in §192.3, they should be reported as distribution pipelines (Form PHMSA F 7100.1-1). If pipelines operating at less than or equal to 20 percent SMYS meet the definition of transmission lines, they should be reported here.

PART L – MILES OF PIPE BY CLASS LOCATION

Report the number of Onshore and Offshore miles of pipe in each Class Location. In addition, report the number of HCA miles in the IMP program for both Onshore and Offshore transmission pipe.

Note: Operators should cross check their numbers for the various Parts, when applicable.

PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS

For the designated Commodity Group, this Part includes reporting for both pipelines and/or pipeline facilities covered by this OPID which are subject to the integrity management (IM) requirements of 49 CFR 192, Subpart O as well as pipelines and/or pipeline facilities covered by this OPID which are *not* subject to the integrity management (IM) requirements of 49 CFR 192, Subpart O. Additional instructions are provided below.

PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA IN CALENDAR YEAR

This Part incorporates transmission pipeline integrity management performance measure reporting required by §192.945 and ASME/ANSI B31.8S, Section 9.4(b)(4) (incorporated into the regulations by reference), along with reporting of all leaks that has historically been part of the Annual Report.

Include all leaks repaired or eliminated including by replaced pipe or other component during the calendar year. Operators with pipe segments in HCA and subject to IM requirements (as reported in Part A, Question 5) should report separately the number of leaks repaired or eliminated in HCA in the appropriate columns. All operators should report leaks for non-HCA pipe segments, including all leaks on pipelines that contain no HCAs and all leaks in non-HCA locations on pipelines in which HCAs exist. Do not include test failures.

Operators with pipe segments in HCA (as reported in Part A, Question 5) should also report the number of failures and incidents in HCAs, as required by §192.945 and ASME/ANSI B31.8S, Section 9.4(b)(4).

Integrity management performance measures are not required for gathering pipelines. For gathering pipelines, report only leaks. Report separately the number of leaks in Type A gathering lines and Type B gathering lines for onshore gathering pipelines.

Leaks are **unintentional escapes of gas from the pipeline that are not reportable as Incidents under §191.3**. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak. Operators should report the number of leaks repaired based on the best data they have available. For sections replaced but retired in place, operators should consider leak survey information to determine, to the extent practical, the number of leaks in the replaced section.

Failure is defined in ASME/ANSI B31.8S as a general term used to imply that a part in service: has become completely inoperable, is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use. Failures that result in an unintentional release of gas should be reported as leaks.

Incidents are defined in §191.3.

For the purposes of this Part M1, Leaks, Failures, and Incidents are to be classified as either:

EXTERNAL CORROSION: includes releases or failures in the pipe or other component due to galvanic, bacterial, chemical, stray current, or other corrosive action initiating on the outside surface of the pipe. For PHMSA's Gas Transmission/Gathering Incident Reporting form, this includes the "External Corrosion" sub-cause under G1 – Corrosion Failure.

INTERNAL CORROSION: includes releases or failures in the pipe or other component due to galvanic, bacterial, chemical, stray current, or other corrosive action initiating on the inside surface of the pipe. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes the "Internal Corrosion" sub-cause under G1 – Corrosion Failure.

STRESS CORROSION CRACKING: includes releases or failures resulting from a form of environmental attack of the pipe metal involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes the "Environmental Cracking-related" sub-cause under G5 – Material Failure of Pipe or Weld, which includes Stress Corrosion Cracking as well as Sulfide Stress Cracking and Hydrogen Stress Cracking.

MANUFACTURING: includes releases or failures caused by a defect or anomaly introduced during the process of manufacturing the pipe, including seam defects and defects in the pipe body or pipe girth weld. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes the "Original Manufacturing Defect-related" sub-cause under G5 – Material Failure of Pipe or Weld.

CONSTRUCTION: includes releases or failures caused by a dent, gouge, excessive stress, or some other defect or anomaly introduced during the process of constructing, installing, or fabricating pipe (or welds which are an integral part of pipe), including welding or other activities performed at the facility. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes the "Construction-, Installation-, or Fabrication-related" sub-cause under G5 – Material Failure of Pipe or Weld.

EQUIPMENT: includes releases from or failures of items other than pipe or welds, and includes releases or failures resulting from: malfunction of control/relief equipment including valves, regulators, or other instrumentation; compressors or compressor-related equipment; various types of connectors, connections, and appurtenances; the body of equipment, vessel plate, or other material (including those caused by: construction-, installation-, or fabrication-related and original manufacturing-related defects or anomalies; and low temperature embrittlement); and, all other equipment-related releases or failures. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes all of the sub-causes under G6 – Equipment Failure.

INCORRECT OPERATIONS: includes releases or failures resulting from operating, maintenance, repair, or other errors by operator or operator contractor personnel, including, but not limited to improper valve selection or operation, inadvertent overpressurization, or improper selection or installation of equipment. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes all of the sub-causes under G7 – Incorrect Operation.

THIRD PARTY DAMAGE/MECHANICAL DAMAGE: includes releases or failures resulting from damage caused by earth moving or other equipment, tools, or vehicles which occurs as a result of excavation activities or a release caused by vandalism or other similar intentional damage. Report separately, as indicated:

- **Excavation Damage** - includes releases or failures resulting directly from excavation damage by operator's personnel (oftentimes referred to as "first party" excavation damage) or by the operator's contractor (oftentimes referred to as "second party" excavation damage) or by people or contractors not associated with the operator (oftentimes referred to as "third party" excavation damage) From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes the Excavation Damage by Operator (First Party), Excavation Damage by Operator's Contractor (Second Party), and Excavation Damage by Third Party sub-causes under G3 – Excavation Damage;

- **Previous Damage (due to Excavation Activity)** - includes releases or failures that are determined to have resulted from previous damage due to excavation activity From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes only the Previous Damage due to Excavation Activity sub-cause under G3 – Excavation Damage; and,

- **Vandalism (includes all Intentional Damage)** – includes releases or failures due to willful or malicious destruction of the operator's pipeline facility or equipment. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes only the "Intentional Damage" sub-cause under G4 – Other Outside Force Damage. (For proper treatment of the other sub-causes under G4 – Other Outside Force Damage, see the next category.)

WEATHER RELATED/OTHER OUTSIDE FORCE DAMAGE: includes releases or failures resulting from earth movement, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslide, scouring, temperature, frost heave, frozen components, high winds, or similar natural causes, or a release from other, non-excavation-related outside forces, such as nearby industrial, man-made, or other fire or explosion; damage by vehicles, boats, fishing or maritime vessels or equipment; and, electrical arcing. Report separately, as indicated:

- **Natural Force Damage (all)** - From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes all of the sub-causes under G2 – Natural Force Damage

- **Other Outside Force Damage (excluding Vandalism and all Intentional Damage) -** From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes all of the sub-causes under G4 – Other Outside Force Damage *except* Intentional Damage.

OTHER: includes releases or failures resulting from any other cause not listed above, including those of a miscellaneous or unknown or unknowable nature. From PHMSA's Gas Transmission/Gathering Incident Reporting form, and specifically for the purposes of this Part M1, this includes both of the two sub-causes under G8 – Other Incident Cause.

PART M2 –KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

Include all known leaks scheduled for elimination by repairing or by replacing pipe or some other component, indicating separately for transmission lines and gathering lines.

Enter zero (0) in any cell for which the pipeline system includes no mileage or there are no known leaks scheduled for repair. Do not leave any cells blank.

PART M3 –LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

FEDERAL LANDS means all lands owned by the United States except lands in the National Park System, lands held in trust for an Indian or Indian tribe, and lands on the Outer Continental Shelf (OCS), as defined in 30 USC 185.

Enter all leaks repaired, eliminated, or scheduled for repair during the reporting year, excluding those reported as incidents on Form PHMSA F 7100.2.

Enter zero (0) in any cell for which the pipeline system includes no mileage or there are no known leaks scheduled for repair. Do not leave any cells blank.

For the designated Commodity Group, complete Part N one time for all of the pipelines and/or pipeline facilities included within this OPID. Complete Part O one time for all the pipelines and/or pipeline facilities covered under this Commodity Group and OPID if any portion(s) of the pipelines and/or pipeline facilities are included in an IM Program subject to Subpart O as indicated in Part A, Question 6.

PART N – PREPARER SIGNATURE

The Preparer is the person who compiled the information and prepared the responses to the Report. Enter the Preparer's name and title, and e-mail address if the Preparer has one, and the phone and fax numbers used by the Preparer.

PART O – CERTIFYING SIGNATURE

CERTIFYING SIGNATURE must be a senior executive officer of the operator. The Pipeline Inspection, Protection, Enforcement and Safety Act (signed in December 2006) requires pipeline operators to have a senior executive officer of the company sign and certify annual pipeline Integrity Management Program (IMP) performance reports (Parts B, F, G, and M1 – HCA data only - of this Report). By this signature, the senior executive officer is certifying that he or she has (1) reviewed the Report and (2) to the best of his or her knowledge, believes the Report is true and complete.

Senior Executive Officer is the person who is certifying the information on Parts B, F, G, and M1 as required by 49 U.S.C. 60109(f).

The name and title of the senior executive officer certifying the Report should be entered in the appropriate blanks on this section of the Report. The name of the senior executive officer certifying the Report should also be entered in the signature block on the Report. Operators should keep in mind that entering the senior executive officer's name onto the electronic Report is equivalent to a paper submission and has the same legal authenticity and requirements.

Notice: This report is required by 49 CFR Part 191. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

Form Approved
OMB No. 2137-0522
Expires: 01/31/2014

U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration	**ANNUAL REPORT FOR CALENDAR YEAR 20___ NATURAL AND OTHER GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS**	INITIAL REPORT ☐ SUPPLEMENTAL REPORT ☐

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 22 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

Important: *Please read the separate instructions for completeing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - OPERATOR INFORMATION	DOT USE ONLY								

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)
   /____/____/____/____/____/

2. NAME OF COMPANY OR ESTABLISHMENT:
   ____

   IF SUBSIDIARY, NAME OF PARENT:
   ____

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

   ____
   Name
   ____
   Title
   ____
   Email Address
   /__/__/__/-/__/__/__/-/__/__/__/__/
   Telephone Number

4. HEADQUARTERS ADDRESS:

   ____
   Company Name
   ____
   Street Address
   State: /__/__/ Zip Code: /__/__/__/__/__/ - /__/__/__/__/
   /__/__/__/-/__/__/__/-/__/__/__/__/
   Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

   ☐ Natural Gas

   ☐ Synthetic Gas

   ☐ Hydrogen Gas

   ☐ Propane Gas

   ☐ Other Gas → Name of Other Gas ___________________

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 192 Subpart O). *(Select only one)*

   ☐ NO portions of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, leave PARTs B, F, G, and the "HCA" portions of L and M1 blank, but complete all remaining PARTs of this form in accordance with PART A, Question 8**.**

   ☐ Portions of SOME OR ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 192. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8**.**

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7. FOR THE DESIGNATED "COMMODITY GROUP", THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

☐ INTERstate pipeline → List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: __, __, __, __, __, etc.

☐ INTRAstate pipeline → List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: __, __, __, __, __, etc.

8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, or L? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☐ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable.

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, or L. Complete PARTs A, C, M, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, or L ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable).

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for PARTs B, D, E, H, I, J, K, or L because of one or more of the following ***change(s) in pipelines and/or pipeline facilities and/or operations*** from those which were covered under last year's report. Complete PARTs A, C, M, and N, along with only those other PARTs which changed (including PARTs B, F, G, and O when applicable). *(Select all reasons for these changes from the following list)*

- ☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
- ☐ Divestiture of pipelines and/or pipeline facilities
- ☐ New construction or new installation of pipelines and/or pipeline facilities
- ☐ Conversion to service, change in commodity transported, or change in MAOP (maximum allowable operating pressure).
- ☐ Abandonment of existing pipelines and/or pipeline facilities
- ☐ Change in HCA's identified, HCA Segments, or other changes to Operator's Integrity Management Program
- ☐ Change in OPID
- ☐ Other → Describe: ____

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For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.

PART B – TRANSMISSION PIPELINE HCA MILES	
	Number of HCA Miles in the IMP Program
Onshore	
Offshore	
Total Miles	*Calc*

PART C - VOLUME TRANSPORTED IN TRANSMISSION PIPELINES (ONLY) IN MILLION SCF PER YEAR (excludesTransmission lines of Gas Distribution systems)	☐ **Check this box and proceed to PART D without completing this PART C if this report only includes gathering pipelines or transmission lines of gas distribution systems.**	
	Onshore	**Offshore**
Natural Gas		
Propane Gas		
Synthetic Gas		
Hydrogen Gas		
Other Gas → Name: ___________________		

PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION					
	Cathodically protected		Cathodically unprotected		Total Miles
	Bare	Coated	Bare	Coated	
Transmission					
Onshore					*Calc*
Offshore					*Calc*
Subtotal Transmission	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Gathering					
Onshore Type A					*Calc*
Onshore Type B					*Calc*
Offshore					*Calc*
Subtotal Gathering	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

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PART E - MILES OF non-STEEL PIPE BY TYPE AND LOCATION

	Cast Iron Pipe	Wrought Iron Pipe	Plastic Pipe	Other Pipe	Total Miles
Transmission					
Onshore					*Calc*
Offshore					*Calc*
Subtotal Transmission	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Gathering					
Onshore Type A					*Calc*
Onshore Type B					*Calc*
Offshore					*Calc*
Subtotal Gathering	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

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For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.

PARTs F and G

The data reported in these PARTs F and G applies to: *(select only one)*

☐ **Interstate pipelines/pipeline facilities**

☐ **Intrastate pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*

PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION	
1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS	
a. Corrosion or metal loss tools	
b. Dent or deformation tools	
c. Crack or long seam defect detection tools	
d. Any other internal inspection tools	
e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d)	*Calc*
2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS	
a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation.	
b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	
c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of:	*Calc*
1. "Immediate repair conditions" [192.933(d)(1)]	
2. "One-year conditions" [192.933(d)(2)]	
3. "Monitored conditions" [192.933(d)(3)]	
4. Other "Scheduled conditions" [192.933(c)]	
3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING	
a. Total mileage inspected by pressure testing in calendar year.	
b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within an HCA Segment and outside of an HCA Segment.	
c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN AN HCA SEGMENT.	
d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN AN HCA SEGMENT.	

(PART F continued)

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4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)	
a. Total mileage inspected by each DA method in calendar year.	*Calc*
1. ECDA	
2. ICDA	
3. SCCDA	
b. Total number of anomalies identified by each DA method and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	*Calc*
1. ECDA	
2. ICDA	
3. SCCDA	
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	*Calc*
1. "Immediate repair conditions" [192.933(d)(1)]	
2. "One-year conditions" [192.933(d)(2)]	
3. "Monitored conditions" [192.933(d)(3)]	
4. Other "Scheduled conditions" [192.933(c)]	
5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES	
a. Total mileage inspected by inspection techniques other than those listed above in calendar year.	
b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within an HCA Segment and outside of an HCA Segment.	
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:	*Calc*
1. "Immediate repair conditions" [192.933(d)(1)]	
2. "One-year conditions" [192.933(d)(2)]	
3. "Monitored conditions" [192.933(d)(3)]	
4. Other "Scheduled conditions" [192.933(c)]	
6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR	
a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a.1 + 4.a.2 + 4.a.3 + 5.a)	*Calc*
b. Total number of anomalies repaired in calendar year both within an HCA Segment and outside of an HCA Segment. (Lines 2.b + 3.b + 4.b.1 + 4.b.2 + 4.b.3 + 5.b)	*Calc*
c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 2.c.4 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 4.c.4 + 5.c.1 + 5.c.2 + 5.c.3 + 5.c.4)	*Calc*

PART G– MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (HCA Segment miles ONLY)	
a. Baseline assessment miles completed during the calendar year.	
b. Reassessment miles completed during the calendar year.	
c. Total assessment and reassessment miles completed during the calendar year.	*Calc*

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For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.

PARTs H, I, J, K, L, and M

The data reported in these PARTs H, I, J, K, L, and M applies to: *(select only one)*

- ☐ **Interstate pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*
- ☐ **Intrastate Pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*

PART H - MILES OF TRANSMISSION PIPE BY NOMINAL PIPE SIZE (NPS)

Onshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	42"	44"	46"	48"	52"	56"	58" and over	Other Pipe Sizes Not Listed	
								Size: __ Miles: ________ *Add Sizes as needed*	
Calc	Total Miles of Onshore Pipe - Transmission								
Offshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	42"	44"	46"	48"	52"	56"	58" and over	Other Pipe Sizes Not Listed	
								Size: __ Miles: ________ *Add Sizes as needed*	
Calc	Total Miles of Offshore Pipe - Transmission								

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PART I - MILES OF GATHERING PIPE BY NOMINAL PIPE SIZE (NPS)									
Onshore Type A	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	42"	44"	46"	48"	52"	56"	58" and over	Other Pipe Sizes Not Listed	
								Size: __ Miles: ________ *Add Sizes as needed*	
Calc	Total Miles of Onshore Type A Pipe - Gathering								
Onshore Type B	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	42"	44"	46"	48"	52"	56"	58" and over	Other Pipe Sizes Not Listed	
								Size: __ Miles: ________ *Add Sizes as needed*	
Calc	Total Miles of Onshore Type B Pipe - Gathering								
Offshore	NPS 4" or less	6"	8"	10"	12"	14"	16"	18"	20"
	22"	24"	26"	28"	30"	32"	34"	36"	38"
	42"	44"	46"	48"	52"	56"	58" and over	Other Pipe Sizes Not Listed	
								Size: __ Miles: ________ *Add Sizes as needed*	
Calc	Total Miles of Offshore Pipe - Gathering								

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PART J – MILES OF PIPE BY DECADE INSTALLED

Decade Pipe Installed	Pre-40 or Unknown	1940 - 1949	1950 - 1959	1960 - 1969	1970 - 1979	1980 - 1989
Transmission						
Onshore						
Offshore						
Subtotal Transmission	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Gathering						
Onshore Type A						
Onshore Type B						
Offshore						
Subtotal Gathering	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

Decade Pipe Installed	1990 - 1999	2000 - 2009	2010 - 2019	Total Miles
Transmission				
Onshore				*Calc*
Offshore				*Calc*
Subtotal Transmission	*Calc*	*Calc*	*Calc*	*Calc*
Gathering				
Onshore Type A				*Calc*
Onshore Type B				*Calc*
Offshore				*Calc*
Subtotal Gathering	*Calc*	*Calc*	*Calc*	*Calc*
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*

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PART K- MILES OF TRANSMISSION PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

ONSHORE	CLASS LOCATION				Total Miles
	Class I	Class 2	Class 3	Class 4	
Less than 20% SMYS					*Calc*
Greater than or equal to 20% SMYS but less than 30% SMYS					*Calc*
Greater than or equal to 30% SMYS but less than or equal to 40% SMYS					*Calc*
Greater than 40% SMYS but less than or equal to 50% SMYS					*Calc*
Greater than 50% SMYS but less than or equal to 60% SMYS					*Calc*
Greater than 60% SMYS but less than or equal to 72% SMYS					*Calc*
Greater than 72% SMYS but less than or equal to 80% SMYS					*Calc*
Greater than 80% SMYS					*Calc*
Unknown percent of SMYS					*Calc*
All Non-Steel pipe					*Calc*
Onshore Totals	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
OFFSHORE	Class I				
Less than or equal to 50% SMYS					
Greater than 50% SMYS but less than or equal to 72% SMYS					
Offshore Total	*Calc*				
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

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PART L - MILES OF PIPE BY CLASS LOCATION

	Class Location				Total Class Location Miles	HCA Miles in the IMP Program
	Class I	Class 2	Class 3	Class 4		
Transmission						
Onshore					*Calc*	
Offshore					*Calc*	
Subtotal Transmission	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*
Gathering						
Onshore Type A					*Calc*	
Onshore Type B					*Calc*	
Offshore					*Calc*	
Subtotal Gathering	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	
Total Miles	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

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PART M – INCIDENTS, FAILURES, LEAKS, AND REPAIRS

PART M1 – ALL LEAKS ELIMINATED/REPAIRED IN CALENDAR YEAR; INCIDENTS & FAILURES IN HCA SEGMENTS IN CALENDAR YEAR

Cause	Transmission Incidents, Leaks, and Failures						Gathering Leaks		
	Incidents in HCA Segments	Leaks				Failures in HCA Segments	Onshore Leaks		Offshore Leaks
		Onshore Leaks		Offshore Leaks					
		HCA	Non-HCA	HCA	Non-HCA		Type A	Type B	
External Corrosion									
Internal Corrosion									
Stress Corrosion Cracking									
Manufacturing									
Construction									
Equipment									
Incorrect Operations									
Third Party Damage/Mechanical Damage									
Excavation Damage									
Previous Damage (due to Excavation Activity)									
Vandalism (includes all Intentional Damage)									
Weather Related/Other Outside Force									
Natural Force Damage (all)									
Other Outside Force Damage (excluding Vandalism and all Intentional Damage)									
Other									
Total	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*	*Calc*

PART M2 – KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

Transmission		Gathering	

PART M3 – LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

Transmission		Gathering	
Onshore		Onshore Type A	
		Onshore Type B	
OCS		OCS	
Subtotal Transmission	*Calc*	Subtotal Gathering	*Calc*
Total	*Calc*		

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For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 192.

PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)

____
Preparer's Name(type or print)

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

____
Preparer's Title

/__/__/__/-/__/__/__/-/__/__/__/__/
Facsimile Number

____
Preparer's E-mail Address

PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and M1)

____
Senior Executive Officer's signature certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

____
Senior Executive Officer's name certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

____
Senior Executive Officer's title certifying the information in PARTs B, F, G, and M as required by 49 U.S.C. 60109(f)

____
Senior Executive Officer's E-mail Address

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NPMS SUBMITTAL AND ANNUAL UPDATES

1. REFERENCE

Pipeline Safety Improvement Act of 2002, PHSMSA Advisory ADB-08-07

2. PURPOSE

The purpose of this procedure is to establish responsibilities for submittal of pipeline mapping information and meta data under the National Pipeline Mapping System (NPMS).

3. RESPONSIBILITY FOR IMPLEMENTATION

The (67) ____________________ is responsible for submitting NPSM information as required by the NPMS standard.

4. LINES REQUIRING SUBMITTAL:

4.1 Only PHMSA jurisdictional gas transmission pipelines are required to submit information to NPMS. PHMSA jurisdictional gas gathering lines are exempt from this requirement.

5. GENERAL REQUIREMENTS AND ANNUAL UPDATES

5.1 Initial information shall be submitted for each jurisdiction gas transmission pipeline upon startup of a new pipeline or acquisition of a new pipeline.

5.2 Annually, between January 1st and March 15th of each year, the company shall submit updates to the NPMS for conditions along the pipeline at the end of the previous calendar year.

5.3 If there are no changes, the company must still notify the NPMS National Repository if there have been no changes from the previous submission. This can be accomplished by emailing to: npms-nr@mbakercorp.com

6. PROCEDURE

6.1 Obtain user name and password through the NPMS website listed below.

http://www.npms.phmsa.dot.gov/

6.2 Gather data and meta data and submit in the format required by the NPMS Operator Standards (January 2011) available on the NPMS website.

6.3 For problems or questions, contact the National Repository by emailing npms-nr@mbakercorp.com or calling 703-317-6294.

7. RELATED PROCEDURES

1.04 Pipeline Annual Reports

8. RECORDS

8.1 The District Office will maintain the official files on the company intranet.

8.2 Each file will be kept for the life of the pipeline facilities.

HCA SURVEY

1. REFERENCE

49 U.S.C. 60109

2. PURPOSE

The purpose of this procedure is to establish responsibilities for annual review of the company pipeline systems to determine if there any new high consequence areas (HCAs).

3. RESPONSIBILITY FOR IMPLEMENTATION

The (68) _____________________ is responsible for implementing this procedure.

4. LINES REQUIRING REVIEW:

4.1 Only PHMSA jurisdictional gas transmission pipelines are required to review their pipeline systems for potential HCAs. PHMSA jurisdictional gas gathering lines are exempt from this requirement.

5. GENERAL REQUIREMENTS AND ANNUAL REVIEWS

5.1 Annually the company shall reviews its pipeline systems, any acquisitions of new pipeline systems, and any newly constructed pipeline systems for potential HCAs.

5.2 Even if there are no HCAs or no changes to the pipeline systems, the company must still document this HCA review annually.

5.3 A newly-identified HCA will be incorporated into the integrity management program within one calendar year of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within ten years of its identification.

6. PROCEDURE FOR ID of HCAs

6.1 The company will conduct and HCA survey once per calendar year using method #1 or method #2 as defined in 192.903.

6.2 Specifically, the two methods that will be used to check for HCAs are using a laser range finder and/or aerial photography maps as described below.

Method #1: Use Laser Range Finder for Determination of HCAs

- A laser range finder will be used by standing directly over the pipeline and pointing the laser range finder at the closest portion of the potential identified site. The findings shall be recorded on one of the more of the following forms:

  - #1-1A (HCA Identification Survey Method #1)
  - #1-1B (HCA Identification Survey Method #2)
  - #1-1C (HCA Identified Site Survey)
  - #1-1D (Change in Operation Affecting HCA)

  Also, the error factor shall be documented on these forms and supported by manufacturer's technical documentation. When manufacturer's technical documentation cannot be obtained, a minimum of ten feet will be used for laser range finder error factor.

Method #2: Use Maps for Determination of HCAs

- Aerial photography with over lay of the pipeline may also be used to support or further define HCAs. Location of the pipeline shall be within ten feet of actual location as defined by as-built drawing alignment sheets [Element #1: Record #9] and/or with GPS points using sub-meter Trimble GPS instrument or equivalent. A ten foot buffer will be added to aerial photography overlay to account for potential minimum errors in alignment sheets and/or collection of GPS data points.

  Include the manufacturer's technical documentation on accuracy for the GPS unit as part of the HCA survey records.

7.0 PHMSA FAQS Used as Procedures for Clarifying Process of ID of HCAs

How the Company Operating Employees Will be Considered in HCA Analysis

The company will count operating employees when identifying HCAs. The rule is intended to provide enhanced protection for gatherings of people, and gatherings of operator employees are expected to gain the same enhanced protection. Areas, including buildings and facilities, where operator employees gather in sufficient numbers and on a sufficient number of days to meet criteria in the definition of HCAs will be so classified. [FAQ #121]

How Standing Traffic Will be Considered in HCA Analysis:

Identified sites are defined as areas that are "occupied" by more than 20 persons for specified periods. While roads and expressways near pipelines could well carry enough traffic that more than 20 persons are in proximity to the pipeline at one time, these travelers cannot be said to "occupy" that location. The definition of identified sites is intended to provide additional protection for areas where people stay for more than a few seconds or minutes. Most roads and expressways need not be considered as potential "outside areas" that could qualify as identified sites. Additionally, the preamble recognized that added protection was provided to pipelines near highways with design characteristics commensurate with the pipeline safety regulations. [FAQ #143]

However, for the company pipelines that are not designed commensurate with the pipeline safety regulations and are located in areas that are regularly congested, such that traffic stands for many minutes within a potential impact circle, the company will make a determination to include or exclude these pipelines as "identified sites" on their own merits based on the integrated information they have about their pipelines at these locations. OPS expects that such areas will usually occur within developed areas where the pipeline would already be defined as a high consequence area, and that HCAs identified solely due to the proximity of traffic choke points will be rare.

How Parking Lots Will be Considered in HCA Analysis:

Where parking lots are used for other purposes (e.g., an antique car club that meets on weekends, regular social gatherings), these uses will be considered on their own merits. Identified sites are defined as areas that are occupied by more than 20 persons for specified periods. While it is possible that sufficient people might be in a parking lot near a pipeline resulting in more than 20 persons in proximity to the pipeline at one time, these persons are considered to be in transit and cannot truly be said to "occupy" the parking lot and therefore are not subject to the regulation. [FAQ #145]

<u>How Commercial and Industrial Buildings Will be Considered in HCA Analysis</u>:

Each commercial and industrial building that is occupied will be considered when determining HCAs. If 20 or more persons occupy a building, it may qualify as an identified site. In buildings with multiple offices/businesses, the company may assume that 20 or more people "occupy" the building 5 days/week and at least 10 weeks/year or they may count the occupants. Commercial buildings that the company concludes are not occupied by 20 or more people will be considered in counting the number of "buildings" intended for human occupancy. Each structure/office/unit that is occupied in such a building shall be counted in the analysis of 20 or more buildings within the impact circle. [FAQ #146]

<u>How Portions of a Building Within PIR Will be Considered in HCA Analysis</u>:

The potential impact radius is an approximation of the extent of immediate damage from a pipeline incident. Damage may extend slightly beyond that radius in some instances. Additionally, structures extending into the radius would very likely burn, and those fires will not be limited to the portion of the structure within the radius. The rule requires that a building containing 20 people for the time periods specified in the rule must be treated as an identified site if any portion of it is within the potential impact radius. [FAQ #162]

<u>How Homes With Disabled Individuals Will be Considered in HCA Analysis</u>:

A single home housing a disabled person will not be considered an identified site. The rule defines identified sites as including "a facility" occupied by persons who are confined, of impaired mobility or would be difficult to evacuate. The rule also provides that COMPANY seek information about these facilities from public safety officials in order to provide a reasonable bound on the efforts that operators must expend to identify such sites. Generally, the focus should be on facilities that are licensed or registered as a care provider, and where multiple disabled individuals would be expected. [FAQ #176]

<u>How Buildings With 20 or More People, but Not All at Once Will be Considered in HCA Analysis</u>:

If a facility or site has 20 or more people visit throughout the day but never 20 or more at one time, this <u>does not</u> meet the identified site criteria. The definition of an identified site provides for buildings/locations that are "occupied by twenty (20) or more persons". A location that 20 or more people passed through in a day would not be "occupied" by 20 or more persons. Twenty or more persons must be present at one time for the building/outside area/open structure to be defined as an identified site. [FAQ #182]

How the Company Will Address Idle and Out of Service Lines (Not Fully Abandoned):

In-service idle pipe (i.e., that contains gas, but is not presently being used to transport gas) represents a potential hazard to public health and the environment, even though idle. If such pipe leaks or ruptures, an explosion could result. Leaks may go undetected for some time, since idle pipe may not be covered by operator's SCADA systems. For these reasons, the company will meet all requirements and deadlines for pipe that contains gas. Such pipe must be included when determining if the requirement to assess 50% of covered pipeline mileage by December 17, 2007, has been met.

Out-of-service pipe (i.e., pipe laid up with nitrogen) represents much less hazard. Degradation of such pipe can occur, but is not likely to result in safety impacts. OPS will accept deferral of activities required by the rule for out-of-service pipe. All deferred activities must be completed as part of any later return of that line to service. A baseline assessment needs not be run immediately if the deadline for completing baseline assessments (i.e., December 17, 2012) has not yet expired, unless the risk posed by the line would require an earlier assessment. The baseline assessment plan shall be modified to assure that a baseline assessment is completed by the appropriate deadline. If the deadline has expired, then a baseline assessment will be completed as part of returning the line to service. Adding an idle line into the IMP program would be considered a substantive program change and would require notification under 192.909(b). [FAQ #7]

How the Company Will Address Facilities:

The company will consider pipeline facilities when establishing potential impact circles (the diameter of the pipe into/out of the equipment will be used), and if applicable, the facility will be included in the integrity management program processes for addressing these facilities. [FAQ #84]

How the Company Will Handle Inherited Gas IMP Segments, Plans, and Deadlines:

The regulatory deadlines for assessments (e.g., that re-assessments be conducted within specified intervals, based on operating stress levels) continue to apply, as well as the schedule requirements for any remediation required by 192.933 that may be pending at the time ownership of the pipeline is transferred. Compliance deadlines established in 192 Subpart O for identifying segments in HCAs and for completing 50% or 100% of Baseline Assessments continues to apply. For purposes of integrity management, if COMPANY inherits or purchases a new pipeline segment with HCAs, it will be integrated into the NPCA IM program within one calendar year. Integration of new assets into existing Baseline Assessment Plans may result in realigning schedules for future assessments based on the relative risk of the acquired pipeline and the operator's existing pipeline(s). [FAQ #10]

8. RELATED PROCEDURES

1.04 Pipeline Annual Reports

9. RECORDS

9.1 Each file will be kept for five years.

PHMSA Registration and Operator ID

1. REFERENCE

   49 CFR 191.22, PHMSA Advisory ADB-12-04

2. PURPOSE

   The purpose of this procedure is to establish responsibilities for obtaining Pipeline Hazardous Materials Safety Administration (PHMSA) operator identification numbers.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (69) ____________________ is responsible for implementing this procedure.

4. LINES REQUIRING PHMSA OPID:

   4.1 Effective January 1, 2012 all PHMSA jurisdictional gas transmission and gathering pipelines and are required to obtain PHMSA operator identification number (OPID).

5. GENERAL REQUIREMENTS AND ANNUAL REVIEWS

   5.1 An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility.

6. PROCEDURE FOR ID of HCAs

   6.1 ***To obtain on OPID***, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline Operators in accordance with §191.7.

   6.2 ***OPID validation***. An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of Pipeline Operators at *http://opsweb.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

   6.3 ***Changes***. Each operator of a gas pipeline or gas pipeline facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov* of certain events.

An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

- Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;
- Construction of 10 or more miles of a new pipeline; or

An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

- A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
- A change in the name of the operator
- A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, or pipeline facility;
- The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter;

6.4 ***Reporting***. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

7. RELATED PROCEDURES

1.04 Pipeline Annual Reports

8. RECORDS

8.1 Each record will be kept for five years.

RECORD KEEPING

1. REFERENCE

   49 CFR, Section 192.491(c) and 192.709.

2. PURPOSE

   The purpose of this procedure is to establish procedures for maintaining records.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (72) _____________________ is responsible for proper documentation and filing of all records.

4. GENERAL

   4.1 49 CFR 192.709 requires records to be kept on each leak discovered, repair made, line break, leakage survey, line patrol, and inspection.

   4.2 Specific documentation requirements will be defined in each related procedure and is also noted in attached table #2.01A.

5. PROCEDURE

   5.1 Maintain records for each leak discovered, repair made, line break, leakage survey, line patrol, and inspection on all gas pipelines. Such records shall be kept on pipe, fittings, vessels, and related items for all pipeline facilities.

   5.2 Permanent operating and maintenance records for DOT inspection purposes shall be available in the District Office or other designated area.

   5.3 Complete all necessary forms and reports and maintain in permanent record file as required by specific procedures.

   5.4 Retain all studies, reports, checks of monitoring devices, and other data for the life of the facility, or as long as the pipeline remains in service, at the District Office.

6. RELATED PROCEDURES

6.1 All procedures in this Manual.
6.2 Table #2.01A

7. RECORDS

7.1 No records are required for this procedure.

CVGS
O&M Table #2.01A
Record Keeping

Reference: 49 CFR 191 & 192	Date Revised: May 2012

Record Keeping

General

The purpose of this procedure is to provide guidance when meeting the requirements of record keeping for DOT pipelines. Maps, drawings and records shall be readily available to any person requiring these documents to perform their pipeline duties.

Index Description:

Each relevant subpart in 49 CFR 191, 192, and 199 is divided into colored sections as shown in detail in the index on the following pages. A summary table is shown below:

	Reg.	
▪ Miscellaneous Reports and Documents	191 & 199	BLUE
▪ Corrosion	192.451-491	ORANGE
▪ Test Requirements & Uprating	192.551-557	GREEN
▪ Operations	192.601-629	RED
▪ Maintenance	192.701-755	YELLOW

Process:

The appropriate person, as defined in the pipeline O&M manual, will generate the record for work performed. All records for reports, corrosion, operations, maintenance, construction, repairs, and operator qualification will be routed through the Pipeline Supervisor or DOT Pipeline Advisor for review and signature. These records will then be placed into the DOT filing system as directed by the Pipeline Supervisor or DOT Pipeline Supervisor. Only files directed by the Pipeline Manager will be allowed to be shipped to long term storage or destroyed.

Record Retention:

Each record will be retained for the time noted on the file index. Generally, routine operations, maintenance, and operator qualification records will be kept for a <u>minimum of five years</u>. Construction, repair, and corrosion records will be kept for the <u>life of the pipeline</u>. File folders with a red dot indicate the file shall be kept for the life of the pipeline.

CVGS
O&M Table #2.01A
Record Keeping

Reference: 49 CFR 191 & 192 | **Date Revised: May 2012**

Records Location:

Generally, routine operations and maintenance records will be kept in a pipeline system binder by calendar year. .

Records that require retention for life of the pipeline will be kept in the appropriate file location as noted in the DOT File Index. New construction, repairs, and other large projects shall be combined into a project binder or file for placement into the DOT filing system.

Misc. Reports & Documents: 49 CFR 191 & 199

Description	Reg.	Freq.	Record Retention	Record Location
1. Safety Related Condition	191.23	NA	Life of Pipeline	
2. Incident Report (telephone)	191.5	NA	Life of Pipeline	
3. Incident Report (written)	191.15	NA	Life of Pipeline	
4. Annual Report	191.17	Annual	Life of Pipeline	
5. Anti-drug Plan	199.7	NA	5 Years	
6. Random Drug Testing of Employees	199.11	Annual	5 Years	
7. Verification of Drug Testing for Contractors	199.21	Qtrly*	5 Years	
8. Drug Testing Records	199.23	NA	5 Years	
9. DOT Agency Audits & Correspondence	NA	1x/3yr	5 Years	
10. DOT Misc. Correspondence	NA	NA	5 Years	
11. New Regulation Tracking	NA	NA	5 Years	
12. NPMS Mapping submission	Dec 2002 Pipeline Safety Act	Annual	5 Years	
13.				
14.				
15.				

* Recommended frequency

CVGS

O&M Table #2.01A

Record Keeping

Reference: 49 CFR 191 & 192	**Date Revised: May 2012**

Corrosion Control: Subpart I 192.451 - 491

Description	**Reg. 192**	**Freq.**	**Record Retention**	**Record Location**
1. Cathodic Protection System Design, etc.	463	NA	Life of Pipeline	
2. CP System Test	465(a)	Annual	Life of Pipeline	
3. Corrosion Remedial Measures	483-85	NA	Life of Pipeline	
4. CP Maps, Dwgs	491	NA	Life of Pipeline	
5.				
6.				
7.				
8.				
9.				
10.				

* Recommended frequency

Test Requirements & Uprating: Subpart J & K, 192.501-557

Description	**Reg. 192**	**Freq.**	**Record Retention**	**Record Location**
1. Strength Test, >30% SYMS	505, 517	NA	Life of Pipeline	
2. Strength Test, <30% SYMS	505, 517	NA	Life of Pipeline	
3. Uprating investigation and survey	553(b)	NA	Life of Pipeline	
4. Uprating written plan	553(c)	NA	Life of Pipeline	
5.				
6.				
7.				
8.				
9.				
10.				

CVGS
O&M Table #2.01A
Record Keeping

Reference: 49 CFR 191 & 192 **Date Revised: May 2012**

Operations: Subpart L 192.601-629

Description	Reg. 192	Freq.	Record Retention	Record Location
1. Customer Notification	16	NA	Life of Pipeline	
2. Update O&M Manual	605(a)	Annual	Until Updated	
3. Training on O&M Manual	605	Annual *	5 Yrs	
4. System maps, construction records, Operating history	605(b)(3)	NA	5 Yrs	
5. Abnormal Operations	605(c)	Annual *	5 Yrs	
6. Change In Class Location Required Study	609	NA	5 Yrs	
7. Change In Class Location MAOP	611	NA	5 Yrs	
8. Continuing Surveillance	613	Annual *	5 Yrs	
9. Damage Prevention – One Call System	614(b)	NA	5 Yrs	
10. Damage Prevention – Excavators	614(c)(1)	Annual	5 Yrs	
11. Damage Prevention – Public Education	614(c)(2)	1x/2yr	5 Yrs	
12. Em. Plan: Review Employee Activities	616(b)(3)	Annual *	5 Yrs	
13. Liaison Program with Public Officials	615(c)	Annual *	5 Yrs	
14. Update Emergency Plan	615	Annual	5 Yrs	
15. Train on Emergency Plan	615(b)(2)	Annual	5 Yrs	
16. Public Education	616	1x/3yr *	5 Yrs	
17. Investigation of Failures	617	NA	Life of Pipeline	
18. MAOP	619	NA	Life of Pipeline	
19. Odorization	625	Monthly	5 Yrs	
20. Tapping Under Pressure	627	NA	5 Yrs	

* Recommended frequency

CVGS
O&M Table #2.01A
Record Keeping

Reference: 49 CFR 191 & 192	Date Revised: May 2012

Maintenance: Subpart M, 192.701-755

Description	Regulation	Freq.	Record Retention	Record Location
1. Patrolling	192.705	4x/yr**	5 Yrs.	
2. Leak Surveys	192.706	Annual **	5 Yrs.	
3. Line Markers: ROW, RR, Comp. Stations	192.707	Annual *	5 Yrs	
4. Pipeline Repair Records	192.709(a)	NA	Life of Pipeline	
5. Component Repair Records	192.709(b)	NA	Life of Pipeline	
6. Repairs	192.711-717	NA	Life of Pipeline	
7. Test of Repairs: Replacement Pipe & Welds	192.719	NA	Life of Pipeline	
8. Abandonment	192.727	NA	5 Yrs	
9. Pres. Reg. Station: Inspect & Test Relief Devices and Equipment	192.739	Annual	5 Yrs	
10. Pres. Reg. Station Telemetering: Insp. of Equip. after Abnormal Conditions	192.741	NA	5 Yrs	
11. Pres. Reg. Station: Test Relief Devices	192.743	Annual	5 Yrs	
12. Valves (& 192.179)	192.745	Annual	5 Yrs	
13. Vaults (& 183, 185, 187, 189)	192.749	Annual	5 Yrs	
14. Prevention of Accidental Ignition	192.751	NA	5 Yrs	

* Recommended frequency

** Frequency is determined by class location and other relevant factors. Frequency shown is most stringent.

MARKING AND DOCUMENTATION OF MATERIALS

1. REFERENCE

   49 CFR, Section 192.63

2. PURPOSE

   The purpose of this procedure is to establish requirements for marking and documentation of pipe, valves, flanges, fittings, pressure containing components, and major mechanical equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (78) ____________________ is responsible for documentation and proper marking of materials outlined in this procedure.

4. GENERAL

   4.1 Pipe, valves, flanges, fittings and pressure containing components used in non-hazardous service, such as instrument air and potable water, are exempted from the requirements of this procedure.

   4.2 Hazardous service means a flammable, toxic, or corrosive gas or a liquid that is poisonous, will burn, inflame or irritate human tissue, or produce flammable vapor at atmospheric pressure.

   4.3 Engine and compressor parts are excluded from the requirements of this procedure. This exclusion does not include valves, flanges, pipe fittings, pipe and similar components used on or with an engine or compressor.

   4.4 Each valve, fitting, pipe, and other component manufactured on or after November 12, 1970 must be marked:

      4.4.1 As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D2513 (49CFR192 currently referenced edition); or

4.4.2 To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

4.5 Paragraph 4.4 above does not apply to items manufactured before November 12, 1970 that meet all of the following:

4.5.1 The item is identifiable as to type, manufacturer, and model.

4.5.2 Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

4.6 Each valve, flange, fitting, length of pipe, or other component that is intended to contain pressure, and mechanical equipment, shall be marked by the vendor or manufacturer per paragraphs 4.4 and 4.5 of this procedure.

4.7 Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

4.8 If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

5. PROCEDURES

5.1 Verify that material received is marked as shown on the purchase document and that material received is what was ordered. Review the documentation and verify that information agrees with purchase document requirements and the material markings. Only items which meet or exceed the purchase document requirements will be accepted by the receiving location.

5.2 Maintain purchase document number markings on all applicable inventory until they are installed.

5.3 Maintain the purchase document number and any other appropriate identification markings on the material in a manner that does not damage the material so that the marking remains visible until the material is installed. Review marking as necessary.

6. RELATED PROCEDURES

2.01 Record Keeping

7. RECORDS

7.1 Maintain a permanent file of applicable purchase documents, material certifications, and as-built drawings, and material lists for the life of the facilities.

7.2 Check marking on inventory materials two times per calendar year, not exceeding 7½ months.

DAMAGE PREVENTION PROGRAM

1. REFERENCE

49 CFR, Sections 192.614, 198.37, 198.37, and 198.39.
PHMSA Advisory Bulletin #ADB-06-03, Accurately Locating and Marking Underground Pipelines Before Excavation Activities Commence Near Pipelines
California Government Code #4216 from SB 1359, Effective January 1, 2007
Common Ground Alliance Best Practices, Version 4.0 published March 2007

2. PURPOSE

The purpose of this procedure is to establish a damage prevention program whose purpose is to minimize possible damage to the Company gas pipeline facilities by outside forces.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (84) ____________________ is responsible for implementation of the damage prevention program.

4. GENERAL

4.1 It is Company intent to include, at a minimum, all regulated onshore pipelines in its prevention program to prevent damage to pipelines owned by the Company. For California pipeline operations additional requirements are noted with reference to Ca. Gov. Code #4216.

4.2 Federal and state pipeline regulations require that each operator of a buried pipeline have a written program to prevent possible damage to a buried pipeline facility by excavation activities. For the purpose of this Procedure 3.01, "excavation activities" include:

4.2.1 Excavation

4.2.2 Blasting

4.2.3 Directional drilling and other trenchless technology, which includes, but is not limited to, a variety of cutting, jetting, boring, reaming, and jacking techniques.

4.2.4 Tunneling

4.2.5 Backfilling

4.2.6 Removal of above or below ground structures by either explosive or mechanical means.

4.2.7 Plowing (installation of flexible pipe, such as drain tile, or cable without open trenching).

4.2.8 Other earth moving or earth disturbing activities.

5. PROCEDURE

5.1 "One Call" Participation

5.1.1 The Company will support and participate, which is required by law, in "one call" system.

5.1.2 Whenever pipelines are included in the geographic boundaries of an operational "one call" system, some activities required in this procedure may be performed by the "one call" system. Periodic confirmation of the procedure requirements that are performed by a "one call" system and subsequently are not carried out by the Company shall occur to assure correct performance.

5.1.3 See Table 3.01C for a listing of local "One Call" phone numbers.

5.2 Identification of Excavators

Develop, on a current basis, a list of contractors and other persons who are normally engaged in excavation activities in the area in which the pipeline is located. Refer to the Procedure for the "Public Education Program" (Procedure 3.03) in this manual.

5.3 Notification of Excavators and the Public

Provide general notification of the public living in the vicinity of the pipeline and actual notification of the individuals identified in 5.2 above, and make them aware of the damage prevention program and its purpose. Refer to the Procedure for the "Public Education Program" (Procedure 3.03) in this manual.

5.4 Receiving and Recording Notices of Planned Excavation Activities

5.4.1 Provide for the receipt of routine notices of planned excavation activities. This can be accomplished by direct telephone communication and/or indirectly through one-call notification systems.

5.4.2 Document all notifications requesting line marking or of excavation activity on a form from the one-call service.

5.5 Responding to Notice of Planned Excavation Activities

5.5.1 Log each notice received and determine if excavation activity will be conducted in the vicinity of the Company's pipeline. If it is determined that the excavation activity is in the vicinity of the Company's pipeline, then that pipeline must be marked in the field.

5.5.2 Advise the requestor that a Company representative will be present during excavation activity in the vicinity of the pipeline.

5.5.3 Inform the requester if a Company pipeline is located in the area of the planned excavation activity and tell him when the pipeline will be marked, what type of marking will be provided and how to identify the marking.

5.6 Pipeline Location and Marking

5.6.1 Locate and mark the pipeline in areas of conflict where excavation activities are observed, anticipated, or will occur as indicated by notification.

5.6.2 Pipelines must be marked within 48 hours of receipt of notification, unless the notifying party agrees to extend this time, and before any excavation activities begin.

5.6.3 Use temporary flags, stakes, or other more permanent marks, if the type and duration of activity so dictates. The minimum length of pipeline to be marked shall be as required by conditions of the site and job. If practical, locate and mark pipelines when a requester's representative is present.

5.6.4 Bends and other changes of direction need to be marked so that the location of the pipe is clearly delineated.

5.6.5 Mark on straight pipeline sections at intervals required by conditions of the site and job, but not to exceed 100 feet (30 meters) onshore.

5.6.6 If an outside party is seen approaching or working over the Company's pipeline, immediately notify the excavator that a conflict exists and ask him to delay until the line is located and marked.

5.6.7 Remove stakes and/or flags when the work has been completed.

5.6.8 California law requires notification and onsite meeting to verify location of pipeline or utility if excavation within <u>10 feet</u> of a "high priority subsurface installation." [Ca. Gov. Code #4216]

High priority subsurface installation is defined as: "High priority subsurface installation" is high pressure natural gas pipeline with normal operating pressures greater than 60 psig, or greater than 6 inches Nominal pipe diameter petroleum pipelines, pressurized sewage pipelines, high voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60kv, or hazardous material pipelines that are potentially hazardous to workers or the public if damage occurs.
[Ca. Gov. Code #4216.1]

5.6.9 Only a "qualified person" is allowed to conduct subsurface installation locating activities. The regulation defines "Qualified person" as a person who completes a safety training program that meets the requirements of 8 CCR 1509 (Injury Prevention Program) & meets the minimum training guidelines and practices of Common Ground Alliance current Best Practices. The company defines qualified person as a person who meets the requirements for locating and marking as specified in the company Operator Qualification Plan. [Ca. Gov. Code #4216(i)]

5.6.10 The excavator must notify the pipeline operator or call 911 when the excavator discovers or causes damage to the pipeline installation.
[Ca. Gov. Code #4216.1]

5.6.11 Ensure up to date pipeline alignment and as-built drawings are available to the locator. The locator shall not rely solely on maps, drawings, or other written materials to locate pipelines.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.12 The locator shall notify the appropriate pipeline operator person when the pipeline alignment and as-built drawings need updates.

5.6.13 Ensure individuals marking & locating are be familiar with state and local marking requirements and Common Ground Alliance Best Practices marking guidelines which includes recommended color codes and marking guidelines. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.14 Ensure individuals marking & locating have knowledge, skills, and abilities (as required by OQ Program) to read & understand pipeline alignment and as-built drawings.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.15 Locate and mark accurately before excavation begins. This applies regardless if using own company employees or contractors for marking. Honor marking of existing pipelines or utilities. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.16 Mark all pipelines including laterals. Consider environmental conditions such as rain or snow when selecting marking methods. In areas where the pipelines are curved or make sharp bends to avoid other utilities or obstructions, consider the visibility and frequency of markers. Individually mark pipelines within the same trench. Also, pipelines at cross-overs shall be marked.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.17 Facilitate communication during the excavation and make sure excavators have sufficient information about underground pipelines at an excavation site to avoid damage to the pipeline.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.18 Calibrate tools and equipment used for line marking and make sure they are in proper working order. [PHMSA Advisor Bulletin #ADB-06-03]

5.6.19 When pipelines are hit or almost hit during excavation, evaluate the practices and procedures before continuing excavation activities.
[PHMSA Advisor Bulletin #ADB-06-03]

5.6.20 When there are reports of third party damage on the pipeline, the company will check the TPD against One-Call tickets and document this review. [PHMSA protocol 195.442]

5.6.21 The company will review "One-Call" reports and generate a list of third parties who actually conducted excavation activities along the pipelines. These companies who conducted excavation activities will be included in the public awareness education program either by mailing of materials or onsite visit. This excavation activities list will be documented once per year including how excavation companies were contacted. [PHMSA protocol 195.442]

5.7 Inspection and Monitoring of Excavation Activities

5.7.1 A Company representative is to be present when excavation occurs that will expose or may be reasonably expected to expose the pipeline. The (85) _______________ may make other provisions to prevent damage to the pipeline when the excavation activities, such as parallel encroachments, require the representative to be present for long time durations, and there is to be no crossing of the Company's pipeline.

5.7.2 If the pipeline is to be crossed, a Company employee will determine its depth at the point of intended crossing if practical and necessary. The Company employee will use a line locator and prodding bar, as appropriate.

5.7.3 Advise the excavator that he may proceed with excavation across the pipeline in a slow and controlled manner, and only if the exact depth and location are known and at least 18" (45.7 cm) of clearance (undisturbed soil) will exist from the bottom of the excavation to the top of the Company pipeline. Monitor the excavation as it occurs to assure that the depth of excavation is maintained as planned.

5.7.4 If less than 18" (45.7 cm) clearance will exist from the top of Company pipeline to the bottom of the excavation, or the crossing will be below the Company's pipeline, prohibit the outside party from approaching the unexposed pipeline closer than 18" (45.7 cm) from the top or 36" (91.4 cm) from the side of the pipeline with mechanical equipment. Require the excavator to expose the pipeline by hand excavation.

5.7.5 Inspection of pipelines must be done as frequently as necessary during and after activities to verify the integrity of the pipeline. Form 3.01B should be utilized for reporting purposes.

5.8 Blasting

If blasting occurs and it is determined that there is possible damage, a leakage survey must be done immediately to verify the integrity of the pipeline. Refer to procedure 5.02 paragraph 4.0 for the type of gas detection equipment to use for a leak survey.

5.9 Horizontal Directional Drilling (HDD) and other Trenchless Technology

Because of the high potential risk associated with HDD and other trenchless technology, the following procedures are in addition to the above stated requirements for normal excavation methods. These additional procedures are to mitigate the risks of damage to Company and other(s) pipelines.

5.9.1 Maximum separation between substructures, when possible, should be designed into the trenchless operation.

5.9.2 The Company must ensure that contractor personnel are following safe practices and are well qualified and experienced in this type of pipeline installation.

5.9.3 Prior to the commencement of any work, a precise and thorough site survey must be done to locate potential conflicts with known existing underground facilities.

Potholes may be required to determine substructure location(s). A knowledgeable substructure owner or representative must be on site at time of exploration (potholing) and actual trenchless operations.

5.9.4 Whenever HDD is proposed within 10 feet (3 meters) of a known substructure, potholes will be dug, when possible, at a maximum of 25 foot (7.6 meter) intervals to determine the exact location of the drill head during pilot and back reaming operations.

Characteristics of soil, i.e. rock, sand, etc., can effect the alignment of the pilot hole. Stiffness of the pipe can affect the accuracy.

5.9.5 Personnel must monitor location and alignment of the operation constantly with a "walkover" detector. Read the drill head every 10 feet (3 meters) for direction and depth and mark on the surface. If a problem is encountered, the operation must be either altered or shutdown immediately until the problem(s) is resolved. The "drill head" should not be removed
in the event of suspected damage or abnormalities. Further damage could be caused.

5.9.6 If necessary, and to ensure additional safety of the HDD operation, it may be necessary to reduce pipeline operating pressure or shutdown the pipeline completely.

5.10 Exposed Pipe

Whenever any buried pipe is exposed for any reason, the company shall examine the pipe for evidence of external corrosion.

If external corrosion requiring remedial action is found, additional investigation circumferentially and longitudinally may be necessary beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

6. <u>PROCEDURE FOR ADDITIONAL PREVENTATIVE MEASURES DUE TO THIRD PARTY DAMAGE IF PIPELINE IS COVERED UNDER THE INTEGRITY MANAGEMENT REGULATIONS</u>

6.1 The Company will implement the following preventive and mitigative requirements regarding threats due to third party damage. These minimum enhancements to the 192.614 required damage prevention program will include the following with respect to IMP covered segments to prevent and minimize the consequences of a release:

1) Using qualified personnel for work the Company is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [192.935(b)(1)(i)]

2) Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative

measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191. [192.935(b)(1)(ii)]

3) Participating in one-call systems in locations where covered segments are present. [192.935(b)(1)(iii)]

4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. [192.935(b)(1)(iv)]

5) When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE RP-0502-2002 must be conducted. [192.935(b)(1)(iv)]

6) If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ANSI/ASME B31.8S Section 7.5 and §192.933. [192.935(b)(1)(iv)]

Note, when the Company has a covered segment operating below 30% SMYS and for plastic transmission pipelines, the Company will implement a subset of these enhancements. See section #6.2 below. If the threat of third party damage is identified by results of the data gathering and integration process, the Company will implement the additional preventive measures, shown in section #6.1.

6.2 The Company will implement the following preventive and mitigative requirements for pipelines operating below 30% SMYS:

1) The Company's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if the Company is conducting a task that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

2) The Company's processes for damage prevention program enhancements will include participating in one-call systems in locations where covered segments are present.

3) Excavations near the pipeline will be monitored, or patrols will be conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2)]

4) If indications of unreported construction activity are found, follow up investigations will be conducted to determine if mechanical damage has occurred. [§192.935(d)(2)]

For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area, the Company will implement the following minimum requirements:

1) The Company's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if the Company is conducting a task that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

2) The Company's processes for damage prevention program enhancements will include participating in one-call systems in locations where covered segments are present.

3) Excavations near the pipeline will be monitored, or patrols will be conducted of the pipeline at bi-monthly intervals as required by 192.705. [192.935(d), 192.935(d)(2)]

4) If indications of unreported construction activity are found, follow up investigations will be conducted to determine if mechanical damage has occurred. [192.935(d)(2)]

5) The Company will perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [192.935(d)(3), Table E.II.1]

7. RELATED PROCEDURES

3.02 Telephone Answering Services
3.03 Public Education Program
3.05 Crossing of Company Pipelines
5.01 Continuing Surveillance
5.02 Gas Leak Detection Survey with Instrumentation for Pipelines without Odorant
6.04 Internal and External Examination of Buried Pipeline

8. RECORDS

7.1 Record pertinent information on one-call service form. Retain forms for one year from date of last entry. In the event of litigation or other unresolved situations, do not destroy records until they are no longer needed for such situation.

7.2 Complete the Pipeline Maintenance and Surveillance Form (Form 3.01B) each time a buried pipeline is inspected, crossed or an above or below grade pipeline is damaged or hit by an outside party. These records are to be retained for at least five years.

PIPELINE MAINTENANCE AND SURVEILLANCE FORM 3.01B

NOTE: FILL OUT THIS REPORT FOR EACH EXPOSURE OF PIPELINE REGARDLESS OF THE CAUSE

COMPANY:	OPERATING LOCATION:	NAME OF LINE:	LINE NO:	DATE OF REPORT MO DAY YR

DRAWING NO:	LOCATION OR STATION PLUS LIMITS	PIPELINE SYSTEM ☐ GAS ☐ LIQ	CLASS LOCATION (GAS):	DATE OF INSPECTION MO ____ DAY ____ YR ____

PIPE:	SIZE O.D.	WALL THICKNESS	GRADE/SPECIFICATIONS/SEAM:	DEPTH OF COVER:

PURPOSE OF MAINTENANCE OR SURVEILLANCE:

☐ PIPELINE LEAK ☐ PIPELINE CHANGE OUT ☐ FOREIGN PIPELINE CROSSING
☐ PIPELINE FAILURE ☐ CATHODIC PROTECTION ☐ ABANDONMENT
☐ TAP ☐ CASING ☐ OTHER:

PIPELINE MAINTENANCE: PROCEDURES 8.02 AND 9.01

☐ NO REPAIR OR REPLACEMENT NEEDED, AS OF DATE ____________ ☐ ACTION REQUIRED

1 REPLACED SECTION: SIZE WALL
FROM: ______ TO: ______ O.D. ______ THICKNESS ______ GRADE______ SPEC. ______ SEAM ______
a) Replacement Section Test Pressure ______ for ______ hrs. Date ______ ☐ Test Chart Attached
b) Field Girth Welds Nondestructively Tested? ☐ No ☐ Yes What method used? ______ %.
c) For Pipelines Parallel to Overhead Electric Transmission Lines, was electric conductor Bonded to Pipeline? ☐ No ☐ Yes

2 REPAIRED SECTION: ☐ TEMPORARY ☐ PERMANENT
a) Method of Repair ______
b) Pressure Reduced During Repair? ☐ No ☐ Yes Pressure During Repair ______
c) Was Gas Leaking During Repair? ☐ No ☐ Yes Describe ______
d) Welding Nondestructively Tested? ☐ No ☐ Yes What Method Used? ______

INTERNAL CONDITION OF PIPELINE: PROCEDURES: Procedures 6.02 & 6.04

A. INTERNAL CORROSION DISCOVERED? ☐ No ☐ Yes Describe ______
B. METHOD OF INTERNAL CORROSION CONTROL IN EFFECT: ☐ None ☐ Chemical Treatment ☐ Coupons ☐ Other ______

EXTERNAL CONDITION OF PIPELINE: PROCEDURES 6.01, 6.03 & 6.04

A. CATHODIC PROTECTION POTENTIAL OF EXCAVATED EXPOSED PIPE VOLTS ______
B. CONDITION OF COATING: ☐ Satisfactory ☐ Disbonded ☐ Deteriorated ☐ Scraped ☐ SCC ______
C. INDICATED CATHODIC PROTECTION POTENTIAL FROM PREVIOUS SURVEY ______ VOLTS DATE ______

HOT TAP REPORT: PROCEDURES 9.05

A. FOR: ______ SIZE: ______ LOCATION: ☐ TOP ☐ SIDE
B. MATERIAL ☐ FULL ENCIRCLEMENT SADDLE ☐ WELD TEE SIZE: ______ GRADE: ______ VALVE: ______ MAKE ______ TYPE
NIPPLE: LENGTH ______ W.T. ______ GRADE ______ INSULATION ______ ☐ No ☐ Yes
C. ASSEMBLY TEST: ☐ HYDRO TEST ______ (Test Chart Attached) ☐ PNEUMATIC TEST ______
OTHER NONDESTRUCTIVE TEST: METHOD ______ HEADER THICKNESS ______

FOREIGN PIPELINE CROSSING: PROCEDURE 3.05

A. COMPANY: ______ LINE SIZE ______ CLEARANCE IN INCHES ______ ☐ ABOVE ☐ BELOW
B. PIPE: ☐ STEEL ☐ OTHER
C. COATING: ☐ COATED ☐ BARE
D. APPROX. ANGLE OF CROSSING ______ PRODUCT TRANSPORTED ______

REMARKS:

______
______
______

SIGNATURES:
COMPLETED BY: ______
SUPERVISOR: ______

Draw Foreign Line Crossing Company line or hot tap and arrow indicating North.
Company Line

CALIFORNIA MARKING GUIDELINES

www.usanorth.org

Suggested Guidelines for Prospective Excavation Site Delineation and Facility Owner Location Markout

General Guidelines

This guide provides for temporary uniform surface marking of both planned excavations and of substructures in potential conflict of planned excavations. White markings are used for excavation delineation. Substructure markings are of a specific color. Appropriate color and common abbreviations are listed herein. Full facility operator and excavator responsibilities are detailed in Section 1, Chapter 3.1 "Protection of Underground Infrastructure", Article 2, of California Code 4216 through 4216.9.

Note: Temporary markings should be clearly seen, functional, and considerate to surface aesthetics and the local community. Also, check to see if any local ordinances apply.

Marking In Paved Areas

Avoid excessive or oversized marking, especially if marking outside the excavation area. Conditions permitting, use spray chalk paints, water based paints or equivalent less permanent type marking. Limit length, height, and interval of marks to those recommended. Letters and numbers should not exceed 3" to 6" in height.

Marking in Non-Paved Areas

When paint is not used, use appropriately colored stakes, lath, pennants or chalk lines. Select marker types that are most compatible to the purpose and marking surface. Adhere to paved area marking suggestions to the extent practical.

If any marking information is omitted due to site conditions, communicate omitted data by direct contact, signs, phone, fax, etc.

"Offset" markings should clearly indicate the direction, the distance, and the path of facility or excavation.

Guidelines For Excavation Delineation

Excavators are reminded that pre-marking (delineation) of excavations is a requirement of California Code 4216.

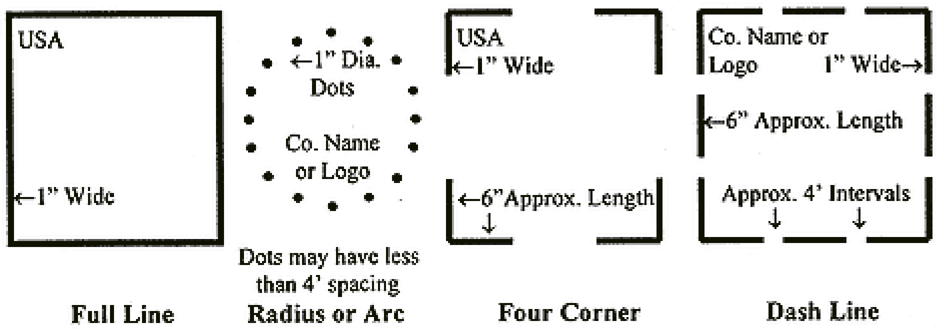
Delineate the area to be excavated before calling USA. Delineated areas should be identified in white markings with USA, or the requesters company name or logo within the pre-marked zones (see examples).

Failure to pre-mark when practical may jeopardize your permit, or result in civil penalty.

Code 4216.2 (f) requires: "If pre-marking is not practical, the excavator shall contact". . USA . . "to advise the operators that the excavator shall identify the area to be excavated in another manner sufficient to enable the operator to determine the exact area of the excavation to be field marked."

Code 4216.2 (e) states delineation must not be misleading, duplicative or misinterpreted as traffic or pedestrian control.

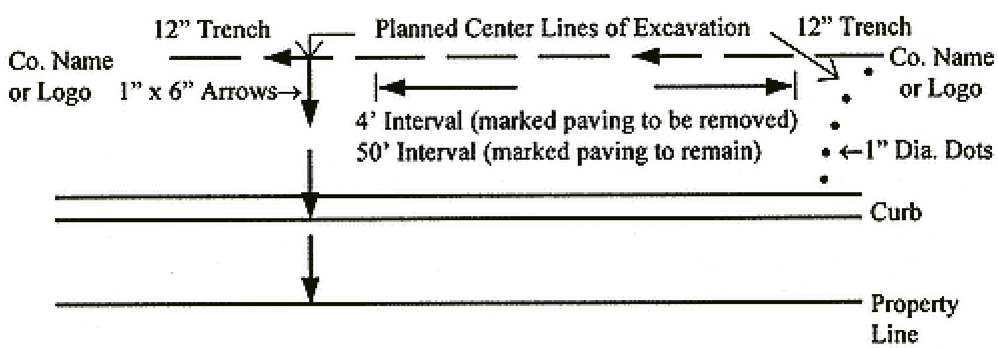
Single Point Excavations Markings



Delineate the exact area of excavation through the use of dots or dashes, or a continuous solid line. Limit the size of each dash to approximately 6" in length and 1" in width with interval spacing not less than approximately 4 feet. Dots of approximately 1" diameter are typically used to define arcs or radii and may be placed at closer intervals in lieu of dashes. Limit width of lines to 1".

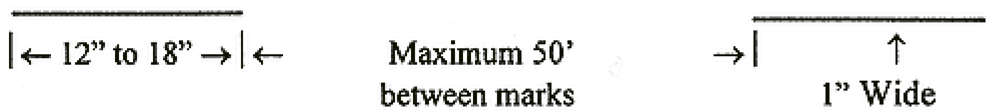
Trenching, Boring, or Other Continuous Type Excavations

Mark centerline of planned excavation with 6" x 1" arrows (approx. 4' apart) to show direction of excavation. For boring or continuous operations where marked paving is not to be removed, mark at critical points with maximum mark separation of approx. 50'. Mark lateral excavations with arrows showing excavation direction from centerline with marks at curb or property line if crossed. Intermittently indicate excavation width on either side of centerline in 3" to 6" high figures. Dots may be used for curves and closer interval marking.

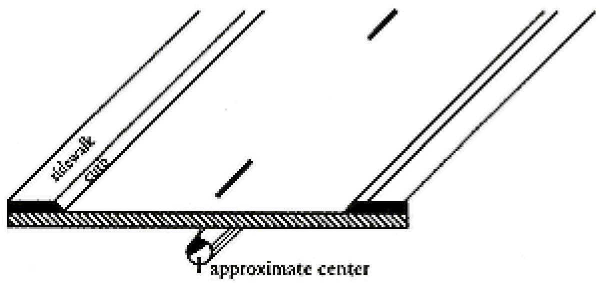


Guidelines For Facility Owner Location Markout

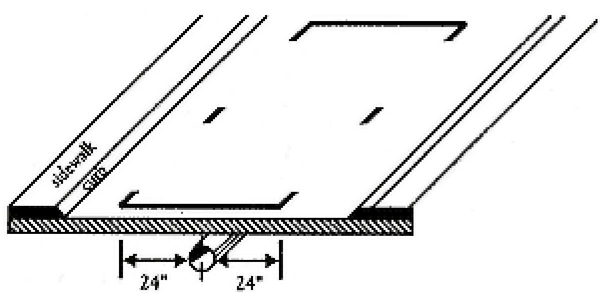
1. Marks in the appropriate color should be approximately 12" to 18" in length, spaced no more than 50' apart.



2. The marks should be placed over the approximate center of the facility.



3. As an alternative, or in addition to, marks can be placed on either side of the facility to define the "Hand Dig Area". The "Hand Dig Area" is defined as the width of the facility itself plus the tolerance zone of 24" on either side of the facility.



4. An operator designator, such as company initials, should be placed at the beginning and end of the proposed work area. This instead of a generic designator such as TEL to avoid confusion between more than one operator of the same type of facility.

<u>CTYSAC</u> <u>CITIZENS</u> <u>GTE</u>

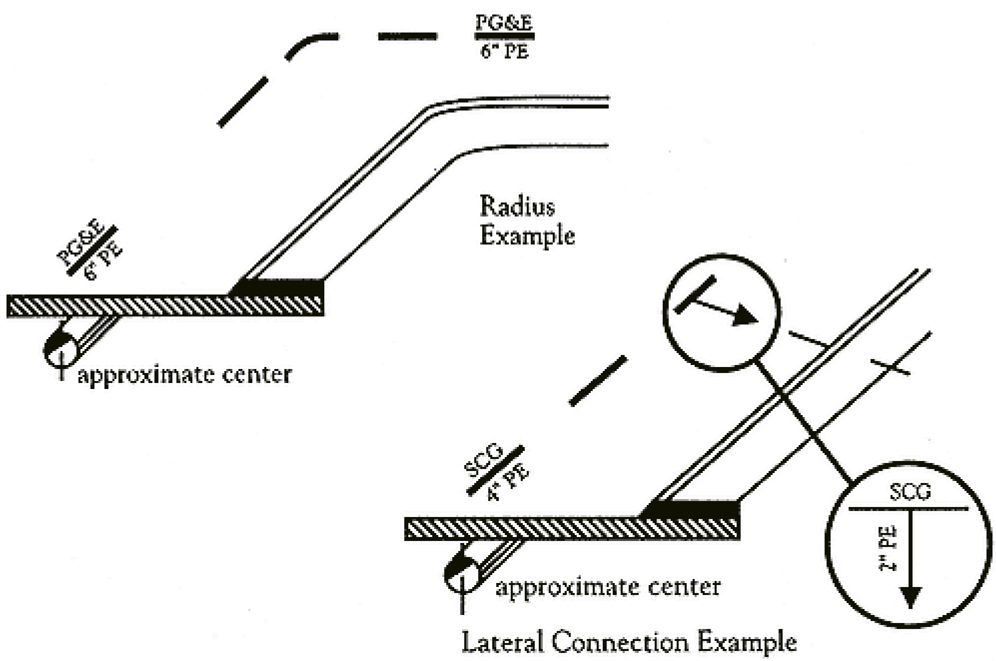
5. Information as to the size and composition of the facility should be marked at an appropriate frequency, if known. Examples are: the number of ducts in a multi-duct structure, diameter of a pipeline, and whether it is steel, plastic, bare cable, etc.

CCWD	RSVTEL	UNOCAL
4" PE	9 DUCTS	12" STL

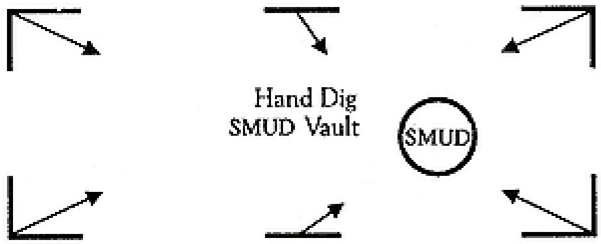
6. If known, a facility installed in a casing should be identified as such. Examples are: 6" polyethylene in 12" steel = 6"PE/12"STL, fiber optic in 4" steel = FO/4"STL.

ACWD	AT&T
6"PE/12"STL	FO/4"STL

7. Changes in direction and lateral connections should be clearly indicated at the point where the change in direction or connection occurs, with an arrow indicating the path of the facility. A radius should be indicated with marks describing the arc.

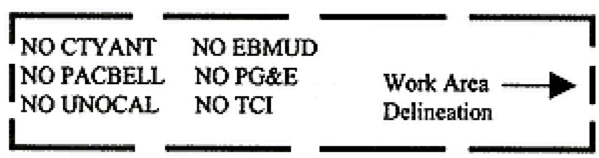


8. Structures, such as vaults, that are physically larger than obvious surface indications, should be marked so as to generally define the parameters of the structure.

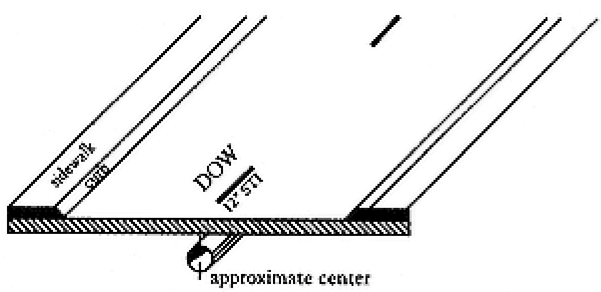


9. Termination points or dead ends should be indicated as such.

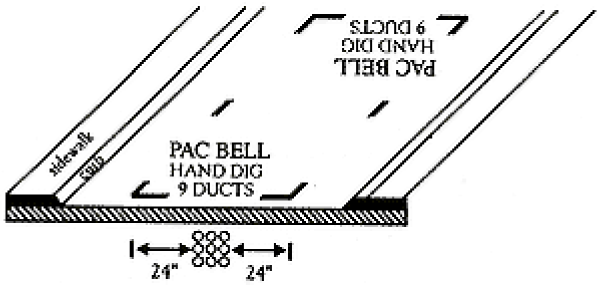
10. If there is "no conflict" and the work area has been pre-marked, no conflict should be marked along with company designator within the delineated work area * or the excavator should be notified verbally, or in writing (e.g. fax). If the work area is not delineated, the excavator should likewise be notified verbally or in writing.
    * Caution - Allow adequate space for all facility mark-outs.
    No conflict marking indicates; there are no facilities within the scope of the delineation, or when there is no delineation, there are no facilities within the work area as described on the locate ticket.



11. Example of marking with an implied 60" "Hand Dig Area" (12" facility plus 24" to the right and 24" to the left



12. Example of marking with "Hand Dig Area" outlined.



Color Code Identifiers

Red	Electric
Yellow	Gas / Oil / Steam / Chemical
Orange	Communications / CATV
Blue	Water
Green	Sewer / Storm Drain
Purple	Reclaimed Water
Pink	Temporary Survey
White	Proposed Excavation

Common Marking Identifiers

E	Electric	TEL	Telephone
FO	Fiber Optic	TS	Traffic Signal
G	Gas	TV	Television
SD	Storm Drain	W	Water / Reclaimed Water
SL	Street Lighting	USA	Underground Service Alert
S	Sewer		

Common Abbreviations And Descriptions As Used In Underground Construction.

ABS	Acrylonitrile -Butadiene - Styrene	MTD	Multiple Tile Duct
		P	Plastic (conduit or pipe)
ACP	Asbestos Cement Pipe	PB	Pull Box
CAP	Corrugated Aluminum Pipe	PC	Plastic Conduit
		PE	Polyethylene
CIP	Cast Iron Pipe	PL	Property Line
CMC	Cement Mortar Coated	PVC	Polyvinyl Chloride
CML	Cement Mortar Lined	R	Radius
CSP	Corrugated Steel Pipe	RCB	Reinforced Concrete Box
CU	Copper	RCP	Reinforced Concrete Pipe
DIP	Ductile Iron Pipe	SCCP	Steel Cylinder Concrete Pipe
DU	Duct		
ELC	Electrolier Lighting Conduit	STL	Steel
		STRUC	Structure
FC	Fiber Conduit	T	Transmission facility
GIP	Galvanized Iron Pipe	TR	Transite (asbestos cement pipe)
GSP	Galvanized Steel Pipe		
IP	Iron Pipe	TRANS	Transition
MCD	Multiple Concrete Duct	TSC	Traffic Signal Conduit
MH	Manhole	VCP	Vertrified Clay Pipe

TELEPHONE ANSWERING SERVICES

1. REFERENCE

49 CFR, Sections 192.614 and 192.615.

2. PURPOSE

The purpose of this procedure is to establish minimum requirements for telephone answering capabilities at locations that are not attended on a continuous basis by a Company employee.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (91) ___________________ is responsible for arranging the telephone answering capabilities as needed.

4. GENERAL

4.1 A Company employee, contract employee, an answering service or a combination of, will be available to receive notices 24 hours per day.

4.2 Locations whose numbers have been given to the public for purposes of reporting emergencies or requesting line locations shall be capable of receiving calls at all times.

4.3 Locations that are periodically unattended shall have the capability of rerouting calls to another location that is attended or to an answering service.

4.4 Callers will not be expected to dial more than one number to reach a Company representative.

4.5 Emergency calls taken by contract employees or answering services must be returned immediately by Company personnel.

5. PROCEDURE

5.1 Select a method for rerouting calls, depending on available local services.

5.2 Engage only professional quality answering services when outside services are required.

5.3 Instruct personnel answering incoming call to:

5.3.1 Obtain the caller's name, telephone number, and location. Ask the caller if there is an emergency.

5.3.2 Advise the caller that a Company employee will return the call.

5.3.3 Record details if the caller insists on leaving a message but remind the caller that a Company employee will return the call.

5.3.4 Call the Company's designated employee immediately.

5.4 Check the quality of service at least annually by making test calls.

5.4.1 Check the time taken to relay a message.

5.4.2 Check the accuracy of the relayed message.

5.4.3 Initiate corrective action within three (3) working days, implement changes within the next thirty (30) days, if required.

6. <u>RELATED PROCEDURES</u>

1.01 Reporting and Control of Accidents
3.01 Damage Prevention Program
3.04 Preparation of an Emergency Plan

7. <u>RECORDS</u>

7.1 Document test calls made by indicating on one-call service form that the test call was made. Document corrective action taken, if any.

7.2 Document Pipeline Marking Requests on one-call service form.

7.3 Document emergency notifications. Maintain records for 5 years.

Contents of this Element:

1.0 Introduction and Scope

1.1 Introduction

CVGS's public awareness program provides safety information to stakeholders to help keep communities near pipelines safe. These procedures define how CVGS will accomplish these objectives.

The following four objectives provide the foundation for the CVGS pipeline public awareness program.

1) **Awareness of pipelines**:
CVGS's public awareness program shall raise stakeholder audience awareness of the presence of pipelines in their communities and of the significant role they can play in helping to prevent pipeline emergencies and releases, including accidents caused by third-party damage and right-of-way (ROW) encroachment. Public awareness programs also help stakeholder audiences understand that pipeline accidents are rare and that pipelines are a safe mode of transportation.

2) **Prevention:**
CVGS's public awareness program shall help stakeholder audiences understand how to prevent pipeline emergencies. Prevention helps reduce the occurrence of pipeline emergencies caused by third-party damage through awareness of safe excavation practices and the use of the One Call Center.
3) **Response:**
Public awareness programs shall help stakeholder audiences understand how to respond to a pipeline emergency. CVGS undertakes a variety of measures to prevent pipeline accidents and anticipate and plan for management of accidents if they occur.
4) **Program Enhancements:**
Provide for periodic program evaluation to enhance the program as circumstances warrant.

1.2 Scope

The scope of these procedures covers the development, implementation, evaluation, and documentation of public awareness programs associated with the normal operation of existing pipeline systems and facilities.

The following pipeline systems and segments are covered by the CVGS PA program:

- 14.7 miles of 24" gas transmission pipeline in Colusa county, Ca.
- Product transported = natural gas (odorized by PG&E)
- Unique attributes: class 1 rural farming location

Communications related to new pipeline construction CVGS and during emergencies are not covered by these procedures. Also, these procedures provide CVGS with the elements of a recommended baseline public awareness program based on API RP #1162 [Dec 2010], and considerations to determine when and how to enhance the program to provide the appropriate level of public awareness outreach. Enhancements may affect messages, delivery frequency and methods, geographic coverage areas, program evaluation, and other elements.

CVGS will follow API RP #1162 unless CVGS provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

1.3 Approval

These public awareness procedures are approved as of __________ by the CVGS Manager. ______________________________(signature)

1.4 Applicability and Summary of the Regulations [192.616]

CVGS's program includes provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a gas pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that shall be taken for public safety in the event of a gas pipeline release; and

(5) Procedures for reporting such an event. [192.616(d)]

Other Regulatory Requirements:

- The program includes activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations [192.616(e)]
- The program and the media used must be as comprehensive as necessary to reach all areas in which CVGS transports gas [192.616(f)]
- The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area [192.616(g)]
- Upon request, CVGS must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility, the appropriate State agency [192.616(h)]
- CVGS's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies [192.616(i)]

2.0 Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline public awareness requirements. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs and general guidelines for public awareness are shown as an appendix in these procedures. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

3.0 Terms, Definitions, Acronyms, and Abbreviations Applicable to Public Awareness

3.1 Terms and Definitions

8-1-1 (call 811 or 811) - National Call Before You Dig telephone number federally mandated to eliminate the need of having to remember a state "One Call Center" toll-free telephone number.

Baseline public awareness program - Relevant components of an operator's public awareness program for delivery frequency, message content, and delivery methods as summarized in Annex A of this document.

Dig Safely - Nationally recognized damage prevention education and public awareness program to enhance safety, environmental protection, and service reliability by reducing underground facility damage.

Encroachment - Unauthorized advancement onto or within the operator's ROW.

Enhanced public awareness program - Components of a public awareness program that exceed baseline program provisions. NOTE Enhancements are also known as supplemental requirements under Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations (49 *CFR* Part 192.616 and 49 *CFR* Part 195.440).

Focus group - Participants representing one or more target audiences who are gathered to provide feedback on a topic.

Gathering line - Pipelines that transport liquid petroleum and gas products from production areas to central collection points.

NOTE Depending on jurisdiction, this may include processing facilities.

High consequence area (HCA) - Location defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment.

Highly volatile liquid (HVL) - Hazardous liquid that will form a vapor cloud when released to the atmosphere and has a vapor pressure exceeding 40 psia (276 kPa) at 100 °F (37.8 °C).

Integrity management program (IMP) - A systematic and comprehensive process designed to provide information to effectively allocate resources for the appropriate prevention, detection, and mitigation activities as referenced in the rules under 49 *CFR* Part 192 or 49 *CFR* Part 195.

May - Denotes the option to conform to a requirement.

One Call Center - Centralized notification system that establishes a communication link between those who dig underground and those who operate underground facilities. Note the role of the One Call Center is to receive notifications of proposed excavations, identify possible conflicts with nearby facilities, process the information, and notify affected facility owners/operators.

Operator - For transportation of hazardous liquid by pipeline, a person who owns or operates pipeline facilities; for transportation of natural and other gas by pipeline, a person who engages in the transportation of gas.

Pipeline(s) - All assets associated with pipeline facilities as defined in 49 *CFR* Parts 192 and 195.

Potential impact radius (PIR) - The radius of a circle as defined in 49 *CFR* Part 192.

Resident - Property owner or tenants occupying residences.

Right-of-way (ROW) - Defined land on which an operator has the rights to construct, operate, and/or maintain a pipeline. Note a ROW may be owned outright by the operator or an easement may be acquired for its specific use.
Should - Denotes a recommendation or that which is advised but not required in order to conform to the requirements of the document.

Sour gas - Natural gas or any other gas containing amounts of hydrogen sulfide (H2S) as defined by regulatory agencies.

Third-party damage (TPD) - Outside force damage to pipelines and other underground facilities that may occur due to excavation activities not performed by the operator or at the request of the operator.

Transmission pipeline - Pipeline systems that transport hazardous liquids or gas products within a state or between states. Note natural gas transmission pipelines deliver product to direct-served customers and local distribution system stations where pressure is lowered for final distribution to end users. Hazardous transmission pipelines transport product to bulk terminals, refineries, chemical plants, and other related facilities.

3.2 Acronyms and Abbreviations

AGA - American Gas Association AOPL -
Association of Oil Pipe Lines APGA -
American Public Gas Association API -
American Petroleum Institute
CFR - Code of Federal Regulations
CGA - Common Ground Alliance
DIRT - Damage Information Reporting Tool
FCC - Federal Communications Commission
H2S - hydrogen sulfide
HCA - high consequence area
HVL highly volatile liquid
IMP - integrity management program
INGAA - Interstate Natural Gas Association of America
LEPC - Local Emergency Planning Committee
NAICS - North American Industry Classification System
NPMS - National Pipeline Mapping System
PHMSA - Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation
PIR - potential impact radius
PSA - public service announcement
ROW - right-of-way
RP - recommended practice
SIC - Standard Industrial Classification

Ref: 49 CFR 192.614	Updated: March 2012

4.0 Public Awareness Program Activities

When establishing the CVGS public awareness program, the following five activities were completed:

1) Define objectives and goals,
    - See section #1.1 of these procedures
2) Obtain management commitment,
    - See CVGS public awareness team charter (section #5.0)
3) Establish program administration,
    - See CVGS public awareness team charter, and
    - "List of Required Ongoing Documentation and R&Rs for Public Awareness" section #12 of these procedures
4) Identify pipeline assets,
    - See section #1.2 of these procedures
5) Identify stakeholder audiences,
    - See section #6.0 of these procedures

5.0 Management Commitment and PA Program Authorities
[API RP #1162, section #5.2]

For the CVGS public awareness program to achieve stated objectives, ongoing support from company management is crucial. The CVGS public awareness Team Charter defines general team member roles and responsibilities. [Procedure #3.03: Record #1]

The required documentation section at the end of this procedure defines who is responsible for completing specific tasks including documentation. The CVGS Team Charter will be reviewed by the appropriate level of management. It will be understood and described on the team charter that when a person is assigned a public awareness task, the person also has the authority to complete that tasks.

6.0 Stakeholders Audiences

The following four categories of stakeholder audiences have been identified and shall receive the program messages.

1. Affected public
2. Emergency officials
3. Public officials
4. Excavators

CVGS may hire outside consultants to assist them in identifying stakeholder audiences. CVGS will keep a record of how the stakeholder audience lists were compiled and what system was employed, such as the Standard Industrial Classification (SIC) and/or the North American Industry Classification System (NAICS).

Table 6-1 through Table 6-4 below identifies the CVGS stakeholders identified by these procedures.

6.1 Affected Public

For the purposes of this document, the affected public is residents and/or businesses located near or adjacent to transmission or gathering pipelines. For a more detailed example of these audiences, please see Table 6-1 below.

CVGS shall determine specific affected public addresses near the pipeline within a specified minimum coverage area. Examples of how CVGS may identify affected public addresses are through a nine-digit zip code address database or geo-spatial address databases. These databases generally provide only the addresses and not the names of the persons residing there. Individual apartment unit addresses shall be used, not just the address of the apartment building or complex.

The following is currently used for affected public address generation for the CVGS PA program: [Procedure #3.03: Record #2]

- Use of Paradigm as third party consultant
- Paradigm method for address generation uses GeoCoding and SIC codes (see Paradigm documentation for details)

For stakeholder audiences identified in Table 6-1, including “Residents located adjacent to the transmission pipeline ROW” and “Places of congregation,” transmission pipeline CVGS stipulates the minimum coverage in their program as shown below. CVGS may choose to define the minimum coverage area in a variety of ways. For example, CVGS may determine the minimum coverage area by using a distance of 660 feet from the centerline of the ROW; or 660 feet from the centerline of the pipeline; or determine the area using a potential impact radius (PIR) calculation.

The following is currently used for affected public minimum coverage distance for the CVGS PA program: [Procedure #3.03: Record #3]

- 660 feet (class location distance for gas pipelines). See Paradigm documentation for details.

Table 6-1—Stakeholder Audiences—Affected Public

Stakeholder Audience	Stakeholder Definition	Examples
Residents located adjacent to the transmission pipeline ROW	People who live or work adjacent to a natural gas and/or hazardous liquid transmission pipeline ROW	• Residents • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along local distribution systems	People who live or work on or immediately adjacent to the land where gas distribution pipelines are buried	• Local distribution company (LDC) customers • Non-customers living immediately adjacent to the land where distribution pipelines are located • Homeowners associations or groups • Neighborhood organizations
Residents near liquid or natural gas storage and other major operational facilities along transmission lines	People who live or work adjacent to or near a major facility such as tank farm, storage field, and pump/compressor station	• Residents • Farmers • Homeowners associations or groups • Neighborhood organizations
Residents located along gathering lines	People who live or work along gathering lines	• Residents • Farmers • Homeowners associations or groups • Neighborhood organizations
Places of congregation	Identified places where people assemble or work on a regular basis—on or along a transmission pipeline ROW, gathering lines, and local distribution systems	• Businesses • Schools • Places of worship • Hospitals and other medical facilities • Parks and recreational areas • Daycare facilities • Playgrounds

6.2 Emergency Officials

CVGS has identified the appropriate emergency officials whose jurisdictions are traversed by the pipeline. For a more detailed example of these audiences, please see Table 6-2 below.

CVGS shall determine specific emergency officials near the pipeline within a specified minimum coverage area. Examples of how CVGS may identify affected public addresses are through a nine-digit zip code address database or geo-spatial address databases. These databases generally provide only the addresses and not the names of the officials residing there.

The following is currently used for emergency officials address generation for the CVGS PA program: [Procedure #3.03: Record #2]

- Use of PAPA as third party consultant
- PAPA method for address generation uses SIC codes based on selected counties where pipeline operations exists (see PAPA documentation for details)

Table 6-2—Stakeholder Audiences—Emergency Officials

Stakeholder Audience	Stakeholder Definition	Examples
Emergency officials	Local, city, county, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction in the area of the pipeline	• Fire departments • Police/sheriff departments • Local Emergency Planning Committees (LEPCs) • County and state emergency management agencies • 911 centers and/or emergency dispatch

6.3 Public Officials

CVGS has identified the appropriate public officials whose jurisdictions are traversed by the pipeline. For a more detailed example of these audiences, please see Table 6-3 below.

CVGS shall determine specific public officials near the pipeline within a specified minimum coverage area. Examples of how CVGS may identify affected public addresses are through a nine-digit zip code address database or geo-spatial address databases. These databases generally provide only the addresses and not the names of the officials residing there.

The following is currently used for public officials address generation for the CVGS PA program: [Procedure #3.03: Record #2]

- Use of PAPA as third party consultant
- PAPA method for address generation uses SIC codes based on selected counties where pipeline operations exists (see PAPA documentation for details)

Table 6-3—Stakeholder Audiences—Public Officials

Stakeholder Audience	Stakeholder Definition	Examples
Public officials	Local, city, county, state, regional, federal officials, agencies and/or their staff having land use and street/road jurisdiction in the area of the pipeline	• Planning boards • Zoning boards • Licensing departments • Permitting departments • Building code enforcement departments • City and county managers • Public and government officials • Public utility boards • Local governing councils • Public officials who manage franchise or license agreements • Military installations

6.4 Excavators

CVGS has identified the appropriate excavators traversed by the pipeline. For a more detailed example of these audiences, please see Table 6-4 below.

CVGS shall determine specific excavators near the pipeline within a specified minimum coverage area. Examples of how CVGS may identify affected public addresses are through a nine-digit zip code address database or geo-spatial address databases. These databases generally provide only the addresses and not the names of the officials residing there.

The following is currently used for excavators address generation for the CVGS PA program: [Procedure #3.03: Record #2]

- Use of PAPA as third party consultant
- PAPA method for address generation uses SIC codes based on selected counties where pipeline operations exists (see PAPA documentation for details)

Table 6-4—Stakeholder Audiences—Excavators

Stakeholder Audience	Stakeholder Definition	Examples
Excavators	Companies and local/state government agencies who are normally engaged in excavation activities and/or land development and planning	• Construction companies • Excavation equipment rental companies • Public works officials • Public street, road, and highway departments (maintenance and construction) • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Well drillers • Land developers • Home builders

7.0 Message Content for Key Stakeholders [API RP #1162, section #6]

The information communicated to the stakeholder audiences plays a vital role in damage prevention. Messages are information that CVGS provides to stakeholder audiences to improve awareness of pipelines. Messages shall be focused, concise, and clear. Such messages are intended to keep communities safe and prevent damage to pipelines.

The program shall be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the area of the CVGS pipeline. The process used to determine the need for additional languages is shown below. [Procedure #3.03: Record #4]

- For the affected public, use of US Census Bureau website (http://quickfacts.census.gov/qfd/states) that shows languages spoken by state and county.
- Based on this this US Census Bureau data, the current languages spoken the CVGS affected public is English and Spanish.

Communications experts agree that people cannot absorb large amounts of information at one time. Therefore, the message content has been divided (by stakeholder audience) into two main categories:

(1) Baseline
(2) Enhanced messages

Baseline messages are core safety messages and vary depending on stakeholder audience and type of pipeline. CVGS will provide baseline messages to each stakeholder audience. CVGS will have the flexibility to determine when and if enhanced messages are necessary (see Section 9).

These procedures provide a general description of the messages. CVGS will develop the wording for each message based on this guidance and what is appropriate for their pipeline assets. Specific messages are contained in the mailer documentation provided as shown in Table 7-1 below.

Ref: 49 CFR 192.614	**Updated: March 2012**

Table 7-1—3rd Party Companies Used for Specific Messages to Stakeholders

	Affected Public	Emergency Officials	Public Officials	Excavators
3rd Party Service Used for Specific Message to Each of the Stake Holders Listed to the Right:	Paradigm [Procedure #3.03: Record #5]	PAPA [Procedure #3.03: Record #6]	PAPA [Procedure #3.03: Record #7]	PAPA [Procedure #3.03: Record #8]

Table 7-2 sets forth baseline message topics that shall be used for each stakeholder audience and type of pipeline. It shall be noted that a particular baseline message may apply to one category of pipelines or stakeholder audience (e.g. only operators of transmission pipelines are required to send the National Pipeline Mapping System (NPMS) baseline message to emergency officials and public officials. Operators of other categories of pipelines are not required to send this specific baseline message). At CVGS's discretion, some or all of these messages may also be reiterated in an enhanced program. CVGS contact information shall be provided to all stakeholders in the baseline public awareness program.

Table 7-2—Baseline Messages

Message	Affected Public	Emergency Officials	Public Officials	Excavators
Damage prevention	T, G		T, G	T, G
Emergency preparedness		T, G		
Leak/damage recognition and response	T, G	T, G	T, G	T, G
NPMS		T	T	
One Call	T, G		T, G	T, G
Pipeline Location Info	T, G	T, G	T, G	T, G
Potential Hazards	T, G	T, G	T, G	T, G
ROW encroachment	T		T	
Letters denote type of pipeline: T = Transmission, G = Gathering				

The tables below summarize the baseline and potential enhanced messages, delivery methods, and delivery frequencies for conducting public awareness programs for CVGS gas transmission pipelines. The tables are not meant to include every possible enhanced program element. CVGS may choose to communicate more frequently using additional messages and methods. Section 9 provides additional guidance for enhancing public awareness programs.

Table 7-2 —Natural Gas Transmission and Gathering Pipeline Potential Enhanced Messages

Affected Public	
Baseline Program *Frequency* — 2 years *Messages* — Damage prevention — Leak/damage recognition and response — One Call requirements — Pipeline location information — Potential hazards — ROW encroachment *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 7 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials	**Enhanced Program** *Frequency* — As determined by the operator For sour gas or sour crude pipelines CVGS will consider annual contact to the affected public to provide special emergency procedures *Messages* — How to get additional information — Integrity management overview — NPMS — Pipeline purpose and reliability — Prevention measures — ROW encroachment (gathering line) *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials

Ref: 49 CFR 192.614	**Updated: March 2012**

Table 7-3 —Natural Gas Transmission and Gathering Pipeline Potential Enhanced Messages (cont.)

Emergency Officials	
Baseline Program *Frequency* — 1 year *Messages* — Emergency preparedness communications — Leak/damage recognition and response — NPMS — Pipeline location information — Potential hazards — Special emergency procedures for sour gas *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Personal contact — Targeted distribution of print materials	**Enhanced Program** *Frequency* — As determined by operator *Messages* — How to get additional information — Integrity management overview — Pipeline purpose and reliability — Prevention measures *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials

Ref: 49 CFR 192.614	**Updated: March 2012**

Table 7-4 —Natural Gas Transmission and Gathering Pipeline Potential Enhanced Messages (cont.)

Public Officials	
Baseline Program *Frequency* — 3 years *Messages* — Damage prevention — Leak/damage recognition and response — NPMS — One Call requirements — Pipeline location information — Potential hazards *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Personal contact — Targeted distribution of print materials	**Enhanced Program** *Frequency* — As determined by operator NOTE If subject to integrity management rules under either 49 *CFR* Part 192 and in HCA, then contact as appropriate per applicable rule. *Messages* — Emergency preparedness — How to get additional information — Pipeline purpose and reliability — ROW encroachment — Prevention measures — Special emergency procedures if sour gas *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials

Ref: 49 CFR 192.614	**Updated: March 2012**

Table 7-5 —Natural Gas Transmission and Gathering Pipeline Potential Enhanced Messages (cont.)

Excavators	
Baseline Program *Frequency* — 1 year *Messages* — Damage prevention — Leak/damage recognition and response — One Call requirements — Pipeline location information — Potential hazards *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials	**Enhanced Program** *Frequency* — As determined by operator *Messages* — How to get additional information — Pipeline purpose and reliability — ROW encroachment — Prevention measures *Methods*—Determined by operator based on specifics of pipeline segment or environment. See Section 8 for available options. General categories include: — Electronic communication — Mass media — Personal contact — Targeted distribution of print materials

7.1 Damage Prevention

CVGS will convey to audiences the importance of damage prevention, noting that even relatively minor excavation activities (e.g. installing mail boxes, privacy fences and flag poles, performing landscaping, constructing storage buildings, etc.) may cause damage to a pipeline or its protective coating or to other buried utilities. CVGS will keep the damage prevention message content consistent with the following “Dig Safely” messages:

- Call 811 or the One Call Center before digging,
- Wait for the site to be marked,
- Respect the marks,
- Dig with care.

CVGS will also use of the 811 logo or the “No Dig” symbol in their materials.

7.2 Suspicious Activity

Messages shall be structured to raise stakeholder awareness of the need to look for and report any suspicious activities or suspected pipeline damage. Encourage stakeholders to report any suspicious activities on or near the pipeline system by individuals who are not performing obvious pipeline operation activities. Reporting suspicious activities is a proactive way to prevent damage to the pipeline system.

7.3 Suspected Damage

Encourage stakeholders to report any damage to the pipeline system or any observed conditions that could threaten the integrity of the pipeline system. Some examples are exposed pipe, subsidence, sink holes, dead vegetation, or unstable soil. This message addresses the important role a stakeholder audience plays in preventing third-party damage and ROW encroachments.

7.4 Emergency Preparedness

These messages demonstrate that CVGS has an ongoing relationship with emergency response officials, including 911 emergency call and dispatch centers and a program designed to prepare for and respond to an emergency.

7.5 Priority to Protect Life

CVGS's emergency response plans and key messages relayed to emergency officials shall emphasize that public safety and environmental and property protection are the top priorities in any pipeline emergency response.

7.6 Emergency Contacts

CVGS's contact information shall be communicated to local and state emergency officials. If practicable, CVGS shall also use the public awareness contact opportunity to confirm the contact information for the local and state emergency officials and calling priorities within each organization.

7.7 Liaison with Emergency Officials

Information communicated to emergency responders will be more detailed, provide an opportunity for two-way feedback, and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison.

The purpose of the emergency official's liaison meetings is to build the relationship between CVGS and the responders and help to understand the expectations of the responders. The preferred method for conducting liaison meetings is face to face with specific emergency officials or group meeting conducted by Paradigm. During these meetings CVGS will provide and verify the following:

- Summary copy of the CVGS pipeline emergency response plan including maps, product transported, and emergency contact info
- Verify the response agency has the proper equipment and resources to respond to a CVGS pipeline emergency

For emergency officials that were invited and don't attend group meetings, a summary copy of the CVGS pipeline emergency response plan including maps, product transported, and emergency contact info will be mailed.

[192.615(c), & PHMSA Advisory ADB 10-08, Nov 3, 2010]
[Procedure #3.03: Record #9]

7.8 Emergency Response Plans

CVGS will communicate emergency response plans to local emergency responders in order to increase awareness of pipelines and response to emergencies. The plan provided to the emergency responders will be a summary version of the full plan and will include the following: [192.615(c) and PHMSA Advisory ADB 10-08, Nov 3, 2010] [Procedure #3.03: Record #10]

- Pipeline description and location including maps
- MSDS or hazard info about product transported
- CVGS emergency contact info
- Defining which types of emergencies that CVGS will contact agencies
- How CVGS will interact with the emergency responder

7.9 Emergency Drills and Exercises

Drills and exercises offer many additional opportunities for communicating messages and information. When participating with emergency response officials in drills and deployment exercises, CVGS will communicate material to them on unified incident command system roles, operating procedures, and preparedness for various emergency scenarios. [192.615(b)(2)] [Procedure #3.03: Record #11]

7.10 Integrity Management Programs (IMPs)

Materials may provide an overview of an CVGS's IMP and identify how more information on IMP may be obtained. An overview of an CVGS's IMP shall include a general description of the basic requirements and components of the program. This does not need to include a summary of the specific locations or schedule of activities undertaken. The overview may be mailed upon request or made available on the CVGS's website.

7.11 How to Get Additional Information

CVGS will consider informing stakeholder audiences about how to get additional pipeline-related information from various sources; including CVGS, trade association and government agencies. CVGS specific information may include encroachment, landscape, property guidelines, crossing requirements, and local contacts.

7.12 Leak or Damage Recognition and Response

Messages about recognizing and responding to leaks and damage to pipelines are important. As appropriate to the product type, messages about recognizing a suspected pipeline leak, release, or observed damage shall relate to the senses of:

- Sight,
- Sound,
- Smell.

Messages about responding to a suspected pipeline leak or release shall include the following:

1. What to do if a leak is suspected;
2. What not to do if a leak is suspected;
3. How to contact CVGS and fire, police, or other appropriate public officials in an emergency. It is important to include specific information on detection and response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of H_2S). Information provided to excavators includes the need to communicate when damage to a pipeline from excavation activities occurs.

Excavators shall be directed to call 911 and CVGS when a leak or damage occurs. For other situations, stakeholder audiences shall be directed to call CVGS.

7.13 National Pipeline Mapping System (NPMS)

Members of the general public may obtain pipeline location and/or mapping information by accessing the NPMS on the Internet. NPMS includes a list of pipeline operators and contact information for operators with pipelines in a specific area along with mapping information. Inquiries may be made by zip code or by county and state. Pipeline location maps are made available electronically to state and local emergency officials, in accordance with federal security measures. Distribution and gathering lines are not included in NPMS. [Procedure #3.03: Record #12]

7.14 One Call Requirements

The Federal Communications Commission (FCC) has designated 811 as the national One Call, toll-free number. In addition, One Call Center telephone numbers for all 50 states can be found on the 811 and Dig Safely websites. The Dig Safely website is shown below:

www.call811.com

The stakeholder audience shall be reminded to call 811 or the state One Call Center before beginning any excavation activity and advised that in most states it is required by law. If the state or locality has established penalties for failure to use established damage prevention procedures, that information may also be communicated, depending on the audience and situation. Excavation and One Call information shall include the following:

- When to contact 811 or the One Call Center before digging,
- What happens when 811 or the One Call Center is notified,
- The 811 or toll-free One Call Center telephone numbers,

7.15 Pipeline Location Information

Following are various methods that can be used to provide pipeline location information.

7.15.1 Pipeline Markers

Pipeline markers are a valuable tool for educating the public regarding the general location of pipelines. The information shall include how to identify transmission pipeline ROWs by recognition of pipeline markers, especially at road crossings, fence lines and street intersections. For specific required information on pipeline markers and their content, see 49 *CFR* Parts 192.707 and 195.410.

NOTE Additional guidance for liquid pipeline marker design, installation, and maintenance is provided in API 1109. See company O&M procedure #5.01.

7.15.2 Pipeline Mapping

Pipeline maps provide useful information to stakeholder audiences. The level of detail in the map depends on the stakeholder's requirements, taking security of the energy infrastructure into consideration.

The following summarizes the types of maps that may be provided to stakeholder audiences. [Procedure #3.03: Record #13]

- *System Maps*—System maps provide general depiction of a pipeline shown on a state, regional, or national scale. This type of map generally is not at a scale that poses security concerns and is often used by operators in a number of publications available to the industry and general public. These maps provide a high-level overview of the pipeline route and location of facilities.
- *Local Maps*—Local maps are generally shown on a neighborhood, town, city, or county level and usually do not show the entire pipeline system. Local maps are especially appropriate in communication with local emergency officials, One Call Centers, and public officials when discussing land use planning.
- *NPMS*—Information including maps of communities that depict all of the natural gas and liquid transmission pipeline systems in the area is available from PHMSA.

7.16 Pipeline Purpose and Reliability

CVGS will consider providing general information about pipeline transportation, such as the following:

- The role, purpose, and function of pipelines and/or associated facilities in U.S. energy supply;
- Pipelines as part of the energy infrastructure;
- Efficiency and reliability of pipelines;
- The industry's safety record;
- The CVGS's pipeline safety actions and environmental record;
- The benefits of the pipeline to the community;
- State and federal regulations with regard to pipeline design, construction, operation, and maintenance;
- Operational activities that promote pipeline integrity, safety, and reliability (testing practices, inspections, patrolling, etc.).

7.17 Potential Hazards

CVGS shall provide a broad overview of potential hazards. General information about pipeline hazards may be communicated, while also assuring the stakeholder audience that accidents are relatively rare. Information about the general product release characteristics and potential hazards that could result from an accidental release of hazardous liquids or gases from the pipeline or distribution system shall be included in the message. CVGS may reference how stakeholders may obtain more information regarding products transported.

7.18 Prevention Measures

CVGS will provide a broad overview of the measures undertaken to prevent or mitigate pipeline incidents. This message shall also reinforce how the stakeholder audience can play an important role in preventing third-party damage and ROW encroachments.

The message includes a general overview of the preventive measures undertaken by CVGS in the planning, design, operation, maintenance, inspection, and testing of the pipeline. The causes of pipeline failures, such as third party excavation damage, corrosion, material defects, and events of nature, shall also be communicated.

7.19 ROW Encroachment

Some ROW encroachments increase the chance of third-party damage and inhibit the CVGS's ability to perform critical activities. CVGS shall communicate that, in order to conduct surveillance, routine maintenance and inspections, CVGS must be able to access the ROW, as provided in the easement agreement. CVGS shall also indicate that to ensure access for maintenance and during emergencies the area must be clear of trees, shrubs, buildings, fences, structures, or any other encroachments. CVGS will point out that the landowner has the obligation to respect the pipeline easement by not placing obstructions or encroachments there, and that maintaining an encroachment-free ROW is essential for pipeline integrity and safety.

CVGS shall consider communicating with local authorities regarding effective zoning and land use requirements/restrictions that protect existing pipeline ROWs from encroachment. Communications with local land use officials may include consideration of the following:

- How community land use decisions (e.g. planning, zoning, etc.) impact community safety;
- Requiring prior authorization from easement holders in the permit process so that construction/development does not impact the safe operation of pipelines;
- Requiring CVGS involvement in road widening or grading, mining, blasting, dredging, and other activities that impacts the safe operation of the pipeline.

When land use and planning messages are communicated, CVGS will use the following PHMSA information, "Safety Guidelines to Better Protect Communities Close to Transmission Pipelines", December 16, 2010.

Residents, excavators, and land developers shall be directed to contact CVGS if there are questions concerning the pipeline or the ROW. Major projects may further require early coordination with CVGS. These audiences shall also be informed that they may be required by state law to provide at least 48 hours advance notice, more in some states, to the appropriate One Call Center prior to performing excavation activities.

7.20 Special Emergency Procedures

Procedures shall be communicated to specific stakeholder audiences if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentrations of H2S, benzene, anhydrous ammonia, etc.). Where appropriate, this shall include product information, steps to take in an emergency, how to contact CVGS, and where to find other relevant information.

7.21 Special Incident Response Notification and Evacuation Measures

CVGS will provide notification and/or evacuation information to residents near liquid or natural gas storage or other major operational facilities along transmission lines. Where appropriate, this shall include product information, steps to take in an emergency, how to contact CVGS, and where to find other relevant information.

8.0 Delivery Frequencies and Methods

Delivery frequencies and methods refer to how often and in what ways public awareness information is presented to stakeholder audiences. These procedures define all the possible potential delivery methods and frequencies in Tables 7-2 thru Table 7-5.

The table below summarizes the delivery frequency and methods currently used by CVGS:

Table 8-1 —Baseline and Enhanced Delivery Frequency and Methods

	Stakeholder Audience:	Baseline Delivery Frequency:	Baseline Delivery Method:	Enhanced Delivery Method:
1.	Affected public	1x/2yrs	Paradigm targeted distribution of print materials	Separate mailer to farmers
2.	Emergency officials	1x/yr	1) PAPA targeted distribution of print materials 2) Face to face and/or emergency drill with responder	None at this time
3.	Public officials	1x/3yrs	PAPA targeted distribution of print materials	PAPA mailer sent annually
4.	Excavators	1x/1yr	PAPA targeted distribution of print materials	None at this time

8.1 Delivery Frequencies

CVGS will use the base line frequencies as defined in Tables 8-1 shown above. An increased delivery frequency constitutes an enhancement to the program. CVGS has the flexibility to determine if changes to delivery frequencies are necessary as determined by the annual reviews.

8.2 Delivery Methods

CVGS shall select the baseline method(s) that would be effective in reaching the identified stakeholder audience. Methods may vary based on many factors, including stakeholder audience and type of pipeline among others. CVGS may choose to enhance the public awareness program by employing additional delivery methods. The remaining procedures in this section describe the potential delivery methods will consider for baseline and enhanced programs. [Procedure #3.03: Record #14]
CVGS shall not exclusively rely on any one of the following methods to meet baseline public awareness program provisions. Although valuable, some methods on their own

are not the most effective manner to communicate baseline messages and may not adequately reach stakeholders. They include the following potential deliver methods:

- Company websites,
- Media news coverage,
- Community and neighborhood newsletters,
- Drills and exercises,
- Open houses,
- Community events,
- Charitable contributions,
- CVGS's employee participation,
- Pipeline markers.

Consideration may be given to joining with other pipeline companies in a local, regional, or national setting to produce and deliver common message materials. This approach may increase effectiveness, avoid conflicting messages, or reduce the cost.

Also, in providing materials to stakeholder audiences, it may be advisable to emphasize to recipients (e.g. the owner of an excavation firm or elected official or public agency department head) the importance of disseminating the materials to all appropriate individuals (e.g. supervisors, inspectors, line personnel, and field personnel) within the organization to further enhance safety and reduce potential costs and liability.

The following describes some delivery methods in more detail. These delivery methods describe the potential delivery methods which will be consider for baseline and enhanced programs.

Electronic Communications Methods

8.2.1 Videos

Videos may be useful in showing activities such as pipeline maintenance, pipeline routes, simulated or actual spills and emergency response exercises, or actual emergency responses. Such videos may be used for landowner contacts, emergency official meetings, or community meetings. CVGS may seek videos from trade organizations or develop their own.

8.2.2 E-mail

Electronic mail ("e-mail") may be used to send public awareness information to stakeholders. E-mail contact information may be provided on company handouts and other written communications to encourage two-way communication between the stakeholder and CVGS.

8.2.3 Company Websites

CVGS may use company websites to share public awareness information with stakeholders. In addition, websites may be used to post educational videos, electronic versions of public awareness brochures, and links to other industry resources and organizations. CVGS website provides information on a variety of subjects, including the following.

General Company Background
In addition to describing the purpose of the pipeline, the website usually includes a general description of the CVGS pipeline system. This may include the following:

- Owner name(s);
- Region and energy market served
- General office and emergency contacts telephone numbers and e-mail addresses;
- Products transported;
- System or general map and location of key offices (headquarters, region, or districts).

Company Pipeline Operations

A broad overview of CVGS's pipeline safety and integrity management approach includes describing the various steps the company takes to ensure the safe operation of its pipelines. While not specifically recommended, additional information to consider for the website includes the following:

- General pipeline system facts;
- An overview of routine operating, maintenance, and inspection practices of the system;
- An overview of major specific inspection programs and pipeline control and monitoring programs.

Transmission Pipeline Maps

A system map is useful for posting on the website. Details on how to obtain additional information may be provided, including reference to the NPMS.

Public Awareness Programs

CVGS may include a summary of the public awareness program and printed material. Contacts shall be provided for requesting additional information.

Emergency Information

The website may contain emergency awareness information, including a summary of CVGS's emergency preparedness and information on how the affected public and/or public officials may help protect, recognize, report and respond to a suspected pipeline emergency. Emergency contact information may be prominently listed on the website.

Damage Prevention

CVGS may provide or link the viewer to additional guidance on preventing excavation damage, such as 811 and the "Dig Safely" program information, contact information for 811, and the One Call Center in each of the states in which CVGS has a pipeline.

8.3 Mass Media Communications

8.3.1 Public Service Announcements (PSAs)

PSAs are non-commercial advertisements, which are communicated through various media, including television, radio, newspapers, magazines, or billboards to inform the public about an issue. Occasionally, radio and television stations allocate free airtime for PSAs. Cable TV public access channels may also be an option.

8.3.2 Media News Coverage

CVGS may encourage the media to cover pipeline issues, such as local projects, excavation safety, or the presence of pipelines as part of the energy infrastructure. If the media is reporting on an emergency or controversial issue, CVGS may leverage the opportunity to reinforce key safety information messages such as damage prevention and the need to be aware of pipelines in the community. Trade magazines such as those for excavators or farmers often welcome guest articles. Local weekly newspapers and "metro" section inserts often include a news release verbatim at no cost.

8.3.3 Paid Advertising

The use of paid advertising media such as television ads, radio spots, newspapers ads, and billboards may be made more cost-effective by joining with other pipelines, including local utilities. Some examples are placement of a public awareness advertisement on a phone book cover or in local shopping guides.

8.3.4 Community and Neighborhood Newsletters

Posting of pipeline safety or other information to community and neighborhood newsletters may be done in conjunction with outreach to those communities and/or neighborhoods and may sometimes be free of charge. CVGS may also develop their own newsletters tailored to specific communities.

8.3.5 Personal Contact

Personal contact between CVGS and the intended stakeholder audience is usually a highly effective form of communication, and it may help build stakeholder trust. This may be done on an individual basis or in a group setting. Some examples of communications through personal contact are as follows.

8.3.6 Door-to-door Contact

On-site visits to specific stakeholders located near the pipeline, which are conducted by CVGS or its representative.

8.3.7 Telephone Calls

Telephone calls to specific stakeholders located near the pipeline, which are conducted by CVGS or its representative.

8.3.8 Group Meetings

CVGS may elect to conduct stakeholder meetings individually or in conjunction with other operators. Some examples of stakeholder group meetings may include: emergency officials, public officials, state One Call Centers, excavators, land developers, schools, community/neighborhood organizations, etc.

8.3.9 Drills and Exercises

Information on unified (incident) command system roles, operating procedures, and preparedness for various emergency scenarios may be communicated effectively to emergency officials during drills and deployment exercises.

8.3.10 Open Houses

CVGS may hold open houses to provide an informal setting to introduce an upcoming project, provide a "get-to-know-your-neighbor" atmosphere or to discuss an upcoming maintenance activity such as pipeline segment replacement. Such events may include tours of company facilities, question-and-answer sessions, videos, and other presentations. Targeted or mass mailings may be used to announce planned open houses and can, in themselves, communicate important information.

8.3.11 Community Events

Community-sponsored events, fairs, charity events, job fairs, trade shows, or civic events may provide opportunities to communicate with stakeholders. Companies may participate with a booth or as a sponsor of the event.

8.3.12 Charitable Contributions

In some cases, contributions to charities and civic causes may provide opportunities to convey public awareness messages. Some examples include the following:

- Sponsorship of emergency responders to fire training school,
- Contribution of natural gas detection equipment to the local volunteer fire department,
- Donation of funds to acquire or improve nature preserves or green space,
- Sponsorship to community arts and theatre,

- Support of scholarships (especially when degree programs are relevant to the company or industry).

8.3.13 CVGS Employee Participation

As members of communities and community service organizations, informed employees of CVGS may play an important role in promoting pipeline awareness. CVGS may include in the public awareness program provisions for familiarizing employees with public awareness information and materials. Many public awareness programs include components for key employee training in public awareness and communication training for key employees.

CVGS employees may be a key part of public awareness efforts. Grassroots employee contacts and communications may be particularly important in reaching out to a community. Interested employees shall be given the necessary training, communications materials, and as appropriate, opportunities for direct involvement with the community.

8.3.14 One Call Center Outreach

Operators are required by 49 *CFR* Parts 192.614 and 195.442 to become members of One Call Centers. Most state One Call Centers implement public awareness activities about the One Call requirements and the 811 Call Before You Dig message. CVGS may count such communication as part of their public awareness programs.

8.3.15 Targeted Distribution of Print and Other Materials

Print materials are used to communicate general public awareness messages to stakeholder audiences. They afford an opportunity to communicate content in a graphical or pictorial way. CVGS shall consider the type, language, and design of the print material, based on the audiences to be reached.

Print materials may be mailed to residents or communities along the pipeline system or handed out at local community fairs, open houses, or other public forums. Information may be obtained from the postal service or service provider on size, folding, and closure requirements to minimize the postage costs for mass mailings. Outside consultants may be used to assist with printing, identification of addresses, mailing, and documentation.

Some examples include the following:

- Brochures (flyers or leaflets), small booklets or pamphlets containing educational material;
- Letters (including door hangers);
- Maps;
- Response cards (referred to bounce back cards or business reply cards), used to maintain/update current mailing lists, permit the recipients to notify the CVGS of any changes in address, provide a way for recipients to make comments, request additional information, raise concerns or ask questions, and help evaluate the effectiveness of CVGS's public awareness program;
- Bill stuffers (printed materials that LDCs frequently send to customers along with invoices);
- Specialty advertising materials, including refrigerator magnets, calendars, day planners, thermometers, key chains, flashlights, hats, jackets, shirts, clocks, wallet cards, and other such items containing a short message (e.g. 811 Call Before You Dig, the company logo, and/or contact information);
- Training materials designed to increase knowledge and skills in responding to pipeline emergencies;
- Electronic materials (including videos, CDs, PowerPoint presentations, PDFs, etc.).

8.3.16 Pipeline Marker Signs

Pipeline marker signs are valuable tools for educating the public regarding the general location of pipelines. For more information, see 49 *CFR* Parts 192.707 and 195.410 and API 1109.

9.0 Program Implementation and Enhancements

Program implementation refers to actions that CVGS will take to plan, conduct, review, evaluate, document, and improve a public awareness program. At any time during program implementation, CVGS may enhance a baseline program. CVGS has developed a specific process for considering whether enhancements are warranted to achieve awareness objectives (see section #9.2 below).

9.1 Program Implementation

To implement the program, CVGS shall do the following:

- Develop a schedule for conducting the program activities; (see table in 9.1)
- Develop resource and obtain monetary support; (see team charter)
- Identify, assign, and task participating company employees needed to implement the program; (see team charter and section #12.5)
- Identify external resources or consultants needed; (see table #7-1)
- Conduct program activities like mass mailings, emergency official meetings; (see table #8-1)
- Periodically update the program with newly identified activities; (see section #9 and annual agenda review)
- Collect feedback from internal and external sources; (see table #10-1)

CVGS will use the public awareness agenda and form #3.03-1 PA implementation checklists as an aid in reviewing and implementing its public awareness program. This form was developed from API #1162 Annex A. [Procedure #3.03: Record #15 & 16]

Table 9-1 —Schedule for Conducting Program Activities

	Stakeholder Audience:	**Delivery Frequency:**	**Deliver Method or Required Documentation:**	**Comments:**
1.	Affected public mailers	1x/2yrs (PM# DOT-123)	Paradigm brochure mailer	
2.	Emergency officials mailers	1x/yr (PM# DOT-119)	Pipeline Association for Public Awareness magazine mailer	
3.	Public officials mailers	1x/yr (PM# DOT-121)	Pipeline Association for Public Awareness newsletter mailer	This is enhanced frequency. Normal frequency is 1x/3yrs
4.	Excavators mailers	1x/1yr (PM# DOT-120)	Pipeline Association for Public Awareness magazine mailer	
5.	One Call Center mailers	1x/yr (PM# DOT-122)	Pipeline Association for Public Awareness magazine mailer	
6.	Affected public survey of	1x/yr (PM# DOT-125)	Paradigm survey cards and summary report	

	effectiveness			
7.	Implement program enhancements	As recommended by annual reviews	As recommended by annual reviews	
8.	Pre-test effectiveness of materials	Initially, when changes made	Paradigm or PAPA surveys	
9.	Annual Self-Assessment of PA Program	1x/yr (PM# DOT-124)	PA agenda and PA implementation form #3.03-1	
10.	Complete program review	1x/4yr (PM# DOT-145)	PA agenda and program review form #3.03-2	

9.2 Program Enhancements

To determine if some additional level of public awareness communication is warranted beyond the baseline program, shall conduct an annual review using the program enhancement review check list with factors listed below and the PHMSA public awareness protocols. Results of the annual program review for enhancements shall be part of the public awareness team charter documentation. See section #5 for details. Factors CVGS will use for review of annual enhancements are as follows:

- Agricultural activity including additional reach out to farmers rather than grouping them with other affected public ;
- Third-party damage incidents (e.g. CVGS data show damages or near misses have increased);
- Public inquiries or concerns tracked
- Land development activity and encroachment (e.g. developers perform frequent excavations near pipeline);
- New developments constructed right after mailings sent to affected public
- Increased frequency to apt complexes, or other areas with there is high turnover
- Change in product or increase in pressure that would increase the coverage area
- Potential hazards (e.g. increased risk due to characteristics of product transported);
- High consequence areas (HCAs) (e.g. potential impact is greater for a specific area);
- Population density (e.g. pipeline traverses densely populated urban area);

- Environmental considerations (e.g. pipeline route traverses environmentally sensitive area);
- Pipeline history in an area (e.g. frequent number of incidents in a particular area);
- Specific local situations (e.g. heightened public concern about pipeline safety);
- Increased coverage areas for large high pressure pipelines where the calculated potential impact radius (PIR) is greater than 660 feet;
- Increased frequencies or other enhancements to pipelines with alternative SMYS or special permits
- Regulatory actions (e.g. advisory bulletin, findings from inspection);
- Results from previous public awareness program evaluations (e.g. survey results indicate low stakeholder awareness);
- Results from annual agenda reviews

Program enhancements that shall be considered include:

- *Increased Frequency*—providing communications to specific stakeholder audiences on a more frequent basis (shorter intervals) than the baseline public awareness program provisions.
- *Additional Message Content*—providing re-phrased, different, or additional messages to specific stakeholder audiences beyond the baseline messages, and/or tailoring messages to address specific audience needs.
- *Alternative Delivery Method(s)*—using different delivery methods (e.g. neighborhood meetings, door hangers, personal contact, etc.) to reach the target stakeholder audience.
- *Increased Coverage Area*—broadening or widening the stakeholder audience coverage area (e.g. widening the buffer distance for reaching the stakeholder audience).

If a determination has been made that enhancements are warranted, CVGS shall implement an enhanced public awareness program and communicate to the appropriate personnel as described on the team charter. [Procedure #3.03: Record #17]

10.0 Evaluations

The purpose of the evaluation of the public awareness program is to:

1. Assess whether the current program is effective in achieving the objectives for CVGS's public awareness programs as defined in 1.1 of these procedures,
2. Provide CVGS with information to determine whether program changes may be warranted.

CVGS program evaluation shall include the following elements:

- Pre-test effectiveness of materials, [Procedure #3.03: Record #18]
- Assess program implementation, [Procedure #3.03: Record #19]
- Measure program effectiveness. [Procedure #3.03: Record #20]

Based on the results of the evaluation, CVGS may determine that changes to the program are warranted to meet awareness objectives, including program implementation or elements, such as stakeholder identification, messages, delivery methods, or delivery frequencies. After completing the evaluation process, CVGS shall document whether changes are needed or not.

Table 10-1 list methods and options available that CVGS will use for baseline or enhanced program based on API #1162. Table 10-2 below describes current methods and frequencies CVGS is using to evaluate the public awareness program.

Table 10-1—Program Evaluation Frequency and Method Options [API #1162]

Method:	Technique:	Frequency:
Pre-test effectiveness of materials	Focus groups (in-house or external participants)	Upon initial design or major redesign of public awareness materials
Assess program implementation	Internal self-assessment, third-party assessment, or regulatory inspection	Annually
Measure program	1) *Survey*—Assess outreach efforts, audience	Every four

effectiveness: • Outreach, • Message compre-hension, • Results.	knowledge, and any anecdotal changes in behavior if available: • CVGS designed and conducted survey; • Use of pre-designed survey by third party or • Industry association; or • Trade association conducted survey segmented by operator, state, or other relevant separation to allow application of results to each operator. 2) Assess notifications and incidents to determine any anecdotal changes in behavior if available. 3) Documented records of incidents to evaluate bottom-line results.	years

Table 10-2—Program Evaluation Method Currently Used by CVGS

Method:	Stakeholder Audience:	Technique:	Frequency:
Pre-test effectiveness of materials	Affected Public	External focus group through Paradigm	Initially and redesign of PA materials
	Emergency Officials	External focus group through PAPA	
	Public Officials	External focus group through PAPA	
	Excavators	External focus group through PAPA	
Assess program implementation	Affected Public	Internal self-assessment, third-party assessment, or regulatory inspection using PA form #3.03-1 and/or PHMSA PA protocols	Annually
	Emergency Officials	Internal self-assessment, third-party assessment, or regulatory inspection using PA form #3.03-1 and/or PHMSA PA protocols	
	Public Officials	Internal self-assessment, third-party assessment, or regulatory	

		inspection using PA form #3.03-1 and/or PHMSA PA protocols	
	Excavators	Internal self-assessment, third-party assessment, or regulatory inspection using PA form #3.03-1 and/or PHMSA PA protocols	
Measure program effectiveness	Affected Public	Survey through Paradigm and company review using PA form #3.03-2	Every 4 years
	Emergency Officials	Survey through PAPA and company review using PA form #3.03-2	
	Public Officials	Survey through PAPA and company review using PA form #3.03-2	
	Excavators	Survey through PAPA and company review using PA form #3.03-2	

10.1 Pre-test Effectiveness of Materials

A focus group is a group of people gathered to provide feedback about the materials or other aspects of a public awareness program. Upon initial design or major redesign of materials, CVGS shall pre-test materials in a focus group before they are distributed.

Typically, a focus group has about 6 to 12 participants. While focus groups may be professionally facilitated, feedback about public awareness materials may be gained by an informal discussion run by individuals connected with the public awareness program. Often participants will be asked to review draft materials and comment on message clarity and what appealed or did not appeal to them. Focus groups may also be used to provide input on the relative effectiveness of various means of delivery.

Focus group participants may be CVGS employees who are not familiar with the public awareness program, citizens living along a pipeline, representatives of homeowner associations, or business people along the pipeline.

Target stakeholder audiences generally are not mixed. The participants usually are not chosen at random but rather are selected to be reasonably representative of the stakeholder group and capable of articulating their reactions to the materials.

CVGS is currently using the pre-test effectiveness of material method as shown in table 10-2 above.

10.2 Assess Program Implementation

CVGS shall complete an annual assessment of the program to answer the following questions.

- Has the program been developed and written to address the objectives, elements, and baseline schedule as described in this RP?
- Has the written program been implemented as planned and documented appropriately?

CVGS is currently using method as shown in table 10-2 above for assessing program implementation.

10.3 Measure Program Effectiveness

Measurement of PA program effectiveness shall be conducted. Several different methodologies, either quantitative or qualitative, may be used. Options to measure attitudes and opinions may include the following:

- Surveys (mail, phone, Internet):
- Develop and conduct a survey using internal or external expertise, or participate in a joint survey,
- Focus groups (mail, phone, Internet);
- Data reports;
- Analyses of business reply cards.

Program effectiveness measurement is meant to validate CVGS's methodologies and the content of the materials used at least <u>every four years</u>. Upon initial measurement, improvements shall be incorporated into the program based on the results. Once validated in this initial manner, program effectiveness measurement shall be conducted at least once every four years. However, additional measurement may be appropriate to validate a program after major design changes.

NOTE For example, if CVGS began implementing its program on June 20, 2006, then program effectiveness measurement would be due by June 20, 2010. Subsequent measurement shall be conducted every four years. In this example, future measurement would be due by June 20, 2014. The following three measures describe what areas CVGS shall evaluate for effectiveness.

- *Measure 1*—Outreach
- *Measure 2*—Message comprehension
- *Measure 3*—Achieving results.

CVGS will collect anecdotal information that may provide insight into actual behavioral changes whenever the opportunity arises. CVGS would like to know that stakeholders are aware of what to do and that they have acted on that knowledge appropriately (performing the correct prevention and mitigation behaviors according to circumstances). However, information on actual behavior by the stakeholder is rarely available.

Anecdotal information regarding actual stakeholder behavior can be used along with other effectiveness measurement information. In some circumstances, it may be possible to ask the stakeholders what actions were taken in a given situation, e.g. such as during a post-incident inquiry of how individuals responded. In other situations, information such as notifications received by CVGS from the One Call Center (e.g. a noticeable increase following distribution of public awareness materials) may help demonstrate that stakeholders performed desired behaviors.

CVGS is currently using the method as shown in table 10-2 above for measuring program effectiveness.

10.3.1 Measure 1—Outreach

To help assess if public awareness messages are getting to the intended stakeholders and to evaluate the effectiveness of the delivery methods used, CVGS shall track the number of individuals or entities attempted to be reached within an intended stakeholder audience (e.g. affected public, excavators, public officials, and emergency officials) and estimate the percentage for each intended stakeholder audience actually reached within the targeted geographic area(s). CVGS will consider tracking the number of:

- Phone inquiries received by CVGS,
- Visits to the public awareness portions of CVGS's website,

- Response cards received by CVGS,
- Public officials or emergency officials who attend emergency response exercises (this is an indicator of interest and the opportunity to gain knowledge).

Currently, measure #1 is conducted by Paradigm and PAPA. CVGS reviews the data during annual reviews.

10.3.2 Measure 2—Message Comprehension and Behavior

To evaluate the effectiveness of the message content, CVGS shall measure the following:

1. The percentage of the intended stakeholders that understood the message,
2. The retention rate of the stakeholders and specific messages.

One possible method for assessing understandability is to survey the target stakeholder audience through personal, telephone or written surveys. Sample surveys are included in API #1162 Annex D. Factors to consider when designing surveys include the following.

- Sample size appropriate to draw general conclusions.
- Questions to gauge understandability of messages and knowledge of survey respondent. For example, one question could ask how a person might respond in a hypothetical situation, such as, “If you observed a suspected leak in a pipeline, what would you do?”
- Retention of messages.

Currently, measure #2 is conducted by Paradigm and PAPA. CVGS reviews the data during annual reviews.

10.3.3 Measure 3—Achieving Results

One measure of the “bottom-line results” is the change in the number and consequences of third-party incidents. As a baseline, CVGS will track the number of incidents and consequences caused by third-party excavators. If available, other data to be considered may include:

- Reported near misses
- Reported pipeline damage occurrences that did not result in a release, and
- Third-party excavation damage events that resulted in pipeline failures.

While third party excavation damage is a major cause of pipeline incidents, data regarding such incidents shall be evaluated over a relatively long period of time to determine any meaningful trends relative to CVGS's public awareness program. This is due to the low frequency of such incidents on a specific pipeline system. CVGS shall also look for other types of bottom-line measures.

Currently, measure #3 is conducted by CVGS in the integrity management program (IMP). CVGS reviews the data during annual reviews.

11.0 Source References

1. API RP #1162, Public Awareness Programs for Pipeline Operators, 2nd Edition, December 2010

2. 49 CFR 192.616 (public education)

3. 49 CFR 192.614(c)(2) (damage prevention)

   49 CFR 192.615(c) (emergency responder liaison activities)

4. OPS interpretation letter, February 4, 1993 (liaison face to face meeting)

5. December 17, 2002 Pipeline Safety Act

6. OPS Advisory Bulletin ADB-03-04, August 2003

7. PHMSA Advisory ADB 10-08, Nov 3, 2010

8. Pipeline Association for Public Awareness (PAPA), www.pipelineawareness.org

9. Common Ground Alliance (CGA), www.comongroundalliance.com

10. CGA, Damage Information Reporting Tool (DIRT) statistics/data

11. CGA, Best Practices, version 7.0, March 2010

Ref: 49 CFR 192.614	Updated: March 2012

12.0 Documentation

CVGS shall collect and retain documentation of the public awareness program. These records demonstrate that CVGS's program is in conformance with these procedures. Documentation allows the program administrator to review the public awareness program, to brief management, and to demonstrate compliance with regulatory requirements.

12.1 Written Program Documentation

The written program shall include the following:

- A statement of management commitment to achieving effective public/community awareness; [5.0 team charter]
- A description of the roles and responsibilities of personnel administering the program; [5.0 team charter]
- Identification of key personnel and their titles (including management responsible for program support through company policy, management participation, and allocation of resources and funding of the program); [5.0, team charter]
- Identification of the media and methods of communication to be used in the program; [8.0, Delivery Frequencies and Methods]
- Documentation of the frequency and the basis for selecting that frequency for communicating with each of the targeted audiences; [8.0, Delivery Frequencies and Methods]
- The process for identifying program enhancements beyond the baseline program, including the basis for implementing such enhancements; [9.0, Program Implementation and Enhancements]
- The program evaluation process, including the evaluation objectives, methodology to be used to perform the evaluation and analysis of the results, and criteria for program improvement based on the results of the evaluation. [10.0, Program Evaluation]

12.2 Other Documentation Records

Following are more examples of documentation records:

- Communication materials provided to each stakeholder audience (e.g. brochures, mailings, letters, etc.);

- Lists, records, or other documentation of stakeholder audiences with whom the CVGS has communicated (e.g. contact mailing rosters);
- Implementation dates;
- Postage receipts;
- Response cards;
- Audience contact documentation (e.g. sign-in sheets, invitation lists, etc.);
- Program evaluations, including current results, follow-up actions and expected results;
- Program enhancement(s).

12.3 Record Retention

The record retention period shall be a minimum of five (5) years, or as defined in CVGS's public awareness program section #12.5, whichever is longer. Record retention shall include:

- Lists, records, or other documentation of stakeholder audiences with whom CVGS has communicated;
- Copies of all materials provided to each stakeholder audience;
- All program evaluations, including current results and follow-up actions.

12.4 Implementation of the Public Awareness Program

CVGS will use the public awareness agenda for implementation of these procedure requirements. CVGS will conduct this PA agenda review a minimum of once per calendar year not to exceed 18 months.
As a minimum the following agenda items will be defined or included:

- Public awareness agenda objectives
- List of personnel that shall attend including name and job title
- Frequency of the public awareness review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms, documents, and procedures needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- Action item list as a result of the PA review

Ref: 49 CFR 192.614	Updated: March 2012

12.5 R&Rs and List of Required Ongoing Documentation for Public Awareness

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Consulted Person	Freq. & Deadline	Record Retention Period	Record Location
1.	5.0	Team Charter	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
2.	6.1	Affected public address generation method	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
3.	6.1	Affected public minimum coverage distance	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
4.	7.0	US Census data showing languages spoken within coverage area	PAT Leader	PAT team members	1x/2yr	5 yrs	company intranet
5.	7.0 8.1 8.2	Affected public specific message to stakeholders as shown in Paradigm documentation (includes documentation of delivery frequency and delivery method as described in section #8.1 and #8.2)	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
6.	7.0 8.1 8.2	Emergency officials specific message to stakeholders as shown in PAPA documentation (includes documentation of delivery frequency and delivery method as described in section #8.1 and #8.2)	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
7.	7.0 8.1 8.2	Public officials specific message to stakeholders as shown in PAPA documentation (includes documentation of delivery frequency and delivery method as described in section #8.1 and #8.2)	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet

Ref: 49 CFR 192.614	Updated: March 2012

12.5 List of Required Ongoing Documentation and R&Rs for Public Awareness (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Consulted Person	Freq. & Deadline	Record Retention Period	Record Location
8.	7.0 8.1 8.2	Excavators officials specific message to stakeholders as shown in PAPA documentation (includes documentation of delivery frequency and delivery method as described in section #8.1 and #8.2)	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
9.	7.7	Liaison with emergency officials	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
10.	7.8	Summary emergency response plan for local emergency responders	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
11.	7.9	Emergency drill or exercise with emergency officials	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
12.	7.13	National Pipeline Mapping System (NPMS) documentation	PAT Leader	PAT team members	1x/yr March 15th	5 yrs	company intranet
13.	7.15.2	Pipeline maps	PAT Leader	PAT team members	1x/yr1	5 yrs	company intranet
14.	8.2	Documentation of enhanced delivery methods when appropriate	PAT Leader	PAT team members	1x/yr1	5 yrs	company intranet
15.	9.1	Annual agenda for implementation and continuous improvement review	PAT Leader	PAT team members	1x/yr1	5 yrs	company intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

12.5 List of Required Ongoing Documentation and R&Rs for Public Awareness (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Consulted Person	Freq. & Deadline	Record Retention Period	Record Location
16.	9.1 10.0	PA implementation checklist form #3.03-1	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
17.	9.2	Documentation of program enhancements when recommended by annual reviews	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
18.	10.0	Pre-test effectiveness of materials	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
19.	10.0	Assess program implementation	PAT Leader	PAT team members	1x/yr[1]	5 yrs	company intranet
20.	10.0	Measure PA program effectiveness	PAT Leader	PAT team members	1x/yr **March 15th**	5 yrs	company intranet

Gas PAT Team Charter: Objectives and Team Organization
49 CFR 192.616 and API #1162

TEAM:	Public awareness team (PAT)
PURPOSE:	The purpose of this team charter and the public awareness regulations is to ensure CVGS's public awareness program provides safety information to stakeholders to help keep communities near pipelines safe.
OBJECTIVE:	The team's objective is to provide an effective and consistent development, implementation, and continuous improvement of the CVGS public awareness program. This supports the company goals to eliminate pipeline incidents which pose significant risk to the public, employees and the environment. The PA team will also provide guidance for anybody conducting operational activities that relate to public awareness.
PAT TEAM MANAGEMENT SUPPORT:	Robert Cornell Director, Storage & Peaking Ops – West Region
PAT TEAM LEADER:	CVGS – Compliance Manager
OTHER PAT TEAM MEMBERS ACTIVELY INVOLVED:	Tim Hermann VP Storage & Peaking Operations
Consultants may be used as needed.	Richard Tucker DBTS – Pipeline Maintenance & Repair (Sub-Contractor to CVGS) Andy Bradfield CS Inc – DOT Pipeline Consultant

Key Activities for PAT

PAT TEAM KEY ACTIVITIES & MILESTONES:	• Validate team charter, approach, and time commitment. • Review roles and responsibilities of all team members. • Conduct annual reviews of public awareness issues using PAT agenda. • Review and update PA procedures and actions and strive for continuous improvement. Use industry standards, agency audits, self-audit, PA conferences, and industry best-practices for ideas and input into continuous improvement process. • Provide guidance for anybody conducting operational activities that could affect the safety of the pipeline. • Provide guidance to management to assist in identifying, assessing, and mitigating pipeline risks that relate to PA.
DELIVERABLES	• Implementation of a public awareness program, including; • Annual reviews by PAT • Compliance with all pipeline regulatory requirements. • Tracking of PA action items and status • Continuous improvement process for the company's PA program. • ***Deliverables to company management:*** 1) Team Charter 2) Action item list and recommendations for improvements based on annual agenda reviews 3) PA measures 4) Additional documentation requested by company mgmt
BENEFITS & MEASURES	• Compliance with public awareness regulations • Reduction or elimination of public awareness incidents • Resources are used for maximum mitigation of risk

PAT Team Management Sponsor and Approval

MANAGEMENT SIGNATURE and AUTHORITY	I, Robert Cornell, Director, Storage & Peaking Operations – West Region authorize the members of this CVGS public awareness team to conduct and complete necessary PA program requirements as outlined in this charter and outlined in the required documentation at the end of the public awareness procedures and public awareness annual agenda. ______________________________________ Robert Cornell, Director, Storage & Peaking Operations – West Region __________ Date

CVGS
Public Awareness Program
Public Awareness Team (PAT) - Agenda & Action Items

Ref: 49 CFR 192.616 & API #1162	**Updated: March 2012**

Objectives for Public Awareness Team (PAT):

- Provide an effective and consistent development and implementation of the PA program including guidance for anybody conducting operational activities that relate to public awareness.
- Provide for annual reviews and continuous improvement of the PA program
- Verify support of the company goals to eliminate pipeline incidents which pose significant risk to the public, employees and the environment due to public awareness issues
- Verify all new pipelines and changes to pipeline operations have been evaluated for public awareness
- Verify all new pipelines or pipeline segments have been properly documented with MOC and communicated to the appropriate personnel
- Verify all required processes for public awareness have been properly documented as required by O&M public awareness procedure #3.03.

Who Should Attend PAT Annual Reviews:

- PAT Leader (Manager, CVGS) [mandatory attendance]
- Operations & Maintenance Staff (CVGS employees) [mandatory attendance]
- Pipeline Consultant (Andy Bradfield, CS Inc) [optional attendance]
- VP Storage & Peaking Operations [optional attendance]
- Director, Storage & Peaking Ops – West Region [optional attendance]

Frequency of PAT Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 15 months

CVGS
Public Awareness Program
Public Awareness Team (PAT) - Agenda & Action Items

Ref: 49 CFR 192.616 & API #1162	**Updated: March 2012**

<u>How This Activity is to be Completed:</u>

- With the appropriate personnel in attendance as shown on this agenda, the PAT Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The PAT Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The PAT Leader shall lead the meeting using the public awareness annual review checklist (form #3.03-1) and make comments for each checklist item. If an item does not apply the PAT Leader shall note with a "NA/not applicable" and state the reason it does not apply.
- The PAT Leader shall collect appropriate records and file as shown in public awareness procedure #.303, section #12.5.
- The PAT Leader shall summarize the meeting notes and actions.
- The PAT Leader shall ask for input and feedback on how to improve the public awareness program and document any feedback comments received.
- If required, the PAT Leader shall communicate the changes and new information, if any, to the appropriate management and personnel not in attendance at the meeting. MOC process shall be used for any major changes (as defined in the MOC procedures) and include the "reasons" for any change.
- Complete annual review using form #3.03-1.

To determine if some additional level of public awareness communication is warranted beyond the baseline program, shall conduct an <u>annual review</u> using the program enhancement review check list with factors listed below and the PHMSA public awareness protocols. Results of the annual program review for enhancements shall be part of the public awareness team charter documentation.

CVGS
Public Awareness Program
Public Awareness Team (PAT) - Agenda & Action Items

Ref: 49 CFR 192.616 & API #1162	**Updated: March 2012**

Regulations, Resources, and Procedures Needed to Review the Public Awareness Program:

- Gas pipeline O&M procedure #3.03
- 49 CFR 192.616, 192.615(c), 192.614
- PHMSA Recent Public Awareness Inspection Q&As, April 2011
- PHMSA PAP Effectiveness Protocol Form, March 2011
- APE #1162, Public Awareness Program for Pipeline Operators, 2nd Edition, December 2010

Forms and Documents Required For This Review:

- Public awareness procedure form #3.03-1
- Public awareness procedure form #3.03-2
- PHMSA public awareness protocols

Record Keeping for Annual Public Awareness Program Review:

- Maintain all records and forms required to complete this meeting for the five years.
- Records will be maintained in the compliance tracking online management system located at www.complianceservicesinc.net

CVGS
Public Awareness Program
Public Awareness Team (PAT) - Agenda & Action Items

Ref: 49 CFR 192.616 & API #1162 **Updated: March 2012**

PUBLIC AWARENESS ANNUAL REVIEW ATTENDANCE LIST

Meeting Date:

Meeting Location:

	Print Name	Signature	Job Title
1			PAT Leader
2			Pipeline Oper/Maint.
3			Pipeline Consultant
4			VP Storage & Peaking Operations
5			Director, Storage & Peaking Ops - West Region
6			
7			

Ref: 49 CFR 192.616 & API #1162 **Updated: March 2012**

Public Awareness – Meeting Notes, Action Items, and Process Improvement Ideas

#	Description of Meeting Notes, Actions Items, and Process Improvement Ideas:	Status:	Who has Primary Respon.	Date Identified	Date Completed
1.					
2.					
3.					
4.					
5.					

PUBLIC AWARENESS PROGRAM EFFECTIVE INSPECTION SPECIFIC INFORMATION

Control Information: (copy and fill-in for each Operator)

Inspection Date(s):		**through**	
Operator ID:			
OpID:		**Name of Operator:**	
State/Other ID:			
Unit ID No.			
Activity Record ID No.			
CompanyAddress:		**Company Official:**	
		Title:	
		Phone Number:	
		Fax Number:	
Web Site:		**Email Address:**	
Total Mileage Represented:			
Mileage in HCA:			

Inspection Date(s):		**through**	
Operator ID:			
OpID:		**Name of Operator:**	
State/Other ID:			
Unit ID No.			
Activity Record ID No.			
CompanyAddress:		**Company Official:**	
		Title:	
		Phone Number:	
		Fax Number:	
Web Site:		**Email Address:**	
Total Mileage Represented:			
Mileage in HCA:			

OpID	Persons Interviewed	Title/Organization	Phone Number	Email Address

To add rows, press TAB with cursor in last cell.

OpID	Third Party Company PAP/Evaluation Support	Part of Plan and/or Evaluation	Phone Number	Email Address

To add rows, press TAB with cursor in last cell.

PHMSA/State Representatives	Region/State	Email Address

To add rows, press TAB with cursor in last cell.

Remarks:

Mileage Covered by Public Awareness Program (by Company and State)

List each company and subsidiary separately, broken down by state (using 2-letter designation). If a company has intrastate and/or interstate mileage in several states, use one row per state. If there are both gas and liquid lines, use the appropriate table for intrastate and/or interstate.

Jurisdictional to Part 192 (Gas) Mileage (Interstate)

Company (Gas Operator)	*Operator ID*	*State*	*Interstate Gathering*	*Interstate Transmission*	*Interstate Distribution**	*Remarks*
Use list from Section 1						

(To add rows, press TAB with cursor in last cell.)

Jurisdictional to Part 192 (Gas) Mileage (Intrastate)

Company (Gas Operator)	*Operator ID*	*State*	*Intrastate Gathering*	*Intrastate Transmission*	*Intrastate Distribution**	*Remarks*
Use list from Section 1						

(To add rows, press TAB with cursor in last cell.)

Jurisdictional to Part 195 (Hazardous Liquid) Mileage (Interstate)

Company (Liquid Operator)	*Operator ID*	*State*	Interstate Transmission	Remarks
Use list from Section 1				

(To add rows, press TAB with cursor in last cell.)

Jurisdictional to Part 195 (Hazardous Liquid) Mileage (Intrastate)

Company (Liquid Operator)	*Operator ID*	*State*	Intrastate Transmission	Remarks
Use list from Section 1				

(To add rows, press TAB with cursor in last cell.)

1. Supply company name and Operator ID, if not the master operator from the first page (i.e., for subsidiary companies).
2. Use OPS-assigned Operator ID. Where not applicable, leave blank or enter N/A
3. Use only 2-letter state codes in column #3, e.g., TX for Texas.
4. Enter number of applicable miles in all other columns. (Only positive values. No need to enter 0 or n/a.)
5. * Please do not include Service Line footage. This should only be MAINS.

1. Administration and Development of Public Awareness Program

1.01 Written Public Education Program

Does the operator have a written continuing public education program in accordance with the general program recommendations in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference), that was developed no later than June 20, 2006 for operators in existence on June 20, 2005, except for master meter or petroleum gas system operators covered under § 194.616(j). Master meter or petroleum gas system operators covered under § 194.616 (j) should have developed a written procedure by June 13, 2008? **(Code Reference: § 192.616 (h); § 195.440 (h))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.02 Program Objectives

Does the operator's program address the objectives of increasing the awareness of the public and key stakeholders of the presence and location of pipelines in their communities and informing the public of appropriate steps to prevent, identify, and respond to pipeline emergencies? **(Code Reference: § 192.616 (a); § 195.440 (a))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.03 Management Commitment and Support

Does the operator's program include a "statement of support"? (i.e., is there evidence of a commitment of participation, resources, and allocation of funding)? **(Code Reference: § 192.616 (a); § 195.440 (a))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.04 Unique Attributes and Characteristics of the Pipeline and Facilities

Does the operator's program clearly define the specific pipeline assets or systems covered in the program and assess the unique attributes and characteristics of the pipeline and facilities? **(Code Reference: § 192.616 (b); § 195.440 (b))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.05 Stakeholder Audiences

Does the operator's program establish methods to identify the individual stakeholders in the four affected stakeholder audience groups: (1) affected public (2) emergency officials (3) local public officials, and (4) excavators, as well as affected municipalities, school districts, businesses, and residents? **(Code Reference: § 192.616 (d), (e); § 195.440 (d), (e))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.06 Message Frequency and Message Delivery

Does the operator's program and media used define the combination of messages, delivery methods, and delivery frequencies to comprehensively reach all areas in which the operator transports gas, hazardous liquid, or carbon dioxide? **(Code Reference: § 192.616 (f); § 195.440 (f))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.07 Pre-Test Materials

Does the operator pre-test program materials and messages for stakeholder appeal and clarity, understandability, and retainability? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

1.08 Written Evaluation Plan

Does the operator's program include a written evaluation plan that specifies how the operator will periodically evaluate program implementation and effectiveness? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2. Program Implementation

2.01 English and other Languages

Has the operator developed and does the operator deliver materials and messages in English and in other languages commonly understood by a significant number and concentration of non-English speaking populations in the operator's areas? **(Code Reference: § 192.616 (g); § 195.440 (g))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2.02 Message Type and Content

Did the messages the operator delivered target the four primary stakeholder audiences to specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

- Use of a one-call notification system prior to excavation and other damage prevention activities;
- Possible hazards associated with unintended releases from a gas pipeline facility;
- Physical indications of a possible release;
- Steps to be taken for public safety in the event of a gas pipeline release; and
- Procedures to report such an event (to the operator)?

(Code Reference: § 192.616 (d); § 195.440 (d))

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2.03 Message Type and Content

Did the operator develop and deliver messages to advise affected municipalities, school districts, businesses, and residents of pipeline facility location? **(Code Reference: § 192.616 (e); § 195.440 (e))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2.04 Baseline Message Delivery Frequency

Has the operator implemented its program such that the delivery frequencies for materials and messages meet or exceed the baseline frequencies specified in API RP 1162, Table 2-1 through Table 2.3? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2.05 Considerations for Supplemental Program Enhancements

Did the operator consider relevant factors along all of its pipeline systems for supplemental program enhancements as described in API RP 1162 in its development and delivery of materials and messages to the stakeholder audiences? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

2.06 Maintaining Liaison with Emergency Response Officials

Did the operator establish and maintain liaison with appropriate fire, police, and other public officials to: learn the responsibility and resources of each government organization that may respond, acquaint the officials with the operator's ability in responding to a pipeline emergency, identify the types of pipeline emergencies of which the operator notifies the officials, and plan how the operator and other officials can engage in mutual assistance to minimize hazards to life or property? **(Code Reference: § 192.616 (c) or § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

3. Program Evaluation & Continuous Improvement (Annual Implementation Audits)

3.01 Measuring Program Implementation

Has the operator performed annual audits of its program implementation since it was developed? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c), (i); § 195.440 (c), (i))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

3.02 Acceptable Methods for Program Implementation Audits

Did the operator use one or more of the three acceptable methods (i.e., internal assessment, 3rd-party contractor review, or regulatory inspections) to complete the annual audits of its program implementation? If not, did the operator provide valid justification for not using one of these methods? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

3.03 Program Changes and Improvements

Did the operator make changes to improve the program and/or implementation process based on evaluating annual audit results? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4. Program Evaluation & Continuous Improvement (Effectiveness Evaluations)

4.01 Evaluating Program Effectiveness

Did the operator perform an evaluation of its program by June 2010 (or no more than 4 years following the date of program development) to assess its program effectiveness in all areas along all systems covered by its program? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.02 Multiple Program Effectiveness Evaluations

For operators implementing multiple public awareness programs for different systems and/or operating entities, did the operator conduct a program effectiveness evaluation for each program? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c) § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.03 Measure Program Outreach

In evaluating its program effectiveness, did the operator measure actual program outreach for each stakeholder audience within all areas along all systems covered by its program? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.04 Measure Percentage Stakeholders Reached

Can the operator demonstrate the methodology used to track the number of individuals or entities reached within an intended audience and its methodology to estimate the percentage of the individual stakeholders actually reached within the target audience within all areas along all systems covered by its program? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616) (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.05 Measure Understandability of Message Content

In evaluating its program effectiveness, did the operator assess the percentage of the intended stakeholder audiences that understood and retained the key information in the messages received, within all areas along all systems covered by its program? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.06 Measure Desired Stakeholder Behavior

In evaluating its program effectiveness, did the operator attempt to determine whether appropriate preventive behaviors have been learned and are taking place when needed, and whether appropriate response and mitigative behaviors would occur and/or have occurred? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.07 Measure Bottom-Line Results

In evaluating its program effectiveness, did the operator attempt to measure bottom-line results of its program by tracking third-party incidents and consequences including: (1) near misses, (2) excavation damages resulting in pipeline failures, (3) excavation damages that do not result in pipeline failures? Did the operator consider other bottom-line measures, such as the affected public's perception of the safety of the operator's pipelines? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c); § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

4.08 Documenting Changes (Effectiveness Evaluation)

Did the operator identify and document needed changes or modifications to its public awareness program(s) based on the results of its program effectiveness evaluation? If not, did the operator provide justification in its program or procedural manual? **(Code Reference: § 192.616 (c), § 195.440 (c))**

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

5. Program Documentation & Record Keeping

5.01 Documentation of Annual Audit Results

Did the operator document implementation changes to the PAP based on annual audit findings?

(Code Reference: § 192.616 (i), § 195.440 (i))

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

5.02 Documentation of Program Effectiveness Evaluation

Did the operator document the PAP effectiveness evaluation and results?

(Code Reference: § 192.616 (i); § 195.440 (i))

☐ S - Satisfactory	Comments:
☐ U - Unsatisfactory (explain)	
☐ N/A - Not Applicable (explain)	
☐ N/C – Not Checked	
Check exactly one box above.	

6. Inspection

6.01 Summary

6.02 Findings

TABLE OF CONTENTS

Damage Prevention Program Self Evaluation Objectives:

The damage prevention program including this evaluation process has the complete support of Company management. This damage prevention self evaluation is performed periodically to verify the following objectives are met:

- The written Damage Prevention Program reflects management support
- The damage prevention program reflects any major changes discovered during self assessments.
- All components of the public awareness program are carried out as described in the Company written program.
- A reduction in third party damage events (close calls, pipeline contact or failure).
- Verification that results of feedback and/or surveys will confirm that there is sufficient knowledge among those who live and work along the pipeline ROW.

How to Use This Self Assessment Form

Status: Each question should be reviewed and marked in the boxes on the right with a sat, unsat, or NA. It will be assumed that each question that is not marked was not reviewed.

Reference: The reference in the brackets refers to the applicable regulation, API RP #1162 reference, or Company program section numbers.

Comments: All questions with an unsat marked in the box also <u>require</u> comments to explain the finding. Other comments are encouraged if applicable, especially observations of best practices or outstanding performance by individuals or teams.

Audit Type: The audit type tells the evaluator how the question should be asked. For example, the audit question below requires the evaluator to conduct an interview with appropriate personnel to determine if they have been any changes and then review the records (ie., written program) to determine if the changes were completed in a timely manner. Note, the strike through on the "Field" audit type means a field review is not necessary for this audit questions.

Sample Audit Question:

		Sat	Unsat	NA
2.	Does the damage prevention program include any major changes in roles and responsibilities within 6 months of such change? [API #1162, section 8, RSPA Public Education Program Self Assessment Form, #5.5, Oct 2003] Comments:	❑	❑	❑

Audit Type:	❑ Record	❑ Field	❑ Interview

Roles and Responsibilities

The Pipeline Manager/Facility Manager will assign a lead evaluator and audit team as necessary to ensure the evaluations are conducted in a timely manner (see frequency of evaluations below). The Lead Evaluator shall review all evaluations and reports from team members and make the final decision on status. Immediate threats to life, property, or the environment shall be reported promptly if discovered by any team member.

Frequency of Evaluations

The following table provides the minimum frequency of evaluations.

Minimum Evaluation Components		
Purpose	**Techniques**	**Recommended Frequency**
Self Assessment	Internal review, Third Party assessment, or Agency Audit	Annual Interval- Evaluate those program development elements consistent with RP 1162 guidelines. Procedures 3.03 Public Education Program (General)
Pre-Test Effectiveness of Materials	Focus Groups, or Written feedback on drafts	Upon redesign of mass-mailed or distributed materials
Measuring Public Awareness Activities	Data tracking of at least two measures similar to those described above	Annual data capture and evaluated on 4 year interval to assess trend
Survey	▪ Operator designed and conducted survey, or ▪ Use of pre-designed survey by third party or industry association, or ▪ Industry-association conducted survey segmented by state	4 year interval, or as appropriate to assess effectiveness of specific program elements A time period for review no greater than 4 years will be undertaken to measure long term effectiveness/outcomes or impacts to validate or improve the RP 1162 program. 3.03 Public Education Program Section 10 defines Evaluation/Survey Objectives

Evaluation Date: ____________________

Evaluators:
(print)

Evaluation location,
segment, or system ____________

Lead: ______________________________

❑ ____________ ______________________________
❑ ____________ ______________________________
❑ ____________ ______________________________
❑ ____________ ______________________________
❑ ____________ ______________________________
❑ ____________ ______________________________

Number of Total Findings: ____________

____
Lead Evaluator Signature

____
Date:

Evaluation Summary Comments:

Program Development and Documentation

		Sat	Unsat	NA
I-1.	Does the Company have a written Public Awareness Program? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
I-2.	Have all of the elements described in section #2 of API #1162, been incorporated into the written program? [API #1162 appendix E]	❑	❑	❑

- ❑ 2.1 Objectives (public awareness, prevention and response)
- ❑ 2.2 Overview and target audiences (affected public, local public officials, emergency officials, excavators)
- ❑ 2.3 Regulatory compliance
- ❑ 2.4 Other resources
- ❑ 2.5 Management support
- ❑ 2.6 Baseline and supplemental programs
- ❑ 2.7 Program development guide (NA)
- ❑ 2.8 Summary of program requirements

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Program Development and Documentation (cont.)

		Sat	Unsat	NA
I-3.	Does the written PA program address all of the objectives of API #1162, section#2.1? [API #1162 appendix E]	❑	❑	❑

❑ 2.1 Objectives (public awareness, prevention and response)

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
I-4.	Does the documented program address regulatory requirements identified in section #2.2 and other regulatory requirements that the company must comply with? [API #1162 appendix E]	❑	❑	❑

❑ 2.2 Overview and target audiences (affected public, local public officials, emergency officials, excavators)

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Program Development and Documentation (cont.)

		Sat	Unsat	NA
I-5.	Does the company have a plan that includes a schedule for implementing the program? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
I-6.	Does the program include requirements for updating responsibilities as organizational changes are made? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Program Implementation

		Sat	Unsat	NA
II-1	Is the program updated and current with any significant organizational or major new pipeline systems changes that have been made? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
II-2	Are personnel assigned responsibilities in the written program aware of their responsibilities and have management support (budget and resources) for carrying out their responsibilities on the program? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Program Implementation (cont.)

		Sat	Unsat	NA
II-3	Has the program implementation been properly and adequately documented? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
II-4	Have all required elements of the program been implemented in accordance with the written plan and schedule? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Program Implementation (cont.)

		Sat	Unsat	NA
II-5	Does the company have documentation of the results of evaluating the program effectiveness? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

		Sat	Unsat	NA
II-6	Are the results of the evaluation of program effectiveness being used in a structured manner to improve the program or determine if supplemental actions (e.g., revised messages, additional delivery methods, increased frequency) in some locations? [API #1162 appendix E]	❑	❑	❑

Comments:

Audit Type:	❑ Record	❑ Field	❑ ~~Interview~~

Public Awareness Program Implementation

In This Appendix:

1.0 Target Audiences – Processes and Materials Currently in Use

1.1) Residents and Business along the Right-of-Way

The company will use direct mail distribution of brochure materials through Paradigm. A copy is in the company DOT files or can be viewed on Company local area network. Paradigm's public awareness website is located at: www.pdigm.com

1.2) Emergency Responders

The company will use direct mail distribution of brochure materials through the Pipeline Association for Public Awareness (PAPA). A copy is in the company DOT files or can be viewed at the PAPA website: www.pipelineawareness.org

1.3) Public Officials

The company will use direct mail distribution of brochure materials through the Pipeline Association for Public Awareness (PAPA). A copy is in the company DOT files or can be viewed at the PAPA website: www.pipelineawareness.org

1.4) Excavators

The company will use direct mail distribution of brochure materials through the Pipeline Association for Public Awareness (PAPA) in Kern and Ventura Counties, California. A copy is in the company DOT files or can be viewed at the PAPA website: www.pipelineawareness.org The company will use a group meeting format organized by The Pipeline Group to distribute and discuss Public Awareness materials in Orange County, California. Meeting content and attendance may be viewed on The company's local area network and in Company DOT files. The Pipeline Group's public awareness website is located at: www.pipelinegroup.com

2.0 High Consequence Areas – Consideration of Supplemental Elements

The company has considered supplemental elements for the high consequence areas and non will be conducted at this time.

3.0 Measuring Program Effectiveness

The company will capture data on four measures on an on-going basis. The company will evaluate these measures on a four year interval to assess trends. The measures to be reviewed are listed below:

Measure 1 – Outreach: Percentage of Each Intended Audience Reached with Desired Messages

1) Residents and Business along the Right-of-Way: %

   The company will use Paradigm to conduct this survey.

Supplemental Measure – Reply or Bounce-back Cards

   The company will use Paradigm to conduct this survey.

2) Emergency Responders: %

   The company will use PAPA to conduct this survey.

3) Public Officials: %

   The company will use PAPA to conduct this survey.

4) Excavators: %

   The company will use The Pipeline Group to conduct this survey in Orange County, California
   The company will use PAPA to conduct this survey in Kern and Ventura Counties, California

Measure 2 – Understandability of the Content of the Message

1) Residents and Business along the Right-of-Way: %

   The company will use Paradigm to conduct this survey.

2) Emergency Responders: %

   The company will use PAPA to conduct this survey.

3) Public Officials: %

   The company will use PAPA to conduct this survey.

4) Excavators: %

The company will use The Pipeline Group to conduct this survey in Orange County, California
The company will use PAPA to conduct this survey in Kern and Ventura Counties, California

Measure 3 – Desired Behaviors by the Intended Stakeholder Audience

1) Residents and Business along the Right-of-Way: %

   The company will use Paradigm to conduct this survey.

2) Emergency Responders: %

   The company will use PAPA to conduct this survey.

3) Public Officials: %

   The company will use PAPA to conduct this survey.

4) Excavators: %

   The company will use The Pipeline Group to conduct this survey in Orange County, California
   The company will use PAPA to conduct this survey in Kern and Ventura Counties, California

Measure 4 – Achieving Bottom-Line Results

1) Residents and Business along the Right-of-Way:

   The company will use Paradigm to conduct this survey and will include a revise the feedback card to include affected public's perception of the safety of pipelines in 2008.

2) Emergency Responders:

   The company will use PAPA to conduct this survey.

3) Public Officials:

   The company will use PAPA to conduct this survey.

4) Excavators:

   The company will use the Damage Information Reporting Tool (DIRT) through the Common Ground Alliance organization to track third party damage. The DIRT website is located at: www.cga-dirt.com

Program Evaluation

Self Assessment of Program Implementation

Annually, The company will conduct an internal review, use Third Party consultant, or use feedback from regulatory inspection to evaluate “Self Assessment of Implementation.” Appendix 3.03A will be used to conduct this review. A copy of the review will be placed into the company DOT files.

Standard Measure Trend Analysis

Every four years The company will conduct an internal review or utilize a Third Party consultant to conduct a standard measure trend analysis.

A copy is in the company DOT files.

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	Date Revised: Sept 2011

Reference Documents Needed:

1. API RP #1162, Public Awareness Programs for Pipeline Operators, 2nd Edition, December 2010
2. 49 CFR 192.616
3. Gas/Liquid O&M procedure, #3.03
4. Pipeline Association for Public Awareness (PAPA) Mailer Documentation
5. Paradigm Mailer Documentation
6. Company Mailer Documentation, if applicable

Action Required	Review the company public awareness program using the checklist provided in this form. Any items marked "unsat" require a comment or action item at the end of this form. This form was developed using API #1162 Annex E.
Frequency	No more than once per calendar year, not to exceed 18 months. The company will consider more frequent reviews as appropriate.

Public Awareness Program Review of Implementation:

1.

Date of Review:

2.

Names of Person(s) Conducting the Review:	

3.

Names of Pipeline System(s) Under Review:

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	Date Revised: Sept 2011

	Condition:			Define Objectives:
#	Sat	Unsat	NA	
1	☐	☐	☐	Awareness [#3.03, 1.1]
2	☐	☐	☐	Prevention [#3.03, 1.1]
3	☐	☐	☐	Response [#3.03, 1.1]
4	☐	☐	☐	Enhancements [#3.03, 1.1]

	Condition:			Obtain Management Commitment:
#	Sat	Unsat	NA	
5	☐	☐	☐	Obtain mgmt commitment [#3.03, 5.0]

	Condition:			Establish Program Administration:
#	Sat	Unsat	NA	
6	☐	☐	☐	Description of R&Rs [#3.03, 5.0, 12.4, &12.5]
7	☐	☐	☐	Identify key personnel and titles [#3.03, 5.0 &12.4]

	Condition:			Identify Pipeline Assets:
#	Sat	Unsat	NA	
8	☐	☐	☐	Identify pipeline assets [#3.03, 1.2]

	Condition:			Identify Stakeholder Audiences:
#	Sat	Unsat	NA	
9	☐	☐	☐	Affected public: residents located adjacent to ROW [#3.03, 6.0 & 6.1]
10	☐	☐	☐	Affected public: places of congregation [#3.03, 6.0 & 6.1]
11	☐	☐	☐	Emergency officials: Local, city, county, state or regional officials, agencies, and organizations with emergency response and/or public safety jurisdiction in the area of the pipeline [#3.03, 6.0 & 6.2]
12	☐	☐	☐	Public officials: Local, city, county, state or regional officials, agencies, and/or their staff having land use and road jurisdiction in the area of the pipeline [#3.03, 6.0 & 6.3]
13	☐	☐	☐	Excavators: Companies and local/state government agencies who are involved in any form of excavation activities and/or land development and planning [#3.03, 6.0 & 6.4]

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Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	Date Revised: Sept 2011

	Condition:			Determine Coverage Area:
#	Sat	Unsat	NA	
14	☐	☐	☐	Determine coverage area [#3.03, 6.1, 6.2, 6.3, & 6.4]

	Condition:			Determine Baseline Messages for Affected Public:
#	Sat	Unsat	NA	
14	☐	☐	☐	Damage prevention: suspicious activity [#3.03: 7.0, 7.2, table 7-1 &7-2]
15	☐	☐	☐	Damage prevention: suspected damage [#3.03: 7.0, 7.3, table 7-1 &7-2]
16	☐	☐	☐	Leak or damage recognition and response: suspicious activity [#3.03: 7.0, 7.2, table 7-1 &7-2, 7.12]
17	☐	☐	☐	One Call requirements [#3.03: 7.0, 7.1, 7.14]
18	☐	☐	☐	Pipeline location information: pipeline markers [7.15.1]
19	☐	☐	☐	Pipeline location information: pipeline mapping [7.15.2]
20	☐	☐	☐	Potential hazards [7.17]
21	☐	☐	☐	Right of way encroachment [7.17]

	Condition:			Determine Baseline Messages for Emergency Officials:
#	Sat	Unsat	NA	
22	☐	☐	☐	Emergency preparedness communications - Priority to protect life [7.3, 7.5, table 701]
23	☐	☐	☐	Emergency preparedness communications - Emergency contacts [7.6]
24	☐	☐	☐	Emergency preparedness communications - Liaison with emergency officials [7.7]
25	☐	☐	☐	Emergency preparedness communications - Emergency response plans [7.8]
26	☐	☐	☐	Emergency preparedness communications - Emergency drills and exercises [7.7]
27	☐	☐	☐	Leak/damage recognition and response [7.12]
28	☐	☐	☐	National Pipeline Mapping System [7.13]
29	☐	☐	☐	Pipeline location information – pipeline markers [7.15.1]
30	☐	☐	☐	Pipeline location information – pipeline mapping [7.15.2]
31	☐	☐	☐	Potential hazards [7.17]

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162 **Date Revised: Sept 2011**

	Condition:			Determine Baseline Messages for Public Officials:
#	Sat	Unsat	NA	
32	☐	☐	☐	Damage prevention - Suspicious activity [7.4, table 7-1]
33	☐	☐	☐	Damage prevention - Suspected damage [7.2]
34	☐	☐	☐	Leak/damage recognition and response [7.3]
35	☐	☐	☐	National Pipeline Mapping System [7.12]
36	☐	☐	☐	One Call requirements [7.14]
37	☐	☐	☐	Pipeline location information [7.15]
38	☐	☐	☐	Potential hazards [7.17]

	Condition:			Determine Baseline Messages for Excavators:
#	Sat	Unsat	NA	
39	☐	☐	☐	Damage prevention - Suspicious activity [7.2, table 7-1]
40	☐	☐	☐	Damage prevention - Suspected damage [7.3]
41	☐	☐	☐	Leak/damage recognition and response [7.12]
42	☐	☐	☐	One Call requirements [7.13]
43	☐	☐	☐	Pipeline location information [7.15]
44	☐	☐	☐	Potential hazards [7.17]

	Condition:			Determine Baseline Delivery Frequency:
#	Sat	Unsat	NA	
45	☐	☐	☐	Affected public: 1x/2 years [8.0]
46	☐	☐	☐	Emergency officials: 1x/year [8.0]
47	☐	☐	☐	Public officials: 1x/3 years [8.0]
48	☐	☐	☐	Excavators: 1x/year [8.0]

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162 **Date Revised: Sept 2011**

	Condition:			Determine Baseline Delivery Method:
#	Sat	Unsat	NA	
49	☐	☐	☐	Affected public: Electronic communication (videos/CDs or e-mail), or Mass media (PSAs, paid advertising), or personal contact(door-to-door, telephone, group meetings), or targeted distribution of print materials [8.0]
50	☐	☐	☐	Emergency officials: Electronic communication (videos/CDs or e-mail), or Personal contact (door-to-door, telephone, group meetings), or targeted distribution of print materials [8.0]
51	☐	☐	☐	Public officials: Electronic communication (videos/CDs or e-mail), or Personal contact (door-to-door, telephone, group meetings), or targeted distribution of print materials [8.0]
52	☐	☐	☐	Excavators: Electronic communication (videos/CDs or e-mail), or Mass media (PSAs, paid advertising), or personal contact (door-to-door, telephone, group meetings), or targeted distribution of print materials [8.0]

	Condition:			Implement the Program:
#	Sat	Unsat	NA	
53	☐	☐	☐	Develop a schedule for conducting the program activities [9.1, 12.5]
54	☐	☐	☐	Develop resource and monetary budgets [5.0, 9.1, 12.5]
55	☐	☐	☐	Identify, assign and task participating company employees needed to implement the program [5.0, 9.1, 12.5]
56	☐	☐	☐	Identify external resources or consultants needed [table #10-2]
57	☐	☐	☐	Conduct program activities [9.1, 12.5]
58	☐	☐	☐	Periodically update the program with newly identified activities [9.1, 12.5]
59	☐	☐	☐	Collect feedback from internal and external sources and document [9.1, 12.5]

	Condition:			Assess Need for Program Enhancements:
#	Sat	Unsat	NA	
60	☐	☐	☐	Establish a written process for considering relevant factors [9.2, form #10-1]

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	Date Revised: Sept 2011

	Condition:			Perform Program Evaluation:
#	Sat	Unsat	NA	
61	☐	☐	☐	Pre-test the effectiveness of materials upon initial design or major redesign [10.0, 10.1]
62	☐	☐	☐	Assess program implementation annually using internal self-assessment, third party assessment, or regulatory inspection [10.0, 10.2]
63	☐	☐	☐	Measure program effectiveness every four years – outreach [10.0, 10.3]
64	☐	☐	☐	Measure program effectiveness every four years – message comprehension [10.0, 10.3]
65	☐	☐	☐	Measure program effectiveness every four years – achieving results [10.0, 10.3]

	Condition:			Collect and Retain Documentation:
#	Sat	Unsat	NA	
66	☐	☐	☐	Communication materials provided to each stakeholder audience [12.1, 12.5]
67	☐	☐	☐	Lists, records or other documentation of stakeholder audiences with whom the operator has communicated [12.1, 12.5]
68	☐	☐	☐	Implementation dates [12.1, 12.5]
69	☐	☐	☐	Postage receipts [12.1, 12.5]
70	☐	☐	☐	Response cards [12.1, 12.5]
71	☐	☐	☐	Audience contact documentation [12.1, 12.5]
72	☐	☐	☐	Program evaluations, including current results, follow-up actions, and expected results [12.1, 12.5]
73	☐	☐	☐	Program enhancement [12.1, 12.5]

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	Date Revised: Sept 2011

	Condition:			PA Procedures Section #9.1, Program Enhancements Review:
#	Sat	Unsat	NA	
74	☐	☐	☐	Agricultural activity (e.g. pipeline route traverses active farming areas);
75	☐	☐	☐	Third-party damage incidents (e.g. SVP data show damages or near misses have increased);
76	☐	☐	☐	Public inquiries or concerns tracked
77	☐	☐	☐	Land development activity and encroachment (e.g. developers perform frequent excavations near pipeline);
78	☐	☐	☐	New developments constructed right after mailings sent to affected public
79	☐	☐	☐	Increased frequency to apt complexes, or other areas with there is high turnover
80	☐	☐	☐	Change in product or increase in pressure that would increase the coverage area
81	☐	☐	☐	Potential hazards (e.g. increased risk due to characteristics of product transported)
82	☐	☐	☐	High consequence areas (HCAs) (e.g. potential impact is greater for a specific area);
83	☐	☐	☐	Population density (e.g. pipeline traverses densely populated urban area);
84	☐	☐	☐	Environmental considerations (e.g. pipeline route traverses environmentally sensitive area);
85	☐	☐	☐	Pipeline history in an area (e.g. frequent number of incidents in a particular area);
86	☐	☐	☐	Specific local situations (e.g. heightened public concern about pipeline safety);
87	☐	☐	☐	Regulatory actions (e.g. advisory bulletin, findings from inspection);
88	☐	☐	☐	Results from previous public awareness program evaluations (e.g. survey results indicate low stakeholder awareness);
89	☐	☐	☐	Results from annual agenda reviews

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	**Date Revised: Sept 2011**

Section #9.1 program enhancements that shall be considered include:

- *Increased Frequency*—providing communications to specific stakeholder audiences on a more frequent basis (shorter intervals) than the baseline public awareness program provisions.
- *Additional Message Content*—providing re-phrased, different, or additional messages to specific stakeholder audiences beyond the baseline messages, and/or tailoring messages to address specific audience needs.
- *Alternative Delivery Method(s)*—using different delivery methods (e.g. neighborhood meetings, door hangers, personal contact, etc.) to reach the target stakeholder audience.
- *Increased Coverage Area*—broadening or widening the stakeholder audience coverage area (e.g. widening the buffer distance for reaching the stakeholder audience).

PUBLIC AWARNESS ANNUAL REVIEW OF IMPLEMENTATION and SUPPLEMENTAL EFFORTS
Form # PA 3.03-1

Reference: 49 CFR 192.616, API #1162	**Date Revised: Sept 2011**

PUBLIC AWARENESS PROGRAM EVALUATION COMMENTS & ACTION ITEMS:

Signature & Date:

Pipeline Mgr/Supervisor Signature

Date

Public Awareness Evaluation of Effectiveness

O&M Procedure 3.03 (Form #3.03-2)

Reference: 49 CFR 192.616	**Date Revised: Sept 2011**

Reference Documents Needed:

1. API RP #1162, Public Awareness Programs for Pipeline Operators, 1st Edition, December 2010
2. 49 CFR 192.616, 195.440
3. Gas/Liquid O&M procedure, #3.03
4. Pipeline Association for Public Awareness (PAPA) Survey Documents
5. Paradigm Survey Documents
6. Company Survey Documents, if applicable
7. Company annual reviews (form #3.03-1)

Public Awareness Target Audience Reviewed:

☐ Business & Residents Along ROW

☐ Excavators

☐ Public Officials

☐ Emergency Officials

Action Required	Review the company public awareness program for each target audience listed above. Evaluate each target audience for the following: • Level of knowledge • Changes in behavior • Bottom line results
Frequency	**No more than 4 years apart. The company will consider more frequent as needed for enhancement or upon major redesign of program.**

Public Awareness Evaluation of Effectiveness

O&M Procedure 3.03 (Form #3.03-2)

Reference: 49 CFR 192.616	**Date Revised: Sept 2011**

Public Awareness Program Effectiveness Review:

1.

Date of Review:

2.

Names of Person(s) Conducting the Review:

3.

Names of Pipeline System(s) Under Review:

Public Awareness Evaluation of Effectiveness

O&M Procedure 3.03 (Form #3.03-2)

Reference: 49 CFR 192.616	**Date Revised: Sept 2011**

PUBLIC AWARENESS PROGRAM EVALUATION COMMENTS
& RECOMMENDATIONS FOR ENHANCEMENTS:

Signature
& Date:

____
Pipeline Mgr/Supervisor Signature

____
Date

PREPARATION OF AN EMERGENCY RESPONSE PLAN

1. REFERENCE

49 CFR, Section 192.605(a) and 192.615.

2. PURPOSE

The purpose of this procedure is to establish the requirement for writing an Emergency Response Plan (ERP) to provide a pre-planned response and method of operation to minimize the hazards in the event of a pipeline facility failure or other emergency.

This procedure must not be considered a system specific ERP in any sense, but only a guideline for writing an ERP. The guidelines written within this procedure may not be inclusive.

The ERP manual should be consulted for definitive guideline and technical information for a given pipeline system or segment.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (105) ____________________ is responsible to train the operating personnel and to assure they are knowledgeable of the emergency procedures and verify that the training is effective.

4. GENERAL

4.1 An emergency is any situation involving Company pipeline facilities which may endanger human life or significant property, or which may affect normal service to customers (if any).

4.2 The intent of the planning, preparation and training required by this procedure is to assure:

4.2.1 Prompt receipt of calls and forwarding of emergency messages to designated personnel for evaluation, investigation, and reporting, at any given time.

4.2.2 Prompt and effective response to any possible emergency with actions taken to protect people first and then property.

4.2.3 Safe and rapid restoration of service to customers (if any).

4.3 An Emergency Response Plan (ERP) must be prepared and distributed prior to commencement of pipeline operations. The ERP and Pipeline Specific Operations Manual (PSOM) shall be kept at locations where operations activities are conducted.

5. PROCEDURE

5.1 The Emergency Response Plan (ERP) shall cover at least the following Items:

5.1.1 Receiving, identifying, and classifying emergency calls which require immediate response.

5.1.1.1 Emergency calls can come from the public, employees, contractors, and/or other sources. A call may be received by the company phone operator or employee, answering service (see Procedure 3.02 within this manual), or a combination of, and must be available 24 hours a day.

The answering service, or anyone other than a company employee, will obtain the caller's name and phone number which will be relayed to the designated "on-call" person. The "on-call" individual will then contact the caller obtaining the information listed below.

5.1.1.2 Critical information must be obtained from a caller and should include the following:

1) Caller's name, address, and phone number.
2) Location of incident, accident or emergency.
3) Type of emergency, i.e. escaping gas from leak or rupture, explosion, fire, other.
4) Known injuries/deaths, if any.
5) Any agencies called or on scene: police, sheriff, fire, etc.
6) Any other pertinent information that the caller volunteers or receiver requires.

Log the time and date of the call and to whom the emergency was reported to within the company.

5.1.1.3 The company's designated "on-call" individual will evaluate the severity of the emergency and determine the priority of action. If necessary, either personnel will be dispatched to the scene or the "on-call" individual will do an on-the-scene investigation. Top priority will be given to the emergency until the situation has been secured. It may be necessary for other individuals and/or agencies to be involved, if not already, such as the gas company, other pipeline and utility operators, emergency response people, etc. The decision(s) will be made by the company's designated individual(s).

5.1.2 Establishing and maintaining liaison with appropriate fire, police, sheriff, Coast Guard, and other public officials at the city, county, state & federal level, and notifying them of gas pipeline emergencies.

5.1.2.1 Establish and maintain adequate communication and coordinate with them on planned and actual responses.

5.1.2.2 Maintain a current listing of applicable phone numbers.

5.1.2.3 Learn the responsibilities and resources of each applicable organization.

5.1.2.4 Acquaint them with the Company's ability to respond to an emergency.

5.1.2.5 Identify the types of emergencies of which they will be notified.

5.1.2.6 Plan how they can assist the Company to minimize hazards to life or property.

5.1.3 Prompt and effective response to a notice of each type of emergency, including the following:

5.1.3.1 Gas detected inside or near a building.

5.1.3.2 Fire located near or directly involving a pipeline facility.

5.1.3.3 Explosion occurring near or directly involving a pipeline facility.

5.1.3.4 Natural Disaster.

5.1.3.5 Significant gas leaks, or ruptures on the pipeline system.

5.1.4 The availability of personnel, equipment, tools and materials, as needed at the scene of an emergency. This should include current list of available equipment and services of pipeline contractors located in the vicinity.

5.1.5 Actions directed towards protecting people and employees first and then property.

The first employee or individual that arrives on the scene must evaluate the situation/emergency and take every possible precaution with his limited resources and until assistance arrives, to protect the public and property.

5.1.5.1 The individual will make an initial survey and evaluation of the situation/emergency, noting location, extent of the hazardous area and if gas migration has occurred, secondary damage, involvement of others (if any), resources, whether the situation/emergency is due to company facilities or others, or if not, could company facilities become involved or aggravate the situation.

If a pipeline leak or rupture, is there a potential for an explosion and fire? Has it already occurred?

5.1.5.2 An effort must be made to evacuate all buildings and structures of people which are or could be in the danger zone. If others, or bystanders, are at the scene, try to enlist their services and encourage them to assist with the notification and evacuation.

When a fire department or applicable responding agency is on the scene, or is represented, they may become the lead agency in directing and securing the emergency. It then becomes the responsibility of the company employee(s) to coordinate and assist the lead agency or incident commander in any way possible and to the best of his/her ability.

If a company facility is involved, assistance could mean the closing of valves and stopping the gas source.

5.1.5.3 Upon arriving at the scene and a gas leak or pipeline rupture is discovered and an explosion and fire have not occurred, every effort will be made to extinguish all open fires and flames. Absolutely no smoking should be allowed. No arcing – sparking devices should be operated!

If vehicles are within the danger zone, they should be shutdown and abandoned. No vehicle should be started or restarted. The above should be done after people have been secured from the area. If a fire department is on the scene, they can wet down areas that could become problems and also assist in preventing accidental ignition.

5.1.5.4 When people and property have been rendered protected as much as possible, the individual will report to the designated individual/supervisor "on-call" with regard to the status of the situation. At that time, the individual should request further assistance if the situation warrants such.

Ensure that individuals are aware of how to communicate with the "on-call" supervisor or incident commander, if not on-site.

5.1.5.5 Monitor any change in the extent of the hazardous area. This should be done only when the emergency situation has been secured and reduced to the point where it is safe to enter the defined area.

5.1.6 Emergency shutdown and pressure reduction of the pipeline system or segment, <u>to minimize immediate hazards to people first and then property</u>.

Instructions and guidelines within the ERP should include but not be limited to the following:

5.1.6.1 List the incidents or situation under which shutdown or pressure reduction would be necessary. These could include manmade or natural disasters. Examples are: explosion, fire, pipeline leak or rupture, earthquake, etc.

5.1.6.2 Specific instructions should be written with regard to the

shutdown and pressure reduction procedure for each pipeline system and facility. Include drawings, maps and schematics. Include: provisions for notification and coordination of proper authorities; how to obtain emergency assistance from fire, police, sheriff, and medical; and notifying other utility and pipeline operators.

5.1.6.3 ERP must have maps and drawings showing DOT/OPS designated emergency valves (EV's), which would include manual block valves, automatic or remotely operated valves, and blowdown valves. Location of valves is extremely important.

These valves must be given a unique number for identification purposes. Number will be on the maps and drawings, as well as physically on the valve in the field.

P & ID and schematics of pipeline systems and facilities, should also be included and must indicate what section or segment of pipeline would be affected if a given valve is operated.

5.1.6.4 Once shutdown or pressure reduction has been achieved, confirm by monitoring pressure gauges for positive pressure and blowdown stacks for gas flow. Also check isolation valve position indicators. During shutdown, continue to monitor pressure and flow.

5.1.7 <u>During an emergency, make safe any actual or potential hazard to life or property</u>.

The ERP should include provisions for locating and making safe any actual or potential hazards:

5.1.7.1 Pedestrian and vehicular traffic in the area of the incident, situation, or emergency, must be controlled. This can be done by employees, police, sheriff, or other agencies. If control measures are not effective, serious injury or death could occur.

5.1.7.2 Potential ignition sources must be eliminated or minimized. Please refer to paragraph 5.1.5.3 above.

5.1.7.3 Leaking gas and its migration must be handled with extreme care regardless of the volume. Once found, whether by instrumentation or other, immediate action must be taken to alleviate the situation. Action could include a simple wrap around pipeline clamp to a complete pipeline shutdown. In any event, and especially in a populous area, the leak must be located, problem exposed, and pipeline repaired to prevent a potentially disastrous situation from occurring.

5.1.7.4 If leaking gas has migrated to a building or structure, or filled a valve vault, efforts must be made to ventilate the affected area. Extreme care must be taken in ventilating due to the possibility of the mixture entering the explosive range. If at all possible, shutdown the pipeline until the problem is rectified.

5.1.7.5 Venting the area of a leak can be accomplished by several means, which could include: barholing; installing vent holes with or without a blower; or pulling a manhole cover.

5.1.7.6 Determine the full extent of the hazardous area. Please see paragraph 5.1.5.1 above.

5.1.7.7 Monitor for a change in the defined and delineated hazardous area. Please see paragraph 5.1.5.5 above.

5.1.7.8 If the situation is such that agencies are involved, like fire, police, sheriff, and other public officials, all efforts will be made to coordinate and centralize control. Please see paragraph 5.1.5.2 above.

5.1.8 Safely restoring any service outage per applicable start-up procedures.

5.1.9 Begin investigation of failures as soon as possible, and record all initial investigative results (see procedure 1.03).

5.1.10 Include the name and telephone number of the following personnel or organizations:

5.1.10.1 Personnel at the operating location.

5.1.10.2 Personnel involved in investigation and reporting of emergencies, such as Code Compliance, Public Relations, Safety, etc.

5.1.10.3 Forestry Department

5.1.10.4 Electrical power companies in the area

5.1.10.5 Police and sheriff departments as well as locally based state police

5.1.10.6 Fire departments

5.1.10.7 Ambulance services

5.1.10.8 Hospitals

5.1.10.9 Civil Defense

5.1.10.10 Telephone Companies

5.1.10.11 All other appropriate companies and organizations which may furnish needed equipment.

5.2 Training

5.2.1 Train the appropriate personnel to assure that they are knowledgeable of the system specific Emergency Response Plan and related procedures.

Training will be accompanied through various means: simulated drills, classroom, hands-on, and others.

5.2.2 Verify that training is effective.

6. EMERGENCY PLANS REVIEW AND UPDATE

6.1 Immediately following an emergency, employee activities and the activities of others such as contractors, public officials, police, fire, etc., should be reviewed to determine whether the procedures were effectively followed. By reviewing logs and diaries of events and the action taken, and interviewing employees or others, effectiveness of the procedures can be determined. Consideration should be given especially to whether responses to the situation/incident/emergency were timely or not.

6.2 Review the ERP, Platform Operating Procedures (POP) if appropriate, and related procedures periodically with local operating personnel at least once a year, preferably at safety or other group meetings.

6.3 Revise, modify, and update the Emergency Response Plans (ERP and POP) as necessary, or as may be indicated by the experience of an emergency.

6.4 Provide the latest versions of the Emergency Plans to all facilities and so they are readily accessible to all employees, including responsible supervisory personnel.

7. RELATED PROCEDURES

1.01 Reporting and Control of Incidents
1.03 Investigation of Failures and Accidents
3.02 Telephone Answering Services
3.03 Public Education Program

System Specific Emergency Response Plan (ERP), and Platform Operating Procedures (POP).

8. RECORDS

8.1 Document dates, attendance and subject matter of training sessions and meetings.

8.2 Document contacts with public officials. Include dates, Company and public persons involved, subject matter and details of any agreements.

8.3 Document incoming calls to the Company operator or answering service.

8.4 Maintain the above records at least five years.

CROSSING OF COMPANY PIPELINES

1. REFERENCE

   49 CFR, Section 192.325.

2. PURPOSE

   The purpose of this procedure is to establish procedures to follow when new or relocated above grade or buried facilities, such as electric power, gas, oil, water, or communication cables are planned to cross Company pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (111) ____________________ is responsible to implement the requirements of this procedure when Company pipelines are crossed by Foreign Operators.

4. GENERAL

   4.1 Whenever possible and practical, parallel pipeline and utility encroachments and the installation of a physical structure, such as an anchor block, tower footing, or alternating current electrical ground system, associated with an overhead transmission facility, should be at least 25 feet (7.6 meters) from Company pipeline.

   4.2 For underground pipeline crossings, a minimum of 12” (30.5 cm) of separation must be maintained between a foreign facility and a Company pipeline unless the pipeline is specially protected from damage that might result from the proximity of the other facility.

   4.3 Communication cables installed by others should be protected from potential damage by Company maintenance activities. This protection should include burial of the cable below the pipeline and the encasement in a 6” (15 cm) diameter pipe, 15’ (4.6 meters) long, or the installation of a 4” (10 cm) thick x 4’ (1.2 meters) wide x 10’ (3.0 meters) long concrete pad over the cable.

   4.4 The cable crossing shall be clearly and permanently marked on each side of the right of way, if practical.

   4.6 It is preferred that all buried crossings be installed under an existing Company pipeline and cross at right angle. If the review of specific job conditions concludes that this requirement is unreasonable or impractical, allowing the crossing above the Company pipeline could be acceptable.

4.7 Foreign operators are responsible for costs of all mitigation equipment and its installation without regard to the facility being protected.

4.8 The leverage by which the Company can force a foreign operator to accept these requirements is dictated primarily by the ownership and/or right of way instrument governing the pipeline. These instruments may include:

4.8.1 Permit

4.8.2 Private Easement (not exclusive)

4.8.3 Exclusive Private Easement

4.8.4 Company Ownership

5. PROCEDURE

5.1 Request that any foreign operators wanting to encroach upon Company facilities supply a written request to do so and a drawing detailing the proposed installation.

5.2 Review the proposed encroachment for compliance with this procedure and work with the foreign operator to eliminate any conflicts.

5.3 Do not allow new electrical transmission line construction over existing blow off risers, and keep them as far as practical from the risers.

6. RELATED PROCEDURES

3.01 Damage Prevention Program
6.05 Cathodic Protection/External Corrosion Control
9.02 Blowdown and Purging Safety

7. RECORDS

7.1 Fill out the required information on the Pipeline Maintenance and Surveillance Form (Form 3.01B).

7.2 Keep copy of the reports for the life of the Company pipeline or the foreign facility, whichever is less.

7.3 Submit information detailing the crossing to (112) __________________ for strip map or plat sheet updating.

PREPARATION OF A PIPELINE
SPECIFIC OPERATIONS MANUAL

1. REFERENCE

49 CFR, Sections 192.605(a), (b), and (c).

2. PURPOSE

The purpose of this procedure is to establish the minimum requirements for writing a Pipeline Specific Operations Manual (PSOM) to provide operating and pre-planned response for normal and abnormal pipeline operating conditions.

This procedure #3.06 must not be considered a PSOM in any sense, but only a guideline for writing a PSOM. The guidelines written within this procedure may not be inclusive.

The PSOM should be consulted for definitive guidelines and technical information for a given pipeline system or segment. The Platform Operating Procedures (POP) manual should also be consulted for additional guidelines and information.

3. RESPONSIBILITY FOR ADMINISTRATION

The (118) ______________ is responsible for the preparation and updates to the PSOM for normal and abnormal conditions. The (119) ________________ is responsible for training operating personnel and to assure they are knowledgeable of the PSOM.

4. GENERAL

4.1 A written PSOM is required to describe the normal operating status of a specific pipeline system, and to provide safety during operations and maintenance.

4.2 A written PSOM is required to describe the abnormal operating status of the pipeline and to provide safety when operating design limits have been exceeded.

4.3 A written PSOM is required to describe the requirements for control room management procedures to increase the likelihood that the pipeline controllers have the necessary knowledge, skills, and abilities to help them prevent accidents. The regulation and these procedures will also help ensure that pipeline operating companies provided controllers with the necessary training, tools, procedures, management support, and environment where a controller's actions can be effective in helping assure a safe operation.

4.4 The intent of these plans is to provide a basis for documenting the physical attributes of a pipeline and to facilitate training of operating personnel for a specific pipeline.

4.5 General Operating and Maintenance Procedures are contained in the Standard Operating and Maintenance Procedures Manual for Gas Pipelines of which this procedure is a sub-part, and shall be used as a basis for preparing the PSOM. As a minimum, the topics contained in this Procedure, 3.06, shall be individually addressed in each PSOM.

4.5 The Emergency Response Plan (ERP) required by Procedure 3.04 of the Standard Operating and Maintenance Procedures Manual for Gas Pipelines, is a separate document.

4.6 A PSOM must be prepared and distributed prior to commencement of pipeline operations. The PSOM shall be kept at locations where operations and maintenance activities are conducted. This manual shall be review once per calendar year, not to exceed 15 months. Appropriate changes will be made as necessary to insure that the manual is effective.

5. PROCEDURE

5.1 A PSOM shall have at least two major divisions. One division shall contain information concerning the normal operation of the pipeline. The second division shall contain information relevant to abnormal conditions.

5.1.1 To provide safety during normal operations, the PSOM or POP manual, shall provide at a minimum, the following information:

5.1.1.1 Current and comprehensive construction records, maps, and operating history shall be available for use by operations, engineering, maintenance personnel, and especially individuals involved with safety and emergency response. These documents can be attached to or stored with the PSOM, but shall be available with facility documentation when appropriate, and upon request from the data library.

5.1.1.2 The normal ranges of operating parameters such as pressure, flow, relief pressure settings, alarm settings, and valve positions.

5.1.1.3 The locations of areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned, shall be included. Provisions for minimizing the potential hazards identified at these locations will also be provided.

5.1.1.4 Provide procedures for the start-up and shutdown of either an existing or new pipeline system, or segment, to assure that the operating parameters and MAOP of the pipeline are not exceeded.

5.1.1.4.1 Procedures should include, but not be limited to, the following for pipeline <u>startup</u>:

1) Insuring that all required manuals: O&M, ERP, PSOM, & POP (if required), are in place prior to startup or restart of a pipeline, especially a new pipeline

2) For a new pipeline, inspecting all relief devices such as relief valves, regulators, and rupture disks, and set pressures of relief devices must be checked and recorded as well as volume.

3) Determining the requirements for purging, if necessary. (See Procedure 9.03 within this manual for purging specifics).

4) Establishing communication with field personnel and gas control (facility) operators.

5) Conducting a follow-up leak survey, if applicable. (See Procedures 5.01,

5.02 and 5.03 within this manual for leak surveys).

6) Ensuring that drawings, maps, schematics, and P & ID's, and other operating parameters and records are updated.

7) Utilize manufacturer's instruction manuals and guidelines when appropriate.

5.1.1.4.2 Procedures should include, but not be limited to, the following for pipeline <u>shutdown</u>:

1) Planning, preparation and written procedures for a shutdown. The plan must provide for full control of the gas in the system or segment, and any related facilities, at all times during the operation (including the shutdown, down period, and startup).

2) General preshutdown activities which might include: briefings and work assignments, communication, pressure limits, serviceability of valves and other devices, precautions to minimize fire hazards, and doing as much work prior to shutdown as possible.

3) Gas control activity. The individual responsible for this function must ensure that all personnel involved are fully versed in their assignments. Caution must be used to prevent accidental gas ignition when blowing down, venting or purging. Gas pressures in the pipeline must be monitored continuously.

4) Must establish safe gas conditions at work-site(s). A procedure must be written to establish a safe working environment whether work is performed on the surface or in an excavation. Include a means of constant gas monitoring especially if a pipeline is open and residual gas could be present or released.

5.1.1.5 The PSOM shall address the physical properties of the gas, elevations along the pipeline, and location and type of pressure monitoring and control devices.

5.1.1.6 The PSOM shall require attended pressure monitoring during start-up and shutdown unless the pipeline system is designed to fail-safe.

5.1.1.7 Means of detecting abnormal conditions, and monitoring pressure, temperature, flow or the appropriate operational data and transmitting this data to an attended location unless the pipeline system is designed to fail safe.

5.1.1.8 Procedures for pipeline pigging, where applicable.

5.1.1.9 Procedures for blowdown of pipeline segments.

5.1.1.10 Procedures for draining of pipeline and components such as scrubbers and other vessels, of liquid. This applies only to regulated portions of the pipeline system.

5.1.1.11 Periodically a <u>review</u> will be made of personnel's performance to determine if the written procedures for normal operating and maintenance in the PSOM and O&M Manual are adequate and effective, or have deficiencies. <u>Discussions</u> with operating and maintenance personnel could also reveal weaknesses and strengths of the procedures. Any suggestions for changes should be taken under advisement.

Taking into consideration the review and recommendations, the procedures in the manuals should be either modified or rewritten accordingly.

5.1.1.12 Inadequacies and needed changes discovered during discussions and periodic review of personnel conducted according to 5.1.1.11 above, will be rectified during the annual review of the manuals, or as soon as possible if deemed necessary.

It will be necessary to retrain and acquaint personnel with any changes to the procedures. All training and procedure modifications must be documented. (See 7. Records below).

5.1.1.13 Procedures to ensure protection of personnel from unsafe accumulations of vapor or gas in excavated trenches. These procedures shall address making available emergency rescue equipment, including breathing apparatus, and a rescue harness. Procedures must be in accordance with Company Confined Space Entry Standards.

5.1.2 To provide safety during incidents where normal pipeline parameters have been exceeded. The abnormal conditions section of the PSOM shall provide at a minimum, the following information:

5.1.2.1 The abnormal operations section shall include sections addressing identification of, responding to, investigating, and rectifying the following situations:

- Unintended opening or closure of valves.
- Increase or decrease of flow rate outside of normal pipeline parameters.
- Increase or decrease of pressure outside of normal pipeline parameters.
- Loss of communications.

- Operation of any safety device.
- Any malfunction of a component or deviation from normal operating parameters or personnel error which could cause a hazard to persons or property.

In addition to considering the type of abnormal conditions listed above, the location where the condition may or could exist (i.e. the proximity to the public, employees, facilities, buildings, and structures) must be considered.

The nature of the condition (i.e. the extent to which it could lead to an emergency situation if not immediately corrected) is another item that must be addressed.

Finally, what the resulting effect would be on the operation of a pipeline system if one of the above listed conditions were to occur.

5.1.2.2 Once an abnormal operating condition has occurred and it has been investigated to determine the cause, and corrective action taken, the pipeline may be returned to service.

The abnormal condition occurrence shall be reviewed to develop measures, if necessary, to prevent the cause of the condition from recurring. If a corrective measure can be applied to the pipeline system or segment in question, it should be considered for implementation in other systems to avoid similar occurrences.

5.1.2.3 Once restarted, provisions for the inspection and monitoring of the pipeline operating conditions and parameters at critical locations along the pipeline, will be made to ensure continued integrity and safe operation.

Monitoring of the restarted pipeline system or segment, shall continue and be based on the nature of the abnormal condition, severity of the incident and/or emergency, and the probability that the cause of the condition could recur. The cause of the condition is considered corrected when at the end of the monitoring period, the pipeline system or segment has maintained operations within its design limits and parameters.

5.1.2.4 A list of responsible operating personnel to be notified in the event of an abnormal situation shall be included. The list shall include current telephone, radio, pager, or cellular telephone numbers as appropriate.

5.1.2.5 Abnormal conditions that result in emergencies shall be addressed in the system specific Emergency Plan prepared per Procedure 3.04.

5.1.2.6 An immediate review of personnel's response to control the abnormal condition, should be conducted based on the extent of the situation/incident/emergency. The review should consider the actions taken, and whether the procedures in the PSOM and/or POP are adequate and effective or have deficiencies that should be modified or rewritten accordingly. In rewriting the procedures, if necessary, specificity or more flexibility should be considered.

5.1.2.7 Inadequacies discovered in either personnel response or the written procedures shall be considered and rectified as follows:

1) Personal response – immediately following startup and stabilization or monitoring period of pipeline

2) Procedures – during the Annual review of the manuals, or as soon as possible, if deemed necessary.

Any changes to the procedures will necessitate the retraining of personnel. All training and procedure modifications must be documented (see 7. Records below).

5.1.3 A written PSOM is required to describe the requirements for control room management procedures to increase the likelihood that the pipeline controllers have the necessary knowledge, skills, and abilities to help them prevent accidents. The regulation and these procedures will also help ensure that pipeline operating companies provided controllers with the necessary training, tools, procedures, management support, and environment where a controller's actions can be effective in helping assure a safe operation.

The control room management section of the PSOM shall provide at a minimum, the following information:

5.1.3.1 Roles and Responsibilities: Items that shall be considered when developing the roles and responsibilities for the Control Room and Controllers include the following:

- Determining and defining clearly for the Controllers to know when responsibility and accountability passes from one Controller to another for any normal shift change or other change of duty from one Controller to another.
- Ensuring that Controllers understand their responsibilities and accountabilities.
- These responsibilities and level of authority should be clear for both the pipeline supervisor and Controller.

5.1.3.2 Tools and Information: The procedures shall describe the minimum tools and information the Controller should have to conduct their job safely.

5.1.3.3 Fatigue Management and Education: The procedures shall describe how to address in shift work to prevent fatigue and training on how to recognize signs of fatigue.

5.1.3.4 Alarm Management: The procedures shall include point to point verification under certain conditions, annual review of alarms, alarm activity review, and documentation of alarm deficiencies.

5.1.3.5 Mangement of Change: The procedure shall include MOC for significant changes as defined by the MOC process.

5.1.3.6 Operating Experience: The procedures shall include a review and implementation of lesson learned including review of incidents.

5.1.3.7 Training Program: The procedures shall include a training program for controllers and also a annual training program review.

6. RELATED PROCEDURES

1.01 Reporting and Control of Accidents
1.03 Investigation of Failures and Accidents
3.02 Telephone Answering Services
3.04 Preparation of an Emergency Response Plan

7. RECORDS

7.1 Document dates of personnel reviews of emergency, normal and abnormal operating plans and revisions required to the plans. The PSOM shall be reviewed at least once each calendar year at intervals not exceeding 15 months, with appropriate changes made as necessary.

7.2 Prepare and distribute a new or revised PSOM. Document issue dates.

7.3 Document dates of operating personnel training.

CLASS LOCATION SURVEY AND DETERMINATION

1. REFERENCE

49 CFR, Sections 192.5, 192.179, 192.605(e), 192.609, 192.611, and 192.613.

2. PURPOSE

To establish methods to be used in determining and updating class locations and their boundaries.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (125) _______________ is responsible for conducting field survey and reporting the class location changes.

4. DEFINITIONS

4.1 Class Location Unit is an area that extends 220 yards (200 meters) on either side of the center line of any continuous one (1) mile (1609 meters) or length of pipeline.

4.2 Class 1 is any class location unit that has ten (10) or less buildings intended for human occupancy.

4.3 Class 2 is any class location unit that has more than ten (10) but less then forty-six (46) buildings intended for human occupancy.

4.4 Class 3 is any class location unit that has forty-six (46) or more buildings intended for human occupancy; or a location where a High Occupancy Location (Definition 4.7) exists.

4.5 Class 4 is any class location unit where buildings with four or more stories above ground are prevalent.

4.5.1 A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

4.6 Cluster: is a group of buildings intended for human occupancy that are closely spaced and have a distinct increase in the density of buildings over the surrounding areas. Examples may include platted subdivisions, trailer parks, multiple dwelling unit buildings or a group of houses in otherwise open country.

4.6.1 When a cluster of buildings intended for human occupancy within a Class 2 or 3 location are in a single cluster, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

4.7 High Occupancy Location is an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12 month period. (The days and weeks need not be consecutive.)

5. GENERAL

5.1 Designated personnel will observe new construction along the pipelines during all routine operations including aerial surveys, patrolling, leak surveys and corrosion surveys.

5.2 If a pipeline segment has been determined to be Class 3, or if the segment has an operating pressure suitable for Class 3 operation, it is not required that individual buildings intended for human occupancy be counted for the entire segment provided that:

5.2.1 The segment is monitored and records are updated for possible changes to Class 4, and

5.2.2 All Operating Procedures Manual requirements for Class 3 are followed for the segment, and

5.2.3 The segment is monitored and reviewed for possible odorization (Procedure 11.01) requirements if the segment is not Class 3.

5.2.4 The parts of the segment that affect adjacent class 1 or class 2 areas, are monitored per 5.1 above, and the records updated.

6. PROCEDURE

6.1 Conduct class location surveys at least once per calendar year, with intervals not to exceed 15 months, or whenever an increase in population density indicates a change in class location for a pipeline segment. Monitor more frequently the pipelines where class changes are likely to occur.

6.2 Record new buildings and locations of places of gathering on Field Note sheets or alignment drawings.

6.3 Update records and document the survey on Form 4.01A.

6.4 Plot buildings and high occupancy locations on an alignment sheet or class location map and determine class location by following Class Location Determination. Notify the (126) ________________ if a class location change occurs or appears likely.

6.5 Refer questions on class interpretation and recommendations for facility modifications required by class changes to the (127) ___________________.

6.6 The (128) ________________ shall review any class change and determine if actions are required to maintain the existing maximum allowable operating pressure. The (129) ________________ shall initiate and follow-up on facility modifications or pressure reductions required by class changes. Modifications or pressure reduction will be completed within 24 months from the time the class location change occurred. If necessary, refer to Procedure 8, MAOP.

6.7 If a class location has changed, it will be necessary to check the sectionalizing block valve(s) spacing to determine if the existing spacing is adequate and conforms to the code. If not, additional valving may be required.

An appeal, or request for waiver can be made to the DOT/OPS Associate Administrator in Washington, D.C. if an equivalent level of safety exists without additional valving.

7. CLASS LOCATION DETERMINATION

7.1 Process

7.1.1 Establish Class 1, Class 2, and Class 3 locations by considering the number of buildings intended for human occupancy located within the class location unit.

7.1.2 Establish Class 3 and Class 4 locations by considering the characteristics of buildings and High Occupancy Locations which may impact class location.

7.1.3 Adjust boundaries of the class locations where High Occupancy Locations and Clusters exist.

7.2 "Moving Mile" Method

7.2.1 Move a class location unit along the pipeline, either by physically using an engineering scale and a scale drawing, or by using station numbers and looking at 5280 feet (1.6 km) in the station numbers. Count the building count within a class location unit and when it reaches a level where the class location changes, then mark the class location changes.

7.2.2 At the beginning and termination of a line, structures within a 220 yards (200 meters) radius of the ends of the line shall be included in the determination of class location.

7.2.3 The process of establishing class location as described above, should be continued until the end of the pipeline or the end of an area recently surveyed is reached.

8. RELATED PROCEDURES

1.04 Pipeline Annual Report
5.01 Continuing Surveillance
8.01 Maximum Allowable Operating Pressure
11.01 Odorization of Gas

9. RECORDS

9.1 Record applicable construction on an alignment sheet or class location map.

9.2 Schedule and document survey dates.

9.3 When class changes occur, document the change on alignment sheets or class location maps.

9.4 Retain records for at least five years.

CLASS LOCATION SURVEY FORM
FORM 4.01A

FROM STATION	TO STATION	BY WHO	DATE M/D/Y	(W) WALK (D) DRIVE (A) AERIAL	CLASS LOCATION CHANGE? (Y OR N)	SIGNATURE	COMMENTS

NOTE: See Procedure 8.02, for Maximum Allowable Operating Pressure (MAOP) calculation.

GAS GATHERING and JURISDICTIONAL DETERMINATION

1. Related References, Documents, & Procedures

1. 49 CFR 192.8, 192.9, 192.13, 192.452, & 192.619
2. Federal Register, March 15, 2006 (Volume 71, Number 50)
3. API RP 80, Guidelines for the Definition of Onshore Gas Gathering Lines
4. Appendix #4.02A, Flow Chart For DOT Onshore Gas Gathering Determination
5. Form #4.02A, DOT Onshore Gas Gathering Determination
6. PHMSA Gas Gathering FAQs, Federal Register, August 28, 2007

2. Purpose

The purpose of this procedure is to define jurisdictional onshore gas gathering pipelines and describe and the various requirements for these pipelines.

3. Responsibility for Implementation

The (#130) ____________ is responsible for evaluating each pipeline to make the jurisdictional determination.

4. Rule Effective Date

The effective date for these procedures is April 14, 2006. Deadlines for compliance with specific requirements are outlined in the procedure below.

5. General

Inspection and maintenance will carried out as shown in the specific sections of these O&M manual and assignment table. Although covered and expanded extensively within individual procedures in this O&M Manual, the various inspection and maintenance requirements are summarized in this procedure.

6. Determination of Onshore Gas Gathering Jurisdiction [192.8(a)(1) – (a)(4)]

The company will use API 80 (incorporated into rule by reference, 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The jurisdictional determination is subject to the limitations listed below:

1. The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."

2. The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

3. If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR Sec. 190.9)

4. The endpoint of gathering under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

7. **<u>Regulated onshore gathering means</u>: [192.8(b)]**

- Each onshore gathering line (or segment of onshore gathering line) with a <u>feature</u> described in the second column that lies in an <u>area</u> described by the third column.
- As applicable, additional lengths of line described in the fourth column to provide a <u>safety buffer</u>.

Type:	Feature:	Area:	Safety Buffer:
A	Metallic and the MAOP produces a hoop stress of 20% or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. Non-metallic and the MAOP is more than 125 psig (862 kPa)	Class 2,3, or 4 location (see Sec. 192.5)	None
B	Metallic and the MAOP produces a hoop stress of less than 20% of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. Non-metallic and the MAOP is 125 psig (862 kPa) or less	<u>Area 1</u>: Class 3 or 4 location. <u>Area 2:</u> An area within a If the gathering line Class 2 location the operator determines by using any of the following three methods: a) Class 2 location b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings. c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

8. Requirements Applicable to Gas Gathering Lines [192.9(a) – (d)]

Offshore Lines
The company will comply with requirements of 49 CFR 192 applicable to transmission lines, except the requirements in Sec. 192.150 (passage of smart pig) and in subpart O (IMP) of this part.

Onshore Type A Lines
The company will comply with the requirements of 49 CFR 192 applicable to transmission lines, except the requirements in Sec. 192.150 (passage of smart pig) and in subpart O (IMP) of this part.

However, when the company operates a Type A regulated onshore gathering line in a Class 2 location the company may demonstrate compliance with subpart N (operator qualification) by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

Onshore Type B Lines

The company will comply with the following for Onshore Type B lines:

1. If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

2. If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;
   See gas O&M section #6, procedures 6.01 through 6.10.

3. Carry out a damage prevention program under Sec. 192.614;
   See gas O&M procedure 3.03.

4. Establish a public education program under Sec. 192.616;
   See gas O&M procedure 3.03.

5. Establish the MAOP of the line under Sec. 192.619; and
   See gas O&M procedure 8.01.

6. Install and maintain line markers according to the requirements for transmission lines in Sec. 192.707.
   See gas O&M procedure 5.04.

9. Compliance Deadlines [192.9(e)]

When the company operates a new, replaced, relocated, or otherwise changed line, it will be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in Sec. 192.13 applies.

If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, the company has until the date stated in the second column (compliance deadline) to comply with the applicable requirement for the line listed in the first column (requirement), unless the OPS Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Carry out a damage prevention program under Sec. 192.614.	October 15, 2007.
Establish MAOP under Sec. 192.619.	October 15, 2007.
Install and maintain line markers under Sec. 192.707.	April 15, 2008.
Establish a public education program under Sec. 192.616.	April 15, 2008.
Control corrosion according to Subpart I requirements for transmission lines.	April 15, 2009.
Other provisions of this part as required by paragraph (c) of this section for Type A lines.	April 15, 2009.

If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the company has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.

10. General Requirements [192.13]

The company will not operate a segment of gas gathering unless it is readied for service under 192.13 and procedure #12.02 (Conversion of Service).

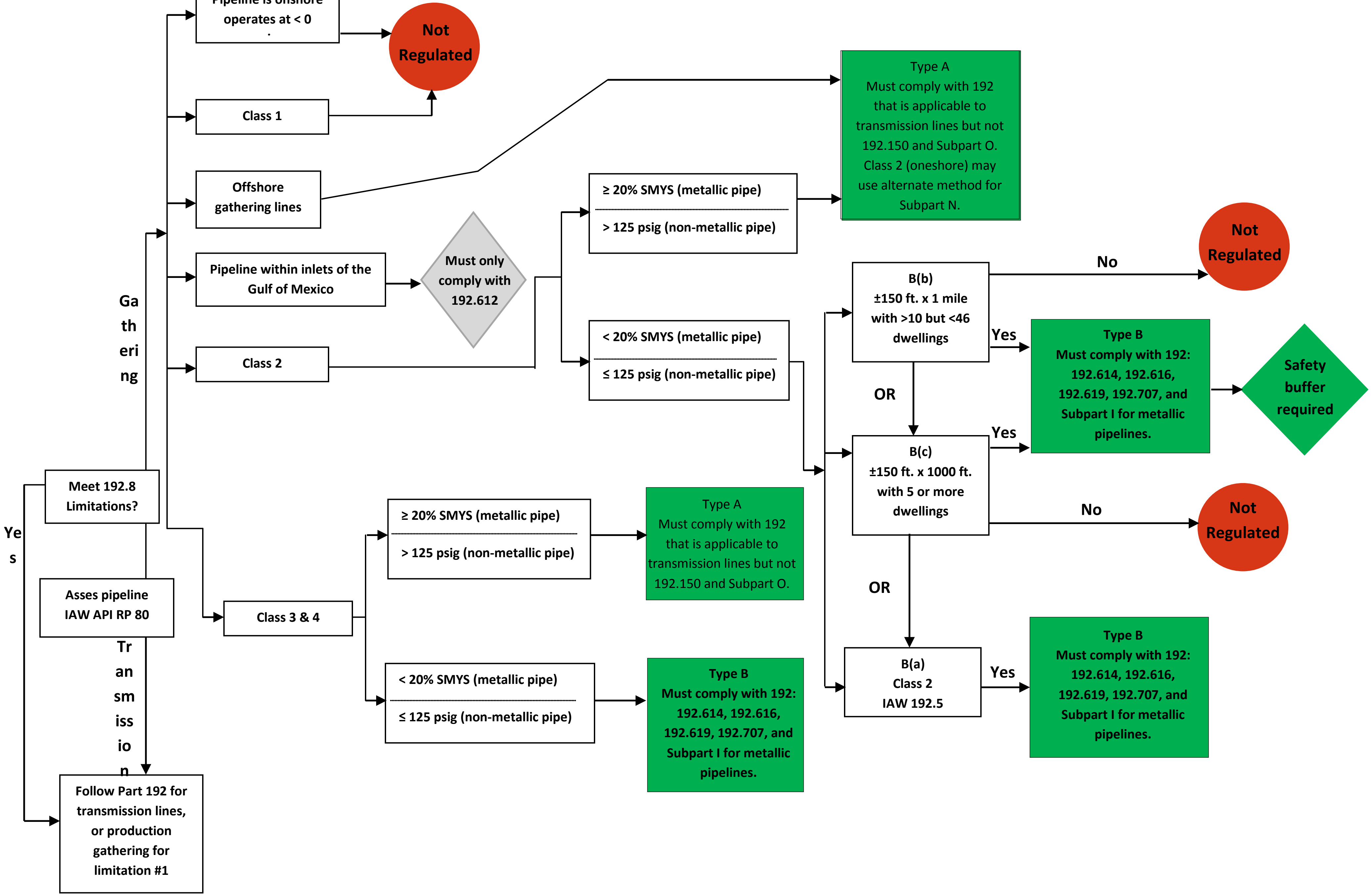
11. Corrosion Control for Converted Pipelines and Regulated Onshore Gathering Lines [192.452]

The company will not operate a converted segment of gas gathering unless the pipeline is appropriately protected with cathodic protection under 192.452 and procedure #6.05.

12. MAOP Determination for Gas Gathering Lines [192.619]

The company will not operate a regulated gas gathering segment unless determination of MAOP is established under 192.619 and procedure #8.01.

Gas Pipeline Jurisdictional Determination (Figure #4.02A)



CONTINUING SURVEILLANCE

1. REFERENCE

49 CFR, Sections 192.613 and 192.703.

2. PURPOSE

The purpose of this procedure is to describe and summarize the various continuing surveillance programs within this O&M Manual. The programs, or procedures, are used for evaluating pipeline systems, segments, and related facilities and, if necessary, taking appropriate action to resolve a problem.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (135) _____________ is responsible for inspections and maintenance, including the completion of any required forms or reports.

The (136) _____________ is responsible for evaluation of the pipeline condition and recommendations affecting the status of the pipeline. This would include remedial action and possible shutdown of the pipeline.

4. GENERAL

4.1 Although covered and expanded extensively within individual procedures in this O&M Manual, the various surveillance programs are summarized in Section 5. "PROCEDURE", for reference.

4.2 Surveillance procedures and instructions are to be reviewed with employee(s) and/or contract personnel at the time of a specific inspection, and on an intermittent basis such as safety, tailgate, and operations meetings. Normally the continuing surveillance review will be conducted on annual bases for class 3 & 4 and minimum once per two years for class 1 & 2. If continuing surveillance reviews are not conducted at these frequencies, the Pipeline Engineer and/or Compliance Manager will document that no pipeline safety issues are pending. Use form #5.01A or equivalent to conduct this review.

Training and/or qualification of personnel is necessary to perform these functions.

4.3 Communication to employees and contract people about the importance and the purpose of continuing "on-site" inspections and related records, must be done on a periodic and routine basis, and stressed that the reason is to detect changing conditions that could eventually result in a hazard to the public and property.

4.4 Should adverse changes or anomalies to a pipeline system, segment, or related facilities be determined by surveillance or inspection, but no immediate hazard exists, a planned and scheduled remediation, phaseout, or shutdown program shall be initiated. However, if damage or adverse conditions are found that could create a dangerous or hazardous situation, an immediate shutdown or operating pressure and MAOP reduction may be necessary until the problem is resolved.

5. PROCEDURE

5.1 The following summary and listing of surveillance and inspection programs is not necessarily inclusive but represents the expanded procedures in this O&M Manual. For detailed guidance, consult the specific procedure. The procedure is indicated after each task. Each task is unique and is designed to identify abnormal or unusual operating and maintenance conditions.

5.1.1 Investigation of Failures and Accidents 1.03

5.1.2 Damage Prevention Program 3.01
Includes: excavation activities, and horizontal directional drilling.

5.1.3 Class Location Survey 4.01
Includes: population density survey (class location), and right-of-way (R/W) observations.

5.1.4 Gas Leak Detection Survey with Instrumentation for pipelines without odorant. 5.02
Includes: gas leak survey of pipelines and casing.

5.1.5 Pipeline Patrolling/Gas Leak Survey without Instrumentation 5.03
Includes: pipeline R/W observation for leaks, construction activity, exposed pipe, erosion, and other detrimental effects on the pipeline.

5.1.6 Corrosion Control and Cathodic Protection Section 6 (all)

Includes: atmospheric, internal and external corrosion, pipeline examination, CP maps and records.

5.1.7	Emergency Valve Maintenance Includes: emergency and blowdown valve maintenance, valve security, valve corrosion.	7.01
5.1.8	Pressure Regulators and Relief Devices (Overpressure safety devices)	7.02
5.1.9	Valve Vaults Includes: overall evaluation of valve vault.	7.03
5.1.10	Pipeline Repair Procedures Includes: preliminary investigation, damage evaluation, and repair of any damage or defect.	9.01
5.1.11	Odorization of Gas	11.01
5.1.12	Pressure Testing	15.01

5.2 If after review and analysis by a qualified individual of any or all of the above procedures, a hazardous condition or developing trend is detected or exists affecting persons or property in the area, immediate steps will be taken to reduce or eliminate the hazard, including a complete shutdown of the system.

5.3 Management must be advised, if not already involved, of the situation, immediate steps taken, and proposed actions to resolve the condition.

5.4 If any part of a pipeline system, facility, or related component is determined to be damaged, defective, or in an unserviceable condition, and the degree of non-serviceability is established, the following options will be considered. Obviously if an immediate or potential <u>hazard to people and property</u> exists, the system will be shutdown and secured.

Options:
1) Recondition or phaseout
2) Replace
3) Abandon
4) Reduce MAOP and operating pressure
5) Modify facilities and/or operating conditions

Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly. The company may operate a segment of pipeline, unless it is maintained in accordance with this subpart M, Maintenance, 192.701-755.

6. RELATED PROCEDURES

All procedures indicated in Paragraph 5. "PROCEDURE", above.

7. RECORDS

As required by each individual procedure.

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 192.613 **Date Revised: Sept 2010**

CONTINUING SURVEILLANCE REPORT

Pipeline System Reviewed: ❑ ____________________ ❑ ____________________ ❑ ____________________

Action #1 – Record Review:

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			Description of Record or Report & Regulation [191 & 192]:
#	Sat.	Unsat.	NA	
				Incident Reports, SRC Reports, Annual Reports [191]
1	❑	❑	❑	Telephone Notice of Certain Incidents [191.5]
2	❑	❑	❑	Written Incident Report [191.7]
3	❑	❑	❑	Supplemental Incident Report [191.15]
4	❑	❑	❑	Annual Report (RSPA 7100.2-1) [191.17]
5	❑	❑	❑	Safety Related Condition Report [191.23]

Corrosion Control: Subpart I [192.451-491]

#	Sat.	Unsat.	NA	Description
1	❑	❑	❑	Exposed Pipe Reports - External [459]
2	❑	❑	❑	Condition of the External Coating [461]
3	❑	❑	❑	Annual CP Survey [465(a)]
4	❑	❑	❑	Bi-Monthly Rectifier Inspections [465(b)]
5	❑	❑	❑	Critical Bond Inspections [465(c)]
6	❑	❑	❑	Any CP Remedial Action Taken [465(d)]
7	❑	❑	❑	Close Internal Survey, if Applicable [465(e)]
8	❑	❑	❑	Electrical Isolation [467]
9	❑	❑	❑	CP Test Stations [469]
10	❑	❑	❑	CP Test Leads [471]
11	❑	❑	❑	Electrical Isolation [473]
12	❑	❑	❑	Corrosive Gas Investigation [475(a)]
13	❑	❑	❑	Exposed Pipe Report & Investigation - Internal [475(b)]
14	❑	❑	❑	Design and Construction of When Replaced [476]
15	❑	❑	❑	Internal Corrosion Control Monitoring (Coupons, Other) [477]
16	❑	❑	❑	Atmospheric Corrosion [479, 481]
17	❑	❑	❑	Remedial Measures [465(d), 483, 485]
18	❑	❑	❑	Direct Assessment [490]
19	❑	❑	❑	CP Records (5 years) [491(c)]
20	❑	❑	❑	CP Records (Life of Pipeline: CP Survey, CIS, Internal Inspection) [491(c)]

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 192.613	Date Revised: Sept 2010

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			**Description of Record or Report & Regulation [191 & 192]:**
#	**Sat.**	**Unsat.**	**NA**	
				Operations: Subpart O [192.601-629]
1	❑	❑	❑	Annual Review of O&M [605(a)]
2	❑	❑	❑	Annual Review of PSOM [605(a)] Public Awareness Mailer – Business & Residents Along ROW [616(e)]
3	❑	❑	❑	Annual Review of Emergency Plan [605(a)]
4	❑	❑	❑	Review Work Performed by Operator [605(b)(8)]
5	❑	❑	❑	Abnormal Operations Reports [605(c)]
6	❑	❑	❑	Class Location Survey [609]
7	❑	❑	❑	Change in Class Location, Confirmation or Revision of MAOP [611]
8	❑	❑	❑	Continuing Surveillance Review [613]
9	❑	❑	❑	Damage Prevention – One Call Records [614(b)]
10	❑	❑	❑	Damage Prevention – List of Excavators [614(c)(1)]]
11	❑	❑	❑	Em. Plan – Training [615(b)(2)]
12	❑	❑	❑	Em. Plan – Review of Response [615(b)(3)]
13	❑	❑	❑	Em. Plan – Government Liaison [615(c)]
14	❑	❑	❑	Public Awareness Mailer – Excavators [616(d)] (1x/yr)
15	❑	❑	❑	Public Awareness Mailer – Em. Officials [616(e)] (1x/yr)
16	❑	❑	❑	Public Awareness Mailer – Public Officials [616(e)] (1x/3yr)
17	❑	❑	❑	Public Awareness Mailer – Bus., Residents, & Schools Along ROW [616(e)] (1x/2yr)
18	❑	❑	❑	PA Mailer: Sour Gas Gathering – Bus., Residents, & Schools ROW [616(e)] (1x/yr)
19	❑	❑	❑	PA Mailer Survey – Excavators [616(d)] (1x/4yr)
20	❑	❑	❑	PA Mailer Survey– Em. Officials [616(e)] (1x/4yr)
21	❑	❑	❑	PA Survey Mailer – Public Officials [616(e)] (1x/4yr)
22	❑	❑	❑	PA Survey Mailer – Business, Residents, & Schools Along ROW [616(e)] (1x4/yr)
23	❑	❑	❑	PA Program Self Assessment & Evaluation, Appendix #3.03A [API #1162, section #8]
24	❑	❑	❑	Investigation of Failures [617]
25	❑	❑	❑	MAOP [619]
26	❑	❑	❑	Alternate MAOP [620]
27	❑	❑	❑	Odorization [625]
28	❑	❑	❑	Hot Taps [627]
29	❑	❑	❑	Purging of Pipeline [629]

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 192.613	Date Revised: Sept 2010

Review each of the following records or reports for completeness, unusual conditions, AOCs, or any condition that could affect the safety, maintenance, operation, or integrity of the pipeline. Comments and/or corrective action are required for each record marked with an unsatisfactory condition.

	Condition:			Description of Record or Report & Regulation [191 & 192]:
#	Sat.	Unsat.	NA	
				Maintenance: Subpart M [192.701-755]
1	❑	❑	❑	Unsafe Segments Replaced, Repaired, or Removed from Service [703]
2	❑	❑	❑	Patrols [705]
3	❑	❑	❑	Critical Crossing Inspections [705]
4	❑	❑	❑	Gas Leak Survey [706]
5	❑	❑	❑	Line Markers [707]
6	❑	❑	❑	Records – (Life of Pipeline: Repairs) [709(b)]
7	❑	❑	❑	Records – (5 years: all other O&M) [709(b)&(c)]
8	❑	❑	❑	Repair for >40% SYMS [711]
9	❑	❑	❑	Permanent Field Repair of Imperfections or Damage [713]
10	❑	❑	❑	Permanent Field Repair of Welds [715]
11	❑	❑	❑	Permanent Field Repair of Leaks [717]
12	❑	❑	❑	Test of Repairs [719]
13	❑	❑	❑	Abandonment [727]
14	❑	❑	❑	Compressor Stations: Inspecting and Testing of Reliefs [731]
15	❑	❑	❑	Compressor Stations: Storage of Combustibles [735}
16	❑	❑	❑	Compressor Stations: Gas Detection [736]
17	❑	❑	❑	Pressure Limiting & Regulating Station: Inspection and Testing [739]
18	❑	❑	❑	Pressure Limiting & Regulating Station: Indications of Hi/Low Pressure [741]
19	❑	❑	❑	Pressure Limiting & Regulating Station: Capacity Review [743]
20	❑	❑	❑	Valve Inspection [745]
21	❑	❑	❑	Vault Inspection [749]
22	❑	❑	❑	Prevention of Accidental Ignition [751]
23	❑	❑	❑	Other (Explain)

Misc:

1	❑	❑	❑	Agency Audit Findings or Agency Reports
2	❑	❑	❑	Pressure Test [501-517]
3	❑	❑	❑	System Up Rating [[551-557]
4	❑	❑	❑	Other (Explain)

CONTINUING SURVEILLANCE REPORT (cont.)

Action #2 Review of Other Conditions:

Review each of the following conditions list below. Comments and/or corrective action are required for each condition marked with a yes.

Yes	No	NA	Description of Condition:
❑	❑	❑	1) Has there been a change in population density that would require a change in class location survey? (If yes, complete class location survey.)
❑	❑	❑	2) Has there been any encroachment on pipeline facilities?
❑	❑	❑	3) Has there been any change in topography, which may have an effect on pipeline facilities?
❑	❑	❑	4) Has there been any lost or un-accounted for gas? (Corrective action required if loss exceeds 2%.)
❑	❑	❑	5) Has there been any additions or alterations to the system which may change pressure or flow maximums?
❑	❑	❑	6) Has there been any loss of flow efficiency or excessive pressure drops either local or system wide?
❑	❑	❑	7) Can the pipeline handle planned future load capacities with the prescribed pressure ranges?

CONTINUING SURVEILLANCE REPORT
Form # 5.01A

Reference: 49 CFR 192.613	**Date Revised: Sept 2010**

CONTINUING SURVEILLANCE REPORT (cont.)

Comments, action taken, and any changes from last review.

Signature
& Date:

Pipeline Mgr/Supervisor Signature

Date

GAS LEAKAGE SURVEYS

1. REFERENCE

49 CFR, Sections 192.703, 192.706, and 192.709, ASME Guide Gas Transmission Systems (Appendix G-11, Gas Leakage Control Guidelines)

2. PURPOSE

To establish the requirements and frequency for conducting gas leakage surveys on Company pipeline facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (142) __________________ is responsible for arrangement and conducting gas leak detection surveys as required by this procedure.

4. FREQUENCY OF PERIODIC SURVEYS

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year for:

- All Class 3 and 4 locations, in principal business districts, or in other comparable areas where wall-to-wall paving or other conditions prevent gas from venting to atmosphere.
- All other Class 3 locations
- All transmission lines in Class 1 and 2 locations.
- All above ground station piping

However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detection equipment must be conducted—

- In Class 3 locations, at intervals not exceeding 7-1/2 months, but at least twice each calendar year;
- In Class 4 locations, at intervals not exceeding 4-1/ 2months, but at least four times each calendar year.

5. LEAKAGE DETECTION

There may be a great variety of conditions encountered within the gas system. These procedures are intended as a guideline to be used as minimum standards. Although these procedures will be found to be applicable in the majority of cases, particular situations may require a more detailed effective leak survey program. More detailed leak survey programs, if appropriate, should be outlined in the company specific O&M (PSOM) manual.

5.1 Qualification of Personnel

Gas leakage surveys shall be performed by personnel who are qualified by training and experience in the type of survey being performed.

5.2 Reports from Outside Sources

Notifications from an outside source (police, fire, other utility, contractor, customer or the general public) regarding an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

5.3 Odors or Indications from Foreign Sources

When leak indications (such as gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility, and where appropriate, to the police department, fire department, or other governmental agency.

6. LEAKAGE SURVEYS

The gas leakage surveys below may be employed, as applicable, singularly or in combination, in accordance with these guidelines. Other test methods may be employed if they are reviewed and deemed to be equivalent or better in determining if a gas leak exist.

6.1 Surface Gas Detection

Definition: A continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to aboveground gas facilities with a gas detector system capable of detecting a concentration of 50 ppm of gas in air at any sampling point.

Utilization: The use of this survey method may be limited by adverse conditions (such as excessive wind, excessive soil moisture or surface sealing by ice or water). The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities and any adverse conditions, which might exist.

Procedures:

Mobile Survey:

Mobil surveys are conducted using a motor vehicle in rights-of-way, alleys, easements and streets where gas facilities are located and a foot survey is impractical or hazardous. The survey speed shall be no faster than 400 feet per minute (4.5 mph).

Foot Survey:

Foot surveys are normally conducted by using a portable Hydrogen Flame Ionization Unit (FIU), or other combustible gas indicator of the filament-bridge type, either hand-bulb aspirated or motor-pumped. Exposed facilities may be tested with leak detection fluid (soap, etc).

Foot surveys may be used to test mains in street or other vehicular areas where safe, effective coverage is possible and it is more practical and economical than a mobile survey. In urban areas this generally can be accomplished by scanning the curb gutter area with the flame ionization intake, and by surveying pavement cracks and substructures.

The survey is performed at exposed piping, at surface opening, pavement cracks and joints, unpaved areas, or at other locations where gas may vent.

Vegetation Survey:

Vegetation surveys can be used as a leak survey method in conjunction with other methods and may be used for Class 1 and 2 locations. When used as the principal method of survey, leakage detection equipment shall be available for verification of findings.

This survey method should be limited to areas where adequate vegetation growth is firmly established. This survey should not be conducted when soil moisture content is abnormally high, when vegetation is dormant or in an accelerated growth period, such as in the early spring. Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.

Personnel performing these surveys should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the system layout, amount and type of vegetation and visibility conditions such as lighting, reflected light, distortions, terrain or obstructions. This survey may be performed by foot, vehicle, or aerial patrol.

6.2 **Sub-surface Gas Detection (Bar Hole)**

Definition: The sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.5 percent gas in air at the sample point.

Utilization: Good judgment should be used to determine when available openings (such as manholes, vaults or valve boxes) are sufficient in number to provide an adequate survey. When necessary, additional sample points (bar holes) should be made. Sampling points should be of sufficient depth to directly sample within the subsurface or substructure atmosphere.

Procedure: The survey should be conducted by performing tests with a CGI in a series of available openings and/or bar holes over, or adjacent to, the gas facility.

The location of the gas facility and its proximity to buildings and other structures should be considered in the spacing of the sample points. Sampling points should be as close as possible to the pipeline, and never further than 15 feet laterally from the facility. Along the route of the pipeline, sampling points should be placed at twice the distance between the pipeline and the nearest building wall, or at 30 feet, whichever is shorter, but in no case need the spacing be less than 10 feet. The sampling pattern should include sample points adjacent to taps, street intersections, and known branch connections.

7. SPECIAL LEAKAGE SURVEYS

Special surveys may include post earthquake, pre-construction/engineering studies, pre-paving, system up-rating, blasting operations or any concern related to the safe operation of the pipeline. These surveys should be performed using leak detection equipment.

8. LEAK CLASSIFICATION GUIDELINES

Guidelines for leak classification and action criteria are provided in Tables 5.02A, 5.02B and 5.02C. The examples of leak conditions provided in the tables are presented as guidelines and are not exclusive. The judgment of the company personnel at the scene is of primary importance in determining the grade assigned to a leak. Reference “ASME Guide for Gas Transmission Systems (Appendix G-11, Gas Leakage Control Guidelines”.

TABLE 5.02A

LEAK CLASSIFICATION AND ACTION CRITERIA

ASME Guide Gas Transmission Systems (Appendix G-11, Gas Leakage Control Guidelines)

GRADE 1 LEAKS

DEFINITION	ACTION CRITERIA	EXAMPLES
A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires *prompt action* * to protect life and property, and continuous action until the conditions are no longer hazardous. Make continuous repair efforts until the leak is eliminated or downgraded. * P*rompt action* in some instances may require one or more of the following: • Implementation of the company Emergency Preparedness Plan. • Evacuating the premises. • Blocking off an area. • Rerouting traffic. • Eliminating sources of ignition. • Venting the area. • Stopping the flow of gas by closing valves or other means. • Notifying police and fire departments.	• A gas leak reported by other than company personnel. • Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. • Escaping gas that has ignited. • Any indication of gas, which has migrated into or under a building, or into a tunnel. • Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. • Any reading of 80% LEL or greater in a confined space. • Any reading of 80% LEL or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. • Any leak that can be seen, heard or felt, and which is in a location that may endanger the general public or property.

TABLE 5.02B

LEAK CLASSIFICATION AND ACTION CRITERIA

ASME Guide Gas Transmission Systems (Appendix G-11, Gas Leakage Control Guidelines)

GRADE 2 LEAKS

DEFINITION	ACTION CRITERIA	EXAMPLES
A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered: • Amount and migration of gas. • Proximity of gas to buildings and subsurface structures. • Extent of pavement. • Soil type, and soil conditions (such as frost cap, moisture and natural venting). Grade 2 leaks will be rechecked and re-evaluated at six month intervals until repairs are completed.	• Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. • Any reading of 40% LEL or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. • Any reading of 100% LEL or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. • Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. • Any reading between 20% LEL and 80% LEL in a confined space. • Any reading on a pipeline operating at 30% SMYS or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. • Any reading of 80% LEL or greater in gas associated substructures. • Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 5.02C

LEAK CLASSIFICATION AND ACTION CRITERIA

ASME Guide Gas Transmission Systems (Appendix G-11, Gas Leakage Control Guidelines)

GRADE 3 LEAKS

DEFINITION	ACTION CRITERIA	EXAMPLES
A leak that is non-hazardous at the time of detection, and can be reasonably expected to remain non-hazardous.	Should be re-evaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is re-graded or no longer results in a reading.	• Any reading of less than 80% LEL in small gas associated substructures. • Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. • Any reading of less than 20% LEL in a confined space.

9. FOLLOW-UP SURVEY

After a leak is repaired, the need for a follow-up survey should be determined by qualified company personnel, based on such factors as residual gas, leak history, age, condition and type of system. For underground leaks, the adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair, a follow-up inspection should be made as soon as practical after allowing the soil atmosphere to vent and stabilize, but, in no case later than one month following the repair. In the case of other leak repairs, qualified personnel should determine the need for a follow-up inspection.

When a leak is to be re-evaluated, it should be classified using the same criteria as when the leak was first discovered.

10. SURVEY EQUIPMENT

Each instrument utilized for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and should be periodically checked while in use to insure that the recommended voltage requirements are available and should be tested monthly or prior to use to insure proper operation. Check sampling system for leaks and change filters as necessary.

11. RECORDS

10.1 Document all gas leak detection surveys. Include beginning and ending mile post or station numbers for each partial segment of the pipeline requiring a survey. (See Form 5.02B/5.03B)

10.2 Identify by unique number all indicated leak locations for making corrective action. Any necessary corrective action must be taken prior to the next survey, or according to the leak survey action guidelines in tables #5.02A, 5.02B, and 5.02C.

10.3 If a pipeline is exposed by excavation, fill out the information requested on Pipeline Maintenance and Surveillance Report form. (See Form 3.01B)

10.4 The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service. (See Procedure 9.01 for repair options)

The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years.

A record of each patrol, survey, inspection, and test required by 49 CFR, 192, Subparts L and M must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

RELATED PROCEDURES

5.01	Continuing Surveillance
5.03	Pipeline Patrolling
6.05	Cathodic Protection/External Corrosion Control
11.01	Odorization of Gas

PIPELINE PATROLLING

1. REFERENCE

   49 CFR, Sections 192.703, 192.705, 192.706, and 192.709.

2. PURPOSE

   To establish a patrol program to observe the surface conditions on and adjacent to the right of way of the pipeline system.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (148) ___________________ is responsible for scheduling and conducting the pipeline patrolling program.

4. GENERAL

   The company will have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

   The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in table 5.03-A

   4.1 Personnel patrolling the pipelines shall be alert for and report any of the following that are on or adjacent to the pipeline rights-of-way:

   - Landslides or threatened slides.
   - Erosion by streams, wave action, rain, etc
   - Land subsidence that could affect the pipeline
   - Construction or maintenance work being done by others along the pipeline.
   - Encroachments into the right-of-way by buildings, structures or the construction of levees, roads, wells, etc, for which no prior permission has been granted by the company.

- Evidence of gas leakage, by checking vents at RR crossings or as indicated by vegetation (See Procedure 5.02, Leakage Surveys), bubbles in surface water, odor, etc.

- Needed repairs to company owned facilities, including fences, pipeline markers, exposed crossings, etc.

- Needed repairs to highway structures and other non-company owned facilities where public safety is a factor.

- Presence of survey parties or other indications of possible future work that might jeopardize the pipeline or effect a change in its class location.

- Any other factors affecting the operation or safety of the pipeline or other company facilities such as slope erosion, blocked culverts, casing vents, and access road washouts.

- Evidence of atmospheric corrosion that would indicate the need for repair and/or re-coating.

- Access roads used by others occasionally, or in areas viewed by the general public that may not be in a passable condition as established in accordance with existing agreements.

- Any activity that could create an unsightly condition in aesthetically sensitive areas.

4.2 Types of Pipeline Patrols:

4.2.1 Boat or aircraft for pipelines in waterways.

4.2.2 Ground patrols, by foot, by vehicle, or by any combination of these methods and aircraft patrols for onshore pipeline locations

4.3 All field personnel shall be responsible to observe, investigate and report any activity noted during the performance of their normal duties and other pipeline inspection activities that could adversely affect the safety, operation and maintenance of the pipeline facilities.

4.4 Pipeline patrols may be used to detect possible changes of population density. (See procedure 4.01, “Class Location Survey and Determination”).

5. PROCEDURE

5.1 Establish a schedule in each operating location area for patrolling pipelines. Include inactive lines in the plan (except lines that are abandoned).

5.2 Review and update the schedule as necessary.

5.3 Special patrols may be warranted by the size of line, operating pressure, class location, terrain, weather and other relevant factors.

5.4 Minimum pipeline patrolling shall be in accordance with the schedule shown in Table 5.03-A.

5.5 All aerial patrol reports and other reports of activities or construction in the vicinity of pipeline facilities shall be field investigated.

5.6 Aerial or boat patrol reports or other reports received that indicate that the safety, operation or maintenance of the pipeline facilities could be in imminent danger, shall be transmitted by radio, telephone or other expedient means to the responsible supervisor as soon as possible and an immediate investigation made.

6. RELATED PROCEDURES

4.01 Class Location Survey and Determination
5.01 Continuing Surveillance
5.02 Gas Leak Survey

. RECORDS

7.1 Record each item found during a patrol that requires further investigation to provide a permanent record on the Gas Leak Survey/Pipeline Patrol (Form 5.02B/5.03B), Navigable Waterway Crossing Inspection Form (Form 5.03C), Critical Crossing Form (Form 5.03D) or equivalent form. This record will ultimately indicate the actual situation and its disposition.

7.2 A record of each patrol, survey, inspection, and test required by CFR 49, 192 Subparts L and M must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

TABLE 5.03-A

Maximum Interval Between Patrols		
Class Location	**At Highway & Railroad Crossings (Critical Crossings)**	**At All Other Places**
1,2	7 1/2 months; but at least twice each calendar year	15 months; but at least once each calendar year.
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year.
4	4 1/2 months; but at least four times each calendar year	4 1/2 months; but at least four times each calendar year.

NOTES:

1. Highway is defined as any hard surface (concrete or asphalt) public road.

2. Vents at cased highway and railroad crossings shall be checked for the presence of gas as part of these patrols.

GAS LEAK SURVEY / PIPELINE PATROL

FORM 5.02B / 5.03B

FREQUENCY
OF SURVEY: ______________

☐ FLAME IONIZATION (F.I.) USED
☐ COMBUSTIBLE GAS INDICATOR (C.G.I.) USED

YEAR: ______________

SYSTEM: ______________

SIGNATURES:
COMPLETED BY: ______________
PATROLLER: ______________
SUPERVISOR: ______________

DATE	LEAK ID #	GRADE PER AGA	READING	LOCATION / STATION	ACTION PLAN

GAS LEAK SURVEY / PIPELINE PATROL

MO-DAY-YR	PATROL LEAKAGE INDICATIONS / VEGETATION CONDITIONS	PATROL LOCATION / STATION	REPORTED TO MAINTENANCE / ACTION
MO-DAY-YR	CONSTRUCTION ACTIVITY	PATROL LOCATION / STATION	REPORTED TO MAINTENANCE / ACTION
MO-DAY-YR	UNUSUAL CONDITIONS @ BRIDGE / HIGHWAYS / RR	PATROL LOCATION / STATION	REPORTED TO MAINTENANCE / ACTION
MO-DAY-YR	EROSION SLIPPAGES	PATROL LOCATION / STATION	REPORTED TO MAINTENANCE / ACTION
MO-DAY-YR	PIPELINE MARKERS MISSING/DAMAGED	PATROL LOCATION/STATION	REPORTED TO MAINTENANCE / ACTION
MO-DAY-YR	COMMENTS	PATROL LOCATION/STATION	REPORTED TO MAINTENANCE / ACTION

NAVIGABLE WATERWAY CROSSING INSPECTION FORM

FORM 5.03C

DATE OF SURVEY: ____________________
MO/DAY/YEAR

NAVIGABLE WATERWAY CROSSED UNDER: ____________________

MAP REFERENCES: ____________________

LEAKAGE INDICATIONS DISCOVERED (DESCRIBE LOCATIONS AND INDICATIONS.): ____________________

LEAKAGE INDICATIONS REPORTED TO: ____________________

DESCRIBE ANY UNUSUAL CONDITIONS AT WATERWAY CROSSING. ____________________

EROSION/SLIPPAGE OR EXPOSURE OF PIPE OBSERVED: ____________________

OTHER FACTORS NOTED WHICH COULD AFFECT SAFETY OF PIPELINE: ____________________

ACTION TAKEN (REPAIRS, MAINTENANCE OR TESTS RESULTING FROM THIS INSPECTION ETC.):

COMMENTS: ____________________

NO. OF PERSON(S) IN PATROL PARTY: ____________________
SIGNATURE OF PERSON(S) IN PATROL PARTY: ____________________
SIGNATURE OF SUPERVISOR: ____________________ DATE: __________
MO/DAY/YR

Critical Crossing Patrol Report
O&M Form 5.03D

Reference: 49 CFR 192.705 | Date Revised: Jan 2011

Pipeline System: ❑

Crossing Location: From: ☐ | To:

Frequency:

Class Location:	Max. Interval Between Patrols
1 & 2	7 ½ months; but at least twice each yr
3 & 4	4 ½ months; but at least 4X each yr

Action:

Perform visual inspection and leak test at each critical crossing listed above. Pipeline Operators shall immediately notify the Pipeline Supervisor of any activity, which may adversely affect the safe operation of the pipeline system.

FI or CGI serial #: ______________________

Condition:

☐ sat	☐ unsat	❑ Exposed pipe or pipe supports
☐ sat	☐ unsat	❑ Vent pipe protected from weather
☐ sat	☐ unsat	❑ Vent pipe leak check with instrument
☐ sat	☐ unsat	❑ Erosion
☐ sat	☐ unsat	❑ Construction activity
		❑ Any factor affecting safety & operation

Comments:

Comments on any of the above actions found in unsatisfactory condition.

Signature & Date:

____
Work Completed By (signature)

____
Date

____
Reviewed By (signature)

____
Date

PIPELINE MARKERS AND SIGNS

1. REFERENCE

49 CFR, Section 192.707, and API #1109 Marking Liquid Petroleum Facilities

2. PURPOSE

The purpose of this procedure is to establish a pipeline marking system for pipelines and other facilities operated by the Company.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (154) _______________ is responsible for installation and maintaining the pipeline markers and signs on all pipeline facilities.

4. GENERAL

4.1 49 CFR Section 192.707 requires installation and maintenance of pipeline markers at each crossing of a public road and railroad and where necessary to identify the location of a pipeline to reduce the possibility of damage or interference. This includes all above ground locations in areas accessible to the public.

4.2 Although it is not the intent to identify the precise location of pipelines by marker placement, they should be installed over the pipeline or at a minimal offset.

4.3 Line markers are not required for buried pipelines located:

4.3.1 At crossings of or under waterways and other bodies of water; or

4.3.2 Markers are not required in Class 3 and Class 4 locations where placement of markers is impractical or where covered by a damage prevention program.

4.4 Pipeline Marker Sign Lettering Must Include:

4.4.1 The word “Warning”, “Caution”, or “Danger”, followed by the words “Gas (or name of gas transported) Pipeline” in letters at least 1-inch, (25mm) high with 1/4-inch, (6.4 mm) stroke (except in heavily developed urban areas) on a background of sharply contrasting color.

4.4.2 The name of the operator and the telephone number (including Area Code) where a Company operator or answering service can be reached at all times.

4.5 Signs need not be installed for office type facilities such as those located in office parks, multistory, or high-rise buildings.

5. PROCEDURE

5.1 Line Markers for Buried Pipelines

5.1.1 Place a sign at existing fence lines in locations where markers are required.

5.1.2 Place a sign at visually identifiable property lines, which are not fenced, in locations where markers are required unless the sign will interfere with land usage.

5.1.3 For pipelines that are within and paralleling public right of way, place signs on the public area right-of-way line where the pipeline enters and exits the right-of-way area with the front of the sign facing towards the right-of-way at a spacing determined appropriate for the expected frequency of excavation activity, and where possible, signs should be at changes of direction and be visible sign-to-sign.

5.1.4 Install aerial patrol signs on pipelines that are flown on a routine basis where a need exists to have reference markers. Space these signs at about 2 mile (3.2 km) intervals, unless local conditions indicate closer or farther spacing would be better.

5.1.5 Install markers at all locations necessary to identify the location of the pipeline to reduce the possibility of damage or interference.

5.2 Line Markers for Public Road and Railroad Crossings

5.2.1 Place one sign on each side of the crossing at the right of way of all public roads and railroad crossings.

5.2.2 Place one sign on the downstream side of the crossing at the right of way line of non-public roads.

5.2.3 Whenever one sign is required (non-public roads only), it must be capable of being easily seen and identifiable when standing on the opposite right of way line during all times of the year. If not, install two signs, one on each side of the crossing at the right of way line.

5.3 Above ground Pipelines

Install and maintain signs at aboveground pipeline facilities that are in areas which are accessible to and used by the public.

5.4 Pipeline Marker Sign Mounting

5.4.1 Paint fence posts on both sides of the road or railroad where the pipeline crosses, unless landowner has made a specific request not to paint these posts.

5.4.2 Mount signs on fence where pipeline crosses.

5.4.3 Place signs parallel to road, highway, railroad and other crossings to obtain the greatest visual attention.

5.4.4 Consider vertical type pipeline marker signs for use in:

5.4.4.1 Populated locations.

5.4.4.2 Those areas where conventional pipeline marker signs may be subject to vandalism, vehicular impact, or damage from livestock.

5.4.4.3 At locations where these markers may be less objectional to landowners.

5.4.5 In the areas covered by 5.4.4.2 above, mount decal-type signs on PVC or steel pipe posts, or flexible plastic composite posts.

5.5 Monitoring

5.5.1 Existing markers shall be observed by employees as follows:

5.5.1.1 During normal travels required by pipeline operation and maintenance.

5.5.1.2 During scheduled patrols of the pipeline.

5.5.2 Replace missing, damaged, outdated, or deteriorated signs within a reasonable time interval.

6. RELATED PROCEDURES

5.03 Pipeline Patrolling/Gas Leak Survey without Instrumentation

7. RECORDS

7.1 Document the reasons that signs cannot be installed as required by this procedure (Form 5.02B/5.03B), such as that sign would interfere with land usage, etc.

7.2 Document the repeated removal of signs by the public to determine justification for legal action (Form 5.02B/5.03B).

7.3 Keep the records for at least five years.

ATMOSPHERIC CORROSION

1. REFERENCE

49 CFR, Sections 192.479, 192.481, 192.485, 192.491, 192.605, 192.613 and 192.709.

2. PURPOSE

To establish the requirements for inspection and maintenance of aboveground pipeline systems for atmospheric corrosion.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (160) ___________________ is responsible for scheduling, conducting inspections, and record-keeping of atmospheric corrosion inspections as required by this procedure. The (161) ___________________ shall initiate any corrective/maintenance actions required as a result of these inspections.

4. GENERAL

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

4.2 Pipeline systems or portions thereof, subject to atmospheric corrosion or moisture penetration and retention, shall be inspected to assure detection of corrosion before detrimental damage, Category 3 Corrosion (heavy, obvious pitting in excess of 10% of new nominal wall thickness) is sustained. (NOTE: See Form 6.01A for explanation of category and conditions).

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

4.4 Inspection programs for atmospheric corrosion shall include, but not be limited to, areas such as under hold-down straps, between pipe and pipe supports, platform risers and riser clamps, at pipe penetrations of building walls, and thermally insulated meter piping.

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

4.6 Corrosion, leaks, and defects may be safety related conditions. Refer to the Reporting of Safety Related Conditions procedure (1.02) for identification and reporting of such conditions.

4.7 The Company must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, unless it meets the exceptions listed below in step 4.7.1. Coating material must be suitable for the prevention of atmospheric corrosion.

4.7.1 Exception to cleaning and coating of pipelines:
Except offshore splash zones or soil-to-air interfaces, the operator does NOT have to clean and coat the pipeline if the operator can demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will;

1) Only be a light surface oxide; or
2) Not affect the safe operation of the pipeline before the next scheduled inspection

5. PROCEDURE

5.1 Inspect all bare aboveground onshore piping every 3 calendar years, not to exceed 39 months for onshore pipelines. Inspect offshore pipelines at least once every calendar year, but not exceeding fifteen (15) months. During inspections, particular attention must be given to soil-to-air interfaces, under thermal insulation, under disbanded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

5.2 The primary method of inspection is visual. Further non-destructive testing (NDT) techniques (such as ultrasonic thickness measurements, pit depth gauge readings, radiography, etc.) may be implemented if visual evidence of corrosion damage or other conditions warrant. (See Section 5.8)

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

5.4 Inspect the transition zone of pipe entering the ground (or water for offshore pipelines) to confirm it is properly coated whereby penetration of moisture between the pipe and coating is prevented. Whenever a condition is observed where moisture may be retained between the coating and pipe, remove the coating, inspect the pipe, evaluate severity of corrosion if present, take remedial actions if necessary, and recoat the pipe prior to the next inspection.

5.5 For thermally insulated systems, visual inspection of the external jacket to ensure its integrity against moisture intrusion under the jacket is usually sufficient; if the integrity of the external jacket has been breached and liquid water may be present against the carrier pipe surface, additional inspection techniques may be required to detect possible corrosion.

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

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

5.8 In cases where pipe wall loss exceeds 10% of the nominal new pipe wall thickness, District Engineer shall review the pipeline MAOP for possible revision and/or recommend pipeline repair requirements.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe"(49CFR192 currently referenced edition).

5.9 If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by 192.479 (cleaning and coating).

6. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
9.01 Repair Procedures

7. RECORDS

7.1 Complete Form 6.01A to document the extent of external corrosion on aboveground facilities.

7.2 Complete the Pipeline Maintenance and Surveillance Form (Form 3.01B) whenever external corrosion is identified and a repair or a preventive maintenance action, other than painting, is required.

7.3 Maintain the above records for at least five years.

EXTERNAL CORROSION TEST FOR ABOVE GROUND FACILITIES

FORM 6.01A

DATE: MO DAY YR

SYSTEM: ______________________

SIGNATURE: ______________________

SIGNATURE OF SUPERVISOR: ______________________

PIPELINE INSPECTION		AREA OF POSSIBLE ACTIVE CORROSION				
FROM	TO	FROM	TO	CONDITION *	ULTRA SONIC READING	COMMENTS
STATION	STATION	STATION	STATION	(0,1,2,OR 3)	READING OR PIT DEPTH GA	

* 0 - NO CORROSION
1 - LIGHT SURFACE RUST - NOT MEASURABLE
2 - MEDIUM SURFACE RUST - MEASURABLE, BUT NOT DETRIMENTAL (LESS THAN 10% OF NEW PIPE NOMINAL WALL THICKNESS)
3 - HEAVY. OBVIOUS PITTING (IN EXCESS OF 10% OF NEW PIPE NOMINAL WALL THICKNESS)

INTERNAL CORROSION

1. REFERENCE

49 CFR, Sections 192.475, 192.477, 192.485, 192.491, 192.605, and 192.613.

2. PURPOSE

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

3. RESPONSIBILITY FOR IMPLEMENTATION

The (167) ___________________ is responsible for scheduling, conducting, and record-keeping of internal corrosion inspection as required by this procedure. The (168) ___________________ shall be responsible for repairing internal corrosion damage and mitigating the detrimental effects of internal corrosion.

4. GENERAL

4.1 This procedure is required if liquids or corrosive gas are ever allowed to flow through or remain in the pipeline.

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

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

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

4.5 If repair, replacement, or operating pressure reduction is necessary, review Reporting of Safety Related Conditions procedure (Procedure 1.02) to see if a reportable safety related condition exists.

- 5. CORROSIVE CONDITIONS

5.1 Gas containing water in liquid phase and at least one of the following components is considered to be potentially corrosive. A combination of two or more components with water in liquid phase may be potentially corrosive at lower concentrations of each component. Gas having a water vapor below the point of saturation may contain concentrations of H_2S and CO_2 and O_2 greater than those listed below and remain non-corrosive.

5.1.1 Hydrogen sulfide (H_2S) concentration greater than .05 psia partial pressure for systems operating at or above 65 psia total pressure. For system pressure less than 65 psia total pressure, (H_2S) content of 50 ppm or greater is considered corrosive.

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

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

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

5.2 Review the gas source dew point history. Water dew points within 10°F (5.6 ° C) of the minimum ambient temperature to which the pipeline is exposed may indicate the presence of liquid water in the pipeline.

5.3 Corrosion will be more severe if any of the following conditions are present in conjunction with the conditions listed in 5.1.

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

5.3.2 Liquids or materials having a pH less than 5.5.

6. PROCEDURE

6.1 Internal Inspections

6.1.1 Whenever any pipe section is opened or removed from a pipeline system, that pipe section and any adjacent pipe sections shall be inspected visually to determine evidence and/or extent of internal corrosion. If internal corrosion is noted visually, further investigation including NDT techniques, shall be used to quantify the extent of the corrosion. Use form #6.02A (Internal Pipe Inspection) or equivalent to documents this review.

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

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

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

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

6.2 Gas Analysis and Evaluation

6.2.1 If there is a reasonable possibility that potentially corrosive gas could occur in a pipeline system, gas samples shall be taken at applicable locations and tested for the presence and concentration of corrosive components. Testing shall be done at least once each year or when new gas stream is introduced into the pipeline system. Use form #6.02B-1 (gas analysis sampling) and form #6.02B-2 (Evaluation of Gas Analysis) or equivalent to documents this review.

Gas samples shall be tested by "Gas Analysis by Chromatography" - ASTM D1945/D 3588 or other ASTM standard that provides component data in both mole percent and weight percent. Total sulfur (ASTM

D3246) and hydrogen sulfide (ASTM D4810) shall also be noted in the testing.

6.2.2 Dew point analysis shall be performed on gas sources at a minimum of once each year or when new gas stream is introduced into the pipeline system. If the gas is considered potentially highly corrosive, more frequent dew point tests should be considered.

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

6.2.4 Installation of Monitoring Devices

6.2.4.1 Identify checkpoint locations at places most susceptible to internal corrosion such as low elevation points, dead ends and drips.

6.2.4.2 Select and install monitoring devices such as weight loss coupons or electrical probes, either resistance or polarization, giving consideration to size of pipe, type of

system, operating conditions, simplicity of installation and ease of gathering information. Install liquid sampling facilities if applicable.

6.2.4.3 Prepare and maintain a schematic diagram showing physical and operating characteristics of the pipeline system, the location of checkpoints and the type of monitoring devices used.

6.2.5 Monitoring and Detection

6.2.5.1 Monitor checkpoints and record the results at least twice each calendar year with intervals not exceeding 7½ months. Monitor more frequently if the level of the corrosive component increases or the effectiveness of the anti-corrosion measures needs to be confirmed. Use form #6.02C (Coupon Monitoring) or equivalent to documents this review.

6.2.5.2 If liquids are present, collect and analyze liquid samples once each year or when new gas stream is introduced into the pipeline system. Special attention should be given to drips, blow downs, and low spots in the pipeline.

6.2.6 Corrosion Rates from NACE RP 0775-99, Table #2.

	Average Corrosion Rate		**Maximum Pitting Rate**	
	Millimeters per Yr	**Mils per Year**	**Millimeters per Yr**	**Mils per Year**
Low	<0.025	<1.0	<0.13	<5.0
Moderate	0.025-0.12	1.0-4.9	0.13-0.20	5.0-7.9
High	0.13-0.25	5.0-10	0.21-0.38	8.0-15
Severe	>0.25	>10	>0.38	>15

6.2.7 Remedial Action

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

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (49CFR1921 currently referenced edition).

6.2.6.2 Apply at least one of the following mitigation measures prior to the next inspection if inspection reveals internal corrosion to be occurring, or if previously installed monitoring equipment shows corrosion to be occurring:

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

6.2.6.2.2 Remove corrosive components.

6.2.6.2.3 Inject corrosion inhibitors.

7. REPAIR

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

8. INTERNAL CORROSION CONTROL: DESIGN AND CONSTRUCTION OF TRANSMISSION LINES [192.476]

8.1 Except as provided by the exceptions below, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to 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:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

8.2 *Exceptions to applicability.* The internal corrosion design and construction requirements do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, and fitting or other line component replaced before May 23, 2007.

8.3 *Change to existing transmission line.* When the company changes the configuration of a transmission line, the company 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.

8.4 *Records.* The company must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing section #5.1 above is impracticable or unnecessary, the company may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

9. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
9.01 Repair Procedures

10. RECORDS

9.1. Complete the Pipeline Maintenance and Surveillance Form (Form 3.01B) when pipeline is checked internally, repaired, or replaced.

9.2 Retain all studies, reports, checks of monitoring devices and other data that may be accumulated, at the District Office. Inspection reports and "Smart Pigging" results are to be retained for the life of the facility.

9.3 Maintain gas water dewpoint historical log for gas sources, where dew points or gas analysis are being performed, for at least five years.

11. CONVERSION EQUATIONS

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

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

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

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

Internal Pipeline Inspection Report
O&M Procedure 6.09

Reference: 192.475 Date Revised: Sept 2012

Pipeline System or Segment: ________________________________
Location General Description: ________________________________
Stationing or GPS Location: ________________________________

Date:	
Reason for Exposure:	
Name of Company Exposing Line:	
Person Conducting Inspection: (print)	
Person Conducting Inspection: (signature)	

Requirements:	Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found: (1) The adjacent pipe must be investigated to determine the extent of internal corrosion; (2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and (3) Steps must be taken to minimize the internal corrosion.

Describe Condition of Internal Pipe Surface:	
Digital Photo Attached of the Internal Pipe Surface:	Yes/No

Internal Pipeline Inspection Report
O&M Procedure 6.09

Reference: 192.475 | Date Revised: Sept 2012

1.	**Was there evidence of internal corrosion?**	Yes/No
2.	**If yes to questions #1 above should the adjacent pipe be investigated to determine the extent of the corrosion?**	Yes/No
3a.	**If yes to questions #1 above, is replacement needed?**	Yes/No
3b.	**What is the maximum pit depth?**	
3c.	**What is the maximum pit length?**	
3d.	**Using modified B31G calculation, what is the predicted failure pressure (P_f)?**	
3e.	**Using modified B31G calculation, what is the safety factor (P/MAOP)?**	
3f.	**Modified B31G calculation is attached?**	Yes/No
4a.	**What steps are recommended to minimize future corrosion?**	
4b.	**Remove corrosion properties of gas with upgraded processing facilities:**	Yes/No
4c.	**Inject corrosion inhibitor chemical:**	Yes/No
4d.	**Install and monitor corrosion coupons:**	Yes/No

Pipeline Supervisor Additional Comments:	

Pipeline Supervisor Signatures & Date:

____
Work Reviewed By (signature)

____
Date

GAS ANALYSIS SAMPING
FORM 6.02B

	Gas Sample Location							
#	Lat	Long	Description of Sample Location:	Person Taking Gas Sample (print)	Person Taking Gas Sample (signature)	DATE Mo./Day/Yr	Chain of Custody Attached (yes/no)	Additional Comments if Needed:
1								
2								
3								
4								
5								
6								
7								
8								

REQUIREMENTS: § 192.475 Internal corrosion gas analysis and evaluation
If there is a reasonable possibility that potentially corrosive gas could occur in a pipeline system, gas samples shall be taken at applicable locations and tested for the presence and concentration of corrosive components. Testing shall be done at least once each year or when new gas stream is introduced into the pipeline system. Dew point analysis shall be performed on gas sources at a minimum of once each year or when new gas stream is introduced into the pipeline system. If the gas is considered potentially highly corrosive, more frequent dew point tests should be considered.

Gas samples shall be tested by "Gas Analysis by Chromatography" - ASTM D1945/D 3588 or other ASTM standard that provides component data in both mole percent and weight percent. Total sulfur (ASTM D3246) and hydrogen sulfide (ASTM D4810) shall also be noted in the testing.

NOTE: See Procedure 8.02, for Maximum Allowable Operating Pressure (MAOP) calculation.

EVALUATION OF GAS ANALYSIS
FORM 6.02B-2

Date of Review: ______________________

Name of person conducting review: (print) ______________________

Name of person conducting review: (signature) ______________________

Sample Location: ______________________

#	Component:	Limit:	Unit of Measure:	Analsysis Actual Result:	Acceptable (yes/no)	Comments on any Quetionable Component:
1	Water					
2	Hydrogen Sulfide (H2S)					
3	Carbond Dioxide					
4	Oxygen					
5	Dew Point					
6	Liquids with Sulfate Reducing Bacteria (SRBs)					
7	pH					
8						

CORROSIVE CONDITIONS:

5.1 Gas containing water in liquid phase and at least one of the following components is considered to be potentially corrosive. A combination of two or more components with water in liquid phase may be potentially corrosive at lower concentrations of each component. Gas having a water vapor below the point of saturation may contain concentrations of H2S and CO2 and O2 greater than those listed below and remain non-corrosive.

5.1.1 Hydrogen sulfide (H2S) concentration greater than .05 psia partial pressure for systems operating at or above 65 psia total pressure. For system pressure less than 65 psia total pressure, (H2S) content of 50 ppm or greater is considered corrosive.

5.1.1.1 Gas containing more than 0.25 grain of H2S per 100 SCF (4 ppm) may not be stored in pipe-type or bottle-type containers.

5.1.2 Carbon dioxide (CO2) concentration greater than 3 psia partial pressure regardless of total pressure.

5.1.3 Oxygen (O2) concentration greater than 50 ppm or greater than 20 ppb where dissolved in a liquid phase.

5.2 Review the gas source dew point history. Water dew points within 10□F (5.6 □C) of the minimum ambient temperature to which the pipeline is exposed may indicate the presence of liquid water in the pipeline.

5.3 Corrosion will be more severe if any of the following conditions are present in conjunction with the conditions listed in 5.1.

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

5.3.2 Liquids or materials having a pH less than 5.5.

Gas samples shall be tested by "Gas Analysis by Chromatography" - ASTM D1945/D 3588 or other ASTM standard that provides component data in both mole percent and weight percent. Total sulfur (ASTM D3246) and hydrogen sulfide (ASTM D4810) shall also be noted in the testing.

COUPON MONITORING FORM
FORM 6.02C

#	Coupon Location: Lat or Description	Coupon Location: Long or Description	Person Conducting Coupon Survey	DATE Mo./Day/Yr	Previous Coupon Reading	Current Coupon Reading	Difference in Coupon Reading	Corrosion Rate (mils/year)	SIGNATURE	COMMENTS
1										
2										
3										
4										
5										
6										
7										
8										

REQUIREMENTS: § 192.477 Internal corrosion control: Monitoring.
If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7 1/2months.

NACE RP 0775-99 Table 2 — Qualitative Categorization of Carbon Steel Corrosion Rates for Oil Production Systems

	Average Corrosion Rate		Maximum Pitting Rate (See Paragraph 2.5)	
	mm/y(A)	mpy(B)	mm/y	mpy
Low	<0.025	<1.0	<0.13	<5.0
Moderate	0.025-0.12	1.0-4.9	0.13-0.20	5.0-7.9
High	0.13-0.25	5.0-10	0.21-0.38	8.0-15
Severe	>0.25	>10	>0.38	>15

(A) mm/y = millimeters per year
(B) mpy = mils per year

NOTE: See Procedure 8.02, for Maximum Allowable Operating Pressure (MAOP) calculation.

EXTERNAL PROTECTIVE COATING

1. REFERENCE

49 CFR, Sections 192.455, 192.457, 192.459, 192.461, 192.463, 192.483, 192.491, and 192.613.

2. PURPOSE

The purpose of this procedure is to outline the practice for the installation of external protective coating for all buried or submerged gas pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (174) ___________________ is responsible to implement the requirements of this procedure.

4. GENERAL

4.1 Buried or submerged natural gas pipelines installed after July 31, 1971 must have an external protective coating system unless:

4.1.1 It can be demonstrated by tests, investigation, or experience in the area of application that a corrosive environment does not exist. This includes as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria. Within 6 months after installation, the line must be further tested per 192.455(b) to evaluate the potential profile along the entire pipeline. If these tests indicate that a corrosive condition exists, the pipeline must be cathodically protected.

4.1.2 The pipeline is a temporary installation with an operating period of service not to exceed 5 years beyond installation and any anticipated corrosion will not be detrimental to public safety.

4.2 If any pipeline is externally coated (notwithstanding 4.1 above), it must be cathodically protected along the entire area that is effectively coated. A pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare.

4.3 When choosing the material to use for repairing a coating, every effort should be made to choose the original material or to come as close to it as possible with compatible coating material.

4.4 In all cases of coating repair, whether during construction or after the pipeline is in service, the pipeline surface to be coated should be cleaned as well as possible of all dirt, grease, weld splatter or other foreign material. Instructions for the coating application prepared by the manufacturer should be followed.

5. <u>COATING PROCEDURE</u>

5.1 The purpose of external protective coatings is to isolate the pipeline from its environment and provide primary corrosion protection. Additionally, external protective coatings facilitate the application of cathodic protection.

5.2 The external protective coating applied for corrosion control must have the following characteristics and properties.

5.2.1 The coating must be applied on a properly prepared surface as recommended by the coating system manufacturer.

5.2.2 The coating must have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture.

5.2.3 The coating must be sufficiently ductile to resist cracking.

5.2.4 The coating must have sufficient strength to resist damage due to the handling and in-service soil stress.

5.2.5 The coating must have properties compatible with the application of cathodic protection to the pipeline.

5.2.6 The coating must have low moisture absorption and high electrical resistance.

5.2.7 Each external protective coating must be inspected by electrical test methods ("jeeping") just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

5.2.8 Each external protective coating must be protected from damage which could result from adverse ditch conditions or from supporting blocks.

5.2.9 If coated pipe is installed by horizontal direction drilling, boring, driving, or other similar method, precaution must be taken to minimize damage to the external coating during installation.

5.3 Coated pipe sections connected by welding and/or mechanical coupling including valves or other underground or submerged appurtenances will be considered field joints. External coating of field joints must be equal to or better than the coating of the pipeline.

5.4 Existing Coated Pipelines

5.4.1 Apply an external protective coating to:

5.4.1.1 Poorly coated or bare portions of pipeline segments that have been exposed for repair or inspection.

5.4.1.2 Pipeline segments that replace existing pipe.

5.4.2 Inspect and repair all coating on replacement segments and coating repairs for defects caused by installation activity.

5.4.3 Existing coating may require repair or upgrading in areas where criteria for achieving cathodic protection is not being met.

5.5 New Pipelines

5.5.1 Apply an external protective coating to all new buried pipelines.

5.5.2 Inspect all coating on new pipeline segments and repair defects caused by installation.

5.6 Surface Preparation

5.6.1 In removing coating to make tie-ins, care must be taken to avoid disbonding of the adjacent coating. Edges of thick film coating must be tapered and enough of the wrapper removed to ensure adhesion of the new coating to the existing coating.

5.6.2 The surface to be coated must be thoroughly cleaned with solvents to remove oil and grease. All dust, dirt, rust, mill scale, loose shop coating, dead primer, welding slag, and burrs must be removed with wire brushes or scrapers.

5.6.3 Nicking the coating to bare the pipe surface must not be permitted.

5.7 Repair of Coating Defects

5.7.1 Inspection shall follow all coating applications. Any defects shall be repaired.

5.7.2 A sufficient portion of the coating must be carefully removed from defective areas of pipe to ensure that the remaining coating is satisfactory and well bonded. Edges of the area should be tapered to increase the strength of the patch.

5.7.3 Foreign matter must be removed from the area to be repaired.

5.7.4 Primer applied to the area, if required, must be allowed to dry properly before the coating is applied.

5.7.5 The coating material used for patching must be such that proper adhesion will occur between the existing coating material and the patching material.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.04 Internal and External Examination of Buried Pipelines
6.05 Cathodic Protection/External Corrosion Control
6.06 Electrical Isolation
6.08 Cathodic Protection Records

7. RECORDS

7.1 Submit appropriate as-built information to the District Office for updating drawings and records.

7.2 Retain these records for as long as the pipeline is in service.

INTERNAL AND EXTERNAL EXAMINATION OF BURIED PIPELINES

1. REFERENCE

   49 CFR, Sections 192.459, 192.475, 192.485, 192.491, 192.605, and 192.613.

2. PURPOSE

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

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (181) ____________________ is responsible to implement the requirements of this procedure and to document the test results whenever gas piping is exposed for any reason.

4. GENERAL

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

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

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

5. PROCEDURE

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

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

   5.3 If corrosion is observed on a bare or coated line, a condition may exist warranting further investigation (disbonded coating, unique soil environment, etc.).

If external corrosion requiring remedial action is found, additional investigation circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial exists in the vicinity of the exposed portion.

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

5.4.1 Continuing corrosion is observed.

5.4.2 CP tests, current requirements or surveys indicate corrosion may be occurring.

5.4.3 Previously unidentified coating deterioration is observed or suspected.

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

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

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

5.6.1 Calculate the acceptable minimum wall thickness limit after corrosion. If wall thickness is less than the calculated minimum, initiate a repair method as outlined in Repair Procedures (Procedure 9.01) or reduce the pipeline MAOP (Procedure 8.01).

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), “Manual for Determining the Remaining Strength of Corroded Pipelines.”

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (49CFR192 currently referenced edition).

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

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

5.6.4 If internal corrosion is noted, apply or confirm compliance with the requirements of Internal Corrosion procedure (Procedure 6.02).

5.6.5 Determine if a safety related condition exists.

6. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
6.02 Internal Corrosion
6.03 External Protective Coating
9.01 Repair Procedures

7. RECORDS

7.1 Complete "Maintenance and Surveillance Report" form (Form 3.01B).

7.2 Keep the records for the life of the pipeline.

CATHODIC PROTECTION and EXTERNAL CORROSION CONTROL

1. REFERENCE

49 CFR, Sections 192.455, 192.457(a), 192.463, 192.465, 192.469, 192.471, 192.473, 192.491, and 192.613.

2. PURPOSE

The purpose of this procedure is to prescribe the minimum design, installation, maintenance, survey, and test requirements to monitor and control external corrosion on buried or submerged steel pipelines per applicable Nace standards.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (187) __________________ is responsible for inspection, scheduling, and documentation as required by this procedure.

4. GENERAL

4.1 Buried or submerged gas pipelines installed after July 31, 1971 must have a cathodic protection (CP) system to protect the pipeline, installed and placed in operation within one year after completion of pipeline construction unless:

4.1.1 It can be demonstrated by tests, investigation, or experience in the area of application that a corrosive environment does not exist. This includes at a minimum, soil resistivity measurements, and tests for corrosion accelerating bacteria. Within 6 months after installation, the line must be further tested per 192.455(b) to evaluate the potential profile along the entire pipeline. If these tests indicate that a corrosive condition exists, the pipeline must be cathodically protected.

4.1.2 The pipeline is a temporary installation with an operating period of service not to exceed 5 years beyond installation and any anticipated corrosion will not be detrimental to public safety.

4.2 If any pipeline is externally coated (notwithstanding 4.1 above), it must be cathodically protected along the entire area that is effectively coated. A pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare.

4.3 Buried or submerged gas pipelines installed before August 1, 1971 must have a cathodic protection system when active corrosion is found for the following:

4.3.1 Bare or ineffectively coated pipelines.

4.3.2 Bare or coated pipes at compressor or regulator stations.

4.3.3 The company will conduct tests to determine the cathodic protection current requirements.

4.4 Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

4.5 The amount of cathodic protection must be controlled so as not do damage the protective coating or the pipe.

4.6 Cathodic protection test stations, commonly known as "electrolysis test stations" (ETS), or contact points shall normally be located and maintained at pipeline mile markers, cased crossings, and other convenient locations. Recommended test station spacing should generally not exceed 1-mile.

Test leads found to be shorted and/or non-conductive during pipeline electrical potential surveys, shall be repaired or replaced prior to the next required survey.

4.7 For new construction after January 1, 1992, cathodic protection test leads shall be anchored by wrapping around the pipe or providing a separate anchor to avoid straining the pipe to wire cad-weld.

4.8 Pipelines receiving cathodic protection from a single CP source of current must be electrically continuous with itself and the source of current. Additionally, the structure to be protected must be electrically isolated from structures which are not intended to be protected.

4.9 Each impressed current type or galvanic anode CP system must be designed and installed so as to minimize any adverse effects on existing adjacent underground or submerged metallic structures.

4.10 Interference and/or stray current effects from impressed current CP systems on foreign structures shall be minimized. Mitigation of interference effects may employ one or more of the following techniques: (1) installation of sacrificial anodes on the affected structure; (2) bonding the affected structure to the offending CP system; (3) coating the affected structure; (4) providing sacrificial anodes connected to each pipeline and buried immediately adjacent to each other in the same backfill. Mitigation measures other than the ones listed above may be utilized if approved by (188) ___________________.

5. PROCEDURE

5.1 Ensure that the CP system provides a level of protection that complies with one or more of the criteria listed in 5.2 below.

5.2 DOT acceptable criteria to assure adequate cathodic protection for steel pipelines are:

5.2.1 For onshore pipelines, a negative polarized (current applied) potential of at least 0.85 volt relative to a saturated copper-copper sulfate reference electrode. For offshore facilities, a negative polarized potential of at least 0.80 volt relative to a silver-silver chloride reference electrode. (Negative 0.85 volts vs. $Cu/CuSO_4$ is equal to 0.80 vs. Ag/AgCl.) Voltage drops (IR) other than those across the structure to electrolyte boundary must be considered for valid interpretation of this voltage measurement. (See NACE Standard Practice 0169-2007, Control of External Corrosion on Underground or Submerged Metallic Piping Systems.)

5.2.2 A minimum of 100 mV of cathodic polarization. The formation of decay of polarization can be used to satisfy this criterion.

5.3 Special Conditions

5.3.1 For pipelines installed before August 1, 1971 which are bare or poorly coated externally, the measurement of a net protective current from the electrolyte to the pipe surface (as measured by the earth current technique) at predetermined discharge points may be sufficient proof of adequate cathodic protection.

5.3.2 In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments and dissimilar metals, the criteria in Section 5.2 may not be sufficient protection.

5.4 At pipeline locations where external corrosion-related leaks are discovered, a measurement of the pipe-to-soil cathodic potential shall be taken. If the level is less than that required by regulations, the (189) ________________ shall reevaluate the CP system capacity and upgrade it as necessary prior to the next inspection.

5.5 Tests and surveys of CP systems according to the frequency schedule listed in Table 6.05A.

5.6 Prompt remedial action, at least prior to the next required survey, must be taken to correct conditions which cause the pipeline to fail to meet the applicable criterion.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.03 External Protective Coating
6.06 Electrical Isolation
6.07 Impressed Current Power Source Inspection

7. RECORDS

7.1. Record the location of cathodically protected pipeline, cathodic protection facilities, and neighboring structures bonded to cathodic protection system. (See pipeline drawings.)

7.2 The pipe-to-soil surveys are to be recorded or plotted on the special forms or charts provided for that purpose. The annual pipe-to-soil surveys, reports, and any remedial action, if any, are to be retained for the life of the facility.

TABLE 6.05A
REQUIRED TESTS FOR CATHODIC PROTECTION

SURVEY OR TEST	FREQUENCY
Pipe-to-Soil	Once each calendar year, but with intervals not exceeding 15 months.
Critical Bond	Six times each calendar year, but with intervals not exceeding 2½ months.
Noncritical Bonds	Once each calendar year, but with intervals not exceeding 15 months.
Electrical Isolation Test	Once each calendar year, but with intervals not exceeding 15 months, or when needed.
Rectifier Inspection	Six times each calendar year, but with intervals not exceeding 2½ months.
	SUPPLEMENTAL TESTING
Foreign Crossing Interference	Initially and as required, if survey done on recurring basis indicates the need.
Soil Resistivity	Initially for magnesium anode or impressed current ground bed installations.
Current Requirement	Initially and as required to determine current density, coating condition and cathodic protection sizing.
Deep Ground Bed Data	Initially to record all ground bed data during installation.
Deep Well Anode Performance	Initially and as required to record anode current outputs and look for ground bed deterioration.
Galvanic Anode Record	Initially to record all data during installation.
Rectifier Efficiency	Initially and as required.

Cathodic Protection System Record

Form # 6.05A

Reference: 49 CFR 192.465	**Date Revised: Jan 2011**

CATHODIC PROTECTION SYSTEM RECORD

Pipeline System:					Date:
Location:					Dwg. No.
Item #	**Test Station #**	**Test Location Description**	**Test Station GPS (lat. & long.)**	**P/S Readings**	**Comments**
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

Cathodic Protection System Record
Form # 6.05A

Reference: 49 CFR 192.465	Date Revised: Jan 2011

Signature
& Date of
CP Tester:

CP Tester Signature

Date

Signature
& Date of
Pipeline
Supervisor:

Pipeline Mgr/Supervisor Signature

Date

Critical Bond Reading Record
Form # 6.05B

Reference: 49 CFR 192.465(b) **Date Revised: Jan 2011**

Bond Readings Record

Date	Volts	Amps	Ohms	P/S	Foreign P/S	Initials

ELECTRICAL ISOLATION

1. REFERENCE

49CFR, Sections 192.467 and 192.613.

2. PURPOSE

The purpose of this procedure is to outline requirements for electrical isolation of buried or submerged pipeline facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (195) _________________ is responsible for implementation of this procedure.

4. GENERAL

4.1 In order to successfully and efficiently cathodically protect a buried or submerged pipeline system, it is vital that the system be electrically isolated from foreign structures. EXCEPTION: When a pipeline terminates on an offshore platform, and both the pipeline and the platform are operated by the Company, electrical isolation of the pipeline from the jacket is not normally recommended. The platforms and pipeline riser are protected as a combined entity. In some cases, an isolating device may sometimes be installed near the pig launcher (or receiver), but provision to short the device should be made.

4.2 Electrical isolating devices are installed on pipeline systems to control current flow to or from foreign structures. Insulating devices are also used to isolate sections of the same pipeline (which can facilitate the application of cathodic protection) and to isolate the pipeline from a casing or structural supports attached to other unprotected metallic structures.

4.3 No electrical isolating device shall be installed in a closed area that could retain an explosive mixture unless provisions are made to prevent electrical arcing. This includes situations similar to insulating flange kits in vaults.

5. STANDARD ELECTRICAL ISOLATION METHOD

5.1 Flange Insulation

Mating standard raised face flanges, may be made an insulating device by installing an insulating kit in the flange. An insulating kit consists of an electrically non-conductive gasket, non-conductive sleeves to encase the studs, and non-conductive washers for both nuts of a stud. Steel washers should also be placed immediately under nuts to protect the insulating washer from being crushed during torquing.

When welding the insulating flange unit or the weld type insulated coupling into the line, care shall be exercised to be sure that the insulation is not damaged by the current “arc” which could occur from welding. This can be achieved by moving the ground cable to the same side of the flange set as the electrode cable thus eliminating current “arc” across the insulating flange during welding.

5.2 Monoblock Insulating Joints

Monoblock insulating joints are factory-assembled insulating assemblies which are welded into a pipeline; they have no serviceable parts.

5.3 Insulated Unions

Insulating unions are usually used for small diameter (3 inches (7.6 cm) or less) piping attachments which required electrical insulation.

5.4 Casing Centralizers and End Seals

Non-conductive centralizing devices are attached to pipelines where the carrier pipe passes through a cased crossing. These centralizers prevent electrical contact between the casing and the carrier pipe. Casing end seals prevent water or soil from entering the annular space between the carrier pipe and casing and causing an “electrolytic” short between the casing and pipe.

5.5 Other Devices

Frequently, high-pressure laminated (e.g., micarta) dielectric blocks or neoprene rubber pads are used to electrically isolate a pipeline from supports or other structural appurtenances which are not a part of the cathodically protected pipeline.

6. CASED CROSSINGS

Whenever possible, casing installations should be avoided. In some cases, however, railroad or public highway regulations required the installation of a casing for railway right-of-way or road crossings. When casings are required, the carrier pipe must be electrically isolated from the casing.

7. PROCEDURE

7.1. Location of Insulating Devices

Generally, insulating devices should not be buried in the soil (or submerged), but located in pipe above ground or in a vault. At the termination of a pipeline, the insulating device should be as close as possible to the point where the pipeline comes above grade. Laterals, pressure taps, etc. should have insulating devices located as close as possible to the cathodically protected pipeline.

Electrical isolation equipment or devices should be installed to isolate structures from the following locations:

7.1.1 at the termination points of a pipeline system and entering or leaving a pump or compressor station;

7.1.2 at exchanges or interconnect points with other pipeline companies;

7.1.3 at connection points for gas operated control lines, electrical conduit attachments or instrumentation connections;

7.1.4 at established above ground Company facilities;

7.1.5 on the downstream side of metering stations;

7.1.6 between the casing and carrier pipe;

7.1.7 between supporting structures and the carrier pipe on bridge crossings;

7.1.8 between all metallic structures not requiring cathodic protection, such as metal valve boxes, conduit, fences, etc. and a cathodically protected pipeline;

7.1.9 where fault currents or lightning can affect the pipeline, such as close to electrical transmission tower footings or ground cables;

7.1.10 at points where dissimilar metals are attached to the pipeline, provided that both the pipeline and the dissimilar metal are buried or submerged.

7.2 Repairs

Prompt remedial action (at least prior to the next required test) shall be taken where the loss of electrical isolation causes a failure to meet the applicable cathodic protection criterion or causes detrimental effects to a foreign structure.

7.2.1 The remedial action should be restoration of electrical isolation; in some cases, other measures (such as increasing the amount of cathodic protection current applied to the pipeline) can be taken that will adequately protect foreign structures.

7.2.2 If the loss of isolation does not require prompt action, the insulating device should be repaired at the earliest opportunity in conjunction with other scheduled maintenance or modifications to the piping system.

7.3 Shorted Casing

Pipeline in casing where isolation was intended when installed, shall be evaluated and acted upon as outlined below:

7.3.1 If casing-to-soil potential is within 100 millivolts of the carrier pipe-to-soil potential, further testing is required to determine if electrical isolation exists.

7.3.2 Determine whether the situation is an “electrolytic condition” or a “metallic” shorted casing.

Note: Basically, an electrolyte is a liquid or semi-liquid substance in Which an electrical current will flow.

7.3.3 Electrolytic conditions in casings require no remedial action.

7.3.4 Retest the casing when a future survey indicates a significant decrease in potential separation from the previous test, at a casing where the test procedures previously indicated an “electrolytic condition.”

7.3.5 Attempt to clear a shorted casing promptly, within next inspection, after discovery by implementing the following actions:

7.3.5.1 Inspect the test wires for possible direct shorts, and repair as necessary.

7.3.5.2 If practical, excavate the ends of the casing and inspect the clearance between the casing and carrier pipe. If contact exists, reposition the carrier pipe and replace damaged insulators and end seals.

7.3.5.3 When a shorted casing cannot be cleared by implementing the above actions, consider installing new carrier pipe insulators when the pipeline segment is out of service for other scheduled repair, replacement, or modification; or consider filling the casing/pipe annulus with high dielectric casing filler.

7.3.5.4 Remove shorted casing when convenient.

7.3.5.5 Pipe wall metal loss may be confirmed by electromagnetic flux leakage, ultrasonic smart pigs, or other detection devices.

7.3.6 Casings that are determined to be shorted and impractical to promptly correct, shall be monitored by using leak detection instruments as shown in Table 6.06A. If a leak is found, it must be repaired immediately.

7.4 Inspection and Testing

Testing and inspection frequency requirements for the electrical isolations and shorted casing are shown in Table 6.06A.

7.5 Close Interval Surveys

Close interval surveys will be conducted if the electrical isolation status of the pipeline can not be determined using other standard corrosion and electrical procedures described in the O&M manual.

8. <u>RELATED PROCEDURES</u>

3.05 Crossing of Company Pipelines
5.01 Continuing Surveillance
5.02 Gas Leak Detection Survey for Pipelines without Odorant
6.05 Cathodic Protection/External Corrosion Control

9. RECORDS

9.1 Document all electrical isolation and casing gas leak testing. Keep these documents for at least five years.

9.2 Record the tests on possible shorted casing. Retain the record for each shorted casing until it is removed.

TABLE 6.06A

TEST FREQUENCIES FOR ELECTRICAL ISOLATION AND SHORTED CASINGS

TEST:	FREQUENCY:
Electrical Isolation:	Once each calendar year at intervals not exceeding fifteen (15) months.
Shorted Casings:	
Class 1, 2, 3 & 4 Locations	Twice each calendar year at intervals not exceeding 7½ months. (Flame Ionization Inspection.)

IMPRESSED CURRENT POWER SOURCE - INSPECTION

1. REFERENCE

49 CFR, Sections 192.465, 192.491, and 192.613.

2. PURPOSE

The purpose of this procedure is to establish the requirements for inspecting and checking impressed current cathodic protection systems.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (201) ____________________ is responsible for scheduling, inspection, and documentation as required by this procedure.

4. GENERAL

4.1 Rectifiers and ground beds provide a driving voltage and current greater than can be produced by galvanic anodes. Compared to sacrificial anodes, this type of protection covers a much larger area and gives greater flexibility to the cathodic protection system by allowing control of the current output.

4.2 The rectifier ground bed method develops an electrolytic cell making the structure to be protected the cathode and the ground bed of the rectifier the anode. (Reversing the polarity will cause rapid corrosion of the pipeline.)

4.3 To gain the greatest benefit from corrosion control, it must be a continuous process. The rectifier will not give protection if it has not been properly installed. Therefore, proper installation of any rectifier is of utmost importance and will serve to prevent trouble later.

5. PROCEDURE

5.1 Inspect each cathodic protection rectifier or other impressed current power source at least six (6) times each calendar year, but at intervals not exceeding 2½ months.

Where impressed current to a company owned pipeline or facility is provided by others, i.e. a third party or other operator, a request to a responsible individual shall be made for rectifier readings and maintenance records.

5.2 Conduct the following tasks during each inspection:

5.2.1 Inspect each impressed current power source and its components for proper operation.

5.2.2 Determine the D.C. volts and amperes as applicable.

5.3 Take prompt remedial action to correct any deficiencies indicated by the monitoring. Any necessary remedial action must be taken prior to the next inspection.

5.3.1 Determine if unusual current and voltage readings are the result of rectifier malfunctions or due to changed pipeline protection requirements.

5.3.2 Notify (202) _______________ of malfunctioning rectifiers.

5.3.3 Notify (203) _______________ of indications of changed pipeline C.P. requirements.

6. <u>RELATED PROCEDURES</u>

5.01 Continuing Surveillance
6.05 Cathodic Protection/External Corrosion Control
6.08 Cathodic Protection Records

7. <u>RECORDS</u>

7.1 Record all survey and test results on a special form or chart for that purpose.

7.2 Maintain the records of power source inspections and efficiency calculations for at least five years.

Rectifier Readings
O&M Procedure 6.07
Form #6.07A

Reference: 49 CFR 192.465(b)	**Date Revised: Jan 2011**

RECTIFER READINGS
Required Frequency: 6x/year not to exceed 2 ½ months

Line Location		Unit Location	Unit Number
Make	Size	Serial Number	Year Installed
Year:			

Month:	**Date:**	**Volts:**	**Amps:**	**Inspect the rectifier and its components for proper operation.**	**Name of Person Performing the Inspection:**
Jan					
Feb					
March					
April					
May					
June					
July					
Aug					
Sept					
Oct					
Nov					
Dec					

CATHODIC PROTECTION MAPS AND RECORDS

1. REFERENCE

   49 CFR, Section 192.491.

2. PURPOSE

   The purpose of this procedure is to establish the methods by which records will be maintained showing the location and type of cathodic protection for all pipelines operated by the Company.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (210) _______________ is responsible to maintain the Corrosion Control Records for the life of the pipeline facilities.

4. PROCEDURE

   4.1 Maintain drawings, plat sheets, maps, or other records for each pipeline showing the location of cathodically protected piping, cathodic protection facilities, and neighboring structures bonded to the system.

   4.2 Show the location of the protection type, such as:

   4.2.1 Sacrificial Anode Bed

   4.2.2 Impressed Current Rectifier

   4.2.3 Bonded Impressed Current

   4.3 Show the location of the protective equipment, such as:

   4.3.1 Rectifier

   4.3.2 Insulation Flange

   4.3.3 Insulating Joint

   4.3.4 Bonds (critical, noncritical, and interference)

4.3.5 Ground Bed - Conventional (surface)

4.3.6 Ground Bed - Well Type (vertical)

4.3.7 Cathodic Protection (CP) or Electrolysis Test Stations (ETS) and monitors

5. RELATED PROCEDURES

5.01 Continuing Surveillance
Section 6 - Pipeline Corrosion Control, in this manual.

6. RECORDS

Maintain the maps and records for the life of the facility, structure, or the pipeline.

EVALUATION OF BARE, BURIED OR SUBMERGED UNPROTECTED PIPELINES

1. REFERENCE

   49 CFR, Sections 192.455, 192.457(b), 192.465(e), 192.491 and 192.613.

2. PURPOSE

   The purpose of this procedure is to establish the inspection practices for bare, unprotected pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (216) __________________ is responsible for implementing the requirements of this procedure to evaluate the external corrosion of bare, unprotected pipe.

4. GENERAL

   4.1 A continuing program of examination and recording the results of the inspection of bare, unprotected pipelines is mandatory for evaluating the effects of external corrosion.

   4.2 It is intended that examinations will monitor the effects of external corrosion and, where necessary to protect the integrity of the pipeline and dictate the installation of cathodic protection equipment.

   4.3 Corrosion, leaks, and defects may be safety related conditions.

5. PROCEDURE

   5.1 After the initial evaluation, bare, below-ground unprotected pipelines shall be visually inspected where naturally accessible at intervals of 3 years, not to exceed 39 months, to determine if areas of possibly active corrosion exist.

      5.1.1 Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

   5.2 Areas of possibly active corrosion shall be evaluated by electrical survey. However, where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include a review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

5.2.1 Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that is subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

5.2.2 Pipeline environment includes soil Resistivity (high or low), soil moisture (wet or dry), soil containments that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

5.3 Areas confirmed to be corrosively active shall be cathodically protected.

5.4 The pipeline MAOP shall be evaluated and revised if necessary or the appropriate pipeline repairs performed. See Procedure 8.01.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), “Manual for Determining the Remaining Strength of Corroded Pipelines.”

2) AGA Pipeline Research Committee, Project PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (49CFR192 currently referenced edition).

5.5 Review the pipeline per the criteria shown on Form 6.09A. Areas with Category 3 corrosion shall be cleaned, coated, repaired, replaced, and/or cathodically protected.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
6.03 External Protective Coating
8.01 Maximum Allowable Operating Pressure
9.01 Repair Procedures

7. RECORDS

7.1 Complete the "Unprotected Pipeline Surveillance Report" (Form 6.09A).

7.2 Complete forms from related procedures wherever active corrosion is identified.

7.3 Retain records for the life of the pipeline.

UNPROTECTED PIPELINE INSPECTION REPORT

FORM 6.09A

DATE: MO DAY YR

SYSTEM: ______________________

SIGNATURE: ______________________

SIGNATURE OF SUPERVISOR: ______________________

PIPELINE INSPECTION		AREA OF POSSIBLE ACTIVE CORROSION				
FROM	TO	FROM	TO	CONDITION *	ULTRA SONIC READING	COMMENTS
STATION	STATION	STATION	STATION	(0,1,2,OR 3)	READING OR PIT DEPTH GA	

* 0 - NO CORROSION
1 - LIGHT SURFACE RUST - NOT MEASURABLE
2 - MEDIUM SURFACE RUST - MEASURABLE, BUT NOT DETRIMENTAL (LESS THAN 10% OF NEW PIPE NOMINAL WALL THICKNESS)
3 - HEAVY. OBVIOUS PITTING (IN EXCESS OF 10% OF NEW PIPE NOMINAL WALL THICKNESS)

CP REPORTS REVIEW

1. REFERENCE

49 CFR, Sections 192.453 and 192.613.

2. PURPOSE

The purpose of this procedure is to describe the role of (222) _____________ in implementing and/or monitoring the corrosion control program. It also provides for flexibility in location of records and staffing.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (223) ________________ is responsible for implementation of corrosion control programs through the company.

4. GENERAL

The (224) ________________ will have one individual qualified by experience and training in pipeline corrosion control methods to carry out the corrosion control program.

5. PROCEDURE

The (225) ________________ will provide overall guidance in corrosion control activities.

5.1 Reviews field corrosion reports and data.

5.2 Recommends corrective action when requested.

5.3 Prepares a yearly report which highlights some pertinent corrosion control activities of the company, which should include as a minimum, the following:

5.3.1 Annual CP system survey status.

5.3.1.1 Annual ETS survey.

5.3.1.2 Miles of close interval survey that have been conducted with the reason for survey, location of the survey, and their results.

5.3.1.3 Number of ground beds installed, improved or abandoned, with the locations and reasons for such activities.

5.3.1.4 Number of foreign line interference tests conducted and their results.

5.3.1.5 Number of rectifiers repaired and new rectifiers installed. The location and the reason for such activities.

5.3.2 Miles of pipelines recoated, and the location and the reason for recoating.

5.3.3 The location and kinds of treatment conducted to improve the internal corrosion mitigation program.

5.3.4 Maintenance painting done on above ground piping and structures.

5.3.5 Other miscellaneous problems in the field with the corrosion control program.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
6.02 Internal Corrosion
6.03 External Protective Coating
6.04 Internal and External Examination of Buried Pipeline
6.05 Cathodic Protection/External Corrosion Control
6.06 Electrical Isolation
6.07 Impressed Current Power Source Inspection
6.08 Cathodic Protection Records
6.09 Evaluation of Bare, Buried or Submerged Unprotected Pipelines

7. RECORDS

Corrosion control records required by corrosion procedures are to be kept at the District Office.

REMEDIAL MEASURES

1. REFERENCE

49 CFR, Sections 192.465 (d), 192.483, and 192.485.

2. PURPOSE

The purpose of this procedure is to describe the role of (226) _____________ in implementing remedial measures should they arise.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (227) ________________ is responsible for implementation of corrosion control remedial measures.

4. GENERAL

The (228) ________________ will have one individual qualified by experience and training in pipeline corrosion control methods to carry out the corrosion control program.

Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly or the pipeline must be shut down until the repair is made. The company may not operate a segment of pipeline, unless it is maintained in accordance with this subpart M, Maintenance, 192.701-755.

5. PROCEDURE

The (229) ________________ will provide overall guidance in corrosion control activities including remedial measures.

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

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

The strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures. No analysis is conducted on a corrosion defect having a depth greater than 80% of the pipe wall thickness; it must be repaired or replaced. If the deepest corrosion pit is less than 10% of the pipe wall thickness, no corrective action is required.

When pipeline corrosion damage has been located, sketch pitting for documentation purposes, recording a number of pit depths which is evenly divisible into the total length of the pitted area. For instance if the length is 5 than take 10 pit depths for a spacing of .5. This multiple pit data is used in the R-Streng calculation to determine the appropriate MAOP for the pipeline. The depth of the deepest pit and the total length of the corrosion pitted area is used in the B-31-G formula.

When corrosion damage on a pipeline is located, the Company pipeline pitting analysis manual should be consulted. The Company Corrosion engineer should be consulted for application of pipeline corrosion analysis procedures and calculations. These include; GPTC G-192-6, B31G and R Streng. Options to be determined by use of these calculations include:

1. Pipeline section replacement
2. Application of sleeve
3. Re-coating and return to service
4. Reductions in MAOP

6. RELATED PROCEDURES

5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
6.02 Internal Corrosion
6.03 External Protective Coating
6.04 Internal and External Examination of Buried Pipeline
6.05 Cathodic Protection/External Corrosion Control
6.06 Electrical Isolation
6.07 Impressed Current Power Source Inspection
6.08 Cathodic Protection Records

6.09 Evaluation of Bare, Buried or Submerged Unprotected Pipelines

7. RECORDS

Corrosion control records required by corrosion procedures are to be kept at the District Office.

INSPECT AND MAINTAIN EMERGENCY VALVES

1. REFERENCE

49 CFR, Sections 192.145, 192.179, and 192.745.

2. PURPOSE

The purpose of this procedure is to provide guidelines for valve inspection and maintenance to ensure the safe operation of any valve that may be required in an emergency.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (231) _________________ is responsible for identifying and inspection of the emergency valves within his area.

4. GENERAL

4.1 Any valve that may be required in an emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

4.2 Valves that may be required in an emergency shall be determined by the (232) _________________ .

4.3 Necessary personnel shall be notified prior to operating any valve that may significantly affect the normal operation of those locations. Other concerned personnel shall be notified when the inspection is complete.

4.4 The inspection and partial operation of all non-emergency valves will be at the discretion of the (233) _________________ .

4.5 Except for cast iron and plastic valves, each valve must meet the minimum requirements of API 6D (ibr, see 192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

5. PROCEDURE

5.1 The valve inspection and maintenance should include but not be limited to:

5.1.1 Grease or lubricate valve if applicable.

5.1.2 Fully operate the valve, if possible; if not, partially operate the valve to check its operation (do not use "cheater" device).

5.1.3 Operate power operated valves by introducing the normal power source to the operator.

5.1.4 Check above-ground valves for atmospheric corrosion.

5.1.5 Ensure the valve environment will not interfere with the operation of the valve or prevent safe personnel access at any time of the year.

5.1.6 Check for possible blowdown obstructions and posted signs if applicable.

5.2 Maintain valves and operators in operating condition. The Company will take prompt remedial action to correct any valve found inoperable, unless the Company designates an alternative valve.

5.3 Protect normally closed valves from conditions which could affect proper operation or cause deterioration.

5.4 Perform inspection and maintenance on frequently operated valves more often if needed.

5.5 Secure valves requiring locking devices to prevent unauthorized operation. Areas not accessible to the public do not require chains and locks on valves. Inaccessible areas could include offshore platforms, locked vaults, and remote, fenced and gated fields, etc.

5.6 Inspect above-ground piping or fabrications associated with a valve outside of a plant yard for atmospheric corrosion when the valve is given its inspection, and maintain as appropriate.

5.7 Ensure the valve environment will not interfere with the operation of the valve or prevent safe personnel access at any time of the year.

5.8 Notify the control room and/or the appropriate person when the valve inspection is complete.

6. RELATED PROCEDURES

- 5.01 Continuing Surveillance
- 6.01 Atmospheric Corrosion
- 9.02 Blowdown and Purging Safety
- 14.01 Valve Security

7. RECORDS

7.1 Fill out “Emergency Valve Inspection Report”, (Form 7.01A) or equivalent.

7.2 Keep inspection records for at least five years.

EMERGENCY VALVE INSPECTION REPORT
FORM 7.01A [192.745]

COMPANY:	OPERATING LOCATION:	DATE: ______ MO-DAY-YR
SYSTEM:	STATION: ☐ Haz. Liq. ☐ Nat. Gas	VALVE I.D.:

VALVE LOCATION

☐ Above Ground	☐ Valve in vault	☐ Under Ground (Buried)
☐ Mainline Block Valve	☐ Branch Block Valve	☐ Bypass
☐ Block Under Relief Valve	☐ Plant Block Valve	☐ Other ______
☐ Blowdown Valve	☐ Upstream	☐ Downstream

VALVE SPECIFICATIONS

Manufacturer:			Type:	Model:	
Size:	Rating:	End Connection:	Screwed:	Flanged:	Welded:
Operator:	☐ Wrench	☐ Hand Wheel	☐ Gear	☐ Operator	

MAINTENANCE PERFORMED

Valve Inspected	☐ YES	☐ NO
Valve Partially Operated	☐ YES	☐ NO
Stem & Gearing Parts Inspected	☐ YES	☐ NO
Stem & Gearing Lubricated	☐ YES	☐ NO
Power Operator Tested	☐ YES	☐ NO
Valve Body Drained	☐ YES	☐ NO
Inspected For Atmospheric Corrosion	☐ YES	☐ NO
Repairs Required	☐ YES	☐ NO
Proper Identification For Blow-Off Locations (GAS)	☐ YES	☐ NO
(Sign Should Indicate "Controlled Blowdown Required Due To Overhead Or Adjacent Facilities")		

VALVE SECURITY

Lock And Chain Required:	☐ YES	☐ NO
Lock And Chain In Place:	☐ YES	☐ NO

REMARKS

DISTRIBUTION:

____

____

____

SUPERVISOR:

____
SIGNATURE

INSPECTED BY:

____
SIGNATURE

PRESSURE REGULATORS AND RELIEF DEVICES
(Overpressure Safety Devices)

1. REFERENCE

49 CFR, Sections 192.145, 192.169, 192.195, 192.199, 192.201, 192.731, 192.739, and 192.743.

2. PURPOSE

The purpose of this procedure is to establish requirements for the inspection, testing, and capacity verification of regulator and relief devices used in natural gas pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (239) ____________________ is responsible for the inspection, maintenance, and mechanical condition of all pressure limiting devices, relief valves, pressure regulators or other items of pressure control.

4. GENERAL

4.1 This procedure outlines inspection, test frequency, documentation, capacity verification requirements and specifies applicable records.

4.2 Disassembly of pressure regulators and relief valves for internal inspection is not required to satisfy the requirements of this procedure.

4.3 Each compressor station and/or pipeline must have pressure relief or other suitable devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure (MAOP) of the system is not exceeded by more than 10%, or the pressure that produces a hoop stress of **75%** of SYMS, whichever is lower. [192.201(a)]

4.4 Except for plastic valves, each valve must meet the minimum requirements, or equivalent, of API 6D.

5. PROCEDURE

5.1 Frequency of Inspection

5.1.1 Inspect and test regulators and relief devices once each calendar year with intervals not to exceed fifteen (15) months.

5.1.2 If equipment or physical conditions change between scheduled inspections and tests, perform the appropriate items required by this procedure to assure continued compliance.

5.1.3 Each pressure regulator and relief shall be reviewed or tested for capacity once each calendar year with intervals not to exceed fifteen (15) months. This capacity review shall verify the pressure limits consistent with 192.201(a). The operator can test the device in place or review by calculation.

5.1.4 If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

5.1.5 If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

5.2 Regulator Inspection

5.2.1 Inspect and test each pressure regulator to assure that:

5.2.1.1 It is in good mechanical condition.

5.2.1.2 It is adequate from the standpoint of capacity and reliability of operating for the service in which it is employed.

5.2.1.3 It is set to function at the correct pressure.

5.2.1.4 Is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operations.

5.2.1.5 Its control system lines are properly supported and protected.

5.2.1.6 Its vent line is terminated in a safe location to prevent a hazardous condition and protected to minimize possible plugging with items such as snow, ice, or insects.

5.2.2 Repair or replace defective or inadequately sized equipment or components prior to the next inspection.

5.3 Relief Device Inspection

5.3.1 Inspect and test each pressure relief device to assure that:

5.3.1.1 It is in good mechanical condition.

5.3.1.2 It opens at the proper pressure. Actuate the "pilot operated" valve piston (main valve) in addition to the pilot.

5.3.1.3 Its vent line is free of obstructions and is protected to prevent entrance of moisture, or plugging with items such as snow, ice, or insects.

5.3.1.4 Its control line is properly supported and protected.

5.3.1.5 It has adequate capacity.

5.3.1.6 Is properly installed and protected from dirt, liquids, or other conditions that might prevent proper operations.

5.3.2 If relief valve capacity test is not feasible, calculate the required capacity or review past calculations. Indicate review on Form 7.02A. Make an on-site review and verification of the facilities and pressures at the time the relief valve is to be tested. Check to see that the correct valve is installed, no changes have been made to the valve, and operating and/or relief flows and pressures are still the same.

5.3.3 Initiate appropriate measures to increase relief capacity promptly if existing capacity does not meet requirements.

5.3.4 Initiate appropriate measures promptly to provide overpressure protection if a defective valve is observed.

5.3.5 Remedial work required on relief valves must be completed (prior to the next inspection).

5.3.6 Secure isolating valves, when installed, in the open position after each relief valve inspection and test. Lock each isolating valve not located within a locked building to avoid accidental or malicious closing.

5.4 Regulator and Relief Devices Set Point

Establish relief valve set points to control or relieve at the correct pressure consistent with the pressure limits of 192.201(a) and shown below in steps 5.4.1 through 5.4.3.

5.4.1 If the MAOP is 60 psig (414 kPa) or more: Each compressor station and/or pipeline must have pressure relief or other suitable devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure (MAOP) of the system is not exceeded by more than 10%, or the pressure that produces a hoop stress of 75% of SYMS, whichever is lower. [192.201]

5.4.2 If the MAOP is 12 psig (83 kPa) or more but less than 60 psig (414 kPa): MAOP plus 6 psig, (42 kPa).

5.4.3 If the MAOP is less than 12 psig (83 kPa): MAOP plus 50%.

5.4.4 For steel pipeline whose MAOP is determined by five year operating history under 192.619(c) and the MAOP is 60 psi gage or more, the control or relief pressure limit is as follows: [192.739]

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 % of SYMS	MAOP plus 4%
Unknown as a % of SYMS	A pressure that will prevent an unsafe condition of the pipeline considering its operating history, maintenance history, and MAOP.

6. RELATED PROCEDURES

5.01 Continuing Surveillance
8.01 Maximum Allowable Operating Pressure (MAOP)
14.01 Valve Security

7. RECORDS

7.1 Document inspection and testing of pressure regulators and relief devices on Forms 7.02A and 7.02B.
7.2 Document capacity confirmations and verifications of calculations.
7.3 Document reasons for needed changes to set points.
7.4 Retain the above documents for at least five years.

RELIEF VALVE REPORT

FORM 7.02A [192.739]

COMPANY:	OPERATING LOCATION:	DATE: ____________ MO-DAY-YR
SYSTEM:	☐ HAZARDOUS LIQUID ☐ NATURAL GAS	VALVE I.D.:

Reason For Report:	☐ Inspection	☐ Repair	☐ New Installation	☐ Removal
System MAOP or MOP:			Set Pressure:	

Manufacturer:	Type/Model:	Serial #:	Orifice Size:

Inlet: ________	☐ Screwed	☐ Flanged	Rating:		
Outlet: ________	☐ Screwed	☐ Flanged	Rating:		
Block Valve	Size:	Type:	Locked:	☐ Yes	☐ No
Test Connection:	☐ Yes	☐ No	Vent Line Size:		
Rain Cap:	☐ Yes	☐ No	Weep Hole:	☐ Yes	☐ No
Lift Lever:	☐ Yes	☐ No	Relief Valve Installation Braced:	☐ Yes	☐ No

Relief Valve Location:		
☐ Side of Header	☐ Top of Header	☐ Remote

Rated Capacity:	____________ gpm or scfm	Required Capacity:	____________ gpm or scfm	Date:
☐ Checked, No Changes				

Remarks: ______________________________

Distribution:

____

____

____

____

____

Serviced By: ______________________________

Witnessed By: ______________________________

Supervisor: ______________________________

REGULATOR REPORT

FORM 7.02B [192.739]

COMPANY:	OPERATING LOCATION:	DATE: ____ MO-DAY-YR
SYSTEM:	☐ HAZARDOUS LIQUID ☐ NATURAL GAS	VALVE I.D.:

Reason For Report: ☐ Inspection ☐ Repair ☐ New Installation ☐ Removal

REGULATOR

Manufacturer:	Model:	Size:	Serial No.:	Make:	Actuator:	Model:	Pressure On Diaphragm: ☐ Open ☐ Close
TYPE INNER VALVE	ORIFICE SIZE		LINER SIZE %	BODY ☐ Screwed ☐ Flanged		ANSI SERIES	MAX. WORKING PRESSURE
TYPE SERVICE	☐ Reducing ☐ Standby	☐ Back Pressure ☐ Monitor		Upstream:	Operating Pressure:	Downstream:	

CONTROLLER

Manufacturer:	Model:	SPRING RANGE:	VARIABLE ORIFICE SETTING INLET: JACKET:

VALVE POSTIONER

Manufacturer:	Model:	Model: ☐ Direct ☐ Reverse

PILOT REGULATORS OR RELAYS

MANUFACTURER	TYPE	PRESS. UPSTREAM	PRESS. DOWNSTREAM

BY-PASS SIZE:	STATION VALVES CHECKED ☐ Yes ☐ No	MAX. INLET PRESS. EXPECTED AT THIS LOCATION:

VALVE SECURITY

Lock And Chain Required:	☐ YES	☐ NO
Lock And Chain In Place:	☐ YES	☐ NO

REMARKS

DISTRIBUTION:

Serviced By: ____________________

Witnessed By: ____________________

Supervisor: ____________________

O&M Procedures – Relief Valve & Regulator Station Capacity Review
Form # 7.02C

Reference: 49 CFR 192.743	Date Revised: Jan 2011

Pipeline Name: ________________ Calculation and Review Date: ___________________

Station Name: ________________ Calculation and Review By (PRINT): ___________________

Station Location: ________________ Calculation and Review By: (Signature):__________________

RELIEF DEVICE TESTING LOCATION

Relief device was tested in place. Date:______________ See Forms #7.02A

Relief device was removed and tested on site. Date:______________ See Forms #7.02A

Relief device was removed and tested off-site. Date:______________ See Forms #7.02A

REASON(S) FOR NOT TESTING IN PLACE

It was not feasible to test the pressure relief device in place due to:

____a. Availability of test media and equipment to conduct the test.
____b. The effect of the test on continuity of service and on other components of the system.
____c. The effect of the venting of gas on the environment due to noise pollution, air pollution and the potential for creating a hazardous condition.
____d. The need to conserve energy.
____e. Governmental regulations.
____f. Other (explain).

____

DETERMINATION OF CAPACITY SUFFICIENCY

The required capacity of the pressure relief device is __________MCF/D. (review documentation is on file):

The calculated, rated or experimentally determined relieving capacity of the pressure relief device is (calculation documentation is on file): __________MCF/D.

_____The calculated, rated or experimentally determined relieving capacity of the pressure relief device is equal to or greater than the required capacity. No new or additional pressure-relieving device is required.

_____The calculated, rated or experimentally determined relieving capacity of the pressure relief device is less than the required capacity. New or additional pressure-relieving device(s) is (are) required.
Date installed:____________

VALVE VAULTS with REGULATORS

1. REFERENCE

49 CFR, Sections 192.183, 192.185, 192.187, 192.189, and 192.749.

2. PURPOSE

The purpose of this procedure is to establish requirements for the inspection and maintenance of valve vaults used to shelter valves along the pipeline.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (245) _________________ is responsible for the inspection, maintenance, and overall condition of all valve vaults along the pipeline.

4. GENERAL

4.1 This procedure outlines inspection criteria and frequency, and maintenance procedures.

4.2 All vaults used to house pressure limiting and pressuring regulating devices, and containing an internal volume of 200 cubic feet (5.7 cubic meters) or more must be inspected annually. Pressure limiting devices DOES NOT include block valves and blow down valves.

5. PROCEDURE

5.1 Vaults containing 200 cubic feet(5.7 cubic meters) or more of internal volume must be inspected each calendar year, at intervals not to exceed 15 months. The inspection is to determine if the vault is in good physical condition and is adequately ventilated.

5.2 Prior to entry, personnel shall verify that the concentration of oxygen is sufficient to permit safe entry by using a personal gas monitor. The concentration of flammable vapor shall also be verified to be safe by personal gas monitor. “Safe” in this case means a flammability reading of less than 10% of the lower explosive limit. Individuals must consult Company Confined Space Entry Standards prior to entering any vault.

5.3 A minimum of 2 personnel must be present on-site prior to a man entering the vault. At least one person must remain outside the vault at all times.

5.4 Crews servicing enclosed vaults should be equipped with portable ventilation equipment, safety harnesses with lanyards, and appropriate hoisting equipment.

5.5 If gas is discovered in a vault, all equipment housed in that vault must be inspected for leaks. Any leak discovered must be repaired promptly (prior to the next inspection).

5.6 Ventilating equipment must be inspected to determine that it is functioning properly. Malfunctioning or dysfunctional ventilation equipment should be repaired or replaced prior to the next inspection.

5.7 All vault covers must be inspected to determine if there is a hazard to public safety.

5.8 Inspection frequency and criteria should be increased if it is determined that a safety hazard may exist in a vault.

6. RELATED PROCEDURES

1.02 Reporting of Safety Related Conditions
5.01 Continuing Surveillance
6.01 Atmospheric Corrosion
14.03 Prevention of Accidental Ignition
Company Confined Space Entry Standard

7. RECORDS

7.1 Complete Form 7.03A to document the inspections, record observations, and any actions taken.

7.2 These records are to be retained for at least five years.

VAULT WITH REGULATOR INSPECTION FORM

FORM 7.03A [192.749]

SYSTEM: ____________________

DATE MO-DAY-YR	BY WHO	TAG ID #	LEAK DISCOVERED (Y / N)	CONDITION OF VAULT COVER	VAULT LOCKED (Y / N)	SIGNATURE	ACTIONS TAKEN / COMMENTS

MAOP

1. REFERENCE

49 CFR, Sections 192.103, 192.105, 192.107, 192.109, 192.111, 192.113, 192.115, 192.485, 192.611, 192.613, and 192.619, and PHMSA "Determination of MAOP in Natural Gas Pipelines"

2. PURPOSE

The purpose of this procedure is to outline the responsibility for establishing the maximum allowable operating pressure of each pipeline segment and the related operating requirements.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (251) _________________ is responsible to establish maximum allowable operating pressure (MAOP) on pipeline facilities and the (252) _________________ is responsible to maintain the operating pressure of the pipeline systems at or below the established maximum operating pressure.

4. GENERAL

4.1 The maximum allowable operating pressure (MAOP) of a steel pipeline segment may not exceed the lowest of the following: [192.619(a)-(4)]

1) The design pressure of the weakest element in the segment (see 4.1.1)
2) The pressure obtained by dividing the pressure to which the segment was tested after construction (see 4.1.2)
3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date (see 4.1.3)
4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure (see 4.1.4)

4.1.1 The design pressure of the weakest element in the segment. [192.619(a)(1)]

4.1.1.1 For steel pipe, the design pressure is defined by the following: [192.105(a)(1)]

P = (2 St/D) x E x F x T where,

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with 192.107. Note that "S" is the specified minimum yield strength for API-5L, ASTM A 53, A106, A333, A381, A671, A672, and A691 steel pipe.

D = Nominal outside diameter of the pipe in inches (millimeters).

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with 192.109.

Additional wall thickness required for concurrent external loads in accordance with 192.103 may not be included in computing design pressure.

F = Design factor determined per the following:

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

E = Longitudinal joint factor determined per the following:

Specification	Pipe Class	E
ASTM A 53	Seamless Electric resistance welded Furnace butt welded	1.00 1.00 0.60
ASTM A 106	Seamless	1.00
ASTM A333/A333 M	Seamless Electric resistance welded	1.00 1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API 5L	Seamless Electric resistance welded Electric flash welded Submerged art welded Furnace butt welded	1.00 1.00 1.00 1.00 0.60
*Other	Pipe over 4 inches	0.80
*Other	Pipe 4 inches or less	0.60

Note: All pipe specifications listed above are to be the 49 CFR 192 currently referenced edition in accordance with 192.7.

*If the type of longitudinal joint cannot be determined, the joint factor used must not exceed that designated for "other."

T = Temperature de-rating factor determined per the following:

Gas Temperature in Degrees Fahrenheit (Celsius)	**Temperature De-rating Factor (F)**
250 or less (121)	1.000
300 (149)	0.967
350 (177)	0.933
400 (204)	0.900
450 (232)	0.867

For intermediate gas temperatures, the de-rating factor is determined by interpolation.

4.1.1.2 For valves, flanges, fittings, and other components, the design pressure is determined by the applicable listed specification and/or manufacturer specification.

4.1.1.3 For steel pipe in pipelines being converted under Conversion of Service, Procedure 12.02, or uprated under Procedure 12.01, if any variable necessary to determine the design pressure under the design formula (Procedure 8.01) is unknown, one of the following pressures is to be used as design pressure:

4.1.2.3a Eighty percent (80%) of the first test pressure that produces yield under Section N5.0 of Appendix N of ASME B31.8 (49CFR192 currently referenced edition), reduced by the appropriate factor in Section 4.1.3 of this procedure; or:

4.1.2.3b If the pipe is 12 3/4 in (324 mm) or less in outside diameter and is not tested to yield under this Section, 200 psig (1379) kPa.

4.1.2 Pressure Test Requirements [192.619(a)(2)]

This regulation applies not only to tests made after initial construction of the pipeline or system, but also to tests of pipe used for extensions, laterals, or services connected to the original pipe, and to any replacement pipe. Any single piece of pipe tested to a lower pressure than the rest of the system will set the MAOP for the entire system. If more than one pressure test has been conducted, the most recent test controls.

For steel pipe operated at 100 psig (689 kPa) or more, the pressure test obtained by dividing the pressure to which the segment was tested under construction as follows:

Class Location	**Factors***		
	Installed before Nov. 12, 1970	**Installed after Nov. 11, 1970**	**Converted under 192.14**
1 **	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

*For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

**If there is a building intended for human occupancy in a Class 1 location, the factor is 1.25. (See Procedure 15.01, paragraph 6.1.6. Also, see paragraph 6.1.7 in Procedure 15.01 for another exception to this table.)

4.1.3 Operating History Requirements [192.619(a)(3)]

If the design pressure rating for system components cannot be determined due to lack of information, setting the MAOP based on Part 192.619(a)(4) or Part 192.619(a)(5) may be considered. This decision shall be cleared through the appropriate regulatory agency. Approval from regulatory agency shall be in writing.

The highest actual operating pressure to which the segment was subjected during the 5 years, preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested per 4.1.2 above after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated per Procedure 12.01.

For onshore pipelines, review records for the highest operating pressure between July 1, 1965, and July 1, 1970, such as pressure charts, regulator station inspection reports showing inlet or outlet pressures, etc. If no records are available, a notarized statement by a person in charge of pipeline operations during that time period, attesting to the operating pressure during that period, may be acceptable at the discretion of regulatory agencies.

The historic operating pressure limit can be overridden in two ways: by a pressure test under Part 192.619(a)(2) conducted after July 1, 1965, or by an uprating in compliance with Part 192, Subpart K. The most recent test or uprating would control.

4.1.4 Maximum Safe Operating After Review of the Pipeline [192.619(a)(4)]

If pipeline records are missing or incomplete, it may be impossible to conclusively determine what the MAOP should be under this criteria. In this situation the operator must consult with the Regulatory Agency, and should look at the normal operating pressures over the last 5 years, and select the highest pressure which did not cause unusual safety or operational problems. This pressure must have applied for a long enough period of time for any problems to become evident. The operator could then conclude that this pressure represents the maximum known safe operating pressure, and determine that it should be the MAOP.

Use of Part 192.619(a)(4) to establish the MAOP will require that the pipeline or system have overpressure protection to prevent the MAOP from being exceeded should a regulator failure occur. Any previous "grandfather" exemption from overpressure protection requirements is overruled. The concept is that if higher than normal pressures could cause a safety problem, or if the safety risk of a higher pressure cannot be determined because of lack of information, then measures must be taken to prevent that higher pressure from occurring.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), "Manual for Determining the Remaining Strength of Corroded Pipelines."

2) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe"(49CFR192 currently referenced edition).

4.2 No person shall operate a gas pipeline at internal pressures which exceed the established maximum allowable operating pressure for that pipeline.

4.3 Determination of MAOP for plastic pipelines is covered in Procedure 16.06.

5. PROCEDURE

5.1 After determining the appropriate pressure limit in each category which applies to the pipeline or pipeline system involved (see sections #4.1.1-4.1.4 above), select the lowest value as the MAOP. Use form #8.01A and form #8.01B to aid in MAOP determination and attach all support documents. These support documents should be for all categories reviewed, not just the one which controlled. This file should be maintained for the life of the pipeline or system involved.

5.2 Establish the maximum allowable operating pressure (MAOP) for each distinct segment of all existing and new pipeline facilities. Records must be available to substantiate any value determined. Form #8.01A and #8.01B can be used to document the MAOP determination. The (253) ________________ shall communicate the MAOP to the appropriate parties.

5.3 Control operating pressures at or below established maximum operating pressure for all pipelines at all times.

5.4 No person shall operate or cause action which will operate any pipeline section in excess of its established maximum allowable operating pressure (MAOP).

5.5 Implement repairs, modifications, or additions to a segment of pipeline so that the maximum allowable operating pressure (MAOP) of the segment is maintained through the use of approved materials, construction and testing methods.

6. <u>RELATED PROCEDURES</u>

8.02 Operating Pressure Limits – Maintenance & Repair
15.01 Pressure Testing

7. <u>RECORDS</u>

7.1 Retain operating logs and/or pressure charts for at least five years.

7.2 Submit all as-built documents to (254) _________________ to update the drawings and confirm the MAOP.

7.3 Maintain as-built documents for the life of the pipeline facility.

7.4 Record MAOP and basis of determination in the operations description portion of the system specific System Operations Manual. Record pertinent data using the Pipeline Qualification Record (Form 8.01A) at the end of this section.

7.5 Retain calculations used to determine the MAOP in the pipeline historical file.

PIPELINE QUALIFICATION RECORD
FOR GAS PIPELINES

OPERATING SYSTEM	

1. System Information	
a. Main Line System	
b. Segment	
c. AFE No.	
d. Date	
e. Drawing References	

2. Pipe Summary	
a. Size O.D. ( )	
b. Wall Thickness *(if unknown, see 192.109(c),(d))*	
c. Specification (API-5L, ASTM A53, etc.)	
d. Grade (B, X42, etc.)	
e. Pipe Class (SMLS, ERW, etc.)	
f. Length ( )	
g. DOT Class Location	
h. Maximum Operating Temperature ( )	
i. Pipe Manufacturer	
j. Year Manufactured	
k. Manufacturing Location	
l. Year Purchased	
m. Method of Transportation	

3. Design Data	
a. Steel Pipe	
(1) Yield Strength, “S” (PSI) *(see 192.107)*	
(2) Design Factor, “F” *(see 192.111)*	
(3) Seam Joint Factor, “E” *(see 192.113)*	
(4) Temperature Derating Factor, “T” *(see 192.115)*	
(5) Test Pressure Factor, “TPF” *(see 192.619(a)(2)(ii))*	
(6) ASME/ANSI Flange Rating (#)	
b. Plastic Pipe	
(1) Yield Strength, “S” (PSI) *(see 192.121)*	
(2) Test Pressure Factor, “TPF” *(see 192.513(c))*	

4. Corrosion Data			
a. Pipe Coated (Yes/No)			
b. Coating Material			
c. Method of Application			
d. Cathodic Protection (Yes/No) (If yes, date started)			
e. Type			
f. Corrosion Tests (1) Soil Resistivity (2) P/S Potential	Sta to Sta	Sta to Sta	Sta to Sta
g. Pipe Coated By			
h. Field Joint Coating			
i. Other CP Facilities			

5. Construction Data	
a. General	
(1) Contractor	
(2) Date Started	
(3) Date Completed	
(4) Depth of Cover	
b. Welding Data	
(1) Company Inspector	
(2) Inspection Company	
(3) Type of Inspection	
c. Pressure Test Data	
(1) Tested By	
(2) Witnessed By	
(3) Type	
(4) Test Pressure	
(5) Test Medium	
(6) Test Date	
(7) Test Duration (hr.)	
(8) Pressure Chart Make	
(9) Temperature Chart Make	
* (10) Accepted Test Pressure, “TP”	

* Note: If there are significant elevation changes along the pipeline and a liquid is used as the test medium, the accepted test pressure will vary due to changes in hydrostatic head, and this variance must be taken into account when determining the MAOP.

6. MAOP Determination	
a. Steel Pipe	
(1) Pipe Design Pressure = (2St/D)xFxExT *(see 192.105)*	
(2) Lowest Flange Pressure Rating	
(3) Design pressure of any component, if less than flange pressure rating, or N/A	
(4) Maximum pressure substantiated by pipeline pressure test = TP/TPF *(see 192.619(a)(2)(ii))*	
(5) If not tested per Item (4) above, maximum pressure substantiated by previous operating pressures, or N/A *(see 192.619(a)(3))*	
(6) Maximum pressure substantiated by mill test for furnace butt welded pipe = 60% of mill test pressure, or N/A *(see 192.615(a)(4))*	
(7) For steel pipe other than furnace butt welded pipe, maximum pressure substantiated by the highest test pressure the pipe has been exposed to whether by the mill test, or post-installation test = 85% of highest test pressure, or N/A *(see 192.619(a)(5))* Note: This criteria only applies to pipe installed prior to November 12, 1970 that has not had a class location change since that date, and has not since been hydrotested.	
(8) The maximum safe pressure as determined by the operator considering operating history, known corrosion and actual operating pressure, or N/A *(see 192.619(a)(6))*	
(9) System Maximum Allowable Operating Pressure, “MAOP” = Lowest of Items (1) through (8) above	
(10) Notwithstanding Item (9) above, MAOP based on maximum operating pressure to which the segment was subjected to during the five (5) years preceding July 1, 1970 (onshore lines) or July 1, 1976 (off-shore lines), subject to class location changes, or N/A *(see 192.619(c))*	

<u>MAOP Determination (Continued)</u>	
(11) System Operating Pressure, "OP"	
(12) MAOP Certified By	
(13) Date	

b. Plastic Pipe	
(1) Pipe Design Pressure = 2Sx(t/(D-t))x.32 *(see 192.121)*	
(2) Lowest Flange Pressure Rating	
(3) Design pressure of any component, if less than flange pressure rating, or N/A	
(4) Maximum pressure substantiated by pipeline pressure test = TP/1.5 *(see 192.619(a)(2)(i))*	
(5) If not tested per Item (4) above, maximum pressure substantiated by previous operating pressures, or N/A *(see 192.619(a)(3))*	
(6) The maximum safe pressure as determined by the operator considering operating history and actual operating pressure, or N/A *(see 192.619(a)(6))*	
(7) System Maximum Allowable Operating Pressure, "MAOP" = Lowest of Items (1) through (6) above	
(8) Notwithstanding Item (7) above, MAOP based on maximum operating pressure to which the segment was subjected to during the five (5) years preceding July 1, 1970 (onshore lines) or July 1, 1976 (off-shore lines), subject to class location changes, or N/A *(see 192.619(c))*	
(9) System Operating Pressure, "OP"	
(10) MAOP Certified By	
(11) Date	

7. <u>Miscellaneous Calculations</u>	
a. Operating Pressure Hoop Stress (%S) = (OPxD/2t)x(100/S)	
b. Test Pressure Hoop Stress (%S) = (TPxD/2t)x(100/S)	
c. MAOP Hoop Stress (%S) = (MAOPxD/2t)x(100/S)	

OPERATING PRESSURES LIMITS – MAINTENANCE & REPAIR

1. REFERENCE

   49 CFR, Sections 192.713, 192.715, and 192.717.

2. PURPOSE

   The purpose of this procedure is to establish recommended maximum pressures at which a pipeline should be operated while excavation, maintenance, repairs, or other such activities are being performed.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (260) ______________________ is responsible to maintain the recommended operating pressure during repair activities to maximize the reduction of risk.

4. GENERAL

   4.1 A pipeline is considered to be damaged if a defect is believed to exist, or has been identified, which requires repair.

   4.2 A pipeline is considered undamaged if no defect exceeding the limits shown in "Repair Procedure" (Table 9.01-A) has been found, or after all known defects have been repaired.

   4.3 The pressure criteria in this procedure are based upon industry experience as opposed to mathematical analysis or empirical expressions predicting pipeline behavior. Such experience indicates that a pipeline which has been damaged and does not subsequently fail (rupture) probably will not fail during the course of repair activities if the actual pressure in the pipe is reduced. With this consideration, the greater the pressure reduction, the lesser the probability that a pipe failure will occur.

   4.4 To maximize the reduction of risk, activities should be accomplished at the lowest operating pressure possible if the opportunity exists to do so without having to implement extraordinary measures.

   4.5 Good engineering judgment and common sense may indicate the need for higher or lower pressures depending on the extent of damage to the pipeline, deliverability requirements or other circumstances.

4.6 The Facility Engineer has the authority to use pressures above the recommended levels after making appropriate evaluations with approval from District Manager.

5. PROCEDURE

5.1 The Facility Engineer, or other designated and qualified individual, should be contacted prior to any repair or remedial work on a pipeline. That individual should review the entire situation taking into consideration such things as:

5.1.1 Pipeline location and exposure.

5.1.2 Pipeline wall thickness, pipe geometry, age, grade, etc.

5.1.3 Specific damage (dent, crack, gouge, groove, etc.), maintenance procedure, leak, or other reason for reducing pipeline operating pressure.

5.1.4 Commodity in pipeline, i.e., gas or liquid.

5.1.5 Existing operating pressure.

5.2 Severe defects should not be repaired under pressure unless there is sufficient experience to make a sound evaluation of the defect. In addition, the effect of any known secondary stresses should be considered.

5.3 Repairing or welding reinforcements directly to pipe which is under pressure can be done successfully. The following formula provides a recommended maximum pressure for the procedure:

$$P = \frac{2S(t - 3/32)(0.72)}{D}$$

(This formula is from the GPTC Guide for Gas Transmission and Distribution Piping Systems, current edition.)

5.4 Operating pressure must be at a safe level during repair operations. Considering the above items, the individual shall make a recommendation for pressure reduction with safety as a primary element. Immediate temporary measures should be taken to protect life and property from hazards resulting from a leaking, defective or damaged pipeline with an injurious damage condition.

6. RELATED PROCEDURES

8.01 Maximum Allowable Operating Pressure (MAOP)
9.01 Repair Procedures

7. RECORDS

None required by this procedure.

PIPELINE REPAIR PROCEDURES

1. REFERENCE

49CFR, Sections 192.150, 192.241, 192.309, 192.483, 192.485, 192.605, 192.703, 192.709, 192.711, 192.713, 192.715, 192.717, and 192.719.

2. PURPOSE

The purpose of this procedure is to define defects in steel pipeline and specify the acceptable method for their disposition.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (269) __________________ is responsible to confirm that all repairs are performed in accordance with this procedure. All repairs discussed in this procedure must occur prior to the next scheduled inspection.

4. GENERAL

4.1 Repair a pipeline as soon as possible whenever an injurious damage condition is found. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. Hazardous leaks must be repaired promptly. The company may operate a segment of pipeline, unless it is maintained in accordance with this subpart M, Maintenance, 192.701-755.

4.2 An injurious damage condition (gouge, groove, dent, corrosion, or leak) is one that impairs the safety and serviceability of a pipeline and requires repair. See Table 9.01-A for limits of damages.

4.3 Operating pressure must be at a safe level during repair operations. Considering the above items, the individual shall make a recommendation for pressure reduction with safety as a primary element. Immediate temporary measures should be taken to protect life and property from hazards resulting from a leaking, defective or damaged pipeline with an injurious damage condition. See section 5.3.1 of these procedures for methods used in determining the remaining strength of pipe.

4.4 Determine the repair method for an injurious condition according to the type of damage or defect.

4.5 Use the unpressurized repair alternate if either of the following two conditions exist (pipeline must be out of service and blown-down):

4.5.1 Pipe geometry is deformed so it prevents proper installation of a pressurized repair.

4.5.2 Leakage makes pressurized repair unsafe.

4.6 A pressurized repair is one which is carried out while the pressure in the pipeline is higher than atmospheric.

4.7 If a pressurized repair is made, reduce the pressure of the line to the limits established by each repair method or as established in “Operating Pressure Limits Maintenance and Repair”, Procedure 8.02.

4.8 All repair methods established by this procedure are considered permanent. The use of a leak clamp is considered only as a temporary measure that may be taken to protect life and property.

4.9 After repairing a leak, verify that the leak has been contained and no additional leaks exist in the immediate area.

4.10 Except as provided in paragraphs 4.11 and 4.12 below, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

4.11 Paragraph 4.10 above does not apply to:

4.11.1 Manifolds.

4.11.2 Station piping such as at compressor stations, meter stations, or regulator stations.

4.11.3 Piping associated with storage facilities, other than a continuous run of pipeline between a compressor station and station facilities.

4.11.4 Cross-overs.

4.11.5 Sizes of pipe for which an instrumented internal inspection device is not commercially available.

4.11.6 Transmission lines, operated in conjunction with a distribution systems which are installed in Class 4 locations.

4.11.7 Offshore transmission lines, except transmission lines 10 inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore, unless;

- Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices, or
- If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices.

4.11.8 Other piping that, under 49CFR 190.9, the administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

4.12 An operator encountering emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph 4.10 above, if the operator determines and documents why an impracticability prohibits compliance with paragraph 4.10 above. Within 30 days after discovering the emergency or construction problem the operator must petition, under 49 CFR 190.9, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

5. PROCEDURE

No operator may use any pipe, valve, or fitting for replacement or repairing pipeline facilities unless it is designed and constructed as required by Part 192.

5.1 Preliminary Investigation

5.1.1 Inspect any exposed pipeline for leaks, impact damage, coating conditions, and external corrosion.

5.1.2 Visually inspect buried welds whenever the coating has been removed for any reason.

5.1.3 Make a preliminary assessment to determine the extent of the damage or defect. In most cases a visual inspection is sufficient. Use X-ray or other forms of inspection that could be considered helpful if conditions warrant.

5.1.4 Investigate to determine the cause of any leaks that are found.

5.1.5 Determine if a safety related condition exists and whether it should be reported. See Procedure 1.02 “Reporting of Safety Related Conditions”.

5.2 Evaluation of Damage Extent

5.2.1 Make a precise evaluation of the extent of any damage or defect.

5.2.2 Compare the extent of any damage or defect against the limits established in Table 9.01-A.

5.2.3 Confirm the damage as injurious if its extent exceeds the limits established.

5.3 Repair of Corrosion Condition

5.3.1 General Corrosion:
Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.

References for determining the remaining strength of a pipeline are:

1) ASME/ANSI B31G (49CFR192 currently referenced edition), “Manual for Determining the Remaining Strength of Corroded Pipelines.”

2) AGA Pipeline Research Committee, Project PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (49CFR192 currently referenced edition).

5.3.2 Localized Corrosion Pitting:

Each segment of transmission line with localized corrosion pitting to a degree where leakage might result must be repaired or removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits. Inspect the interior of the cutout and the ends of the remaining pipe for internal corrosion, record on Form 3.01B.

5.3.3 Remedial Measures, General

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of Sec. 192.461.
(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.
(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

5.4 Repair of Imperfections and Damages

5.4.1 Except as provided in 5.4.2 below, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of specified minimum yield strength must be repaired as follows:

5.4.1.1 If it is feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength, or

5.4.1.2 If it is not feasible to take the segment out of service, the pipeline can be repaired by a means that has been proven, through engineering tests and analyses, to restore serviceability of the pipe.

5.4.2 Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a bolted full encirclement split sleeve of appropriate design over the imperfection or damage.

5.5 Repair of Welds

5.5.1 If it is feasible to take the segment of transmission line out of service, the weld must be repaired per Procedure 9.06.

5.5.2 A weld may be repaired in accordance with repair or removal of defective welds per applicable code and standard while the segment of transmission line is in service if:

5.5.2.1 The weld is not leaking;

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

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

5.5.3 The method of repair for a defective weld, whether onshore or submerged, which cannot be repaired in accordance with 5.5.1 or 5.5.2 above, will be determined on an individual basis.

For onshore pipelines, the weld can generally be repaired by installing a full encirclement welded split sleeve of appropriate design.

5.6 Repair of Leaks

5.6.1 If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength, or

5.6.2 If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design.

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

5.6.4 If the leak is due to a corrosion pit and on pipe with an SMYS of 40,000 psi or less, a steel plate patch with the following characteristics can be used: rounded corners; same thickness or greater; and, not more than half the pipe diameter in size.

5.6.5 For submerged offshore pipelines and submerged pipelines in inland navigable waters, leaks may be repaired by mechanically applying a bolted full encirclement split sleeve of appropriate design over the leak.

5.6.6 Regardless of the repair method, insure that the means of repair has been proven, through engineering tests and analyses, to restore serviceability of the pipe.

5.6.7 All repairs must meet API 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999) or equivalent welding procedures.

5.6.8 All repairs performed must be tested and inspected.

5.7 Use of Full Encirclement Welded Split Sleeves, or other Similar Devices

5.7.1 An "Alert Notice" was issued by the DOT/OPS on March 13, 1987 with regard to the welding of full encirclement repair sleeves. It cautioned operators not to use non-low hydrogen welding electrodes with cellulosic coating.

5.7.2 The recommendation in the repair weld procedure is E7018 low hydrogen electrode with vertical uphill weld progression.

5.8 Testing of Repairs

5.8.1 Testing of replacement pipe:

The replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

5.8.2 Inspection and test of welds:

5.8.2.1 Visual inspection of welding must be conducted to insure that the welding is performed in accordance with the welding procedure and the requirements of Section 9 of API Standard 1104, "Welding of Pipelines and Related

Facilities" (Welding of Pipelines and Related Facilities, 19th edition, 1999).

5.8.2.2 The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20% or more of SMYS must be nondestructively tested in accordance with Procedure 15.02, except that welds that are visually inspected and approved by a qualified welder inspector need not be nondestructively tested if:

5.8.2.2.1 The pipe has a nominal diameter of less than 6 inches (152 mm); or

5.8.2.2.2 The pipeline is to be operated at a pressure that produces a hoop stress of less than 40% of SMYS and the welds are so limited in number and nondestructive testing is impractical.

5.8.2.3 The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 of API Standard 1104 (See 5.8.2.1) (Welding of Pipelines and Related Facilities, 19th edition, 1999)

6. RELATED PROCEDURES

- 1.01 Reporting and Control of Accidents
- 1.02 Reporting of Safety Related Conditions
- 5.01 Continuing Surveillance
- 5.02 Gas Leak Detection Survey with Instrumentation for Pipelines without Odorant
- 8.02 Operating Pressures Limits – Maintenance & Repair
- 9.06 Pipeline Welding
- 15.02 Visual Inspection and Non-Destructive Testing

7. RECORDS

7.1 Complete Maintenance and Surveillance Form (Form 3.01B).

7.2 Submit as-built sketches to the (270) ________________ to update the drawings if pipe is replaced.

7.3 Maintain the records for the life of the pipeline facility.

7.4 Maintain records of replaced pipeline components for 5 years.

TABLE 9.01-A

PIPELINE REPAIR - PIPE DAMAGE OR DEFECT

DAMAGE OR DEFECT	DISPOSITION OF CONDITION	
	Unpressurized	Pressurized
Dent on: (See Note 3) Welds Body of pipe 12" (305 mm) or less nominal diameter: Depth greater than 1/4" (6.4 mm) Body of pipe larger than 12" (305 mm) nominal diameter: 2% or more of nominal diameter	 C C C	 E, P, CS E, P, CS E, P, CS
Groove, gouge or scratch with remaining wall thickness: Less than Design Wall Thickness	 C	 E, P, CS
Welds: No Leak With Leak (See Note 2)	 X X	 E, P, CS E, P
General Corrosion: (See Note 4) No Leak External corrosion with <80% wall loss	 C	 C, M CS
Localized Corrosion Pitting: No Leak With Leak (See Note 2) External corrosion with <80% wall loss	 C C	 E, C, M, P L, E, P CS
All Other Leaks (See Note 2)	C	E, P

TABLE 9.01-A
(Continued)

LEGEND

C Cutting out a cylindrical piece of pipe and replacing it with pretested pipe of similar or greater design strength.

E Full encirclement, welded split sleeve of appropriate design.

L Leak clamp.

M Establish new maximum operating pressure base on the actual remaining wall thickness.

P Plidco sleeve or equivalent (offshore or submerged).

R Weld repair (see Note 1).

X Cut out repair per applicable code and standard.

CS Clock Spring

NOTES:

1. A weld on a pressurized pipeline segment may be repaired if:

   a. The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the specified minimum yield strength of the pipe; and
   b. Grinding of the defective area can be limited so that at least 1/8 inch (3.2 mm) thickness in the pipe weld remains.

2. Either the sleeve or the leak clamp are to be removed and replaced by a cylindrical piece as soon as it is feasible to take the piping out of service.
3. Each dent in steel pipe that operates at or more than 20% SMYS, must be removed unless the dent is repaired by a means than has been proven to restore permanent serviceability of the pipe.
4. Each transmission pipeline with general corrosion, and with a remaining wall thickness less than required for the exiting MAOP, must be replaced or the MAOP reduced based on the actual wall thickness. However, as stated in Note 3 above, the pipe can be repaired by a means that has been proven to restore permanent serviceability of the pipe.

NOT CURRENTLY IN USE

9.02

PURGING AND PURGING SAFETY OF PIPELINES
INCLUDING PIPELINE BLOWDOWN

1. REFERENCE

49 CFR, Sections 192.179(c), 192.629, and 192.751

2. PURPOSE

The purpose of this procedure is to establish guidelines for purging new and modified pipelines of air prior to placing them in service, or purging a pipeline of natural gas prior to performing maintenance, testing, or abandonment. This procedure also establishes criteria for identifying hazards that may exist at blowdown locations, and the need to develop safety practices when purging or blowing down facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (282) ______________________ is responsibility for implementing the requirements of this procedure: purging safety practices, blowdown hazards, and pipeline purging.

4. GENERAL

4.1 A perfect purge is one in which the replacement of gas or air by a purge gas is effected entirely by displacement, and only one volume of purge gas is needed. Purging can be achieved by several means, two of which are the "indirect method" – using an inert gas slug, or the "displacement method" – filling the pipeline completely with an inert gas.

4.2 The person entrusted with the responsibility of directing a purging operation should be experienced and qualified, and should have the necessary authority to conduct the operation.

4.3 The number of persons required to control a purging operation will vary depending on the complexity and magnitude of the purge.

4.4 Planning a purge is extremely important. The main considerations to decide upon
in planning and making an action plan are: A) What facility to purge; B) What and how to isolate; C) Where to introduce inerts and vent the purge gas; D) The

method of testing to insure proper purge and the needed result; E) The time and probable duration of the operation.

4.5 The action plan must be reviewed with all participating personnel to make certain that all phases of the purge operation are fully understood.

5. PROCEDURES

5.1 Plan of Action

A detailed Plan of Action (POA) must be written for the purging operation. Included, but not limited to, must be the following elements:

5.1.1 The facility to be purged and how isolated. Consider whether the facility is a new or modified pipeline, or a pipeline that is to be tested, maintained, or abandoned;

5.1.2 The gases involved;

5.1.3 The purging operation time and schedule;

5.1.4 Installation of adequate input and vent connections;

5.1.5 Listing of valves to be operated;

5.1.6 Deactivation of remote or automatic valve controllers;

5.1.7 Listing of test equipment and accessories;

5.1.8 Instruction and assignment of personnel;

5.1.9 Provision for communication;

5.1.10 Notification of public agencies, general public, and affected customers (if any);

5.1.11 Supply, control and measurement of purge medium, including volume, rate, pressures and temperatures;

5.1.12 Control of venting.

5.2 Tail Gate or POA Meeting

Conduct a meeting with all involved and concerned individuals prior to start of purging. Include at the least the following in the discussion of the purging operation:

5.2.1 Blowdown and purging safety (See Section 5.4 below);

5.2.2 The location of each person involved with the purging operation along with his or her specific duty and responsibility during the purge;

5.2.3 The description, use, and location of each piece of work equipment;

5.2.4 Using a schematic of the piping involved, explain and show:

A) The facility that is to be purged and how it is to be isolated.
B) The flow of the purge gas.
C) The location where the purge gas enters and leaves the system.
D) The location of fire fighting equipment.
E) The locations of key personnel and equipment.

5.2.5 The pressure of the gas to be used to purge the pipeline;

5.2.6 The length of time required to purge the system or the method to be used to check the air/gas mixture concentration;

5.2.7 Sequence of valve operations;

5.2.8 Presence of liquids, iron sulfide, or other special conditions, such as blind legs or dead ends to consider;

5.2.9 Possible sources of ignition, in and out of the pipeline;

5.2.10 Any other safety related items, such as the use of personal protective equipment (PPE).

5.3 Purging Operation

The following procedures shall be used for purging pipe of known size and length. An example of how to determine what is needed and how to use this section is given at the end of this procedure.

5.3.1 Establish and identify the facility to be purged and whether to be purged of gas or air, and how the facility is be isolated. Isolation can be accomplished by several means: blanking, valving, removal of fittings or a section of pipe and capping, blanking or plugging of the open ends.

5.3.2 Install a vent stack, if not already available, as close as practible to the opposite end of the pipeline to be purged. Vent must extend to a safe location, 6 to 8 feet above ground level. Refer to Section 5.4, below, for blowdown safety precautions.

5.3.3 Install an injection fitting as close as practical to the other end of the pipeline to be purged. This fitting is to be used for injection of air or nitrogen. It is not necessary to inject gas through a bypass hose and injection fitting when a line valve can be opened at the injection end of the pipeline being purged.

5.3.4 Knowing the pipeline size, length of section to be purged, and vent stack (blowdown) size, determine the inlet control pressure from Table 9.03A at the end of this procedure.

5.3.5 Make a determination as to the number of nitrogen cylinders required for an N2 slug, or to fill the pipeline, if nitrogen is to be used. Nitrogen makes purging much safer and minimizes commingling of air/gas or gas/air. Refer to Tables 9.03B and 9.03C, knowing the pipe size and length of pipe to be purged.

5.3.6 Many configurations and arrangements are available for connecting gas, air, and N2 to the injection fitting for purging purposes. In selecting the correct hookup, determine whether the direct or indirect method is to be used, and if nitrogen will be injected. Please refer to Figures 9.03D, 9.03E, 9.03F, 9.03G and 9.03H. The drawings are self-explanatory. Figure 9.03I shows a suggested N2 bottle manifold and connection for injecting into a pipeline.

5.3.7 Calculate the purging period which is equal to two (2) minutes for each mile of pipe in the section to be purged.

5.3.8 Install a pressure gauge at the inlet of the section to be purged. The pressure gauge should be accurate and readable to within 1 psi (6.9kPa), so that the inlet pressure can be observed. The gauge should be connected through several feet of flexible tubing, or hi-pressure hose, to eliminate excessive vibration.

5.3.9 Open the blowdown valve at the downstream end of the section to be purged. Downstream blowdown valves should always be in the fully open position.

5.3.10 Prevent a hazardous mixture of gas and air in the pipeline.

5.3.11 If the pipeline is clean and traps have been installed and/or are available, pigs could be run ahead of the purging medium. This will reduce the possibility of commingling air/gas or gas/air and creating a potentially explosive situation.

5.3.12 Control medium pressure using only experienced personnel. Do not allow unauthorized contractor or Company employees to operate valves.

5.3.13 Inject nitrogen into the pipeline (at the inlet end) to rapidly displace at least 2 miles (3.2 km) of pipe, if practical.

5.3.14 Start purging with gas or air by opening the inlet valve far enough to quickly obtain the determined control pressure and maintain this pressure for the necessary purging time.

5.3.15 At the end of the purging time (two minutes per mile), close the inlet flow control valve and continue to vent through the downstream blowdown valve for an additional minute per mile of the pipe being purged.

5.3.16 Verify completeness of the purge. The use of a combustible gas indicator provides a means of analyzing the gas-air mixture throughout the purging operation, and also of confirming the gas to be free of air, or the air free of gas.

5.3.17 Close the downstream blowdown valve.

5.3.18 Open the inlet valve and slowly load the pipeline to operating pressure, if the purge was to displace the pipeline of air with gas.

5.3.19 If purging is done through a crossover arrangement, open mainline valve after checking that pressures are equalized across the valve setting.

5.4 Blowdown and Purging Safety

5.4.1 Identification of Blowdown Locations

5.4.1.1 Identify blowdown locations where precautions should be taken during a blowdown.

5.4.1.2 Mark each such location with a sign indicating “Controlled Blowdown Required Due to Overhead or Adjacent Facilities”.

5.4.1.3 Verify on the Emergency Valve Inspection Report (Form 7.01A) that the location is properly marked during each subsequent periodic inspection of emergency valves.

5.4.2 Blowdown Planning

5.4.2.1 Prepare a plan and review it with the crew prior to purging or blowing down a facility. Discuss any hazards involved, such as power lines, public highways and railroads.

5.4.2.2 Use silencers in populated areas when necessary.

5.4.2.3 Post warning signs where appropriate.

5.4.2.4 Notify the following regarding the time and place before blowing gas to the atmosphere:

A) People living in the area.
B) Public agencies such as the county sheriff, local police or fire department as required.
C) Facilities supplying the pipeline and receiving from the pipeline, if any, which will be interrupted.

5.4.2.5 Traffic control, if required, should be performed by local law enforcement officials on all preplanned activities.

5.4.2.6 Ensure that appropriate fire extinguishing equipment is available at strategic locations.

5.4.2.7 Do not begin work until communications have been established with personnel diverting traffic and among personnel at the ends of the pipeline sections being purged.

5.4.3 Blowdown Operations

5.4.3.1 Do not exhaust gas at any time into overhead electrical wires or into the atmosphere when an electrical storm is in the vicinity.

5.4.3.2 Locate personnel a safe distance upwind of blowdown location.

5.4.3.3 Block or divert traffic if gas may “drift” across public roadways.

5.4.3.4 Do not allow vehicles closer than 100 feet (30 meters) upwind from a vertical blowdown. Do not allow vehicles anywhere except upwind of a blowdown!

5.4.3.5 Require personnel to wear adequate safety equipment, including eye and ear protection.

5.4.3.6 Continue using precautions throughout the entire blowdown period, until all valves are shut and flow has stopped, and until all gas has had time to disperse.

6. <u>RELATED PROCEDURES</u>

3.06 Preparation of an Operations Plan-Normal and Abnormal Conditions
7.01 Emergency Valve Maintenance
14.03 Prevention of Accidental Ignition
System Specific Operations Manual (PSOM)

7. <u>ADDENDUM</u>

Reference: American Gas Association (AGA)
“Purging Principles and Practice”

8. <u>RECORDS</u>

Retain all documentation copies in the District office files for at least five (5) years, or longer if necessary, if there is a pending claim or litigation.

PURGING PROCEDURE – EXAMPLE
12- INCH GAS TRANSMISSION PIPELINE

The following steps are an example of a purging operation utilizing Procedure 9.03, "Purging and Purging Safety of Pipelines – Including Pipeline Blowdown".

Given: 12-inch gas transmission pipeline.
9.5 miles (50,160 feet) in length.
Blowdown stack is 4-inch's in size.
Pipeline is newly installed and must be cleared of air.
It is desired to use the N2 slug – indirect method of purging.
No pig traps are available.

1. Make a Plan of Action (POA) as directed in Section 5.1 (Section 5.1 of Procedure 9.03).

2. Determine the minimum purge gas control pressure (psig). Using the given data above, enter Table 9.03-A.
The 12-inch pipeline with a 4-inch blowdown stack and 9.5 miles in length, needs a minimum inlet pressure of 27-28 psig (Table 9.03-A).

3. Nitrogen will be used as the "slugging" medium. From Table 9.03-B, 3 to 4 N2 cylinders (250 cubic feet each) will be required (Table 9.03-B).
These should be manifolded as suggested in Figure 9.03-I, and connected to the pipeline as shown in either Figure 9.03-G or 9.03-H. Figure 9.03-G allows gas to follow the N2 through a "bypass" arrangement allowing finite pressure control. Figure 9.03-H does not use a bypass system, but uses a mainline block valve for gas control (Figures 9.03-G, H, & I).

4. The purging time is equal to 2 minutes per mile. Therefore, 2 x 9.5 = 19.0 minutes (Paragraph 5.3.7 of Procedure 9.03).

5. Insure that the pressure control gage has an accuracy to within 1 psig, so that the inlet pressure can be observed (Paragraph 5.3.8 of Procedure 9.03).

6. After all of the planning details (POA) are worked out and before any purging activity commences, conduct a "Tailgate" meeting. Use Section 5.2 of Procedure 9.03 as a guide (See 5.2 of Procedure 9.03).

7. Check all connections, valves, blowdowns, fittings and other hardware to insure they are all of the proper material and pressure rating. Make a final check of isolation devices and injection arrangement.

   A practice run or two should be performed before purging commences to make sure all individuals understand the process and their responsibility!!

8. Purging commences.
   Fully open the 4-inch blowdown stack valve at the downstream end of the section being purged (Paragraph 5.3.9 of Procedure 9.03).

9. Commence injecting the 3 or 4 cylinders of N2 at the upstream end of the purge section. Injection should be at or above the 27-28 psig. Control pressure with the valve on the manifold. The injection fitting on the pipeline should be fully open.
   Continue to inject N2 until the N2 pressure can no longer be maintained.
   Close off N2 valve after gas injection has commenced (Paragraph 5.3.13 of Procedure 9.03).

10. Immediately commence gas injection at or above the minimum gage pressure of 27-28 psig. Control pressure with the valve attached to the bypass fitting if configured to Figure 9.03-I.

11. Maintain pressure (and purging) for 19-20 minutes (See Number 4 above).

12. At the end of the purge time, close the inlet valve.

13. Continue to vent through the 4-inch blowdown for 10 minutes (Paragraph 5.3.15 of Procedure 9.03).

14. Monitor at the blowdown stack to verify completeness of the purge (Paragraph 5.3.16 of Procedure 9.03).

15. If purge has been successful, close the downstream blowdown stack valve. If not, continue to inject gas until purge has been satisfactory (Paragraph 5.3.17 of Procedure 9.03).

16. Slowly open the pipeline to operating pressure through the mainline valve. Open or close other valves as appropriate, or as needed, to return the pipeline to service.

PURGING OF PIPELINE

TABLE 9.03B

NUMBER OF NITROGEN CYLINDERS (250 CUBIC FEET EACH) REQUIRED TO FORM SLUG IN PIPELINE - INDIRECT METHOD

Pipe Size (Inches)	500	1000	2000	3000	4000	6000	8000	10,000	20,000	50,000
2 to 8	1	1	1	1	1	1	1	1	1	1
10	1	1	1	1	1	1	1	2	2	2
12	2	2	2	2	2	2	2	2	2	3
16	3	3	3	3	4	4	4	4	4	5

TABLE 9.03C

NUMBER OF NITROGEN CYLINDERS (250 CUBIC FEET EACH) REQUIRED TO FILL PIPELINE - DISPLACEMENT METHOD

Pipe Size (Inches)	500	1000	2000	3000	4000	6000	8000	10,000	20,000	50,000
2	1	1	1	1	1	1	1	2	3	6
3	1	1	1	1	2	2	3	3	6	13
4	1	1	1	2	2	3	4	5	9	
6	1	1	2	3	4	6	8	10		
8	1	2	4	5	7	10	14	17		
10	2	3	6	8	11	16				
12	2	4	8	12	15					
16	3	6	12	18						

PURGING OF PIPELINES

FIGURE 9.03D. ARRANGEMENT FOR DIRECTLY PURGING GAS FROM PIPELINES

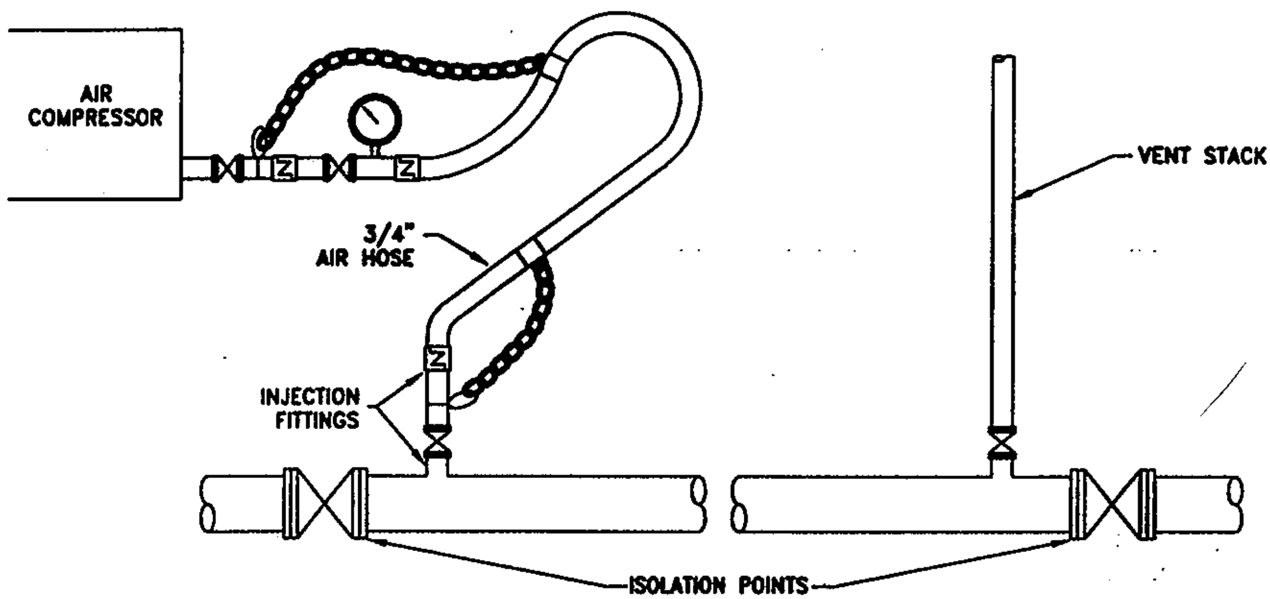
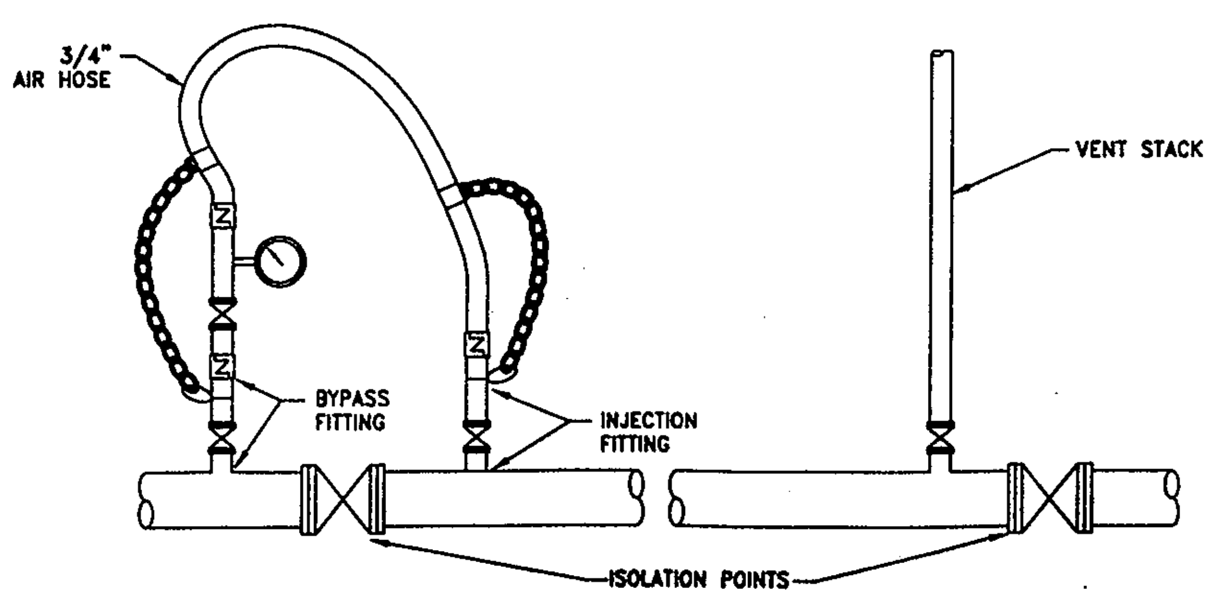


FIGURE 9.03E. ARRANGEMENT FOR DIRECTLY PURGING AIR FROM PIPELINES



PURGING OF PIPELINES

FIGURE 9.03F. ARRANGEMENT FOR PURGING GAS FROM PIPELINES USING INDIRECT METHOD

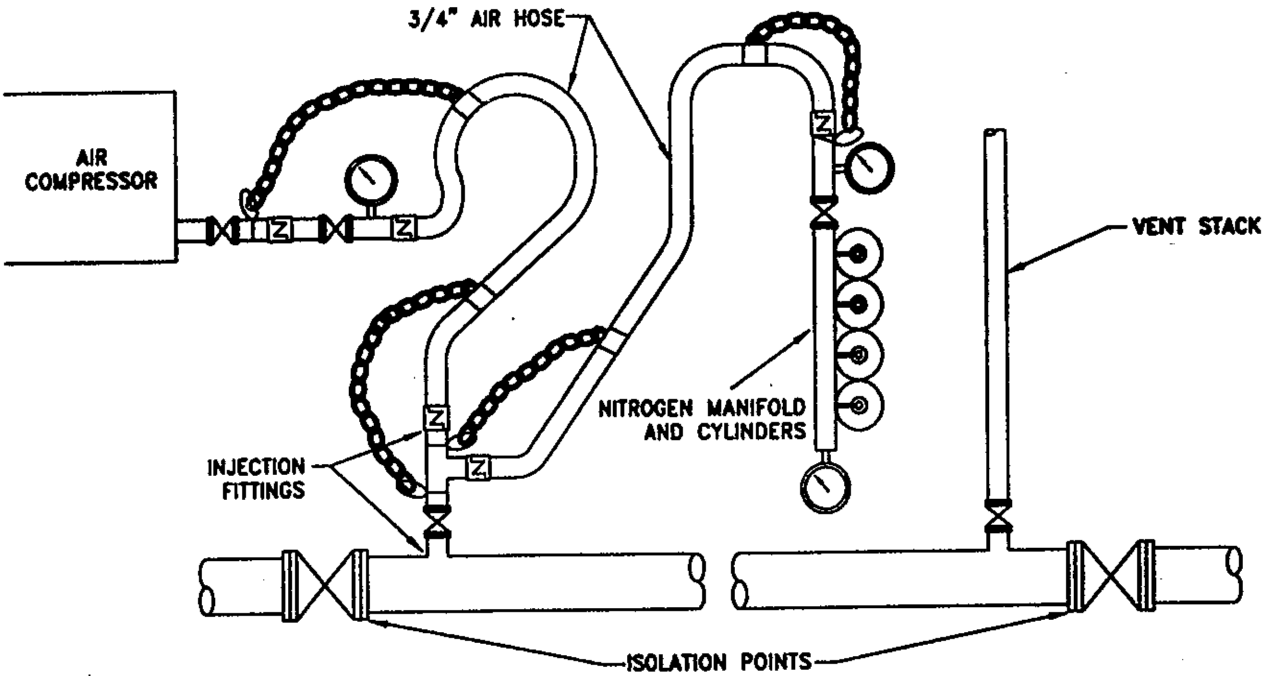
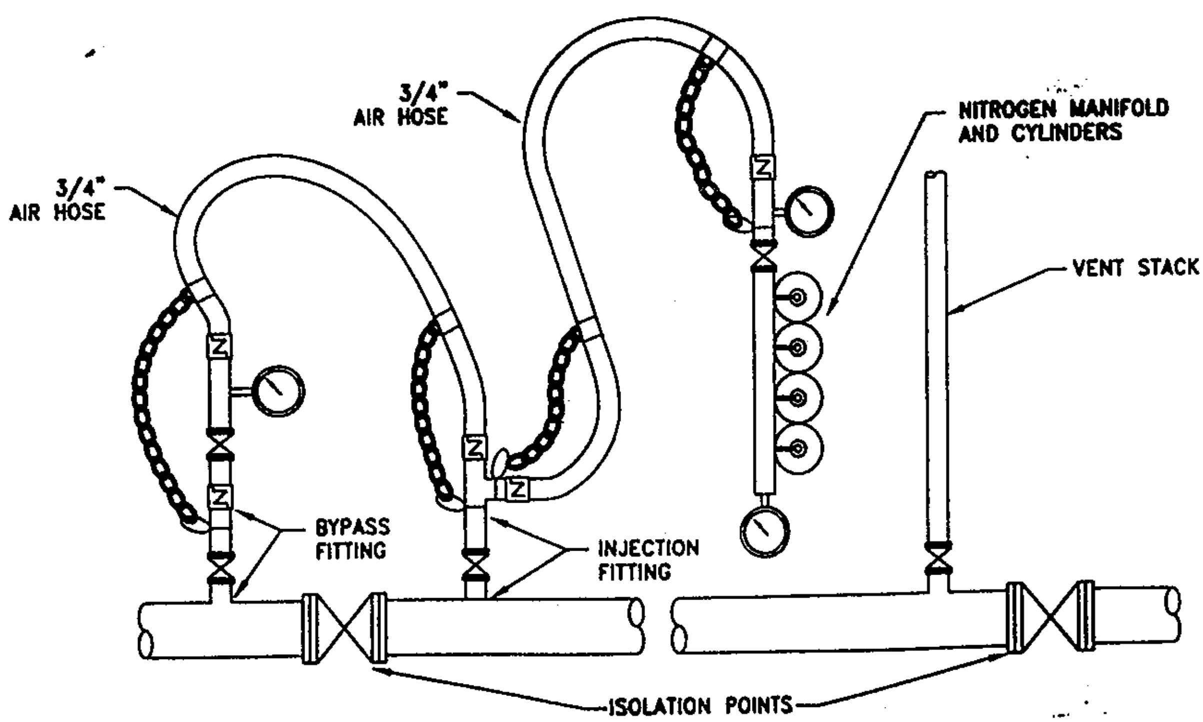


FIGURE 9.03G. ARRANGEMENT FOR PURGING AIR FROM PIPELINES USING INDIRECT METHOD.



PURGING OF PIPELINES

FIGURE 9.03H. ARRANGEMENT FOR DISPLACING AIR OR GAS FROM PIPELINES

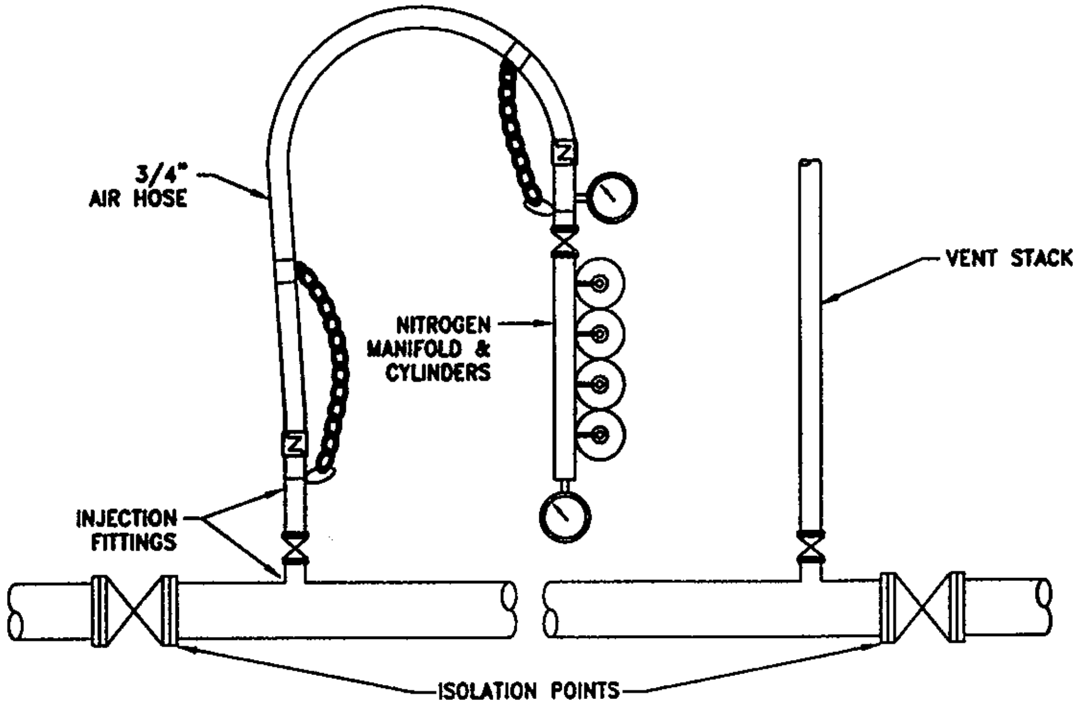
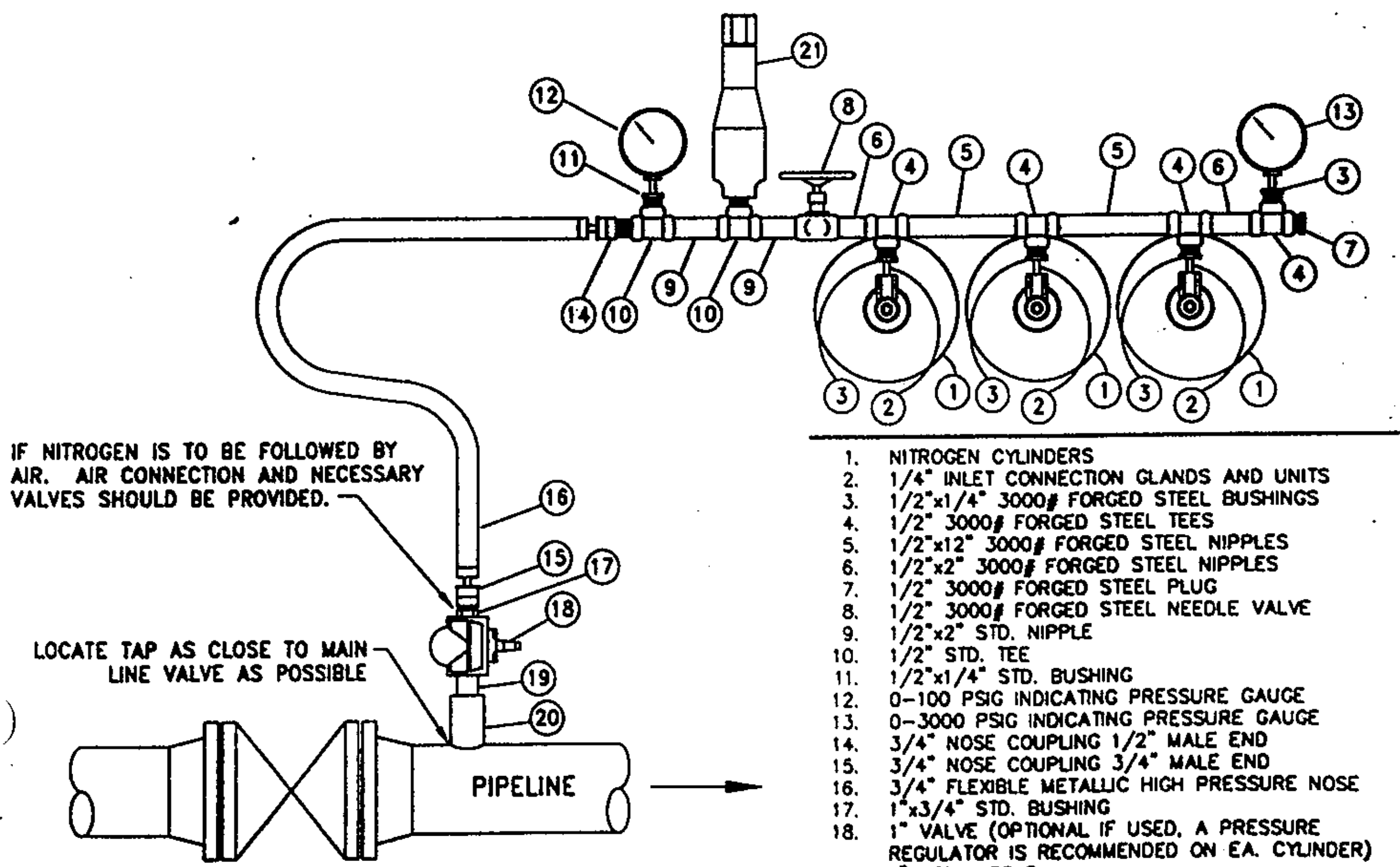


FIGURE 9.03I TYP. MANIFOLD & CONNECTION FOR INJECTING HIGH PRESS. N_2 INTO PIPELINE



1. NITROGEN CYLINDERS
2. 1/4" INLET CONNECTION GLANDS AND UNITS
3. 1/2"x1/4" 3000# FORGED STEEL BUSHINGS
4. 1/2" 3000# FORGED STEEL TEES
5. 1/2"x12" 3000# FORGED STEEL NIPPLES
6. 1/2"x2" 3000# FORGED STEEL NIPPLES
7. 1/2" 3000# FORGED STEEL PLUG
8. 1/2" 3000# FORGED STEEL NEEDLE VALVE
9. 1/2"x2" STD. NIPPLE
10. 1/2" STD. TEE
11. 1/2"x1/4" STD. BUSHING
12. 0-100 PSIG INDICATING PRESSURE GAUGE
13. 0-3000 PSIG INDICATING PRESSURE GAUGE
14. 3/4" NOSE COUPLING 1/2" MALE END
15. 3/4" NOSE COUPLING 3/4" MALE END
16. 3/4" FLEXIBLE METALLIC HIGH PRESSURE NOSE
17. 1"x3/4" STD. BUSHING
18. 1" VALVE (OPTIONAL IF USED, A PRESSURE REGULATOR IS RECOMMENDED ON EA. CYLINDER)
19. 1" STD. NIPPLE
20. 1" COUPLING
21. 1/2"x1" RELIEF VALVE

AIR MOVERS

1. REFERENCE

49 CFR, Sections 192.629 and 192.751.

2. PURPOSE

The purpose of this procedure is to establish practices when using pipeline air movers to purge gas from pipelines in conjunction with cutting and welding.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (288) ______________________ is responsible for maintaining a sequence of events that will accomplish the work in a safe and successful manner.

4. AIR MOVER DEVICE

4.1 Air movers are essentially portable ventilating devices that have no moving parts and are employed as either blowers or exhausters. But like many other tools used on natural gas pipelines, they must be used with care, discretion and advance planning. When air movers are properly utilized, cuts or repairs on the pipeline that contains natural gas at atmospheric pressure can be made without the danger of gas venting or flowing through open ends into a work area.

4.2 The air mover device converts the pressure of a compressed air or gas into a large induced volume of moving atmosphere.

4.3 In the air mover, the supply air or gas is expanded at high velocity through an annular orifice. The design of the device produces a powerful venturi effect. This causes the atmosphere being moved to be drawn through the bell of the air mover, and delivered with the expanded air or gas supply through the outlet horn.

5. GENERAL

5.1 Pipeline air movers are intended to improve the safety of welding and cutting on gas pipelines by providing positive air purging of gas pipelines and a gas free welding atmosphere.

5.2 When air movers are used, cutting and welding is limited to:

5.2.1 Cutting of access holes only in preparation of air mover use.

5.2.2 Cutting or welding after the air movers are in operation and it has been established that an explosive mixture is not present.

5.3 In the absence of a gas supply to operate the air movers, air compressors may be used. If this is done, the time required to evacuate the gas from the pipeline will be longer because the amount of energy available from air compressors is usually less than that normally available from high pressure gas in the pipeline.

5.4 If compressed air is to be used to operate the air mover, establish radio communication between the control and work areas or make available an alternate source of air supply for use in case the primary source fails.

5.5 All safety precautions shall be strictly observed at all times. This includes ensuring that whenever a hazardous amount of gas is being vented into open air, each potential source of ignition is removed from the area, and that a fire extinguisher is provided.

6. AIR MOVER INSTALLATION

6.1 Install air movers on blowoff on each end of a blowdown section to draw air into the pipe at the work site and move combustible gas through the pipe toward the air mover.

6.2 Seal the gap between the air mover and the blowoff valve face by using a gasket cut from 1/4” (6.4 mm) thick soft sheet rubber.

6.3 Attach the air mover to the blowoff with three 6” (15.2 cm) sharp pointed “C” clamps, spaced evenly around the bell. The sharp points provide the metal to metal contact across the soft rubber gasket necessary to drain off effectively any possible buildup of static electricity during the operation of the air mover.

6.4 If a single mover is utilized to purge a continuous section of pipeline, the opening at the inlet to the line being purged must be at least as large as the air mover being used to produce a successful purge with a minimum amount of mixing.

6.5 Install a 0-100 psig (0-689 kPa) pressure gauge on supply gas to allow the operator to make any adjustment in supply necessary to produce the desired control of draft at the point of severance in the blowdown section.

7. AIR MOVER SELECTION

7.1 Velocity

7.1.1 When selecting size and air or gas pressure requirements, select the conditions that will produce a velocity of 100 feet (30 meters) per minute or more in the pipe.

7.1.2 Table 9.04A shows the capacity of air movers for various conditions as shown by lines for full size access hole. Plug valve with air supply, and plug valve with gas supply. To the right of these lines is a velocity of less than 100 feet (30 meters) per minute and to the left is a velocity of more than 100 feet (30 meters) per minute.

7.2 Selection

7.2.1 From Table 9.04A, select pressure and size to obtain minimum 100 feet (30 meters) per minute velocity of air within the pipeline.

7.2.2 When an air mover is mounted on a plug valve, the air mover capacity is 40 percent of the listed induced air value and when gas is used as the supply, the corrected volume of induced air is further reduced by 60 percent.

7.3 Examples of Use

Determine velocity of air within a 30” (76.2 cm) pipeline (0.312” (7.9 mm) wall thickness) using a 6” (15.2 cm) air mover at 50 psig (345 kPa) through a full size access hole and gas supply and through a plug valve.

$$\text{Velocity of Air} = \frac{\text{Induced Air x 40\% x 60\%}}{\text{Inside Area}}$$

$$= \frac{2058 \text{ x } .40 \text{ x } .60}{4.71} = 105 \text{ ft. per minute}$$

8. PLANNING

8.1 Plan the project so that the start of hot cutting begins as soon as possible after the completion of the blowdown.

8.2 Prior to reducing the pressure in the isolated section to just above atmospheric, the following items should be accomplished.

8.2.1 Inform all persons assigned to the project and explain their responsibilities.

8.2.2 Check material and equipment required to complete the scheduled work.

8.2.3 Lubricate and operate all valves involved.

8.2.4 Isolate other sources where gas may enter the section to be isolated.

8.2.5 Deactivate remote control or automatic valve operators.

8.2.6 Shut off rectifiers with a pre-described distance from the work sites.

8.2.7 Establish a reliable communication system.

8.2.8 Provide sufficient fire extinguishers of the proper type which must be located at each work site.

8.3 If liquid hydrocarbons are present, removal of the liquids is necessary and may be accomplished by the following:

8.3.1 Install a siphon drip.

8.3.2 Drill holes in the pipe.

8.3.3 Sever the pipe with mechanical cutters.

8.3.4 Internally clean the pipe.

8.4 <u>PROCEDURE</u>

8.4.1 Cutting of Access Hole

The procedure for cutting access hole is described below in a sequence that should be followed after the isolated section has been reduced to just above atmospheric.

8.4.1.1 Move excess personnel away from openings in the pipe before beginning cutting or welding on a pipeline.

8.4.1.2 No air should be allowed to enter the blowoff prior to cutting out the access coupon or hot cutting the pipe.

8.4.1.3 Install air movers on blowoff at each end of the isolated section.

8.4.1.4 Install shunt wire and ground at the work site. The shunt wire should remain attached to the pipe until the stringer weld has been completed.

8.4.1.5 A handle may be welded at the access coupon for ease of handling when removing the access coupon from the pipe.

8.4.1.6 Drill or cut a small hole near the access coupon area. Close this hole with tape until air movers are in use. This hole is used to check the gas pressure and also enables the person in charge to aid controlling the fire using the blowdown while noting the flame height. Electric drills are not to be used.

8.4.1.7 Cut an elliptical shaped access coupon at the approximate center of the segment of pipe to be removed. Size of access coupon should be:

8.4.1.7.1

Length:

Size of Pipe	Size of Access Coupon
26” to 36” (66 cm to 91.4 cm)	24” elliptical hole (61 cm)
12” to 24” (30.5 cm to 61 cm)	16” elliptical hole (41 cm)
10” (25.4 cm) and under	Sever and separate pipe

8.4.1.7.2

Width:
Approximately 70 percent of the pipe diameter.

8.4.1.8 In hot cutting the pipe, leave one inch or more of metal on the top side of pipe if it shows evidence of being twisted or contracted. This should be carefully watched for by the cutting torch operator during the progress of the cut. Before completing the cut, the pipe should be restrained by clamps, side boom or blocking.

8.4.1.9 As the cut is being made, seal and extinguish all fires in the work area. Inspect inside of pipe and coupon for liquids and iron sulfides to determine if air movers may be used.

8.4.1.10 No additional cutting or welding is permitted until the air movers have adequately removed all gas from the work area.

8.4.2 Air Mover Operation

The procedure for operation of an air mover is described below in a sequence that should be followed after the air access hole has been cut and the fire extinguished.

8.4.2.1 Attach ribbons to center of air mover outlets so operation of the air movers can be visually observed and monitored at all times.

8.4.2.2 Attach ribbons at each end of access hole or end of pipe and observe angle of streamers to determine that air is flowing into the pipe toward both air movers.

8.4.2.3 When authorized by the supervisor at the work location, fully open blow off valves.

8.4.2.4 When authorized, slowly open control valve to air movers for five minutes until the desired set pressure is achieved at the work location. Control volume of air through air movers by regulating gas or air pressure supply and observing supply pressure. Do not exceed 80 psig (551 kPa).

8.4.2.5 Operate air mover for five minutes at reduced pressure so air will not bypass the gas.

8.4.2.6 The air mover at the higher elevation will require less control pressure than the air mover located at the lower elevation.

8.4.2.7 Attend air movers constantly using personnel having radio contact with personnel working on the pipe.

8.4.2.8 When equalizing the movement of air in both directions as indicated by the streamers, the evacuation of the pipeline should continue for fifteen minutes.

8.4.2.9 Conduct gas test with a combustible gas indicator for the presence of gas in and around the access opening or in the ends of the pipe. If no gas is indicated, the pipeline is available for cutting "cold" operation.

8.4.2.10 The movement of air into the access hole or open ends of the pipe must be maintained throughout the cutting and welding operation.

8.4.2.11 Prior to cutting out cylindrical piece of pipe, reduce the air mover rate so as to minimize spark travel in the pipe. Before severing, the pipe should be restrained by clamps, side boom or blocking.

8.4.2.12 When the cutting has been completed, the air mover may be adjusted to a rate required for the next operation.

8.4.2.13 The air mover should be adjusted to a rate that will minimize welding problems on the replacement pipe. Control the pressure settings on the air movers to control vacuum on the pipeline and eliminate blow in of welds as the pipeline is closed to the atmosphere by welding.

8.4.2.14 Upon completion and acceptance of the welds, remove air mover equipment and return pipeline to service after purging the pipeline with natural gas (See Procedure 9.03).

9. RELATED PROCEDURES

9.03 Purging and Purging Safety of Pipelines Including Pipeline Blowdown

10. RECORDS

None required.

AIR MOVERS

TABLE 9.04A

CAPACITY OF VARIOUS AIR MOVERS

AIR MOVER SIZE INCH	CAGE PRESSURE PSIG	COMPRESSED AIR SCFM	DISCHARGE AIR SCFM	INDUCED AIR SCFM	PIPELINE SIZE, INCH 8	10	12	16	24	20	30	36
3	20	19.0	274	255.0								
	30	26.4	397	370.6								
	40	33.4	496	462.6								
	50	40.8	561	520.2								
	60	49.8	614	561.2								
	70	60.0	681	621.0								
	80	72.4	736	663.6								
6	20	48.0	900	852.0								
	30	91.0	1350	1259.0								
	40	141.0	1800	1658.0								
	50	192.0	2250	2058.0								
	60	242.0	2700	2458.0								
	70	293.0	3150	2857.0								
10	30	149.0	2900	2751.0								
	42	214.0	3700	3486.0								
	55	262.0	4240	5879.0								
	70	342.0	5050	4708.0								
	81	398.0	5560	5162.0								

FULL SIZE ACCESS HOLE WITH AIR SUPPLY
PLUG VALVE WITH AIR SUPPLY
PLUG VALVE WITH GAS SUPPLY

SOURCE: AGA PURGING PRINCIPAL AND PRACTICE 1975.TABLE 8-2.

AIR MOVERS

TAPPING PIPELINES

1. REFERENCE

49 CFR, Sections 192.151, 192.155, and 192.627.

2. PURPOSE

The purpose of this procedure is to establish the requirements necessary for the installation of hot taps on pipelines under pressure.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (294) ___________________ is responsible for hot tap installation and implementation of this procedure.

4. GENERAL

4.1 Mechanical fittings and material used to make a hot tap shall be designed for at least the Maximum Allowable Operating Pressure (MAOP) of the pipeline.

4.2 This procedure outlines the items to be considered and the steps to be followed for the tapping of pipelines under pressure. This procedure should be used in conjunction with API 2201, "Procedures for Welding and Hot Tapping on Equipment Containing Flammables" (Latest edition), and the API 2201 check sheet.

4.3 Each tap made on a pipeline under pressure shall be performed by a properly trained and qualified crew.

4.4 All welding must be performed by a qualified welder in accordance with qualified welding procedures as required by "Pipeline Welding", Procedure 9.06.

4.5 Weld-o-lets, saddles or split tapping tees may be used for branch connections. An experienced person shall select the proper fitting for the connection. The fitting shall be properly sized to accommodate the hot tapping machine, to allow for full depth of cutter penetration with the travel limits of the machine, and to allow for uninterrupted tapping valve closure when the cutter and cut out coupon are retrieved.

4.6 The term saddle shall include reinforcing saddles, wrap around saddles, or wrap around pipe, saddles, and proprietary fittings.

4.7 Split tapping tees and saddles shall be welded utilizing a qualified welder and welding procedure specifying low hydrogen welding rod.

5. <u>PROCEDURE</u>

5.1 Tap Location

5.1.1 The tap location must be at least 18 inches (46 cm) to a flange or threaded connection.

5.1.2 Assure the connection is positioned so as to allow for the installation, operation, and removal of the hot tapping machine.

5.1.3 The outside diameter of the hot tap nipple, if possible, will be a minimum of two (2) inches (5 cm) from the longitudinal seam of the carrier pipe and shall be a minimum distance of three (3) inches (7 cm) from a girth weld.

5.1.4 Hot taps are to be installed in a horizontal plane where possible.

5.2 Conditions of the Carrier Pipe

Prior to welding the hot tap nipple to the carrier pipe:

5.2.1 Visually inspect the outside diameter of the pipe for defects such as corrosion, mechanical damage, etc.

5.2.2 Check the wall thickness of the carrier pipe in the area where the nipple is to be attached.

5.2.3 Check for evidence of lamination.

5.3 Maximum Line Pressure

The maximum line pressure during the process of welding the hot tap nipple to the carrier pipe will be per Operating Pressure Limits - Maintenance & Repair Procedure (Procedure 8.02, Table 8.02A).

5.4 Installation of Hot Tap Nipple and Valve

5.4.1 Specifications:

To provide added structural strength to the branch connection point, unless otherwise specified, pre-tested heavy wall thickness pipe will be used for all hot tap nipples as follows:

5.4.1.1 For tap sizes 8” (20.3 cm) and above, 1/2” (1.27 cm) wall thickness minimum, a minimum of 35,000 psi specified minimum yield strength (SMYS) up to the

SMYS of the carrier pipe, seamless, minimum length 8-1/2” (21.6 cm).

5.4.1.2 For tap sizes 6” (15.2 cm) and under, use schedule 80 wall thickness, minimum of 35,000 psi specified minimum yield strength, seamless, minimum length 6-1/2” (16.5 cm).

5.4.2 Preparation and Welding of Hot Tap Nipple

5.4.2.1 The hot tap nipple shall be fitted, beveled, and welded only by a qualified welder.

5.4.2.2 The hot tap nipple will be fitted and beveled to provide equal spacing around the circumference of the nipple.

5.4.2.3 The nipple is to be inspected to assure that the proper bevel is present and that the fit-up is adequate to provide complete penetration without burn through. Complete penetration of the root bead is necessary. Excessive penetration is undesirable due to interference with the cutter head of the tapping machine. An inside pass of the weld joining the nipple to the carrier pipe will not be permitted.

5.4.2.4 Extreme care will be exercised to maintain a true 90° angle between the axis of the hot tap nipple and the axis of the carrier pipe and to maintain a straight center line between the nipple and valve in order to maintain the proper position of the cutter head during the tapping operation.

5.4.2.5 All moisture and condensation shall be dried from the carrier pipe and the saddled end of the hot tap nipple by heating immediately before welding commences.

5.5 Testing and Inspection

5.5.1 Each hot tap fabrication shall be hydrostatically tested. Pretested pipe may be used.

5.5.2 Before making any welds on the saddle, a leak test of the fillet weld must be performed. Refer to Procedure 15.01, Pressure Testing.

5.5.3 Radiographic inspection of butt welds is necessary. The fillet weld joining the hot tap nipple to the carrier pipe is to be examined visually and, at the discretion of the welding inspector, it can be inspected for surface defects utilizing the magnetic particle or penetrant testing methods.

5.6 Installation of Split Tapping Tee

5.6.1 Installation and Welding

5.6.1.1 The split tee shall be installed using a chain and jack or similar arrangement to insure a snug fit around the carrier pipe.

5.6.1.2 The longitudinal welds shall be made first. The welder(s) shall begin at the center of the saddle and work toward the ends. Each pass, including the stringer bead, shall be made for the entire length of the weld by each welder before successive passes are added. No connecting weld will be made between the split tee and the carrier pipe along the longitudinal seam (use a backing piece when possible).

5.6.1.3 Weld the ends of the split tee to the carrier pipe.

5.6.1.4 The extruded outlet of the split tee reinforcement will be butt welded to the hot tap nipple or flange.

5.6.2 Completion of Hot Tap

5.6.2.1 The tapping machine will be bolted to the flange of the valve. If a horizontal tap is being made, the tapping machine shall be supported so that no stress will be placed on the hot tap nipple and valve. Extreme care is to be exercised in properly aligning and operating the tapping machine.

5.6.2.2 Each hot tap fabrication with the connected tapping machine shall be hydrostatically leak tested for a period of 30 minutes prior to cutting the hole. Pressure shall be limited to prevent overstressing the carrier pipe from external pressure and overpressuring the tapping machine.

5.6.2.3 The hole will then be cut in the carrier pipe to complete the hot tap.

5.7 Installation of Full Encirclement Reinforcing Saddle

5.7.1 Preparation

5.7.1.1 The effectiveness of a full encirclement reinforcing saddle depends upon a snug fit around the carrier pipe. Maximum surface contact between the outside of the carrier pipe and the inside of the saddle is necessary prior to welding the two halves of the saddle together.

5.7.1.2 To accomplish the snug fit it might be necessary to grind a smooth groove inside the saddle to fit the longitudinal weld of the carrier pipe, if ERW pipe. The saddle thickness shall not be reduced to less than the thickness of the carrier pipe. The groove in the saddle must be such that the longitudinal carrier pipe weld will not contact the bottom of the groove before the inside of the saddle contacts the outside of the carrier pipe.

5.7.2 Installation and Welding

5.7.2.1 The saddle shall be installed using a chain and jack or similar arrangement to insure a snug fit around the carrier pipe and the hot tap nipple.

5.7.2.2 The longitudinal welds shall be made first. The welder(s) shall begin at the center of the saddle and work toward the ends. Each pass, including the stringer bead, shall be made for the entire length of the weld by each welder before successive passes are added. No connecting weld will be made between the reinforcement and the carrier pipe (use a backing piece when possible).

5.7.2.3 The extruded outlet of the reinforcement will be fillet welded to the hot tap nipple.

5.7.2.4 Welding the ends of the reinforcing saddle to the carrier pipe is optional.

5.7.3 Completion of Hot Tap

5.7.3.1 The tapping machine will be bolted to the flange of the valve. If a horizontal tap is being made, the tapping machine shall be supported so that no stress will be placed on the hot tap nipple and valve. Extreme care is to be exercised in properly aligning and operating the tapping machine.

5.7.3.2 Each hot tap fabrication with the connected tapping machine shall be hydrostatically leak tested for a period of 30 minutes prior to cutting the hole. Pressure shall be limited to prevent overstressing the carrier pipe from external pressure and overpressuring the tapping machine.

5.7.3.3 The hole will then be cut in the carrier pipe to complete the hot tap.

5.8 Coating of Assembly

Upon completion of the tap the entire assembly is to be thoroughly cleaned, primed, and coated with a coating that is compatible with the coating system on the carrier pipe. Special care should be taken to effectively seal the ends of a full encirclement saddle so that no moisture can penetrate and enter the area between the saddle and carrier pipe. This is extremely important since the ends of the saddle are not welded to the carrier pipe.

5.9 Concrete Support

Horizontal tap installations will be supported by concrete foundations extending back and under the line being tapped, placed on firm soil and installed as soon as possible after the side connection is welded in place.

6. RELATED PROCEDURES

8.01 Maximum Allowable Operating Pressure
8.02 Operating Pressure Limits - Maintenance

7. RECORDS

7.1 Submit as built documentation to (295) ________________ for updating of drawings.

7.2 On buried pipeline, complete “Pipeline Maintenance and Surveillance Report” (Form 3.01B).

7.3 Keep above documents for the life of the pipeline.

PIPELINE WELDING

1. REFERENCE

49 CFR, Subpart E (Sections 192.221 through 192.245), API 1104 (Welding of Pipelines and Related Facilities, 19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008)

2. PURPOSE

The purpose of this procedure is to establish the requirements for qualifying welding procedure and welders for work on steel pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (301) ___________________ is responsible to confirm that all pipeline welding is performed in accordance with this procedure.

The (302) ___________________ is responsible for reviewing and approving all qualified welding procedures prior to start of production welding.

The (303) ___________________ is responsible for retaining and maintaining a current record of approved welders, their identification numbers, and the procedures to which each welder is qualified.

4. GENERAL

4.1 All welding to be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements specified. The quality of the tests used to qualify the procedure shall be determined by destructive testing. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

4.2 A Welding Procedure Specification (WPS) is a written procedure prepared to provide direction for making production welds to specific requirements. It specifies the materials, consumables, and procedures to be used in making welds, either for a variety or for specific connection geometry, steel types and steel thickness.

4.3 The Procedure Qualification Record (PQR) documents the welding materials, consumables, and procedures defined by the WPS used to weld a test coupon.

It also contains the test results of the tested specimens. The PQR basically establishes that the weldments specified by the WPS are capable of providing the required properties for its intended application.

4.4 The Welder Performance Qualification (WPQ) documents the ability of the welder being tested to produce a weld using a specific set of materials, consumables, and procedures to meet certain quality requirements.

4.5 A weld map and weld location record shall be completed.

4.6 All visual inspection and nondestructive testing shall be per Procedure 15.02.

5. QUALIFICATION OF WELDING PROCEDURES AND WELDERS

5.1 All welding performed on gas pipeline systems shall be completed using welding procedures qualified in accordance with the API Standard 1104 section #5 (19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008, or Section IX “Welding and Brazing Qualifications” of the ASME Boiler and Pressure Vessel Code (incorporated by reference, 49 CFR192.7 currently referenced editions).

5.2 Welders welding on pipelines that operate at less than 20% SMYS shall qualify and test according to the requirements for pipelines that operate at 20% SMYS or more.

5.3 Each welder shall be qualified in accordance with section 6 of API Standard 1104 (19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008). or Section IX “Welding and Brazing Qualifications” of the ASME Boiler and Pressure Vessel Code (ibr, 49 CFR192.7 currently referenced editions).

5.3.1 No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process. For welders qualified under 192.227(b), less than 20% SMYS, may not weld unless;

- The welder has re-qualified at least once per calendar year not to exceed 15 months, or
- At least twice each calendar year, not to exceed 7 ½ months the welder has had a production weld cut out, tested, and found acceptable in accordance with the qualifying test.

5.3.2 A welder may not weld on pipe operating at a pressure that produces a hoop stress of 20% or more of SMYS unless within the preceding 6

calendar months the welder has had one weld tested and found acceptable
under sections 6 or 9 of API Standard 1104 (19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008). Alternatively, welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7 ½ months.

5.3.3 No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

5.3.4 When there is specific reason to question the welder's ability to make welds that meet the specification, the WPQ qualification which supports the welding he is doing shall be retested. All other qualifications not questioned remain in effect.

5.4 Each contractor is responsible for the welding performed by their organization. They will conduct the tests required to qualify their welding procedures and each of their welders.

5.5 It is the contractor's responsibility to furnish the Company with complete copies of their welding procedure specification (WPS), procedure qualification record (PQR), and welding performance qualifications record (WPQ) for each welder, and any changes that occur thereto while working for the Company. The contractor is also responsible for retaining and maintaining complete documentation of same, and providing full access to the Company as required.

6. PROCEDURE

6.1 Prior to the start of any welding, an appropriate weld procedure shall be selected and qualified, if not presently qualified.

6.2 Each welder must be qualified to weld by the selected procedure.

6.3 All production welding must conform to the requirements of design drawings or specifications, the selected qualified welding procedure specification (WPS), and within the limits of the welder's performance qualification (WPQ).

6.4 The welding operation must be protected from the weather conditions that would impair the quality of the completed weld.

6.5 Before beginning any welding,

6.5.1 The welding to be performed shall be evaluated for hazards which may affect the safety and health of personnel working in the area or the general public. Welding shall begin only when safe conditions are indicated.

6.5.1.1 A thorough check shall be made in or around a structure or area containing gas facilities to determine the possible presence of a combustible mixture.

6.5.1.2 Where welding is performed in a public area, a means to shield the public from welding arcs shall be provided between welding and public, or assure that public is not present during welding.

6.5.2 Welding surfaces must be free of defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.5.3 Welding surfaces must be clean and free of any material that may be detrimental to the weld. Each joint of pipe may require swabbing to remove all dirt and foreign materials from the inside.

6.5.4 Bevels shall be checked for proper dimensions and angle.

6.5.5 Ensure that the longitudinal seams are offset. The seams should be located on the upper quadrant of the line and preferably within 30 degrees of top center. Alternate joints shall be rotated to right or left at least 15 degrees to avoid aligning the seams in adjacent joints. Exceptions to this requirement shall be made for making bends, as the longitudinal seam must remain on the neutral axis of the bend, and at other locations as may be indicated on the design drawings.

6.5.6 The line-up shall be checked to ensure proper root spacing and alignment. This alignment must be preserved while the root bead is being deposited.

6.5.7 Welding consumables shall be confirmed for correct type, proper use, control and handling prior to and during use. All welding rod stubs and discarded rods shall be gathered and disposed of in a manner and place authorized by the Company. No welding rod shall be left on or around the working area or deposited in the ditch.

6.6 Preheated and interpass temperatures shall be maintained within the specified ranges.

6.6.1 Preheating shall be required when the welding procedure indicated that chemical composition, ambient and/or metal temperature, material thickness, or weld-end geometry require such treatment to produce satisfactory welds.

6.6.2 The temperature shall be checked by the use of temperature-indicating crayons, thermocouple pyrometers, or other suitable methods to assure that the required preheat temperature is obtained prior to and maintained during the welding operation.

6.7 Grinding and cleaning of the stringer (root) bead shall be completed prior to depositing subsequent filler passes.

6.8 Welds in carbon steels having a high carbon content which requires stress relieving by the applicable code (API 1104-Welding of Pipelines and Related Facilities, 19th edition 1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008or ASME/ANSI B31.8) shall be stress relieved as prescribed in ASME Boiler and Pressure Vessel Code, Section VIII. Stress relieving may also be advisable for welds in steel having lower carbon or carbon equivalent when adverse conditions exist which cool the weld too rapidly.

6.8.1 Welds in carbon steels shall be stress relieved when the wall thickness exceeds 1-1/4 in (3.81 cm).

Note: Above mentioned codes shall be the 49CFR192 currently referenced edition.

6.9 Mark and ensure that all arc burns are removed and repaired. A ground may not be welded to the pipe or fitting that is being welded.

6.10 A miter joint is not permitted (not including defections up to 3 degrees that are caused by misalignment). Any weld which is not at right angles to the axis of the pipe will be considered a mitered weld, unless the angle is specifically called for on the design drawings.

6.11 Weld numbers and welder identification numbers shall be applied using waterproof crayon, paint pens, or similar markers on the pipe coating adjacent to the weld for temporary identification. Marks shall be made on the top of the pipe approximately 1 foot (0.30 meters) from the cutbacks on the pipe coating, and shall be visible after joint coating is complete.

6.12 A permanent record in the form of weld maps shall be made indicating the location of all welds that can be cross referenced to the weld's nondestructive testing and to the welder making the weld.

7. REPAIR OR REMOVAL OF WELD DEFECTS

7.1 Qualified procedures and currently qualified welders are required for all repair work.

7.2 Each weld that is found unacceptable must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be completely removed if it has a crack that is more than 8 percent of the weld length.

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

7.4 The repair of a crack in a weld, providing it does not exceed 8% of the weld length, or, of any defect or flaw in a previously repaired weld, must be according to a written weld procedure qualified under Section 5.0 "Qualification of welding procedures and welders". The welder(s) must have qualified to the repair procedure prior to affecting the repair.
The repair procedure must provide that the repaired defect(s) equal or exceed the original mechanical properties of the originally intended weld.

Re-repair of welds will not be permitted unless approved by the District Engineer using a qualified welding procedure.

After any repair or re-repair, the weld must be non-destructively tested by any process to determine and ensure the repair's integrity. Please refer to Procedure 15.02 "Visual Inspection and Nondestructive Testing".

7.5 An arc burn caused by any means, whether by welding or other, can be injurious to the carrier pipe and is totally unacceptable. Arc burn affects the integrity of the pipe and can cause mechanical deficiencies and possible stress concentrations.

An arc burn can be completely removed by grinding. However, the grinding process must not be excessive and to the point where the wall thickness is less than the minimum thickness required by the tolerances in the original specification of the pipe.

If the arc burn cannot be removed by grinding, a cylinder of the pipe containing the defect must be removed.

If grinding provides a thinner pipe wall than originally manufactured, and the pipe is to be retained, derating of the pipe must be considered.

8. RELATED PROCEDURES

9.01 Pipeline Repair Procedures
15.02 Visual Inspection and Nondestructive Testing

9. RECORDS

9.1 Insert copies of the welding procedures used, the location of the welds, the welders used, and the results of all nondestructive testing in the pipeline historical file.

9.2 Insert copies of pipe and fitting material qualifications, as-built drawings, and hydrostatic test records in the pipeline historical file.

9.3 Maintain records for the life of the facility.

COMPRESSOR STATION EMERGENCY SHUTDOWN SYSTEM

1. REFERENCE

49 CFR, Sections 192.163(e), 192.165(b)(2), 192.167, 192.171, 192.731(c), 192.736, and 192.605(b)(7).

2. PURPOSE

The purpose of this procedure is to define which compressor stations require an Emergency Shutdown System, and the minimum requirements of these systems.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (309) ________________________ is responsible to determine which compressor stations require an Emergency Shutdown System. The (310) __________________ is responsible for ensuring that compressor stations that require an Emergency Shutdown System are in accordance with the minimum requirements defined in this procedure.

4. GENERAL

4.1 Except for unattended field compressor stations of 1000 H.P. (746 kilowatts) or less, each compressor station must have an Emergency Shutdown System that meets the following:

4.1.1 The system must be able to isolate the station and blow down the station piping.

4.1.2 Blow-down gas must be discharged in a non-hazardous location.

4.1.3 It must be capable of shutting down gas compressing equipment, gas fires, and all non-essential electric facilities. Essential electrical circuits are those providing emergency lighting for personnel, those in the vicinity of the gas headers, and those needed to protect equipment from damage. Essential electrical circuits must remain energized.

4.1.4 It must be operable from at least two locations. All locations must be located outside the areas of the station exposed to gas, near the exit gates (if fenced) or near emergency exits (if not fenced), and not more than 500 feet (153 meters) from the limits of the station.

4.2 On a platform located offshore or in inland navigable waters, the Emergency Shutdown System shall be designed to actuate automatically under the following conditions:

4.2.1 For unattended compressor stations:

4.2.1.1 When gas pressure exceeds 115% of Maximum Allowable Operating Pressure (MAOP).

4.2.1.2 When an uncontrolled fire occurs on the platform.

4.2.2 For compressor stations in a building:

4.2.2.1 When an uncontrolled fire occurs in the building.

4.2.2.2 When the gas concentration reaches 50% of the lower explosive limit in a building that has a source of ignition. Electrical facilities conforming to Class 1, Group D of the National Electrical Code are not considered to be a source of ignition for the purposes of this procedure.

4.3 Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the Emergency Shutdown System.

4.4 Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

4.5 Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

4.6 Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

5. PROCEDURE

5.1 Test each compressor station Emergency Shutdown System by either:

5.1.1 Actuating each remote control shutdown device and verifying that the system physically shuts down; or

5.1.2 Disconnecting remote control shutdown device lead wires as close as possible to the compressor and verifying circuit continuity.

5.2 Perform the appropriate test at least once per calendar year, not exceeding 15 months.

6. RELATED PROCEDURES

2.01 Record Keeping
7.01 Emergency Valve Maintenance
10.03 Compressor Station Gas Detection and Alarm System

7. RECORDS

7.1 Complete the Remote Control Shutdown Device Test Form (Form 10.01A) as required.

7.2 Retain records for at least five years.

REMOTE CONTROL SHUTDOWN DEVICE TEST FORM

FORM 10.01A [192.731(c)]

DATE: ______________
MO/DAY/YR

FREQUENCY OF SURVEY: ______________

SYSTEM: ______________

SIGNATURES:
COMPLETED BY: ______________
SUPERVISOR: ______________

DEVICE ID#:
UPON DEVICE ACTUATION: ☐ SYSTEM PHYSICALLY SHUTDOWN ☐ CIRCUIT CONTINUITY VERIFIED
SYSTEM FAILED, ACTION TAKEN:

DEVICE ID#:
UPON DEVICE ACTUATION: ☐ SYSTEM PHYSICALLY SHUTDOWN ☐ CIRCUIT CONTINUITY VERIFIED
SYSTEM FAILED, ACTION TAKEN: ______________

DEVICE ID#:
UPON DEVICE ACTUATION: ☐ SYSTEM PHYSICALLY SHUTDOWN ☐ CIRCUIT CONTINUITY VERIFIED
SYSTEM FAILED, ACTION TAKEN: ______________

DEVICE ID#:
UPON DEVICE ACTUATION: ☐ SYSTEM PHYSICALLY SHUTDOWN ☐ CIRCUIT CONTINUITY VERIFIED
SYSTEM FAILED, ACTION TAKEN: ______________

DEVICE ID#:
UPON DEVICE ACTUATION: ☐ SYSTEM PHYSICALLY SHUTDOWN ☐ CIRCUIT CONTINUITY VERIFIED
SYSTEM FAILED, ACTION TAKEN: ______________

COMPRESSOR STATION STORAGE OF COMBUSTIBLES

1. REFERENCE

49 CFR, Sections 192.735.

2. PURPOSE

The purpose of this procedure is to define how combustibles shall be stored in compressor stations for safety of personnel and equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (311) __________________ is responsible for ensuring that combustibles are properly stored at pipeline jurisdictional compressor stations.

4. GENERAL

4.1 All flammable or combustible materials, which are used in the compressor buildings for daily maintenance, shall be stored in approved safety containers. These containers shall have spring-loaded covers, proper vents, and flame arrestors in each opening. All rags, which might be flammable or combustible, must be stored in covered metal containers, the type, which close automatically. All Class A flammable material shall be stored in covered metal containers. No paint shall be stored in compressor buildings.

4.2 All flammable or combustible materials other than those normally used in the compressor building, shall be stored in structures built of non-combustible material and shall be placed a suitable distance from compressor building.

4.2 Where possible, all aboveground storage tanks shall be a safe distance from any building or structure as provided in the National Fire Protection Association Standard No. 30. They shall be properly vented and equipped with emergency pressure relief valves in accordance with NFPA Standard No. 30. Where necessary to provide adequate protection of adjacent property or waterways, all aboveground storage tanks shall be diked in such a manner as to contain the volume of those tanks.

5. PROCEDURE

5.1 Verify proper storage of combustibles at each pipeline jurisdictional compressor station.

5.2 It is recommended to verify storage of combustibles at least once per calendar year, not exceeding 15 months.

6. RELATED PROCEDURES

10.01 Compressor Station Emergency Shutdown System
10.03 Compressor Station Gas Detection and Alarm System

7. RECORDS

7.1 Document storage on combustibles on gas detection and alarm form or other form as appropriate.

7.2 Retain records for at least five years.

COMPRESSOR STATION GAS DETECTION AND ALARM SYSTEM

1. REFERENCE

49 CFR, Section 192.736.

2. PURPOSE

The purpose of this procedure is to define which compressor station buildings require a gas detection and alarm system, and the minimum requirements of these systems.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (316) ____________________ is responsible to determine which compressor station buildings require a gas detection and alarm system. The (317) _______________ is responsible for ensuring that compressor station buildings that require a gas detection and alarm system are in accordance with the minimum requirements defined in this procedure.

4. GENERAL

4.1 Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is:

4.1.1 Constructed so that at least 50 percent of its upright side area is permanently open; or

4.1.2 Located in an unattended field compressor station of 1000 horsepower (746 kw) or less.

4.2 Except when shutdown of the system is necessary for maintenance, each gas detection and alarm system must:

4.2.1 Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

4.2.2 If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

4.3 Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

5. PROCEDURE

5.1 Make a determination as to which compressor station buildings require gas detection and alarm systems prior to September 16, 1996.

5.2 Maintain each gas detection and alarm system as recommended by manufacturer(s) of the equipment, at intervals not to exceed one year.

5.3 Physically test the system to ensure the gas detection system is properly calibrated and that the alarm system enunciators are operating properly.

6. RELATED PROCEDURES

10.01 Compressor Station Emergency Shutdown System

7. RECORDS

7.1 Record results of all gas detection and alarm system tests on Form 10.03A.

7.2 Retain records for at least five years.

GAS DETECTION AND ALARM SYSTEM TEST AND EVALUATION FORM

FORM 10.03A [192.736]

DATE OF EVALUATION: ______________________

LOCATIONS: ______________________

BUILDING NAME/#: ______________________

☐ GAS DECTECTION AND ALARM SYSTEM REQUIRED

EXPLAIN: ______________________

____

____

DATE OF TEST: ______________________

CALIBRATION INSTRUMENT ID #: ______________________

ALARM ACTIVATION LEVEL: ______________________
DURING TEST (% LEVEL)

DATE OF RECALIBRATION: ______________________

DATE(S) OF REPAIR(S): ______________________

EXPLAIN/ITEMIZE: ______________________

____

____

____

TOTAL BUILDING H.P.: ______________________

APPROX. % SIDE AREA OF BLDG. OPEN: ______________________

☐ GAS DECTECTION AND ALARM SYSTEM NOT REQUIRED

ANNUNCIATOR VOLUME ACCEPTABLE? ______ YES ______ NO

SYSTEM RECALIBRATED OR REPAIRED? ______ YES ______ NO

EXPLAIN: ______________________

____

____

____

ODORIZATION OF GAS

1. REFERENCE

49 CFR, Section 192.613 and 192.625.

2. PURPOSE

To establish requirements for the odorization of natural gas transported by transmission or distribution pipelines and branch lines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (323) ____________________ is responsible to identify and odorize the pipelines that require odorization.

4. GENERAL

4.1 Natural gas in transmission lines in Class 3 and Class 4 locations must contain a natural odorant or be odorized except in the following situations:

4.1.1 When at least 50% of the length of the line downstream from that location is in a Class 1 or Class 2 location.

4.1.2 When a lateral line transports gas to a distribution center and at least 50% of the length of that line is in a Class 1 or Class 2 location.

4.1.3 The line transports gas to any of the following facilities which received unodorized gas from that line prior to May 5, 1975:

4.1.3.1 An underground storage field

4.1.3.2 A gas processing plant

4.1.3.3 A gas dehydration plant

4.1.3.4 An industrial plant using gas where the presence of an odorant makes the end product unfit for the purpose for which it was intended, reduces the activity of a catalyst, or reduces the percentage completion of a chemical reaction.

4.1.4 The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

4.2 Natural gas that is used in Company owned or operated facilities for such purposes as space heating, refrigeration, water heating, cooking and other domestic uses, or for heating or air conditioning office or living quarters, shall be odorized unless it contains a natural odorant.

5. ODORANT CONCENTRATION

Where odorization of gas is required per Criteria listed above, the gas must be odorized so that at a concentration in air of 20% of the lower explosive limit (LEL), the gas is readily detectable by a person with normal sense of smell. The odorant manufacturer's recommendations should be used in determining the appropriate amount of odorant to be injected.

6. GENERAL

6.1 In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

6.1.1 The odorants shall not be harmful to persons, materials, or pipe.

6.1.2 The products of combustion from the odorant are not toxic when breathed nor corrosive or harmful to those materials to which the products of combustion will be exposed.

6.2 Odorants shall not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

6.3 Odorizing equipment shall be used which will introduce the odorant without wide variation in the level of odorant. Positive displacement odorant pumps with variable stroke or rate provide low variation injection rates and can be activated by a signal from a flow meter to provide odorant injection proportional to gas flow. Other types of odorization equipment may also be suitable for specific applications. The (324) ________________ shall approve new odorant injection equipment installations.

7. PROCEDURE

7.1 Determine segments of natural gas pipelines that require odorization according to the Criteria listed above.

7.2 If it is determined that odorization is required, the gas needs to be odorized if it does not contain a natural odorant.

7.3 If odorization is required:

7.3.1 To assure proper concentration of odorant, the Company will conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.

7.3.2 Sampling sites shall be used which insure that all gas within the piping system contains the required odorant concentrations. The locations of sampling should be distant from any gas being vented and the odorizer. The number of sites selected depends upon the size and configuration of the system, location of odorization stations, and locations that may contain low odorant levels.

7.3.3 Sampling and testing shall be performed at least once per calendar year (but not exceeding 15 months between tests).

8. <u>RELATED PROCEDURES</u>

4.01 Class Location Survey and Determination
5.01 Continuing Surveillance
5.03 Pipeline Patrolling/Gas Leak Survey without Instrumentation

9. <u>RECORDS</u>

9.1 Record sampling data on Form 11.01B.

9.2 Retain documentation for at least five years.

ODORANT SAMPLING REPORT

FORM 11.01B [192.625]

OWNER: ______________________ DATE: ______________
MO/DAY/YR

PIPELINE SYSTEM: ______________________

LOCATION OF TEST POINT: ______________________

INTENSITY SCALE:

1) ABSENT (NO DECTABLE ODOR)
2) BARELY DETECTABLE
3) READILY DETECTABLE
4) STRONG
5) VERY STRONG (OBNOXIOUS)

ALLOWABLE % GAS CONCENTRATION RANGE: 0.5% TO 0.9%

SPECIFIC GRAVITY OF GAS RELATIVE TO AIR:

INTENSITY SCALE READING:

ROTAMETER READING:

% GAS CONCENTRATION READING:

** FOR SPECIFIC GRAVITY OTHER THAN 0.620, MULTIPLY % GAS READING BY CORRECTION FACTOR.

__________ % x __________ = __________ % GAS IN ODOROMETER EFFLUENT

REMARKS: ______________________

____

____

____

____

____

____

SIGNED: ______________________

SUPERVISOR SIGNATURE: ______________________

PIPELINE UPRATING

1. REFERENCE

49 CFR Sections 192.551, 192.553, 192.555, 192.557, and 192.619.

2. PURPOSE

The purpose of this procedure is to outline the minimum requirements for increasing the maximum allowable operating pressure (MAOP) in pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (330) ____________________ is responsible for the implementation of pipeline uprates, including determination of the new MAOP, as well as providing a specific written procedure for uprating each pipeline.

The (331) _____________________ is responsible for the operation of the pipeline once the upgrade is finished.

4. GENERAL

The (332) _____________________ will provide detailed written procedures for uprating pipelines and associated facilities. This written procedure will address:

4.1 *Pressure increases.* Whenever the requirements of this procedure require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

4.1.1 At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

4.1.2 Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

4.2 *Limitation on increase in maximum allowable operating pressure.* Except as provided in paragraph 5.1 of this procedure, a new maximum allowable operating pressure (MAOP) established under this subpart may not exceed the

maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.
However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula in Procedure 8.01, paragraph 4.1, is unknown, the MAOP may be increased as provided in Procedure 8.01, paragraph 4.1.2.

4.3 Uprating requirements for plastic pipelines follow the requirements outlined in paragraph 5.2 of this procedure.

5. UPRATING REQUIREMENTS

5.1 No segment of pipeline may be subjected to an operating pressure that will produce a hoop stress of 30% or more of SMYS and that is above the established maximum allowable operating pressure (MAOP) unless it is in accordance with the following:

5.1.1 Before increasing operating pressure above the previously established maximum allowable operating pressure (MAOP) the operator shall:

5.1.1.1 Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this procedure.

5.1.1.2 Make any repairs, replacements, or alternations in the segment of pipeline that are necessary for safe operation at the increased pressure.

5.1.2 After complying with paragraph 5.1.1 above, the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970 may be increased to the highest pressure permitted in Procedure 8.01, using as a test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

5.1.3 After complying with paragraph 5.1.1 above, the maximum allowable operating pressure of a pipeline segment that does not qualify under paragraph 5.1.2 may be increased if at least one of the following requirements is met:

5.1.3.1 The segment of pipeline is successfully tested in accordance with the requirements of Procedure 15.01 for a new line of the same material in the same location.

5.1.3.2 The maximum allowable operating pressure of a pipeline segment in a Class 1 location that has not been previously pressure tested may be increased if:

5.1.3.2.1 It is impractical to test it in accordance with the requirements of this part;

5.1.3.2.2 The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

5.1.3.2.3 The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this procedure.

5.2 No segment of a steel pipeline may be subjected to an operating pressure that will produce a hoop stress of <u>less</u> than 30 percent of SMYS and that is above the established maximum allowable operating pressure unless it is in accordance with paragraphs 5.2.1 and 5.2.2 below.

Also, no segment of plastic pipeline may be subjected to an operating pressure that is above the established maximum allowable operating pressure unless it is in accordance with paragraphs 5.2.1 and 5.2.2 below.

5.2.1 Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

5.2.1.1 Review the design, operating, and maintenance history of the segment of pipeline.

5.2.1.2 Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, it is monitored during the pressure increase and it does not become potentially hazardous.

5.2.1.3 Make any repairs, replacement, or alterations in the segment of pipeline that are necessary for safe operation at the increase pressure.

5.2.1.4 Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure.

5.2.2 After complying with paragraph 5.2.1 above, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 psig (69 kPa) or 25 percent of the total pressure increase, whichever produces the few number of increments.

6. PROCEDURE

6.1 Establish a written procedure that is in accordance with the requirements outlined in this procedure for each segment of pipeline to be uprated.

6.2 Ensure that a new MAOP cannot be exceeded in operation.

7. RELATED PROCEDURES

5.02	Gas Leak Detection Survey for Pipelines without Odorant
8.01	Maximum Allowable Operating Pressure
8.02	Operating Pressure Limits – Maintenance & Repair
9.01	Repair Procedures
15.01	Pressure Testing
16.05	Test Requirements for Plastic Pipelines

8. RECORDS

Maintain records for the life of the pipeline of each investigation required by this procedure, all work performed, and all pressure tests conducted in conjunction with the pressure uprate.

CONVERSION OF SERVICE

1. REFERENCE

49 CFR, Sections 192.14 and 192.452.
GPTC – Guide for Gas Transmission and Distribution Piping Systems
ASME B31.8 – Gas Transmission and Distribution Piping Systems, section #856

2. PURPOSE

The purpose of this procedure is to outline the steps required to convert a pipeline previously not used for gas service to gas service.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (338) ______________________ is responsible for developing a written procedure to convert a pipeline to gas service.

4. GENERAL

4.1 A written procedure must be prepared for the line conversion covering at a minimum, the procedures and requirements described below.

4.2 Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each converted pipeline must meet the requirements of Section 6 (Pipeline Corrosion Control) of this manual specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of Section 6 of this manual specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

5. PROCEDURE

5.1 Conduct historical records study by reviewing design, construction, operation, and maintenance history of the pipeline. If available, particular attention should be paid to welding procedures used and other joining methods, internal and external coating, pipe material, and other material descriptions. Study available operating and maintenance data including leak surveys, leak records, inspections, failures, cathodic protection, and internal corrosion control practices. Use form #12.02A and form #12.02B (pipeline fact sheet template) or equivalent to document this review. If sufficient historical records are not available, then appropriate tests must be conducted to determine if the pipeline is safe to operate.

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient historical records are not available [192.14(a)(1)]:

- Corrosion surveys including one or more of the processes used in the integrity management program:
    1) External Corrosion Direct Assessment (ECDA) evaluations. These normally include close interval surveys (CIS), direct current voltage gradient (DCVG), and pipeline current mapper (PCM)
    2) In line inspection (ILI) tools
    3) Guided wave
- Ultrasonic inspections for corrosion and wall thickness determinations
- Positive material identification inspection using portable XRF analyzers
- Acoustic emissions inspection
- Tensile tests
- Internals inspections in accordance with O&M procedure #6.02
- Radiographic inspections

5.2 Visually inspect the pipeline right-of-way, all aboveground segments, and appropriate underground segments of the pipeline for physical defects or other conditions which could impair the strength or tightness of the line.

Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites:

- Corrosion surveys
- Segments with coating damage or deterioration due to soil stresses and/or internal or external temperature extremes
- Pipeline component locations
- Locations subject to mechanical damage
- Foreign pipeline crossings
- Locations subject to damage due to chemicals such as acid
- Population density (document class location study per 192.5)

5.3 Correct any defects or conditions discovered during reviews and/or inspections prior to line commissioning.

5.4 Determine new MAOP for the line in accordance with 192.619 and Procedure 8.01.

5.5 Conduct class location survey in accordance with 192.5 and compare the proposed MAOP and operating stress levels with those allowed for the location class. Replace pipe and/or facilities to make sure the operating stress levels is commensurate the location class.

5.5 Conduct a pressure test the line to substantiate the new line MAOP in accordance with 192 subpart J and procedure #15.01.

5.6 Within one year of the date that the converted line is placed in gas service, provide cathodic protection as required by 192.455.

6. RELATED PROCEDURES

8.01	Maximum Allowable Operating Pressure
9.01	Repair Procedures
15.01	Pressure Testing
15.02	Visual Inspection and Nondestructive Testing

7. RECORDS

7.1 Appropriate documentation of all investigations, tests, repairs, replacements, and alterations will be maintained in the District Engineering Office for the life of the pipeline.

7.2 Document investigations, repairs, replacements, and alternations on Form 12.02A or equivalent.

7.3 Document pressure tests on suitable or third party forms.

7.4 Maintain all conversion of service records for life of the pipeline.

CONVERSION OF SERVICE FORM

FORM 12.02A [192.14]

SYSTEM: ____________________ SIGNATURE: ____________________

DATE: ____________________ SUPERVISOR SIGNATURE: ____________________

MO-DAY-YEAR

	PREVIOUS SERVICE:	NEW SERVICE:

Relief Valves

TAG	STATION	SETPOINT	CAPACITY

Pipe Data

FROM STATION	TO STATION	CLASS LOCATION (GAS)	PIPE DIAMETER	WALL THICKNESS	GRADE	U.T. READING

Hydrostatic Testing

DATE OF LAST TEST: ____________________ NEW PRESSURE TEST REQ'D? ☐ Yes ☐ No

TEST PRESSURE: ____________________ IF YES, PRESSURE: ____________________

OLD MAOP OR MOP: ____________________ NEW MAOP OR MOP: ____________________

Components

PRESSURE RATING OF WEAKEST COMPONENT: ____________________

LOCATION AND DESCRIPTION OF WEAKEST COMPONENT: ____________________

Summaries

DESCRIBE CLEANING/DRYING PROCEDURE:

SUMMARIZE INVESTIGATION TESTS PERFORMED AS A PART OF THE CONVERSION SERVICE:

SUMMARIZE REPAIRS, REPLACEMENTS, ALTERATIONS MADE AS A PART OF THE CONVERSION OF SERVICE:

ABANDONMENT OR INACTIVATION OF FACILITIES

1. REFERENCE

   49 CFR, Section 192.727

2. PURPOSE

   The purpose of this procedure is to establish minimum requirements for the abandonment of natural gas pipeline facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (344) ______________________ is responsible for determination, evaluation, and taking proper action to comply with this procedure for abandonment of pipeline facilities.

4. DEFINITIONS

   4.1 Abandoned facilities are those which have been determined to have no present or future use, and have ceased operation, either due to deterioration or because they are not needed for gas transportation use now or in the future.

   4.2 Inactive facilities are those which have ceased operation, but may be returned to service in the future.

   4.3 Inactive and unmaintained facilities shall be disconnected from all gas sources, and purged and capped as abandoned pipelines.

5. GENERAL

   5.1 Facilities to be abandoned will be evaluated and handled on an individual basis.

   5.2 All applicable Federal (MMS, Corps of Engineers, BLM), state, county, and local regulations or ordinances shall be complied with in the abandonment of gas facilities.

   5.3 Physically remove all abandoned facilities, if practical. If this is not feasible, sever below grade and remove all aboveground piping and equipment.

5.4 Pipeline facilities abandoned in place will not be maintained and should not be considered for reactivation for service at a later date.

6. PROCEDURE – ABANDONMENT (Permanently Removed from Service)

6.1 Facilities to be abandoned shall be disconnected and isolated from all sources and supplies of gas such as other pipelines mains, crossover piping, meter stations, control lines, and other appurtenance by a physical separation. Customer valves shall be locked closed and/or disconnected.

6.2 Open ends of pipelines shall be sealed by a welded plate or a permanent type closure or fitting. Branch connections or taps on the facility shall be plugged or sealed.

6.3 Pipeline segments shall be pigged when applicable, prior to or as part of purging to ensure that no liquid hydrocarbons remain in the line.

6.4 The (345) ____________________ shall review local abandonment procedures and permitting requirements prior to the start of work.

6.5 Abandoned facilities shall be purged of natural gas. If air is used as a purging medium, precautions shall be taken to ensure that a combustible mixture is not present after purging and that the mixture cannot ignite during purging. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

6.6 Abandoned pipelines may be filled with air, inert gas, inhibited water, Bentonite Clay (drilling mud), sand slurry, lean cement slurry or other inert materials.

6.7 Where possible, pipeline vaults should be filled with compacted inert material. Acceptable backfill material includes but is not limited to native material, sand slurry and lean cement slurry.

6.8 Whenever service to a customer is disconnected, one of the following must be complied with:

1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized the company.

2) A mechanical device or fitting that will prevent the flow of gas must be installed on the service line or in the meter assembly.
3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

6.9 For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crossed over, under, or through a commercially navigable waterway, the last operator of that facility must file a report when that facility is abandoned.

For pipelines abandoned after October 10, 2000, notification and data submittal about the abandoned facility is to be to the National Pipeline Mapping System (NPMS). Submission will be in accordance with the NPMS "Standards for Pipeline & Liquefied Natural Gas Operator Submissions".

Other submission alternatives exist.

Data on pipelines abandoned prior to October 10, 2000 must be filed by April 10, 2001.

Please refer to 49CFR 192.727 for additional information on submission.

7. PROCEDURE - INACTIVATION

7.1 Protect inactive facilities, as they were protected before inactivation, from corrosion by using cathodic protection or other means to prevent deterioration. Generally, pipelines should remain filled with natural or inert gas and be pressurized above atmospheric pressure. Offshore pipelines should be filled with a non-hazardous liquid to maintain negative buoyancy.

7.2 Inactive facilities must be treated the same as active facilities and all requirements of the Standard Operating and Maintenance Procedure Manual for Gas Pipelines requirements must be carried out on inactive facilities.

7.3 Inactive, unmaintained facilities may be returned to service after a thorough engineering review, testing and conversion to service.

8. RELATED PROCEDURES

9.02 Blowdown and Purging Safety
9.03 Purging of Pipeline
12.02 Conversion of Service

9. RECORDS

9.1 Complete form Pipeline Abandonment Record (Form 13.01A) or Pipeline Inactivation Record (Form 13.01B). A copy of this form shall be sent to the (346) ________________and placed in the system historical file.

9.2 Update drawings with abandonments or removals. Pipelines that have been removed or abandoned in-place and sold will be eliminated from the drawings. Other in-place abandonments need to be indicated on drawings as being abandoned in-place.

9.3 Retain the original of the form in a permanent District Office abandonment file for future reference.

FACILITY ABANDONMENT RECORD

FORM 13.01A [192.727]

COMPANY:	DISTRICT / LOCATION:	DATE: MO-DAY-YR
SYSTEM:		
DESCRIPTION OF FACILITY:		
TYPE OF SERVICE: ☐ Natural Gas	☐ Liquid	
LOCATION:		
CITY:	COUNTY:	STATE:
SECTION:	TOWNSHIP:	RANGE:
DATE PLACED IN SERVICE:	DATE ABANDONED:	
Type of Abandonment	☐ In Place	☐ Removed
If abandoned in place, describe final position of ownership.		
Purged with:		
Filled with:		
Describe procedure used to insure that no volatile flammable hydrocarbons remained in the facilities:		
PREPARED BY:		LOCATION MANAGER APPROVAL:

Distribution:

____

____

____

____

Signatures:

Completed By: ______________________

Supervisor: ______________________

VALVE SECURITY

1. REFERENCE

   49 CFR, Section 192.179(b)(1).

2. PURPOSE

   To outline the requirements for securing or locking valves to prevent accidental, inadvertent operation, and protection from tampering.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (352) ___________________ is responsible for providing security devices to prevent unauthorized operation of the valves.

4. GENERAL

   4.1 All valves at unrestricted facility locations, meter stations, and remote valve settings which could cause disruption of flow, allow natural gas to be released to atmosphere, or cause a safety device to become inoperative, shall be secured.

   4.2 All power operated valves at unattended locations shall have the control boxes locked to prevent manual operation.

   4.3 Other valves at attended or restricted locations which require security may be locked or secured as determined by the (353) _____________________ .

5. PROCEDURE

   5.1 The (354) ____________________ shall determine which valves require security devices to prevent unauthorized operation.

   5.2 Secure all applicable valves against unauthorized operation by:

      5.2.1 Locks or lock and chain combinations.

      5.2.2 Removal of valve handles or hand-wheels.

      5.2.3 Location inside a locked building or enclosure.

5.3 Valves which are normally secured in the open position include:

5.3.1 Mainline valves.

5.3.2 Branch line block and side valves.

5.3.3 Delivery station isolation valves.

5.3.4 Isolation valves under relief valves or on relief valve discharge.

5.4 Valves which are normally secured in the closed position include:

5.4.1 Blow down valve or valves open to atmospheric pressure.

5.4.2 Valves isolating systems having different maximum allowable operating pressures.

5.4.2 One valve in each bypass line around a station.

6. RELATED PROCEDURES

7.01 Emergency Valve Maintenance
14.02 Pipeline Isolation - Lock and Tag

7. RECORDS

See Procedure 7.01, “Valve Maintenance”

PIPELINE ISOLATION - LOCK AND TAG

1. REFERENCE

49 CFR, Sections 192.605(b).

2. PURPOSE

The purpose of this procedure is to establish a procedure to be used during isolation of pipeline facilities for maintenance or modification and to protect people and machinery against unauthorized operation of equipment, valves, or electrical switches while work is performed on facility equipment.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (360) _____________________ must use his best judgment in deciding the extent of blinding and purging of the pipeline section with an inert gas necessary to safely complete the maintenance work.

4. GENERAL

4.1 Prior to commencement of work, checks need to be conducted by supervisors to assure procedure compliance by personnel, that adequate instruction for their portion of the work exists, and adequate communications between the various sections of the overall work site is in place.

4.2 Locks and tags will be used to prevent inadvertent operation of valves, controlling devices, circuit breakers, electrical switches, electrically driven equipment, or other equipment that must not be operated while maintenance or construction is performed on facilities.

4.3 Include actions to insure safe ditching conditions, backfill disposal, and sufficient fire extinguishers.

5. PROCEDURE

5.1 Piping and Equipment Isolation

5.1.1 Identify all valves, lines, electrical switches, and equipment controlling devices, which must be de-energized, de-pressured, drained, or isolated before maintenance work can safely begin.

5.1.2 Isolate all piping and equipment associated with the maintenance or construction activities to be performed.

5.1.3 Remove all hydrocarbon gas or volatile liquids within the work area by draining or venting to atmosphere.

5.2 Lock and Tag

5.2.1 Safety locks and “Danger – DO NOT OPERATE” tags shall be used where applicable to prevent inadvertent operation of those devices that pose a hazard if operated while performing maintenance or construction activities.

5.2.2 Complete a “Danger - DO NOT OPERATE” tag showing the date, time, reason for tagging, and name of person performing the lockout. Secure this lock and tag to the equipment to preclude unauthorized operation.

5.3 Verifications and Checking

5.3.1 Verify that the equipment is:

5.3.1.1 Shut down

5.3.1.2 De-energized

5.3.1.3 De-pressured and drained

5.3.1.4 Isolated from all process or utility lines

5.3.2 After isolation and venting, conduct a check for leakage. If leakage occurs and cannot be controlled by adjustments and/or grease sealing, the use of skillets, blind flanges, or other suitable means will be employed to prevent gas and/or volatile liquids from entering the isolated section.

5.3.3 Ensure that the work area remains properly ventilated throughout the course of work. If applicable, use a combustible gas indicator to verify that adequate ventilation is maintained before and during the maintenance period.

5.4 Restoring Isolated Sections of Service

5.4.1 Purge isolated sections of piping and related equipment before placing in service. Give consideration to the purge gas and venting locations to assure that all possible air entrapments are removed and to insure that no combustible mixtures reside within the piping and/or equipment at the completion of the purge period.

Refer to Procedure 9.03 "Purging Pipelines" for complete purging procedures.

5.4.2 After the purge is completed and vents are closed, a low pressure hold may be used to allow for leak checks. Upon full pressurization, conduct a final leak check.

5.4.3 After all related operating checks are completed and pertinent piping and/or equipment are ready to be placed in service, remove the locks and tags. Removal of the lock and tag must be by the person who placed them, or by a supervisor.

6. RELATED PROCEDURES

9.03 Purging and Purging Safety of Pipelines Including Pipeline Blowdown
14.03 Prevention of Accidental Ignition
Company Lockout/Tagout Procedure

7. RECORDS

None required by this procedure.

PREVENTION OF ACCIDENTAL IGNITION

1. REFERENCE

   49 CFR, Sections 192.735 and 192.751.

2. PURPOSE

   The purpose of this procedure is to establish safety practices to minimize the danger of accidental ignition of combustible gas mixtures in the areas where the presence of gas constitute a hazard of fire or explosion.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (366) ______________________ is responsible for implementation of this procedure, which shall be followed closely to minimize the possibility of accidental ignition and shall be carried out on a continual basis with highest priority.

4. GENERAL

   4.1 Continually implement and monitor this procedure to insure safe operations.

   4.2 Permit only the required personnel, vehicles and work equipment in the hazardous work area.

   4.3 Prohibit smoking materials within the hazardous areas.

   4.4 Exercise precautions during venting operations, cutting, welding, and grinding activities on pipelines which could possibly contain an explosive gas-air mixture or distillates.

   4.5 Exercise precautions during pigging operations, handling of flammable liquids, and when using or working with internal combustion equipment (welding machines, etc.) in the vicinity of hazardous areas.

   4.6 Do not install electrical isolation devices, such as insulating flange kits, to be installed in vaults or other areas subject to the accumulation of explosive gas-air mixtures.

5. PROCEDURE

5.1 Smoking, open flames and other sources of ignition are prohibited around and near scrubbers, meter run areas, enclosures and other areas where the possible leakage or presence of gas or flammable/combustible liquids present a hazard of fire or explosion.

5.2 Post “No Smoking” signs to serve warning in hazardous areas.

5.3 During construction and maintenance of facilities, post temporary “No Smoking” signs in the applicable areas. Advise construction employees they will be expected to comply with these signs.

5.4 Prohibit smoking in any area where gas is being vented to atmosphere or where a combustible mixture might be present.

5.5 Locate and nullify all possible sources of ignition in an area before a hazardous amount of gas is vented to the atmosphere. Prior to venting, review the potential hazards involved when blowing down or purging facilities in congested areas, streets, highways, subdivisions, plants, and around electrical transmission lines.

5.6 Do not use open flame devices such as heaters and lanterns in hazardous areas.

5.7 Use explosion-proof, approved for Division I, Group D locations, flashlights, lighting fixtures, extension cords, and other electrical devices in hazardous areas. Maintain these devices in good working condition.

5.8 Fire extinguishers shall be manned and ready for use at all times during venting, cutting and welding operations.

5.9 Make a thorough check with a combustible gas indicator prior to welding in or around a structure or area containing gas facilities to determine the possible presence of a combustible mixture. If safe conditions are indicated, welding and/or cutting may begin.

5.10 Make efforts to minimize the mixing of air with gas when welding or cutting on or around gas piping.

5.11 Do not weld or cut on pipe or pipe components that contain a known combustible mixture of gas and air.

5.12 Store flammable or combustible materials a minimum of 20 feet (6 meters) from any compressor shelter or building.

5.13 Tanks storing liquid hydrocarbons shall be spaced and protected with fire extinguishing devices per NFPA 30, (49CFR192 currently referenced edition).

5.14 Where cutting or rejoining pipelines, use a wire jumper connected between the line sections to prevent arcing caused by cathodic protection or induced currents. If possible, shutdown cathodic protection (CP) rectifier(s) during performance of work.

6. RELATED PROCEDURES

9.03 Purging and Purging Safety of Pipelines Including Pipeline Blowdown
14.02 Pipeline Isolation - Lock and Tag

7. RECORDS

None required by this procedure.

EXCAVATIONS

1. REFERENCE

49 CFR, Section 192.605(a) and 192.605(b).

2. PURPOSE

The purpose of this procedure is to establish safety requirements for protection of personnel who enter excavations such as narrow trenches for pipeline maintenance activities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (372) ______________________ is responsible for implementation and compliance with this procedure.

4. GENERAL

For personnel safety, plan all excavations in advance, giving consideration to such items as underground installations, soil stability, weather conditions, and other construction activities.

5. PROCEDURE

5.1 Preparation for Excavations

5.1.1 Notify other operating companies affected and request them to locate their underground structures. Utilize a One Call System, if available. (See Procedure 3.01)

5.1.2 Notify all affected landowners.

5.1.3 Remove or stabilize trees, boulders, and other surface encumbrances that create a hazard, when feasible.

5.2 Protection of Personnel from Ground Movement

5.2.1 Protect personnel from ground movement in any excavation using a support system or sloping.

5.2.2 Use slope or support system for:

5.2.2.1 Banks 5 feet (1.5 meters) high or greater.

5.2.2.2 Trenches less than 5 feet (1.5 meters) deep if hazardous ground movement may be expected.

5.2.2.3 Trenches 5 feet (1.5 meters) deep or more.

5.2.3 Use support system for trenches 5 feet (1.5 meters) or more deep and 8 feet (2.4 meters) or more long. In lieu of support system, use sloping above the 5 foot (1.5 meters) level at a rise not steeper than 1 foot (0.30 meters) rise per 1/2 foot (0.15 meters) horizontal.

5.2.4 Trench shields or boxes may be used in lieu of shoring or sloping.

5.2.5 Provide a means of exit, such as ramps, ladders, or steps located so the maximum travel distance is 25 feet (7.6 meters) when employees must work in trenches 4 feet (1.2 meters) deep or more.

5.2.6 Move bracing or shoring along with the excavation.

5.2.7 Remove trench supports from the bottom as backfilling operations progress. Release trench jacks slowly in unstable soil. Use ropes to remove them after personnel have cleared the trench.

5.3 Precautions for All Excavations

5.3.1 Inspect excavations at least daily and after every rainstorm or other hazard-increasing occurrence.

5.3.2 Do not allow hazardous accumulations of water, i.e., that can weaken the walls, hinder a person’s ability to escape from an emergency situation, or otherwise endanger personnel.

5.3.3 Store excavated material at least 2 feet (0.61 meters) from the edge of excavations or use effective barriers to prevent material from falling.

5.3.4 Do not allow any person to stand under loads handled by lifting equipment.

5.3.5 Properly mark or barricade any excavations left open after working hours.

5.3.6 Protect personnel from flammable and/or toxic gases when ventilation is inadequate. Additional safety and monitoring information is available from the Company Confined Space Entry Standards.

5.3.7 Provide emergency rescue equipment including breathing apparatus and rescue harness and lines where unsafe accumulations of vapor or gas could be present in an excavation where personnel are required to enter or work.

5.3.8 Observe barricading rules of the local governing authority when excavations are at road crossings. Provide high visibility vests for all personnel exposed to traffic.

5.4 Protective Systems Design

5.4.1 Design all support systems using accepted engineering principles or State requirements if they are more stringent.

5.4.2 See OSHA Regulation or applicable state or local regulations for sloping and trench shoring requirements.

5.5 Protection of Personnel from the Accumulation of Hazardous Vapors and Gas

5.5.1 Prior to entering an excavation, that has the potential to contain hazardous vapors or gas, the atmosphere shall be tested with an appropriate instrument, which has been calibrated prior to its use.

5.5.1.1 If the excavation does not contain a hazardous atmosphere, it may be entered but shall be monitored continuously while personnel remain in the excavation.

5.5.1.2 If the excavation contains a hazardous atmosphere, entry shall be denied. The excavation shall then be classified as a permit required confined space and require the completion of an Entry Plan and Entry Permit before entry can be made.

5.5.2 The Company maintains the appropriate respirators and breathing apparatus for use when entry into hazardous atmosphere is necessary. Respirators shall be used in accordance with the Company respiratory protection program.

5.5.3 The Company maintains rescue harnesses and line for use in hazardous excavations.

5.5.4 If, due to the nature of the project, it is determined the Company's rescue equipment is inadequate, the local emergency response agency will be contacted to provide assistance.

6. RELATED PROCEDURES

3.01 Damage Prevention Program
Company's Confined Space Entry Standards

7. RECORDS

None required by this procedure.

PRESSURE TESTING

1. REFERENCE

49 CFR, Sections 192.65, 192.501, 192.503, 192.505, 192.507, 192.509, 192.515, 192.517, 192.619 and 192.719.

2. PURPOSE

The purpose of this procedure is to establish minimum requirements for pressure testing of all gas piping facilities installations and repairs.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (378) ______________________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

4.1 This procedure includes leak test and strength test requirements.

4.2 No operator may operate a new segment of pipeline or return to service a segment of pipeline that has been relocated or replaced until:

4.2.1 It has been pressure tested per the requirements of this procedure and those of Procedure 8.01, to substantiate the maximum allowable operating pressure.

4.2.2 Each potentially hazardous leak has been located and eliminated.

4.3 Test medium must be liquid, air, natural gas, or inert gas that is:

4.3.1 Compatible with the material of which the pipeline is constructed.

4.3.2 Relatively free of sedimentary materials.

4.3.3 Non-flammable, except when natural gas is used as the test medium.

4.4 Hydrostatic Testing

Testing with liquid (water) is generally preferred because of the ease of identifying leaks, correlating temperature and pressure changes, and the reduced risk when catastrophic test failures occur.
Hydrostatic test pressures in excess of those required by D.O.T. to support a pipeline's MAOP are recommended for some new construction. When possible, pipeline facilities should be tested to 90% SMYS or to the limiting flange, fitting, valve or equipment test pressure. Hydrostatic testing at low pressures does not provide a strength test capable of identifying flawed pipe, fittings or welds.

4.5 Pneumatic Testing

Pneumatic testing (testing with air, natural gas, or inert gas) is not recommended because of the difficulty in identifying leaks and because of the hazards associated with expanding gas when catastrophic leaks occur.

4.6 If air, natural gas, or inert gas is used as the test medium, the maximum hoop stress of the pipeline may not exceed the following:

Class Location	Maximum Hoop Stress Allowed as Percentage of SMYS	
	Natural Gas	**Air or Inert Gas**
* 1	80	80
* 2	30	75
3	30	50
4	30	40

* Certain Class 1 and Class 2 locations have a different maximum allowable hoop stress per paragraphs 6.1.6 and 6.1.7 of this procedure.

4.7 Each joint used to tie-in a test segment of pipeline is excepted from the specific test requirements of this procedure, but each non-welded joint must be leak tested at not less than its operating pressure.

4.8 Due to permits that may be required for water procurement and/or discharge, adequate advance design and planning must be scheduled whenever possible.

4.9 Pipeline must be backfilled as much as is practicable prior to filling the line in order to minimize pipeline expansion due to temperature changes and test pressure. Note that temperature sensors must be installed prior to backfilling at temperature sensor location (see 8.3.3 of this procedure).
Temperature variations must be minimized to permit accurate calculations of temperature compensation to pressure readings and to minimize damage to the pipeline coating. Recorded temperature must also accurately represent actual test fluid temperature throughout the test with minimal error from ambient air or radiant influences.

4.10 The requirements for pressure testing of plastic pipelines are covered in Procedure 16.05.

5. DEFINITIONS

5.1 Stabilization Time

The stabilization time is the time period, following the fill of the system with the test medium, during which temperatures of the test medium, pipe and backfill equalize to the extent necessary to conduct a valid leak test. The time required to achieve stabilization will depend on individual test conditions but must be sufficient to allow proper leak testing based on correlation of temperature and pressure changes during the hold period.

5.2 Leak Test

5.2.1 For piping that is entirely visible during the test, the leak test will consist of observation of the piping while under pressure to check for visible or audible evidence of a leak.

5.2.2 For piping below ground or otherwise not visible, the leak test will consist of an approved procedure whereby pressure variations during strength testing are accounted for, taking into account the effects of temperature and pressure on the test medium and pipe. Pressure loss that cannot be satisfactorily attributed to these factors, measurement error, or other factors peculiar to the situation will be considered evidence of a leak.

5.2.3 Strength Test

5.2.3.1 A strength test is the pressurization of piping to a minimum predetermined stress level or pressure and maintaining this stress level or pressure for a predetermined time interval or hold period.

5.2.3.2 The hold period for the strength test shall start after the stabilization period and continue until the specified time has elapsed. During this time period the test section may be repressured or depressured as required to maintain the test pressure within the established limits. For piping below ground or otherwise not visible, maintain accurate records including depressuring and repressuring times, pressure and volumes during the hold period.

5.2.4 Maximum Test Pressure

The maximum test pressure is a pressure range above the specified minimum test pressure to allow for such variables as change in elevation in the test section, temperature changes, piping or equipment limitations, etc., but shall not exceed the lowest of the following:

5.2.4.1 When water is used, the hoop stress at 100% SMYS of the pipe at the lowest point on the test segment.

5.2.4.2 When air, nitrogen, or other inert gas is used to test natural gas systems, hoop stress at 80% SMYS in Class 1, 75% SMYS in Class 2, 50% SMYS in Class 3, and 40% SMYS in Class 4 (refer to paragraphs 6.1.6 and 6.1.7 of this procedure for exceptions to this).

5.2.4.3 When natural gas is used to test natural gas systems, hoop stress at 80% SMYS in Class 1 and 30% SMYS in other classes (refer to paragraph 6.1.7 of this Procedure for an exception to this).

5.2.4.4 For pressure rated components, 1.5 times the rating, or per manufacturer's specification.

5.2.5 Minimum Test Pressure

The minimum test pressure is the test pressure required to substantiate the desired MAOP. Note that although the minimum test pressure is acceptable, it is desirable to test to the maximum possible per 5.2.4, above, to maximize identification of flawed pipe, welds, or other components (i.e., leaks).

5.2.6 Pipeline Component

A pipeline component is a valve, flange, standard fitting, prefabricated assembly, or similar item.

5.2.7 Prefabricated Assembly

A prefabricated assembly is one which is constructed prior to installation and installed as a single unit.

5.2.8 Documented Test Pressure

The pressure used for record summaries and determination of MAOP will be the <u>minimum</u> test pressure at the <u>highest</u> elevation of the pipeline during the test period.

6. <u>TEST REQUIREMENTS</u>

See Table 15.01A for a summary of test requirements.

6.1 Facilities and piping systems, except as excluded below, that are to <u>operate at a hoop stress of 30 percent or more of SMYS, require eight (8) hours strength testing</u> before being placed in service, regardless of whether they are installed as a temporary or permanent installation. This includes all new, relocated, replaced, and modified segments of a pipeline.

6.1.1 No pressure test is required for vent or drain lines which are open to atmosphere and do not include in-line items which could restrict or block flow, such as valves or tanks.

6.1.2 If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required if the manufacturer of the component certifies that:

6.1.2.1 The component was tested to at least the pressure required for the pipeline to which it is being added; or

6.1.2.2 The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added: or

6.1.2.3 The component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in 192.143.

6.1.3 Prefabricated assemblies and short segments of pipe are not required to be retested at the time of installation if a post installation test is impractical and they are pretested prior to installation by maintaining the pressure at or above the test pressure for at least 4 hours.

6.1.4 Pipe used to tie-in a previously tested segment of pipeline must have been pretested per this testing procedure, and all tie-in welds shall be 100% non-destructively inspected.

6.1.5 Sensitive components such as relief valves, regulators, instruments, control valves, and related items which may be damaged at elevated pressures shall either be removed or isolated from the system during testing.

6.1.6 In a Class 1 or Class 2 location, if a building(s) intended for human occupancy exists within 300 feet (91.4 meters) of a pipeline whose design hoop stress level is 30% or more of SMYS, the test pressure must be a minimum of 1.25 times MAOP (see Procedure 8.01, paragraph 4.1.2). In no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). If an inert gas or air test is to be conducted, the building(s) must be evacuated while the hoop stress level exceeds 50% of SMYS. If building(s) cannot be evacuated, the piping must be hydrostatically tested.

6.1.7 In Class 1 or Class 2 each compressor station must be tested to at least Class 3 test requirements.

6.1.8 In a pipeline to be operated at a hoop stress of 20% SMYS or more, pipe having an outer diameter to wall thickness ratio of 70 to 1 or more that has been transported by railroad may not be used unless:

6.1.8.1 The transportation is performed in accordance with API RP 5L1 (49CFR currently referenced edition).

6.1.8.2 In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with this procedure to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a Class 3, 4, or 4 location. Notwithstanding any shorter time period permitted under this procedure, the test pressure must be maintained for at least 8 hours.

6.2 Each segment of a pipeline that is to be operated at a hoop stress <u>less than 30% of SMYS and at or above 100 psig (689 kPa)</u> must be tested in accordance with the following:

6.2.1 The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

6.2.2 If the segment is to be stressed to 20% or more of SMYS during the test, and natural gas, inert gas, or air is the test medium:

6.2.2.1 A leak test must be made at a pressure between 100 psig (689 kPa) and the pressure required to produce a hoop stress of 20% of SMYS; or

6.2.2.2 The line must be walked to check for leaks while the hoop stress is held at approximately 20% of SMYS.

6.2.3 The pressure must be maintained at or above the test pressure for at <u>least one hour</u>.

6.2.4 Paragraph 6.1.8 of this procedure applies here if the pipeline is to be operated at a hoop stress of 20% of SMYS or more.

6.3 Each segment of a pipeline that is to be <u>operated at or below 100 psig (689 kPa)</u> must be leak tested in accordance with the following:

6.3.1 The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

6.3.2 Each line that is to be operated at less than 1 psig (6.9 kPa) must be tested to at least 10 psig (69 kPa).

6.3.3 Each line that is to be operated at or above 1 psig (6.9 kPa) must be tested to at least 90 psig (621 kPa).

6.3.4 Paragraph 6.1.8 of this procedure applies here if the pipeline is to be operated at a hoop stress of 20% of SMYS or more.

7. PRETESTED PIPE

7.1 An unlimited length of pretested pipe may be used for emergency replacement. Considerable care must be taken to maintain the qualification of pretested pipe in the process of identification, handling, hauling, stocking, and installation. If a sufficient length of pretested pipe is unavailable, the remainder shall be tested at the job site.

7.2 For planned replacement of short sections, pretested pipe may be used. For planned replacement of longer sections, pipe shall be tested at the job location only. In-place testing is preferred, but on-site is acceptable.

7.3 Pipe stocked for emergency replacement shall be pretested for four (4) hours duration.

8. PRESSURE & TEMPERATURE CHARTS

8.1 General Requirements

8.1.1 For test intervals exceeding two (2) hours, calibrated & certified pressure and temperature recorders shall be used, except that fluid temperature recording is not required on any test of aboveground piping that can visually be inspected for leaks. It is recommended to also use a calibrated and certified pressure gage.

8.1.2 For test intervals less than or equal to two (2) hours, pressure and temperature recording charts are not required if the following conditions are met:

8.1.2.1 Dead weight pressure is obtained at time intervals not exceeding 15 minutes, and

8.1.2.2 If a dead weight pressure is less than the minimum test pressure, the test is restarted, and

8.1.2.3 The dead weight pressure, the corresponding time, and the ambient temperature will be recorded.

8.2 Pressure Charts

8.2.1 The date and the time test is started and the time at which the test period ends shall be noted on the chart.

8.2.2 Charts must show “pressure up” line and “bleed down” line, as well as recording of pressure during the test interval.

8.2.3 Drastic deviations in the recorded pressure shall be noted and explained.

8.2.4 The facility being tested shall be identified by pipeline name and/or number and Work Order number on the chart.

8.2.5 If more than one test section is involved in the Work Order or project, the test section number and location by station number or mile post for pipelines or drawing number for stations shall also be indicated.

8.2.6 Charts shall be signed by an authorized Company representative and Test Contractor’s representative or test technician.

8.3 Temperature Charts - Test Fluid

8.3.1 Temperature recordings shall be started prior to the start of the fill operation when hydrostatic testing.

8.3.2 Identification information and signatures shall be the same as for pressure charts.

8.3.3 Temperature sensing device must be placed on the pipeline below grade and shaded from the sun to prevent erroneous readings.

9. <u>PROCEDURE</u>

9.1 Determine test pressure and test medium based on the considerations outlined in this procedure.

9.2 Establish a test plan in accordance with the requirements of this procedure. Review and obtain approval of the plan prior to testing.

9.3 Do not test against closed valves, unless absolutely necessary. If testing against closed valves, verify that the test pressure will not damage the valve.

9.4 Conduct a leak test concurrently with a strength test unless no strength test is required.

9.5 Test fabricated assemblies, including line valve assemblies, cross connections, river crossing headers, etc., which have been appropriately pretested shall be tested in the same manner, to at least the same pressure as the pipeline on either side of the assembly.

9.6 Leak test hot taps or stopple connection after welding to the header pipe and prior to tapping at the operating pressure at the time of tapping and for 30 minutes duration.

9.7 Use pigs and squeegees in good condition, where practical, to dry long test sections.

9.8 Run pigs as many times as necessary to remove all free water. Normally, the test section will be considered satisfactorily dry when no water or mist expelled ahead of the pig and no water can be wrung from a poly foam pig.

9.9 For test sections where water or water vapor remaining in this test section will cause future operating problems, dry the test section further using dehydrated air or other means deemed suitable and necessary. Methanol injection will not normally be approved due to environmental restrictions.

10. RELATED PROCEDURES

5.01 Continuing Surveillance
15.02 Visual Inspection and Nondestructive Testing

11. RECORDS

11.1 Record of each test performed must be contain at least the following information:

11.1.1 The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used. Date, time of test, and test instrument calibration data.

11.1.2 Test medium used.

11.1.3 Minimum pressure.

11.1.4 Test duration.

11.1.5 Pressure recording charts, or other record of pressure readings.

11.1.6 Elevation variations, whenever significant for the particular test.

11.1.7 Leaks and failures noted and their disposition.

11.1.8 Record make, model and serial number of dead weight tester, and date of last certification.

11.1.9 Test instrument calibration data.

11.1.10 Date and time of the test.

11.1.11 Description of facilities tested and the test apparatus.

11.1.12 Prepare an explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.

11.1.13 Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section.

11.2 All required test forms, pressure and temperature charts shall be retained for the life of the pipeline facilities.

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES

TABLE 15.01A

	Other Than Plastic				Plastic (See Note 8)
	Less Than 100 P.S.I.G.		Under 30% SMYS	30% SMYS and over	
Maximum Operating Pressure	Less than 1 p.s.i.g.	1 p.s.i.g. and over but less than 100 p.s.i.g.	100 p.s.i.g. and over	All pressures	All pressures
Test Medium	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas See note (1)	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas See note (2)
Maximum Test Pressure	See note (3)	See note (3)	See note (3)	See note (3)	3 x design pressure
Minimum Test Pressure	10 p.s.i.g.	90 p.s.i.g.	Maximum allowable operating pressure multiplied by class location factor in 192.619 (a) (2) (ii) see notes (1) and (4)	Maximum allowable operating pressure multiplied by class location factor in 192.619 (a) (2) (ii) see notes (4) and (5)	50 p.s.i.g. or 1.5 x MAOP whichever is greater
Minimum Test Duration	See note (6)	See note (6)	1 Hour see notes (4) and (6)	8 Hours see notes (6) and (7)	See note (6) and note (8)

NOTES:

1. Whenever test pressure is 20 percent SMYS or greater and natural gas, inert gas, or air is the test medium, the line must be checked for leaks either by a leak test at pressure greater than 100 psig but less than 20 percent SMYS or by walking the line while the pressure the pressure is held at 20 percent of SMYS. (See paragraph 6.2.3. of this procedure)
2. Temperature of thermoplastic must not exceed 100 F during test. See note (8).
3. Refer to paragraph 5.2.4. of this procedure for limitations when testing with water, air, natural gas, or inert gas. For all test media, pipeline components must be taken into consideration when determining the maximum test pressure.
4. Refer to paragraph 6.1.8. of this procedure for pipe O.D. to wall thickness ratio limitations for a pipeline to be operated at a hoop stress of 20% or more of SMYS.
5. Refer to paragraph 6.1.6 and 6.1.7 of this procedure for testing criteria covering pipelines located within 300 feet of buildings intended for human occupancy and compressor stations.
6. Duration determined by volumetric content of test section and instrumentation in order to ensure discovery of all potentially hazardous leaks.
7. For short sections of pipe or pre-fab assembly, a test prior to installation in the pipeline is acceptable.
8. For more complete information regarding pressure testing of plastic pipelines, refer to Procedure 16.05.

VISUAL INSPECTION AND NONDESTRUCTIVE TESTING

1. REFERENCE

49 CFR, Sections 192.241, 192.243, 192.245, 192.715 and 192.719.

2. PURPOSE

The purpose of this procedure is to establish minimum requirements for visual inspection and nondestructive testing of field made butt welds in piping to be operated under pressure.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (384) ______________________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

4.1 All visual inspection and nondestructive testing of field made butt welds in pressurized gas facility piping shall be in accordance with the API Standard 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999).

4.2 Radiographic inspection or ultrasonic inspection shall be used to satisfy the requirements for nondestructive testing of field made girth welds.

4.3 Persons nondestructively testing welds shall be trained and qualified to perform test and interpret results in the testing method employed, per written nondestructive testing procedures, and be familiar with all requirements of the of API Standard 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999).

4.4 The acceptability of a weld that is nondestructively tested or visually inspected, is determined according to the standards in Section 9 of API Standard 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999). Only level II or III qualified under SNT-TC-1A will be allowed to intrepet test results. Recommended Practice No. SNT-TC-1A: Personnel Qualification and Certification in Nondestructive Testing (2011) provides guidelines for employers wishing to establish in-house certification programs. Personnel qualification records under SNT-TC-1a will be maintained by the company.

4.4.1 If a girth weld is unacceptable under those standards for a reason other than a crack, and if the appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that appendix.

4.5 Welding Inspector shall be qualified to perform visual weld inspection.

4.5.1 The qualified visual inspector shall have appropriate training and experience to ensure that;

1) The welding is performed in accordance with the welding procedure; and
2) The weld is acceptable under 192.241(c). This means the acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 9 of API 1104 (Welding of Pipelines and Related Facilities, 19th edition, 1999). However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

5. WELD NONDESTRUCTIVE TESTING

5.1 Nondestructive testing of welds must be performed by any process that will clearly indicate defects that may affect the integrity of the weld.

5.2 Each weld that is found unacceptable must be removed or repaired, and then found acceptable. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be completely removed if it has a crack that is more than 8% of the weld length.

5.3 Each weld that is repaired must have the defect removed down to the sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair.

5.4 After repair, the segment of the weld that was repaired must be inspected to insure its acceptability.

5.5 Ensure the interpretation of all nondestructive test results by Nondestructive Testing Contractor are correct.

5.6 Follow the schedule in 15.02A of this procedure for the minimum percentage of each day's field butt welds to be nondestructively tested over the entire circumference.

5.7 Ensure that girth welds on pressurized piping have been nondestructively tested in the correct amount.

5.8 At least one of each welder's daily welds will be inspected when non-destructive testing is required unless his work is isolated from the principal welding activity.

6. <u>WELD VISUAL INSPECTION</u>

6.1 Welding of a regulated pipeline shall be visually inspected by a qualified inspector to insure that:

6.1.1 The welding is performed in accordance with the welding procedures; and

6.1.2 The welds are acceptable to the standards in Section 9 of API Standard 1104 (49CFR192 currently referenced edition).

6.1.3 The welds conform to the requirements of Pipeline Welding Procedure 9.06 and this Visual Inspection and Nondestructive Testing Procedure.

6.2 Ensure that each joint of pipe is inspected for defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.3 Bevels shall be inspected for proper dimensions, cleanliness and angle.

6.4 Ensure that each joint of pipe is swabbed as necessary to remove all dirt and foreign materials from the inside.

6.5 Ensure that the longitudinal seams are offset as stated in Procedure 9.06. The line up shall be inspected to ensure proper root spacing and alignment.

6.6 The stringer (root) bead shall be inspected for proper grinding and cleaning.

6.7 If more than one grade or weight of pipe or fittings are used, ensure that it is according to the approved construction drawings.

6.8 Mark and ensure that all arc burns are removed and repaired according to Procedure 9.06.

7. RELATED PROCEDURES

9.06 Pipeline Welding
15.01 Pressure Testing

8. RECORDS

8.1 Develop a record keeping system for location of non-destructively testing welds on stations (i.e., compressor stations, meter stations, etc.) piping to ensure that girth welds on pressurized piping have been nondestructively tested in the correct amount (show in station piping drawings).

8.2 Record to show by milepost, station plus, or by geographic feature, the location of girth welds made, the number of girth welds made, the number of nondestructively tested, the number rejected, and the disposition of the rejects.

8.3 Retain the above records for the life of the pipeline system.

8.4 Record radiograph films and ultrasonic testing results with a unique numbering system allowing identification of the radiograph film or ultrasonic testing results to its respective weld.

8.5 Radiographic film must be retained for at least one year. However, as indicated above, the certification sheets and other records showing the disposition of the welds must be retained for the life of the pipeline.

8.6 Personnel qualification records for personnel reading and intrepeting test result will be qualified under SNT-TC-1a and all records of these qualification will be maintained the company.

TABLE 15.02 A
MINIMUM NON-DESTRUCTIVE TESTING REQUIREMENTS (IN PERCENTAGE OF TOTAL WELDS PER DAY) FOR WELDED PIPING

	<20% SMYS (1)	≥20% SMYS (2)
Class Location and OtherAreas:		
I		10%
II		15%
III & IV		100%(3)
Major Rivers & Offshore		100%(3)
Navigable River		100%(3)
Railroads or Public Highways (4)		100%(3)
Tie-ins & Weld Repair (5)		100%(3)

NOTES:

1. NDT or visual inspection of pipelines operating at <20% SMYS, is at operator's discretion.

2. Except:

   a) If pipeline is <6" in diameter, then visually inspected and approved by WI (Welding Inspector).

   b) If pipeline is operating <40% SMYS and welds are so limited in number that NDT is impractical.

3. 100% non-destructive testing must be used if practicable, but in no case less than 90% Non-destructive testing must be impracticable for each girth weld not tested.

4. Within railroad or public highway rights of each way, including tunnels, bridges, and overhead road crossing. Non-destructive testing may be subject to other agency permit requirements.

5. All tie-in welds should be non-destructively tested.

DESIGN OF PLASTIC PIPELINES

1. REFERENCE

49 CFR, Sections 192.121, 192.123, 192.191, and 192.193.

2. PURPOSE

The purpose of this procedure is to set guidelines for the design of plastic pipelines and components, and to establish responsibility for the development, implementation, and documentation design procedures in accordance with these guidelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (390) ______________________ is responsible for the development, implementation, and documentation of design procedures for plastic pipelines which are consistent with this procedure.

4. GENERAL

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

5. DESIGN GUIDELINES

The following guidelines are presented for evaluation when designing a plastic pipeline:

5.1 Consider service life requirements.

5.2 Consider the pipe inside diameter required to meet flow requirements.

5.3 Consider the pipe and wall thickness required to meet pressure requirements.

5.4 Work with the pipe size and wall thickness until the flow and pressure in the pipe selected are acceptable for both.

5.5 Consider the external "Earth Load and Live Loads".

5.6 Adjust pipe wall thickness as required for external loads.

5.7 Consider rerouting the pipe based upon the environmental or operating temperature.

5.8 Review the final pipe size and wall thickness to meet flow, pressure, and external load requirements at a given temperature and system life expectancy.

5.9 Select a route to protect the pipe from head (high pressure) sources.

6. <u>DESIGN PRESSURE</u>

6.1 The design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitations listed in Design Limitations (Part 7 of this procedure):

$$P = 2S\,[t / (D - t)] \times 0.32, \text{ or}$$

$$P = 2S \times 0.32 / (SDR - 1)$$

Where: P = Design pressure, gauge, psi (kPa).

S = For thermoplastic pipe, the (Hydrostatic Design Basis (HDB) determined with the listed specification in a temperature equal to 73°F (23°C), 100°F (38°C), 120°F (49°C), or 140°F (60°C). In the absence of HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at he specified temperature by arithmetic interpolation using the procedure in Part E of PPI TR-3/200 entitled, Policy for Determining Lon Term Strength by Temperature Interpolation, as published in the technical report TR-3/2000 "HDB/Pressure Design Basis (PDB)/Minimum Required Strength (MRS) policies", (ibr, see 192.7). For reinforced thermosetting plastic pipe, use 11,000 psi (75, 842 kPa).

t = Specified wall thickness, inch (mm)

D = Specified outside diameter, inch (mm)

SDR = <u>S</u>tandard <u>D</u>imension <u>R</u>atio, the ratio of the average specified outside diamenter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute (ANSI) preferred number series 10.

7. DESIGN LIMITATIONS

7.1 The design pressure may not exceed a gauge pressure of 125 psig (862kPa) for plastic pipe used in:

7.1.1 Distribution systems; or

7.1.2 Class 3 and 4 locations.

7.2 Plastic pipe may not be used where operating temperatures of the pipe will be:

7.2.1 Below -20°F (-29°C), or -40°F (-40°C) if all pipe and pipeline components whose operating temperature will be below -20°F (-29°C) have a temperature rating by the manufacturer consistent with that operating temperature.

7.2.3 For thermoplastic pipe, above the temperature at which the HDB used in the design formula under 192.121 is determined.

7.2.3 In the case of reinforced thermosetting plastic pipe, above 150°F (66°F).

7.3 Thermosetting plastic pipe and thermoplastic pipe larger than 6 inches (15.2 cm) nominal diameter is not allowed in transmission or distribution systems.

7.4 The wall thickness for thermoplastic pipe may not be less than 0.062 inch (1.57 mm).

7.5 The wall thickness for reinforced thermosetting plastic pipe may not be less than listed in the following table:

Nominal Size In Inches (millimeters)	Minimum Wall Thickness In Inches (millimeters)
2 (51mm)	0.060 (1.52 mm)
3 (76mm)	0.060 (1.52 mm)
4 (102mm)	0.070 (1.78 mm)
6 (152mm)	0.100 (2.54 mm)

7.6 The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed gauge pressure of 100 psig (689 kPa) provided that
1) The design pressure does not exceed 125 psig (862 KPa)
2) The material is a PE2406 or a PE3408 as specified within ASTM D2513 (ibr 192.7)

3) The pipe size is nominal pipe size (IPS) 12” or less
4) The design pressure is determined in accordance with the design equation defined in 192.121.

8. DESIGN OF PIPELINE COMPONENTS

8.1 Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.

8.2 Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

8.3 The design pressure of thermoplastic fittings for plastic pipe must conform to ASTM D 2513.

8.4 The design pressure of Acrylonitrile-butadiene-styrene (ABS) and polyvinyl

choride (PVC) schedule 40 and 80 thermoplastic fittings are shown in Table 16.01A. These pressure ratings are the same value as the design pressure of the corresponding pipe size and schedule in the same class location, as determined by the design formula and the design limitations.

9. PLASTIC VALVES

9.1 Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

9.2 Each plastic valve must comply with the following:

9.2.1 The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

9.2.2 The valve must be tested as part of the manufacturing, as follows:

9.2.2.1 With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

9.2.2.2 After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating.

Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

9.2.2.3 After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

9.3 Each valve must be able to meet the anticipated operating conditions.

10. PROCEDURE

Develop a specific written policy for the design of plastic pipelines using the procedure as a guideline.

11. RELATED PROCEDURES

4.01 Class Location Survey and Determination
15.01 Pressure Testing
16.02 Plastic Pipeline Materials
16.05 Test Requirements for Plastic Pipelines
16.06 MAOP of Plastic Pipelines

12. RECORDS

Retain all records for the lifetime of the system.

TABLE 16.01A
DESIGN PRESSURE OF THERMOPLASTIC FITTINGS, PSIG

Size Inches	Schedule	ABS Type I and PVC Type II Class Location 1	2 & 3	4	PVC Type I Class Location 1	2 & 3	4
1/2	40	100	100	100	100	100	100
	80	100	100	100	100	100	100
3/4	40	100	100	96	100	100	100
	80	100	100	100	100	100	100
1	40	100	100	90	100	100	100
	80	100	100	100	100	100	100
1 1/2	40	100	83	66	100	100	100
	80	100	100	94	100	100	100
1 3/4	40	100	92	74	100	100	100
	80	100	100	100	100	100	100
2	40	89	69	55	100	100	100
	80	100	100	81	100	100	100
2 1/2	40	99	76	61	100	100	100
	80	100	100	85	100	100	100
3	40	84	66	53	100	100	100
	80	100	94	75	100	100	100
3 1/2	40	77	60	48	100	100	96
	80	100	86	69	100	100	100
4	40	71	56	44	100	100	89
	80	100	81	65	100	100	100
5	40	62	49	39	100	97	78
	80	93	72	58	100	100	100
6	40	56	44	35	100	88	71
	80	89	70	56	100	100	100

PLASTIC PIPELINE MATERIALS

1. REFERENCE

49 CFR, Sections 192.59 and 192.63.

2. PURPOSE

The purpose of this procedure is to set guidelines for the selection of plastic pipeline materials and to establish responsibility for the development, implementation, and documentation of procedures for the acquisition of plastic pipeline materials which are consistent with these guidelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (396) ________________________ is responsible for the development, implementation, and documentation of specific written procedures for the acquisition of plastic pipeline materials which are consistent with this procedure.

4. GENERAL

4.1 Materials for plastic pipe and components must be able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated.

4.2 Materials for plastic pipe and components must be chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact.

4.3 Requirements for marking the thermoplastic fittings are covered in Procedure 2.02 of this manual.

5. REQUIREMENTS

5.1 New plastic pipe is qualified for use if:

5.1.1 It is manufactured in accordance with a listed specification; and

5.1.2 It is resistant to chemicals with which contact may be anticipated.

5.2 Used plastic pipe is qualified for use if:

5.2.1 It was manufactured in accordance with a listed specification;
5.2.2 It is resistant to chemicals with which contact may be anticipated;
5.2.3 It has been used only in natural gas service;

5.2.4 Its dimensions are still within the tolerances of the specification to which it was manufactured; and

5.2.5 It is free of visible defects.

5.3 For the purpose of Paragraphs 5.1.1 and 5.2.1 above, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it -

5.3.1 Meets the strength and design criteria required of pipe included in that listed specification; and

5.3.2 Is manufactured from plastic compounds which meet the criteria for material required for pipe included in that listed specification.

5.4 At the time of installation, plastic pipe shall not have been subjected to unprotected outdoor exposure longer than the time recommended by the manufacturer, shall be free of deterioration from weathering, and:

5.4.1 Black polyethylene pipe must be certified by the manufacturer to be capable of withstanding continual outdoor weathering including direct sunlight for at least five (5) years. After not more than five (5) years of cumulative unprotected outdoor exposure, black polyethylene must be tested in accordance with procedure described in 5.5 below. Pipe which passes the test must be used within one (1) year. Pipe which fails must be discarded.

5.4.2 Non-black polyethylene pipe must be certified by the manufacturer to comply with ASTM F678 (latest edition). No later than eighteen (18) months from the month of manufacture, non-black polyethylene pipe must be tested in accordance with the procedure described in 5.5 below. Pipe which fails the test must be discarded.

5.4.3 No later than eighteen (18) months from the month of manufacture, non-black polyethylene pipe must be covered or stored in a manner which will protect it from direct exposure to sunlight or weathering. Pipe not protected after this time shall be discarded. Non-black polyethylene pipe in transit from storage to installation need not be protected, provided that such exposure does not exceed 30 days.

5.5 A compressed-ring test complying with the requirement of 5.4 above, shall be performed in the following manner.
A ring of uniform width approximately one inch wide shall be cut from a length of pipe being tested. The ring shall be compressed between two parallel flat plates

until the center opening of the pipe is completely closed. After two (2) minutes while it is still compressed, the sides of the ring shall be examined for cracks at the locations with the greatest curvature (where the wall is folded). The ring should then be released from compression and examined internally and externally for cracking. A visible crack will be considered evidence of pipe failure.

6. MARKING OF MATERIALS

6.1 Each valve, fitting, length of pipe, and other component must be marked -

6.1.1 As prescribed in the specification of standard to which it was manufactured; or

6.1.2 To indicate size, material, manufacturer, pressure rating, temperature rating, and as appropriate, type, grade, and model.

6.2 In addition to the requirements in Paragraph 6.1, thermoplastic pipe manufactured in accordance with ASTM D2513 (49CFR currently referenced edition), must be marked as required by Section 9.2 of ASTM D2513 unless the pipe was manufactured before August 16, 1978, and is installed where operating temperatures are not above 100°F (38°C).

7. PROCEDURE

Develop a specific written policy for the selection of plastic pipeline using this procedure as a guideline.

8. RELATED PROCEDURES

16.01 Design of Plastic Pipelines
16.06 MAOP of Plastic Pipelines

9. RECORDS

Retain all records for the lifetime of the system.

JOINING OF PLASTIC PIPING

1. REFERENCE

49 CFR, Sections 192.271, 192.273, 192.281, 192.283, 192.285, and 192.287.

2. PURPOSE

The purpose of this procedure is to set guidelines for the joining of plastic piping and to establish responsibility for the development, implementation, and documentation of procedures for the joining of plastic piping in accordance with these guidelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (402) _________________________ is responsible for the development, implementation, and documentation of specific written procedures for the joining of plastic pipeline piping which are consistent with this procedure.

4. GENERAL

4.1 The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

4.2 Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gas tight joints.

4.3 A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set.

4.4 Plastic pipe may not be joined by a threaded joint or miter joint.

5. SOLVENT CEMENT JOINTS

Each solvent cement joint on plastic pipe must comply with the following:

5.1 The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

5.2 The solvent cement must conform to the requirements of ASTM Designation D 2513 (49CFR currently referenced edition).

5.3 The joint may not be heated to accelerate the setting of the cement.

5.4 The safety requirements of the Appendices of ASTM Specification D-2513 must be met.

6. HEAT FUSION JOINTS

6.1 The principle of heat fusion is to heat two surfaces to a fusion temperature, then make contact between the two surfaces and allow the two surfaces to fuse together by application of pressure. On cooling, the original interfaces are gone and the two parts are united.

Heat may not be applied with a torch or other open flame.

6.2 An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements described in Section 9 of this Procedure, to be at least equivalent to those of the fittings manufacturer.

6.3 Butt fusion joints may easily be cut out and redone. This fact has a bearing on the quantity and quality of training necessary and favorably affects operator attitude toward quality in the field. These joints can be easily cut out and destructively tested in the field to check joining proficiency and equipment condition.

6.4 Each heat fusion joint on plastic pipe must comply with the following:

6.4.1 A butt heat fusion joint must be jointed by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe proper alignment, while the plastic hardens.

6.4.2 A socket heat fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

6.4.3 Heat may not be applied with a torch or other open flame.

7. ADHESIVE JOINTS

Each adhesive joint on plastic pipe must comply with the following:

7.1 The adhesive must conform to ASTM Designation D 2517 (49CFR currently referenced edition).

7.2 The materials and adhesive must be compatible with each other.

8. MECHANICAL JOINTS

8.1 Mechanical joining to other piping materials such as fittings, valves, tanks, pumps, etc., may be accomplished with flange adapters or stub ends and metal back up flanges.

8.2 Flange adapters and stub ends are pressure rated the same as the pipe. Flange adapters can be but fused to the pipe as outlined in the butt fusion section. Stub ends may be butt fused to pipe, utilizing either stub end holders or clamping inserts depending on the type of fusion unit used.

8.3 Sufficient torque should be applied evenly to the bolts to prevent leaks. After initial installation and tightening of flanged connections, it is a good practice to allow the connections to set for a period of time, usually a few hours, then conduct a final tightening of the bolts.

8.4 Each compression type mechanical joint on plastic pipe must comply with the following:

8.4.1 The gasket material in the coupling must be compatible with the plastic.

8.4.2 A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

9. QUALIFYING JOINING PROCEDURES FOR HEAT FUSION, SOLVENT CEMENT AND ADHESIVE JOINTS

9.1 Before any written procedure is established for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

9.1.1 The burst test requirements of:

9.1.1.1 In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D 2513; or

9.1.1.2 In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D 2517.

9.1.1.3 In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4

(Joint Integrity Tests) of ASTM Designation F 1055 (49 CFR currently referenced edition).

9.1.2 For procedures intended for lateral pipe connections, follow the tensile test requirements subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

9.1.3 For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D 638 (49CFR currently referenced edition), except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.

9.1.4 For saddle connections to pressurized thermoplastic pipe, the joining procedure must be tested to demonstrate that the joint can be made safely at the operating pressure in the pipe.

9.2 A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

10. QUALIFYING JOINING PROCEDURES FOR MECHANICAL JOINTS

10.1 Before any written procedure is established for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five specimen joints made according to the procedure to the following tensile test:

10.1.1 Use an apparatus for the test as specified in ASTM D 638 (except for conditioning).

10.1.2 The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

10.1.3 The speed of testing is 0.20 inch (5.0mm) per minute, plus or minus 25%.

10.1.4 Pipe specimens less than 4 inch (102mm) in diameter are qualified if the pipe yields to an elongation of no less than 25% or failure initiates outside the joint area.

10.1.5 Pipe specimens 4 inch (102mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100°F (38°C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress.

10.1.6 Each specimen that fails at the grips must be retested using new pipe.

10.1.7 Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe, may be used to qualify pipe of the same material but with a lesser wall thickness.

10.2 A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

11. QUALIFYING JOINING PROCEDURES FOR PIPE OR FITTINGS MANUFACTURED BEFORE JULY 1, 1980

Pipe fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

12. QUALIFYING PERSONS TO MAKE JOINTS

12.1 49 CFR Section 192.285, requires each operator to ensure that every individual performing fusion joining is qualified in the use of the recommended fusion procedure(s) by the following:

12.1.1 Appropriate training or experience in the use of the procedure; and

12.1.2 Making a sample joint according to the procedure that passes the following inspections and tests.

12.2 The joint must be:

12.2.1 Visually examined during and after joining and found to have the same appearance as a joint or photograph of an acceptable joint that was joined in accordance with the procedure, and

12.2.2 The joint must be tested or examined by one of the following methods:

12.2.2.1 Tested under any one of the test methods listed under Qualifying Joining Procedures applicable to the type of joint and material being tested;

12.2.2.2 Examined by ultrasonic inspection and found to be free of flaws that would cause failure; or

12.2.2.3 Cut into at least three longitudinal straps, each of which is:

12.2.2.3.1 Visually examined and found to be free of voids or discontinuity on the cut surface of the joint area, and

12.2.2.3.2 Deformed by bending, torque or impact, and if failure occurs, it must not initiate in the joint area.

12.3 A person must be requalified under an applicable procedure, if during any twelve month period that person:

12.3.1 Does not make any joints under the procedure; or

12.3.2 Has three joints or three percent of the joints he has made, whichever is greater, that are found unacceptable by testing under 49 CFR, Section 192.513.

12.4 Each operator shall establish a method to determine that each person making joints in plastic pipelines in this system is qualified in accordance with this section.

13. INSPECTION OF JOINTS

No person may carry out the inspection of joints in plastic pipes required by 49 CFR Sections 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

14. PROCEDURE

Develop a specific written policy and procedures for the Joining of Plastic Piping.

15. RELATED PROCEDURES

16.01 Design of Plastic Pipelines

16. RECORDS

Retain all records for the lifetime of the system.

PLASTIC PIPELINE CONSTRUCTION REQUIREMENTS

1. REFERENCE

49 CFR, Sections 192.311, 192.321, 192.325(c), and 192.327.

2. PURPOSE

The purpose of this procedure is to define construction requirements for the installation of plastic pipelines and to establish responsibility for the development, implementation, and documentation of construction procedures in accordance with these guidelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (408) ____________________ is responsible for the development, implementation, and documentation of specific written procedures for the installation of plastic pipeline, which are in accordance with the procedure.

4. INSPECTION OF MATERIALS

4.1 Care shall be taken in the selection of the handling equipment and in handling, hauling, unloading, and placing the pipe so as not to damage the pipe.

4.2 Each length of pipe and each other component must be visually inspected at the time of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

5. INSTALLATION OF PLASTIC PIPE

5.1 Plastic pipe must be installed below ground level.

5.2 Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

5.3 Plastic pipe must be installed so as to minimize shear or tensile stresses.

5.4 Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (2.29 mm), except that pipe with an outside diameter of 0.875 inches (22 mm) or less may have a minimum wall thickness of 0.062 inches (1.58mm).

5.5 Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

5.6 Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

5.7 A reasonable distance should be established and maintained from any source of heat.

6. PROTECTION FROM HAZARDS

6.1 Each transmission line or main must be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.

6.2 Each above ground metal fitting, valve, and other piping materials that are directly connected to the underground plastic pipe or fittings, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

7. UNDERGROUND CLEARANCE

7.1 Each plastic transmission line must be installed with at least 12 inches (305 mm) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

7.2 Each plastic main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

7.3 Each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

8. COVER

8.1 Except as provided in 8.3, below, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil Inches (centimeters)	Consolidated rock Inches (centimeters)
Class 1 location	30 (76.2 cm)	18 (45.7)
Class 2, 3 and 4 locations	36 (91.4 cm)	24 (61.0)
Drainage ditches of public roads and railroad crossings	36 (91.4 cm)	24 (61.0)

8.2 Except as provided in paragraph 8.4, below, each buried main must be installed with at least 24 inches (61 cm) of cover.

8.3 Where an underground structure prevents the installation of a transmission line or main with a minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

8.4 A main may be installed with less than 24 inches (61 cm) of cover if the law of the State or municipality -

8.4.1 Establishes a minimum cover of less than 24 inches (61 cm);

8.4.2 Requires that mains be installed in a common trench with other utility lines; and

8.4.3 Provides adequately for prevention of damage to the pipe by external forces.

8.5 To protect the pipe from traffic loading and/or frost penetration, consideration should be given to establishing minimum earth cover requirements.

9. TRENCHING

9.1 The trench width will vary depending on its depth and type of soil.

9.2 The pipe should have some slack and the bed width should be great enough to allow for adequate compaction around the pipe. Generally, a bed width one foot wider than the nominal pipe diameter is adequate. However, to reduce trenching costs, narrow trench and/or bed widths are possible for small diameter pipe.

9.3 The depth of the trench should be sufficient to provide minimum cover.

9.4 The trench bottom should be relatively smooth and free of rock. When rocks, boulders, or large stones are encountered which may cause point loading on the pipe, they should be removed and the trench bottom padded using tamped bedding material. The bedding should consist of a free flowing material such as gravel, and, silly sand, or clayey sand that is free of stones or hard particles.

9.5 If an unstable soil condition exists, such as mucky or sand solids with poor bearing strength, the trench bottom should be undercut and filled to proper trench depth with a selected material of gravel or small crushed stone.

9.6 Valve locations should be planned so that “bell holes” can be provided which will permit the pipe to lay flat on the trench bottom after being connected and before initial backfill and compaction.

9.7 Since gas liquids, including water, will collect in the low spots of any gathering system, it may be desirable to establish “drip pots” at the collecting points to provide for removal of the liquids.

9.8 The length of open trench required should be such that bending and lowering of the pipe into the ditch does not exceed the minimum recommended bend radius, and result in kinking.

9.9 Consider all precautions necessary to prevent trench cave-ins. Trench failure is influenced by the presence of construction equipment near the edge of an excavation or adverse climatic conditions. OSHA and other regulatory agencies specify the maximum vertical height of unbraced trench which is permitted and the suggested angle of repose for the soil type involved.

10. PIPE AND FITTINGS INSTALLATION

10.1 Care should be taken not to drop the pipe. Avoid excess stress or strain conditions during installation.

10.2 In order to locate the underground polyethylene pipe in the future, a copper or galvanize tracer wire should be laid next to the pipe during installation to later permit use of location devices. The metal wire should not touch the pipe in case of lightning.

10.3 Slight changes in direction of the pipe can be accommodated by field sweeping of the pipe in the ditch. If proper compaction is obtained, field sweeps do not require thrust blocks. Good soil compaction around fittings such as elbows or tees is usually sufficient.

10.4 If thrust blocks are required, concrete encasement or concrete bearing surfaces set in undisturbed soil will provide adequate protection. The encasement or thrust block should be constructed of reinforced concrete and act as an anchor between pipe or fitting and the solid trench wall.

10.5 Polyethylene flanged connections with metal back up flanges should be used to connect plastic pipe to metal fittings, valves, pumps or other piping materials.

10.6 Where pipe or fittings are connected to rigid structures, movement or bending at that point should be prevented. Either well compacted fill should provide full support or a support pad should be constructed beneath the pipe and fitting. This pad, usually reinforced concrete, should be fixed to a rigid structure and extend one pipe diameter or a minimum of 12" (30 cm) from the flanged joint.

10.7 The bolts in the flanged connection as well as the clamps in a support pad should undergo one final re-tightening. This should be done after initial installation just before final backfill if it is a buried application.

10.8 Particular attention should be given to the compaction achieved around the fittings, and extending several pipe diameters beyond the ends of the fitting. Compaction of 90% Proctor density or greater in these areas is recommended.

10.9 Polyethylene pipe or fittings may be totally enclosed in concrete if required in the design. Reinforced concrete encasement can be used to stabilize heavy valves or fittings, and control thermal expansion or contraction.

11. <u>BACKFILLING AND TAMPING</u>

11.1 The purpose of backfilling the trench is to provide firm, continuous support around the pipe. Achieving this proper soil backfill around the pipe is probably the most important aspect of a successful buried application.

11.2 The material excavated from the trench can usually be used as the initial backfill if it is smooth, free of rocks, crumbles and breaks up easily. Economics usually dictate maximum reuse of the excavated material.

11.3 Where trenches are located within roadways and are subject to vehicular traffic, cohesionless granular soils are generally specified. The best initial backfill material is sand. When loading conditions are severe, such as road crossings, sand should be used where the pipe is laid in low quality soils such as heavy gumbo or muck. Coarse sand will usually reach the required density during placement without compaction.

11.4 Initial backfill should be placed in two phases. The first is up to or slightly above the spring line of the pipe. Then compact or flush with water to assure that the lower part or the pipe is supported.

11.5 Compaction of the soil around the pipe is accomplished by applying an external force to the individual layers of backfill as they are placed in the trench. Compacting brings the soil particles closer together and thus increases their density and shear strength. Compaction depends upon soil properties, moisture content, layer thickness, compactive effort, and other factors. Compaction is usually applied by a mechanical tamper, vibrating plate or water flushing.

11.6 Care should be used while flushing to prevent the pipe from floating out of position in the trench. To keep the pipeline from floating or shifting, it can be internally filled with water prior to flushing until initial backfiling procedures are complete. This also assures that the horizontal diameter does not shorten excessively during compaction to the spring line. The water flushing method of achieving compaction should only be used with “free draining” granular materials and a positive drainage outlet provided.

11.7 In the second phase of initial backfill, additional fill in 8”-10” (20-25 cm) layers should be added and well compacted until about 6”-12” (15-30 cm) above the top of the pipe. Large diameter pipe requires the higher initial backfill. At this point the on-site material excavated from the trench can be used for final backfill to ground level. In a heavy traffic area, this excavated backfill of granular material should be compacted to a minimum of 90% to 95% density.

11.8 Compaction utilizing heavy equipment is not advisable unless a minimum of 15 psi (104 kPa) pressure is maintained in the pipe and then only after a minimum of 20 inches (51 cm) of cover has been established.

11.9 Due to expansion and contraction, inherent in thermoplastics, it is recommended that sufficient time be provided to permit the pipe to attain the lower ground temperatures before the pipe is joined to other sections or the system is terminated.

12. PROCEDURE

Develop specific written Plastic Pipeline Construction policy and procedures which are consistent with this procedure.

13. RELATED PROCEDURES

16.01 Design of Plastic Pipelines
16.02 Plastic Pipeline Materials
16.03 Joining of Plastic Piping
16.05 Test Requirements for Plastics Pipelines

14. RECORDS

Retain all records for the lifetime of the system.

TEST REQUIREMENTS FOR PLASTIC PIPELINES

1. REFERENCE

49 CFR, Sections 192.513 and 192.517.

2. PURPOSE

The purpose of this procedure is to establish the minimum requirements for pressure testing of all plastic piping facilities.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (414) ___________________________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

4.1 The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

4.2 The test pressure must be at least 150 percent of the maximum operating pressure or 50 psig (345 kPa), whichever is greater. However, the maximum test pressure may not be more than three (3) times the pressure determined under Procedure 16.01 of this manual, using a temperature not less than the pipe temperature during the test.

4.3 The temperature of thermoplastic material must not be more than 100° F (38° C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

4.4 Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements but must be leak tested at not less than its operating pressure.

4.5 The test medium must be liquid that is -

4.5.1 Compatible with the material of which the pipeline is constructed; and

4.5.2 Relatively free of sedimentary materials.

5. ENVIRONMENTAL PROTECTION AND SAFETY REQUIREMENTS

5.1 In conducting tests each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing.

5.2 The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

6. RELATED PROCEDURES

15.01 Pressure Testing
16.01 Design of Plastic Pipelines
16.02 Plastic Pipeline Materials
16.06 MAOP of Plastic Pipelines

7. RECORDS

7.1 A record of each test performed shall be made and retained for the useful life of the pipeline.

7.2 The record must contain at least the following information:

7.2.1 The operator’s name, the name of the operator’s employee responsible for making the test, and the name of any test company used.

7.2.2 Test medium used.

7.2.3 Test pressure.

7.2.4 Test duration.

7.2.5 Pressure recording charts, or other record of pressure readings.

7.2.6 Elevation variations, whenever significant for the particular test.

7.2.7 Leaks and failures noted and their disposition.

MAOP OF PLASTIC PIPELINE FACILITIES

1. REFERENCE

   49 CFR, Sections 192.121, 192.123, and 192.191.

2. PURPOSE

   The purpose of this procedure is to outline the responsibility for establishing the maximum allowable operating pressure (MAOP) each plastic pipeline segment and the related operating requirements.

3. RESPONSIBILITY FOR IMPLEMENTATION

   The (420) ______________________ is responsible to establish maximum allowable operating pressure on plastic pipeline facilities and the (421) __________________ is responsible to maintain the operating pressure of the plastic pipeline systems at or below the established maximum allowable operating pressure.

4. GENERAL

   4.1 The maximum allowable operating pressure of each plastic pipeline segment shall be determined and communicated to the appropriate parties by the (422) _____________________ .

   4.2 No person shall operate a gas pipeline at internal pressures which exceed the established maximum allowable operating pressure for that pipeline.

   4.3 To increase the MAOP on an existing plastic pipeline, refer to Procedure 12.01, paragraph 4.3 for requirements.

5. PROCEDURE

   5.1 Establish the maximum allowable operating pressure of all existing and new plastic pipeline facilities.

   The maximum allowable operating pressure of any plastic pipeline segment shall not exceed the lowest of the following: (Also, see Form 8.01A in Procedure 8.01)

   5.1.1 The design pressure of the weakest element in that pipeline segment determined in accordance with Procedure 16.01.

   5.1.2 The pressure obtained by dividing the pressure to which the segment was tested after construction by a factor of 1.5 in all class locations.

   5.2 Control operating pressures at or below established maximum allowable operating pressure for all pipelines at all times.

5.3 No person shall operate or cause action which will operate any plastic pipeline section in excess of the established maximum allowable operating pressure.

5.4 Implement repairs, modifications, or additions to a segment of pipeline so that the maximum allowable operating pressure of the segment is maintained through the use of approved materials, construction and testing methods.

6. <u>RELATED PROCEDURES</u>

16.01 Design of Plastic Pipelines
16.05 Test Requirements for Plastic Pipelines

7. <u>RECORDS</u>

7.1 Retain operating logs and/or pressure charts for at least five years.

7.2 Submit all as-built documents to (423) ________________________ to update the drawings and confirm the maximum allowable operating pressure.

7.3 Maintain as-built documents for the life of the pipeline facility.

7.4 Record MAOP and basis of determination of the operations description portion of the operations manual.

7.5 Retain MAOP calculations determination of the Pipeline Historical File.

CVGS 24" Gas Transmission Pipeline
Pipeline Specific O&M (PSOM)
Procedure #17

Ref: 49 CFR 192	Updated: June 2013

Contents of this Element:

17.01 PURPOSE, SCOPE, AND ANNUAL REVIEW

17.01.1 References

49 CFR, sections 192.605(a) and 192.605(b)(8).

17.01.2 Purpose

The purpose of this section is to define the information requirements specific to the CVGS gas transmission pipeline in Princeton, California. This section of the O&M manual is referred to as the Pipeline Specific Operations and Maintenance Manual (PSOM). Each pipeline facility supervisor shall review these minimum requirements and write procedures and requirements specific to the facility. The PSOM table of contents contains all the procedures that shall be developed or reviewed for facility specific requirements. In addition, section 3.06 of the O&M Manual shall be used as a guide when developing the PSOM.

17.01.3 Responsibility for Implementation

The (500) __________________ is responsible for implementation of this procedure.

17.01.4 Scope and Policy

This Operating & Maintenance (O&M) Plan for the CVGS gas transmission pipeline in Princeton, California has been prepared by its operator, CVGS, in compliance with the regulatory requirements of Pipeline and Hazardous Materials Safety Administration (PHMSA) according to 49 CFR Parts 191, Parts 192 and California Public Utilities Commission (CPUC) General Order #112-E.

It is the policy of CVGS to strive for the safety of life, protection of the environment, and protection of property. This PSOM provides a comprehensive operating guide for the CVGS gas transmission pipeline in Princeton, California. The plan defines the roles and responsibilities and lines of authority of operations personnel. Procedures for the safe operation and maintenance of the pipelines during both normal and abnormal operating conditions are also provided. The DOT Emergency Response Plan establishes written procedures to minimize the hazard resulting from an emergency (e.g., gas release, fire, explosion, natural disaster).

17.01.5 ANNUAL REVIEW of PSOM

This PSOM section of the O&M Manual shall be reviewed annually, not to exceed 15 months, for completeness and accuracy by the (501)________________. The plan shall be revised as necessary, and personnel shall be made aware of these changes, as required. All approved revisions/updates shall be distributed to holders of the Operating & Maintenance Plan by email or equivalent. The notice provided in section 17.02 may be used for distributions of updated PSOM procedures. All revisions shall be documented in O&M record of revisions tab or equivalent.

17.01.6 PERIODIC REVIEW OF WORK PERFORMED BY OPERATORS [192.605(b)(8)]

It is the primary responsibility of the (503)__________________ to periodically review the work performed by operators. The intent of this review is to determine the effectiveness of the procedures used in normal operations and maintenance and modifying the procedures when deficiencies are found. Use "Review Work Performed by Operator" form or equivalent to document this review.

17.01.7 Training

Training will be conducted for following personnel performing pipeline activities covered by this O&M Manual:

- New employees
- Change in job assignment or transfer
- Reasonable cause (see company OQ plan)
- Management of change (see company OQ plan)

Use training registration form or equivalent to document this training.

17.02 PSOM Updates

This update notice is for all holders of the Operating & Maintenance Plan for the CVGS gas transmission pipeline in Princeton, California.

Revision Number ___________________

Date ___________________

Attached are revised pages of the Operating & Maintenance Plan which have been assigned to you. Please remove pages in your book and replace with these revisions. When this is done, record the revision in the "Revision History" (tab #2) of your O&M manual.

Remove Old Pages (page numbers)

Replace with Revised Pages (new page number and date)

PIPELINE O&M and PSOM PLAN DISTRIBUTION LIST

CVGS

Name	Title	Location
Pipeline Operators	Pipeline Operators	CVGS control room in Princeton, Ca.
Brian Hackney	Mgr. Storage Operations (CVGS)	CVGS

17.03 Pipeline Description and Fact Sheet

CVGS 24" Gas Transmission Pipeline
Pipeline Specific O&M (PSOM)
Procedure #17

Ref: 49 CFR 192	Updated: June 2013

Basic Description:	The pipeline starts at the Central Valley natural gas storage facility near Princeton, California and extends approximately 14.7 miles west to a point of termination into PG&E's gas transmission system near Delevan, California.	
Critical Crossings:	The project contains 4 crossings by HDD which are summarized below. There are other miscellaneous crossings of minor irrigation canals, creeks, county roads, and foreign lines. The four HDDs are as follows: 1. Glenn Colusa Canal by HDD 2. Interstate-5, Hunters Creek, Highway 99, and Union Pacific Railroad by HDD. 3. NRCS Easement by HDD 4. Colusa Trough by HDD	
Type Pipeline:	Gas Transmission	
Miles Pipeline:	14.7	
Size and Type of Pipeline:	Class 1) Design Factor = 0.72 (192.111) 24inch O.D., 0.312 wall thickness API 5L ERW, X-65 (SMYS = 65,300#) Class 2) Design Factor = 0.6 (192.111) 24inch O.D., 0.406 wall thickness API 5L ERW, X-65 (SMYS = 65,300#) Class 3) Design Factor = 0.5 (192.111) 24inch O.D., 0.438 wall thickness API 5L ERW, X-65 (SMYS = 65,300#)	
Class Location: **[per 192.5]**	Primarily Class 1, (agricultural), short stretches of Class 3	
Pipeline Owner contact info:	Brian Hackney Mgr., Storage Operations 5285 McAusland Rd Princeton, CA 95970 630-427-5522 WMardia@NICOR.COM	Tim Hermann, VP Storage and Peaking Operations 3333 Warrenville Road, St. 300 Lisle, IL 60532 630/ 245-7836 therman@nicor.com
Pipeline Maintenance Contractor contact info:	Andy Bradfield, President Compliance Services Inc PO Box 22410 Bakersfield, CA 93390 661-549-8518 cell andy@complianceservicesinc.net	

CVGS 24" Gas Transmission Pipeline
Pipeline Specific O&M (PSOM)
Procedure #17

Ref: 49 CFR 192	Updated: June 2013

GAS PIPELINE FACT SHEET

Product:	Transmission quality natural gas
Odorized:	Yes (odorized by PG&E).
Coating:	14 to 16 mils of fusion bonded epoxy (FBE). HDDs have an additional 30 mils of abrasion resistant overcoat applied over the FBE.
Normal Operating Pressure Range:	800 psig to 1,100 psig
Max. Allowable Operating Pressure (MAOP):	1,100 psig MAOP as %SMYS= 65.1% (???? Component) MAOP as %SMYS = 50% (API 5L ERW X-65 pipe)
Method MAOP Determined: [Per 49 CFR 192.619]	o The pipeline system MAOP is determined by design pressure of weakest component.
Em. Shutdown Valves	At PG&E tie-in and at gas storage plant facility
Pipeline Start Up Date:	July 2012
Gas IMP HCAs:	Class 3 location outside CVGS compressor station.
Potential Impact Radius (PIR):	550 ft. Calculated in accordance with CFR 192.903.
CP System Design:	Impressed current system
Operator ID:	**32603**

Well Piping Info:	The 16" gathering laterals between the well pad and the compressor site (compressor station and dehydration, metering, and regulating facility sit) are of the same specification as they are within the well pad and compressor site. All are designed with a 1456 psig MAOP @ 120 F and for a 0.5 Part 192 design factor F for a Class 3 location. Pipe is 16" OD x .500" wt, API 5LX52 (52,000 psi Specified Minimum Yield Strength (SMYS)).

Over Pressure Protection:	Overpressure Protection (OPP) o There are at least seven (7) Part 192 gas transportation MAOPs to be protected for the main gas piping within the CVGS system. There are also higher rated piping components and vessels but those are inherently protected by the protection for the lower rated facilities described here. The seven pertinent subsystem MAOPs are: 1. Main Compressor Station (CS) and Storage Facilities – Piping MAOP is 1456 psig @ 120 F and ASME Vessel MAWPs on discharge side are 1525 psig minimum. 2. CVGS Pipeline side of Main Regulators at CS Site and the CVGS 24" Pipeline itself from the CS site to the PG&E L401-CVGS Interconnect Meter Station – MAOP is 1100 psig @ 120 F. Filter-separator MAWP at CS Site is 1145 psig. 3. PG&E L401- CVGS Interconnect Meter Station – Piping MAOP is 1200 psig @ 120F 4. PG&E 42" L401 Pipeline – MAOP is 1040 psig. 5. PG&E Owned L172 Temporary Pipeline Interconnect Facilities – L172 and PG&E Portion MAOP is 800 psig. 6. Hot Gas Piping - CS Site Compressor Discharge facilities from Compressor Cylinders thru and including Gas After coolers (Equipment No's. HAL-2010, -2020, & -2030) – Piping MAOP is 1456 psig at 300 F; After cooler Gas Coil MAWP is 1525 psig at 350 F. o The OPP for these systems is as follows: 1. Main CS and Storage Facilities – The only sources of pressure than can exceed the 1456 psig are the main compressor units (CAE-5010, 5020, & 5030 The engine-compressor packages have pressure control set to not exceed 1456 psig, relief valves set at 1525 psig (~105% of 1456 psig), and high pressure shutdowns set below the relief valve settings (~103% of 1456 psig.) These settings protect all 1456 psig Part 192 piping and 1525 psig vessels (as well as higher rated items.) The pressure vessels must be rated higher than pipelines need to be, because ASME Section VIII code requires pressure vessels to be rated to at least the set point of the OPP while Part 192 only

requires that OPP devices prevent overpressure in excess of 110% for piping with a 0.5 design factor. The OPP set point can be and is higher than the MAOP. Similarly, at the Well pad, the UCP high pressure shutdown, triggered by the field adjustable PSHs on the package discharge, protect the 1650 psig discharge side components of the package, as well as the 1456 psig rated CVGS piping up to the unit discharge isolator valve BV-5902 (Reference Drawing CVGS1-M-951-01.) This inherently also protects all of the other 1456 psig piping beyond the unit discharge isolation valve.

2. Pipeline side of Main Regulators at CS Site and CVGS 24" Pipeline itself to PG&E L401- CVGS Interconnect Meter Station – The 1456 psig rated storage & compression facilities are separated from the 1100 psig MAOP CVGS 24" pipeline by two parallel pressure regulator runs. Each regulator "run" includes a flow control valve with pressure override with a set point controlled by the station control panel (SCP), a pressure monitor control valve set at 102% of 1100 psig (1122 psig), and isolation ball valves also controlled by the SCP. The SCP will monitor the pressure both at both ends of the 24" CVGS pipeline and modulate the flow control valve if necessary to maintain the far end at or below 1040 psig and the near end at or below 1100 psig. It will also close the isolation ball valves if the pressure was to continue to rise at 104% of 1100 psig (1144 psig). These valves are all in series on each run, thus protecting against both failure of any single device, as well as protecting against leakage thru closed valves.
3. PG&E L401- CVGS Interconnect Meter Station – By being rated at 1200 psig which is higher than the L-401-CVGS Interconnecting Pipeline, there is no potential to overpressure that facility; it is protected by the same worker, monitor, high pressure shut-in valving that protects the 1100 psig and 1040 psig Pipelines.
4. PG&E 42" L401 Pipeline – Between the L-401- CVGS Interconnection Meter Station and the CVGS pressure regulation, there are several miles of pipeline creating pressure drop in a flowing condition. The variable set

point controlled by the CS Site UCP is the primary "pressure control" to maintain the pressure into the L401-CVGS Interconnect Meter no higher than 1040 psig. To provide OPP against the non-flowing condition and potential to build pressure above the L-401 rating of 1040 psig, several provisions have been made. First, shutoff of the delivery will normally be initiated at the CVGS CS site regulation runs, and not at the L401 end. Shutting off at the PG&E end would trap the line pack between the CS site and the meter site, and the pressure would equalize somewhere above 1040 psig. By shutting off at the CS Site, the line pack will bleed down into the 1040 psig system never increasing the pressure at the meter. However, there are also redundant OPP valves at the L401-CVGS meter. CVGS's 12" pressure regulating valve PCV-1011 is installed between the pipeline and PG&E's meter run and is set to limit pressure to 1040 psig if necessary. Furthermore, PG&E high pressure shut-in valve V-3 at the CVGS end of their meter run is set to close at 1050 psig as the third level of protection.

5. Compressor Discharge facilities from Compressor Cylinders thru and including the Gas After coolers (Equipment No's. HAL-2010, -2020, & -2030) – The ANSI B16.5 Class 600 Rated facilities are protected to their 120 F and 1456 psig rating from the Class 900 rated high temperature discharge system by the after coolers. The after coolers drop the temperature from up to 300 F, down to no more than 120 F at which temperature the Class 600 flanges, valves, and equipment are all rated for the 1456 psig which is protected by the pressure shutdowns and relief valves.

- There are of course numerous other auxiliary systems such as fuel gas, process liquids, dehydration regeneration subsystems, etc. Interfaces between higher and lower rated systems ("pressure breaks") in such systems are all protected by traditional pressure control valves with relief valves, worker-monitor regulator pairs, or high pressure shut-ins.

Flange Info:	Generally, the process gas piping throughout the project and various sites, is ASME/ANSI B16.5 (B16.5) Class 600 (CL600.) There are the following exceptions. o Compressor package flange connections (suction & discharge) are CL900 RF. o Compressor hot piping from the package discharge thru the gas after coolers, including the outlet flange on the after coolers are all CL900 RF to meet the combination of 300 F and 1456 psig. o All high pressure gas ASME (Section VIII) pressure vessel flange connections are CL900 RF (this is due to ASME rules requiring a relief valve set no higher than MAWP, forcing raising the MAWP above the 1456 psig & 120 F which is the maximum rating of the ordinary CS CL600 flange at that temperature.) 1. This includes the Well pad piping flanges, flange sets, and blinds installed in Phase 1-3 for later installation of the Well pad filter/separators and individual Wellhead separators. 2. The launchers and receivers are not ASME Section VIII vessels and thus do not have the CL900 flanges. o The Wellhead "Christmas trees" are made up of API 6A valves and flanges. The wing valves are 6" 6A 3000# which the CVGS piping will mate to with 6" RTJ B16.5 CL900 flanges. The top valves are 2" 6A 5000# which the CVGS piping will mate to with 2" RTJ B16.5 CL1500 flanges.

Pressure Test Info:	Pressure Test Info: • The best way to ascertain the hydro testing pressures and other requirements are to refer to the various drawings. • The 16" laterals between the Well pad and the CS site are to be tested in accordance with dwg CVGS-P-501-00 (Line A) and CVGS-P-502-00 (Line B.) • The CVGS 24" pipeline between the L401/CVGS Interconnect Meter Site and the CVGS CS Site is designed by Fluor and Fluor should be contacted for the hydrostatic testing requirements. • The testing for the Phase 1-3 (K001) contract piping is covered on dwg CVGS1-M-004-01.

	• The testing for the Phase 5-6 (K002) contract piping at both the Well pad and the CS Site is covered on dwg CVGS1-M-005-01, -02, & -03. It is assumed that all low pressure L172 PG&E piping and temporary compressor suction are isolated at this point, leaving only the 1456 psig permanent facilities. • The testing for the L401/CVGS Interconnect Meter Site itself is not yet defined. Those drawings are in progress and are awaiting PG&E design information.

Valve Info:	Emergency Valves for Start, Shutdown, and Emergency Shutdown – • It is not possible to provide a comprehensive description at this time for this item. Complete coverage will be provided by the Cause and Effect Lists and the Software documentation, and the Station Operating Manual. o Valve Types ▪ All valves NPS 2 and larger are generally API 6D flanged or welded valves. ▪ Additional exceptions are the individual Wellhead Safety Shut-in Valves (SSVs). These are API 6D Nordstrom plug valves with Electro-Hydraulic fail closed actuators. These provide for both normal switching of Wells in and out of service as well as emergency shut-in of wells for either station ESD or overpressure. ▪ Each Wellhead has a 2" Taylor Angled Choke serving the well bore; these are used among other reasons, to produce the water from a waterlogged well. The Upper Sands Wellheads also have a 6" Taylor Angled Choke serving the combined flow from the wing valves and the wellbore for balancing all of the wells. The Lower Sands Wellheads have a 10" in this service. The Taylor Angled Chokes are all of an API 6A body design with ASME/ANSI B16.5 CL600 flanges. o Valve Operation ▪ See the description of the Fisher valves, SSVs, and Angled Choke valves above under Valve Types for their purpose. Please also see the Overpressure Protection section for additional description of the roles the Fisher and shut-in ball valve (PCV-59025) play for that purpose.

Compressor Site Info:	Compressor Site Outline Description – o Valve Types ▪ All valves NPS 2 and larger are generally API 6D flanged or welded valves. ▪ Exceptions include: ▪ The (4) flow control and pressure monitor valves in the main regulator runs described under Overpressure Protection. These are all Becker Ball Valve Regulators which are made with API 6D valves but with diminished seat springs and not intended for bubble tight shutoff. ▪ The discharge to suction combination recycle/starting bypass valves on each unit are Fisher globe style valves. ▪ FCV-0049 will be a modulating flow control valve for the purpose of transferring some flow from one discharge manifold to the other (lower pressure one), allowing the output of a given compressor to split between Upper and Lower sand injection even if the split is less than half a unit; unit 2 also allows split service but each side of the compressor can only inject into a single header, assuming the headers may be at different pressures.

Compressor Site Valve Info:	Compressor Valve Operation • Please see the Overpressure Protection section for additional description of the roles the Becker regulator valves and shut-in ball valves serving each run. • Besides the pressure control and overpressure protections valves, the following additional information is offered: o Compressor Installation – This is DOT CFR Title 49 Part 192 Compressor Station installation with hp in excess of 1000 hp. However, only the "compressor station proper", is served by the automatic shutdown and blow down systems. The "compressor station" within the greater CS fenced site includes the three units with unit lead lines, suction and discharge isolation valves, and unit blow downs. If further includes the (4) four NPS 16" headers (two suction and two discharge) running along the compressor building and ending at the switching valve manifold depicted on dwg CVGS1-M-104-01. Closure of the following (6) six ESD isolation valves at the south end of the compressor station will completely isolate the compressors from the rest of the facilities. These (6) ESD valves are from left to right, BV-0041, BV-0051, BV-0047, BV-0057, BV-0043, & BV-0053. These are all spring close piston actuated ball valves. Subsequent opening of the following (4) four blow down valves will completely blow down the headers. These (4) blow down valves are from left to right: BDV-0045, BDV-0055, BDV-0046, & BDV-0056. These are all spring open piston actuated ball valves. o The compressors have individual unit valves, in addition to the station valves just described. These valves are cycled on a normal basis by the compressor UCP for its startup and shutdown sequence. ESD of the unit piping is accomplished by opening the individual unit blow down valves shown on dwg CVGS1-M-110-01: BV-5018, BV-5028, & BV-5038. These blow down valves are operated both by the station ESD system, and the building gas detection system. In the event of a high-high gas detection, the units will be shut down and the unit isolation valves will close before the blow down valves would be opened. o The Station ESD and Blowdown system is operated by the ESD panel

	tied into fire detection in the compressor building, and also by manual panic stations.

17.04 UPDATING MAPS AND RECORDS

17.04.1 References

49 CFR, sections 192.605(b)(3), 192.517, and 192.491

17.04.2 Purpose

The purpose of this procedure is to provide guidelines for maintaining and updating DOT pipeline maps and records.

17.04.3 Responsibilities for Updating Maps and Records

The (530) ________________ will keep current and comprehensive construction records, maps, and operating history and this information shall be available for use by the appropriate pipeline operations personnel. These records may be contained in this PSOM or may be kept in the facility DOT files.

17.04.4 Tracking and Documentation of Updates to Construction Maps and Records

The Company will use the pipeline Management of Change procedure to initiate, review, approve, and track major changes to construction maps and records.

17.05 NORMAL SHUTDOWN AND START-UP

17.05.1 References

49 CFR, sections 192.605(b)(5).

17.05.2 Purpose

The purpose of this procedure is to provide guidelines for starting up and shutting down any part of the in a manner designed to assure operation within MAOP limits.

17.05.3 Responsibility for Implementation

The (540)__________________ is responsible for overall implementation of this procedure.

17.05.4 General

This procedure is written for the startup of new pipelines and the shutdown of pipelines for normal maintenance. In addition other sections of the Operating and Maintenance Procedure shall also be followed with particular attention paid to the sections on Purging of Pipelines, Maximum Allowable Operating Pressure, Pressure Monitoring, Odorization of Gas, Repair Procedures, Prevention of Accidental Ignition, By Pass Operation, Regulator Station Inspection, and Emergency Valve Procedure. The Emergency plan shall be followed for the shutdown of a pipeline in an emergency.

Specific instructions for the startup or shutdown of the pipeline are shown below in section 17.05.9. Procedures shall be designed to provide safety during maintenance and operations and shall include provisions on how to perform the work in a manner designed to assure operation within the established MAOP.

17.05.5 Start Up of a New Pipeline

The person in charge of placing the pipeline in service shall establish written procedures for commissioning the new pipeline and placing it in service. The procedures shall be discussed with operating personnel prior to the startup operations. The procedures shall include provisions for:

1. Reviewing the Company O&M Manual to ensure it addresses operations, maintenance, and emergency procedures for the new pipeline.

2. Inspecting all regulator and overpressure protection devices required for the start-up of the new pipeline, including the testing of set pressures and the checking of capacities, if necessary.
3. Reviewing the Company O&M Manual for purging procedures, purging times and gas volumes.
4. Reviewing Company Emergency Manual for notification procedures.
5. Establishing communication with field personnel and gas control personnel.
6. Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established.
7. After completing purge and load operations, all valves are to be checked to be sure that they are in the proper operating position before leaving the scene. If facilities have been altered so that pressures, volumes, or over pressure protection devices have been affected, the local Supervisor is responsible for ensuring that properly calibrated and installed over pressure protection devices protect all affected pipe segments.
8. Updating maps and other pertinent operating records.

17.05.6 Shutdown of Pipelines for Normal Maintenance

A written plan shall be prepared to provide for the shutdown of gas in the pipeline segment. The plan shall provide gas supply for adjoining or affected facilities. The plan shall provide for the shutdown, the down period and the return to service. The written plan shall include the use of a line drawing or a schematic diagram of the segment to be shut down. The plan shall designate personnel responsible for the various aspects of the shutdown. The following are among the factors to be considered in the planning:

1. Facilities affected by the shutdown.
2. Sequence of operating valves and control devices.
3. Verification of valve closure by:
   a. Counting turns to close.
   b. Block and bleed techniques.
   c. Observation of position indicators.
   d. Timing.
4. Automatic valves.
5. Settings of affected safety devices, regulators and control devices.
6. Switching of meter stations.
7. Installation of stopping equipment.
8. Supply of gas to customers.
9. Gas flow capacity of affected equipment and facilities.

10. Monitoring of pressures during each phase of the operation.
11. Blow down location, conditions and procedures.
12. Venting and control of any leakage past closed valves and closures.
13. Purging conditions and procedures.
14. Re-pressuring for return to service.
15. Alternate gas control procedures to be used in an emergency.

During the planning, it shall be determined if there is any additional work, which needs to be performed which would also require a shutdown. If practical, this additional work shall be incorporated in the plan. This will reduce the number of shutdowns and thereby enhance the overall continuity and safety of the pipeline operation.

Schedule the shutdown at the most advantageous time and as far in advance as possible. The following are among the factors to be considered in the scheduling:

1. Pipeline gas flow and load conditions.
2. Special operating problems.
3. Customer gas demands.
4. Continuity of service to customers.
5. Coordination with gas suppliers and interconnecting operators.
6. Condition of readiness at work sites.
7. Availability of materials, personnel and equipment.
8. Weather conditions.
9. Time of year.

Established standard procedures shall be used for cutting and welding operations, for the venting of gas leakage, and for maintaining safe gas conditions during the progress of the work.

A positive method shall be provided for preventing pressure buildup against temporary or unbraced end closures. End closures, which are to be operated under pressure, shall be braced or anchored.

Bonding cables, grounding rods or grounding mats shall be used to minimize hazards from electricity.

The person in charge shall determine when the facility is ready to return to service.

Established procedures shall be followed to purge, re-pressure and return all facilities to normal operation. These procedures shall consider the potential for unknown hazards and include evacuation of personnel from excavations until all conditions are determined to be safe.

Flow rates shall be carefully controlled during re-pressuring, and pressures shall be monitored until normal operations have been established.

Pressure limiting stations, district regulator stations, relief valves, automatic valves and other control equipment shall be returned to their normal settings.

17.05.7 Startup and Shutdown Briefing

A startup and shutdown briefing shall be conducted by the supervisor in charge before the actual startup or shutdown. This meeting shall include such topics as the following.

1. Work assignments.
2. Duties to be performed and order of performance.
3. Means of communication.
4. Pressure limits to be maintained.
5. Normal and abnormal conditions that may be expected.
6. Alternate procedures in the event of an emergency.
7. Appropriate governmental agencies, civil agencies and other utility operators that shall be notified.

17.05.8 Action Required by Field Personnel before Startup or Shutdown

The pipeline operator shall:

1. Ensure proper functioning and serviceability of valves, and other devices, which will be used to block or control the gas, making inspections and doing necessary servicing.
2. Place under manual control those automatic valves, which might be adversely affected.
3. Adjust or change the settings of pressure limiting stations, district regulator stations, relief stations, relief valves and other control equipment (as required) to maintain safe pressures throughout the system.
4. Take precautions to minimize fire hazard where liquid hydrocarbons can be expected at a pipeline cut.
5. Do as much of the following work (as is practical or necessary and consistent with safe operating practices) prior to the startup or shutdown.
   a. Excavate, identify and verify the pipeline at the work site.
   b. Clean and inspect the exterior of the pipe.
   c. Check pipe for undersize or oversize.
   d. Install taps for blow downs or vents.
   e. Install bypass equipment.
   f. Install fittings for line stoppers.
   g. Deactivate rectifiers.
   h. Arrange for nondestructive testing.
   i. Check availability and operating condition of required work equipment.
   j. Provide and check fire extinguishers.
   k. Calibrate pressure test gauges and recorders, and assure that their connections are not obstructed.
   l. Check gas detection equipment for satisfactory condition and availability, and the availability of personnel qualified to operate the equipment.
   m. Provide for first aid equipment, supplies and protective clothing.

17.05.9 Action Required by Gas Control before Startup or Shutdown

Before commencing the start up or shut down, the person in charge at Gas Control shall determine that:

1. All personnel and equipment are at assigned locations.
2. Everything is ready at the job sites.
3. Conditions in the gas system are conducive to satisfactory start up or shut down.

17.05.9 Action Required by Gas Control during Startup or Shutdown

Gas pressures in the system shall be continuously monitored. Pressures shall be maintained within the prescribed limits during the period from the startup or shutdown. Where line packing is necessary or desirable or where the start up or shut down may cause a pressure buildup, special attention shall be taken to avoid exceeding maximum allowable operating pressures.

When the startup or shutdown will cause installed pressure regulating or overpressure protection devices to be ineffective, the procedures established shall at least provide that:

1. Operations are carried out by personnel qualified by training and/or experience.
2. Personnel are instructed in the operating characteristics of the components of the pipeline facilities affected.
3. Pressures in the affected facility are continuously monitored utilizing gauges (which shall be selected after considering pressure levels and degree of control required).
4. Communications are established to insure proper coordination of work.
5. Valves used for manually throttling pressures are constantly attended.

17.05.10 CVGS Gas Transmission Pipeline Normal Start-Up Specific Steps

1) Notify PG&E gas control and other appropriate PG&E operating personnel
2) Open appropriate valves as shown below
3) Monitor pressures and flows until normal

17.05.11 CVGS Gas Transmission Pipeline Normal Down Specific Steps

1) Notify PG&E gas control and other appropriate PG&E operating personnel
2) Shut appropriate valves as shown below
3) Monitor pressures and flows until normal

Valve #	PG&E Connection Valve Location:	Comments:
1	BV-1502 16" BV Remote Controlled Controlled by CVGS	
2	FCV-1011 Flow Control Valve Remote Controlled Controlled by CVGS	

Valve #	PG&E Connection Valve Location:	Comments:
3	V-3 16" BV Remote Controlled Controlled by PG&E	

17.05.11 Related References, Documents, & Procedures for Normal Start Up and Shut Down of the Pipeline

1. 49 CFR 192.605(a)(5)
2. GPTC, December 1998
3. Purging
4. Odorization
5. MAOP
6. Pressure Monitoring
7. Emergency Valve Procedures
8. Prevention of Accidental Ignition
9. Regulator Station
10. Compressor Station

17.06 PIGGING OPERATIONS

17.06.1 References

49 CFR, sections 192.605(b)(5).

Ref: 49 CFR 192	Updated: June 2013

17.06.2 Purpose

The purpose of this procedure is to provide guidelines for starting up and shutting down any part of the in a manner designed to assure operation within MAOP limits.

17.06.3 Responsibility for Implementation

The (550)_____________________ is responsible for overall implementation of this procedure. Wayne Mardian, the CVGS OPERATIONS MANAGER is responsible for taking adequate precautions in during pigging operations to protect personnel from the hazards of unsafe accumulations of vapors or gas. Wayne Mardian, the CVGS OPERATIONS MANAGER is also responsible for the scheduling, conducting, correction, and record keeping for this procedure.

17.06.4 General

The purpose of this procedure is to define proper operation and maintenance of pig launcher facilities and operation of the pig launcher facility. Launchers and receivers must be equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. A suitable pressure indicator must be installed on all launchers and receivers to verify that pressure has been relieved in the barrel or, a means to prevent insertion or removal of scrapers or spheres before pressure has been relieved in the barrel must be provided.

17.06.5 Scope and Purpose

This section only applies to the CVGS gas transmission pipeline in Princeton, California. The purpose of this procedure is to define proper operation and maintenance of pig launcher facilities and operation of the pig launcher facility.

Two above ground facilities have been constructed in conjunction with the Pipeline. A meter, related piping and a "pig launcher" was constructed at the beginning of the Pipeline with a similar meter, related piping and "pig receiver" constructed at the termination of the pipeline.

17.06.6 Procedure - General

Verify that all launchers and receivers have the capabilities described in the paragraph above. If not, install the appropriate equipment to meet the requirements. Implement corrosion detection program designed to detect corrosion before launcher/receiver strength is impaired. Inspect pressure relief devices according to the pressure relief procedures. Ensure that insertion or removal of inspection devices will not occur prior to pressure relief in the barrel.

17.06.7 Pigging Safety Requirements

In addition to the standard company minimum personnel protective equipment,

following shall be provided for this procedure:

- Face shield
- Chemical gloves
- SCBA at the scene for emergency use

The following procedures shall be performed by qualified operators only.

17.06.8 Pig Loading and Launching Procedure

1. Check that the following valves and fittings are closed:
    - Pig launcher trap outlet
    - Pig launcher trap inlet
    - Pig launcher trap vent
    - Pig launcher trap drain
    - Pig launcher trap end closure

2. Drain and depressurize the pig launcher trap by opening the pig launcher trap drain line on the bottom of the pig launcher trap and opening the vent valve. Allow trap to vent after opening the vent valve. Ascertain that the pressure gauge on the trap indicates 0 psig.

3. Close the drain valve.

4. Open the pig launcher trap end closure. Note: Initially loosen the end closure to be sure all pressure is relieved and that no liquid is present.

5. Insert the pig.

6. Close and tighten the pig launcher trap end closure.

7. Close the vent valve.

8. Slowly open the pig launcher trap kicker valve to allow the pig launcher trap to gradually build up pressure equal to that of the pipeline. Check the pressure gauge on the pig launcher trap to verify pressure build-up.

9. Open the pig launcher trap outlet valve.

10. Pinch the pipeline side line valve to divert flow through the pig launcher trap to launch the pig.

11. Listen for the pig to leave the pig launcher trap.

12. After the pig is launched, open the pipeline side line valve.

13. To return the pig launcher trap to its standby status, close the trap exit valve and kicker valve.

14. Verify the drain valve is closed.

17.06.9 Pig Receiving and Unloading Procedure

Initial Set-up

1. Make notifications that pig is ready to launch. State the number of pigs to be launched and style.

2. Pig receiver operator will verify that pig receiver and plant valves are properly aligned.

3. Verify all pig receiver pressure gauges operational and ensure bleeder valves closed and drains closed.

4. Call and verify ready to receive pig. Determine pig travel time.

5. Check that pig indicator is reset.

6. Stand-by pig receiver area and monitor when pig is expected to arrive.

7. Verify proper operation of portable gas monitor.

8. Check "pig detector" shows the pig is in the receiver

Set-up Pig Receiver for Pig Removal

1. Notify operations personnel that pig removal operations are being initiated.

2. Depressure pig receiver to oil sump or collection facility and isolate.

3. Slowly pressure pig receiver up with gas to 25#.

4. Depressure; repeat steps #2 and #3 at least five (5) times.

5. On final depressure, ensure upstream and downstream gauges on pig receiver are showing zero pressure.

6. Open bleed valves on PI immediately downstream of 6" inlet valve to pig receiver to ensure that the receiver is completely depressured.

7. Loosen pig receiver door clamp. (Stand upstream of door and opposite of door hinge.)

8. While standing next to receiver, remove all pigs using the pig pulling hook. DO NOT STAND IN FRONT OF PIG RECEIVER UNTIL ALL PIGS HAVE BEEN REMOVED.

Returning Pig Receiver to Service

1. Clean door, door hinge and receiver face. Look for any defects and lube as necessary.

2. Inspect inside the receiver, clean out any debris and report any unusual conditions and number of pigs received in the operator's log.

3. Close pig receiver door.

4. Close all bleed valves. (Failure to close valves will result in gas release to atmosphere).

5. Using gas, pressure pig receiver up to 25# and check for leaks.

6. Call control room to report pig count, condition and arrival time.

CAUTION: Use of unapproved tools such as snipes, pry bars, etc., on the pig receiver door is strictly prohibited.

17.06.10 Launcher and Receiver Trap Maintenance

Each time a trap is pressurized, the pig launcher trap end closure seal should be checked for tightness. If leakage is found, the pig launcher trap closure "O" ring should be replaced. When replacing the "O" ring, the "O" ring groove must be wiped clean of all existing grease and dirt. A new "O" ring should be greased and installed.

17.06.11 Reports and Records

Retain all pigging procedures and reports for five years.

17.06.12 Scope Related References, Documents, & Procedures

1. 49 CFR 195.426
2. Atmospheric Corrosion, Corrosion Manual
3. Internal Corrosion, Corrosion Manual
4. Regulator Stations and Relief Valves
5. Repair and Pressure Testing

17.07 Pipeline Maintenance Re-Occurring Tasks

17.07.1 References

49 CFR, sections 192.605(b)(1) and 191.13(c).

17.07.2 Purpose

The purpose of this procedure is to provide guidance for scheduling and performance for all the required DOT pipeline operations and maintenance requirements described in 49 CFR 192 subpart L (operations) and subpart M (maintenance) and 49 CFR 191 (reporting). CVGS will use Compliance Services Inc compliance tracking system to track, initiate, and document re-occurring pipeline maintenance tasks. Go to www.complianceservicesinc.net and log in with user name and password to review assigned tasks to this pipeline facility.

17.07.3 Responsibility for Implementation

The (560)__________________ is responsible for implementation of this procedure.

17.08 ABNORMAL OPERATIONS

17.08.1 References

49 CFR, sections 192.605(c).

17.08.2 Purpose

The purpose of this procedure is to provide safety when operating design limits have been exceeded.

17.08.3 Responsibility for Implementation

The (570)________________ is responsible for implementation of this procedure.

17.08.4 General

An abnormal operation is a non-emergency condition on a gas transmission facility which occurs when the operating design limits have been exceeded due to pressure, flow rate, or temperature change outside the limits of normal operation. When an abnormal operation occurs, it does not pose an immediate threat to life or property, but could if not promptly corrected.

The procedures in this section are to be followed when an "abnormal operating" condition exists, and when responding to, investigating, and correcting the cause of:

- Unintended closure of valves or shutdowns;
- An increase or decrease in pressure or flow rate outside normal operating limits;
- System Over-Pressure Situation or System Under-Pressure Situation (Refer to Emergency Response Procedures for Abnormal Pressure Conditions)
- Loss of communications with automatic device essential for the operation of the system;
- Operation of any safety device;
- Any other malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.

The individual who receives notification that an abnormal condition exists is to notify the (570)_____________. The (570)_____________, upon notification of an abnormal condition is to:

- ✓ Verify that the condition exists and if necessary respond to the location.
- ✓ Take the necessary steps to rectify the situation which may include the need for additional operational and/or supervisory personnel.
- ✓ Once the situation is rectified, the system shall be checked for variations from normal operation at sufficient critical locations particular to the abnormal condition and the system in which condition occurred. The steps to be taken must ensure the continued integrity and safe operation of all facilities.
- ✓ The (570)_____________ must notify the pipeline operating company that the event has been rectified.

The pipeline operator will decide if further action is necessary. The pipeline supervisor will notify the discovering person that the situation has been rectified.

17.08.5 Prevention of Condition from Recurrence

Once the condition has been investigated, and normal or safe operations are restored, the (570)_____________ shall determine what measures can be taken to prevent the cause of the condition from recurring. The PIPELINE SUPERVISOR shall also consider whether these measures shall be implemented elsewhere in the transmission system to avoid similar occurrences of abnormal condition.

17.08.6 Follow-up Monitoring

Various critical locations in the system shall be checked for variations from normal operation after abnormal operation has ended. The extent of follow-up monitoring after the end of an abnormal condition is based on the nature of the condition and the probability that the cause of the condition can recur. The condition is considered corrected when the pipeline operator determines at the end of the monitoring period that the pipeline facility has maintained operations within its operating design limits.

17.08.7 Review of Personnel Response

The (570)_____________ will undertake a review of personnel response based on the extent of the abnormal condition. The review shall consider the actions taken, and whether the procedures followed were adequate for the given situation or shall be revised to provide more specificity or more flexibility.

The specific steps for review of the procedures during abnormal conditions include;

1. The (570)______________, or designee, will develop a sequence of events by reviewing logs/records and interviewing appropriate personnel involved in the abnormal condition event.
2. The (570)______________ will evaluate the actions (i.e., sequence of events) taken to rectify the abnormal condition to determine if they were adequate.
3. If procedures are determined to be in-adequate, they will be re- written by the Pipeline Consultant) with input from appropriate operating personnel.
4. Results of the abnormal condition events will be reviewed with operating personnel.

17.08.8 Abnormal Operation Notification

The Pipelines are monitored by operating personnel who report all abnormal operations to the (570)______________. If further study into the cause or the correction of the condition that caused the abnormal operation is necessary, the (570)______________ shall notify the facility engineering staff. Use **Form #17.10A: Abnormal Operations Report** or its equivalent to document the abnormal operating condition.

17.08.9 Remedial Measures

If the operability of a pipeline is impaired as a result of abnormal operations, the affected pipeline operation shall be evaluated and changes made to improve its operation. The Operating and Maintenance Plan shall be updated if necessary and all affected personnel trained on the changes.

17.08.10 Records and Reports

Any reviews performed under this procedure shall be documented and maintained in the DOT records file for a minimum of five years.

17.08.11 Abnormal Operations – Specific Actions

Unintended Valve Closure

This will cause a pressure rise upstream of the valve, an immediate decrease in pressure downstream of the valve, and an immediate reduction in flow rate in the system.

Action: Initiate Emergency Shutdown Procedures for the system with the closed valve. Notify the Operations Personnel to investigate and determine the cause for the valve operation. Call out other personnel as needed to:

- Check and verify the system integrity and perform an inspection of the pipeline.
- Determine and correct cause for the valve closure prior to resuming normal operations.

Do not restart the system until the Operations Personnel have verified the system is ready for operation.

Abnormal Change in Flow Rate or Pressure

An abnormal change in flow rate or pressure are changes that cannot readily be attributed to a grade change or a planned system throughput change such as a change in delivery or process change at all facilities.

Action: Check with Operators at all pumping and delivery locations for any changes they may have made or may observe on their pressure/flow recording instruments. If no reason for the change can be found, notify the appropriate Operations Foreman and initiate shutdown procedures for the system. Call out other operations personnel as needed to determine and correct the cause of abnormal pressure/flow change and verify the system integrity prior to resuming normal operations.

Loss of Communication

If the phone system is inoperable, the Company's radio systems can be used to communicate between the appropriate operation personnel.

Personnel in the field can communicate with the CVGS Office via the paging service, cellular phones.

Mobile Radio

The company has mobile radio communications with the foreman.

All radio transmissions must comply with FCC regulations and may be heard by anyone monitoring that system. It is essential that all transmissions be conducted in a businesslike, courteous, and confident manner which will be a credit to the company and its employees. Only messages directly related to safety, the protection of lives and property, and the normal operation of the company's business should be transmitted.

Nextel Radio Service

The company has Nextel radio service to all employees.

Cellular Phones

The company has mobile phone communications.

Operation of Safety Devices

The pipeline is equipped with a number of protective devices designed to shut down the pipeline if preset limits are exceeded. This operation is intended to occur before system design limits are exceeded. The pipeline may be restarted as soon as the cause for the operation of the protective device (low suction pressure and electrical power failure) has been corrected. The occurrence of certain other events is more critical and requires an on-site investigation by Operations personnel before equipment is restarted. These devices include: high discharge pressure, low pressure, high flow rate, low flow rate, and hazardous atmosphere.

Action: When a section is shut down by high discharge pressure, high flow rate, hazardous atmosphere, vibration, it will be necessary to call the Operations Personnel to investigate and determine the cause for the shutdown. Do not attempt to restart the facility until advised that corrections have been made and the equipment is ready for operation.

Any Malfunction of Components, Deviation from Normal Operations or Personnel Error

Any malfunction of components, deviation from normal operations and personnel error could possibly cause any one of the abnormal conditions described in Section 6.1 through 6.4. They can be identified as such and will be handled as described in these sections.

Ref: 49 CFR 192	**Updated: June 2013**

17.09 CPUC and OTHER AGENCY SPECIFIC REQUIREMENTS

17.09.1 References

CPUC General Order #112-E (see table below for specific regulations) and agency permit(s), if any.

17.09.2 Purpose

The purpose of this procedure is to provide guidance for compliance with CPUC and agency specific tasks.

17.09.3 Responsibility for Implementation

The (580)__________________ is responsible for implementation of this procedure.

TABLE 17.10-1
SUMMARY OF O&M MANUAL ADDITIONAL CPUC REQUIREMENTS

O&M Sect #	DESCRIPTION	DOT 49 CFR PART 192	CPUC General Order 112-E	ADDITIONAL CPUC REQUIREMENTS:
17.09.4	**Reporting to CPUC**		122, Gas Incident Reports	**All reports** required by DOT (annual reports, incident reports, safety related conditions) also require submission to the CPUC.
17.09.5	**Report of Gas Leak**		122(c), Gas Incident Reports	"**Report of Gas Leak**", use CPUC form #420. This report is for leaks of escaping gas causing property damage, including loss of gas, in excess of $1,000. Note: DOT incident report level is $50,000, death, injury requiring hospitalization, or significant event in the judgment of the operator.
17.09.6	**Quarterly Gas Leak Summary Reports**		122(e), Gas Incident Reports	**Quarter Summary Reports** are required by CPUC which summarize all reportable leaks and incidents as required by the DOT/CPUC. In addition, this report must include information on incidents that; Include property damage between $0 and $1,000, and involve fire, explosion, or underground digs.
17.09.7	**New Construction Notification**		125, Proposed Installation Report	**Report of New Construction/Installation** must be filed with the CPUC at least 30 days prior to construction of a new pipeline. This report shall include seven requirements listed in the CPUC regulations.
17.11.8	**Report of Change in Maximum Allowable Operating Pressure**		126, Change in Maximum Allowable Operating Pressure	**Report of Change in Maximum Allowable Operating Pressure (MAOP)** must be filed with the CPUC at least 30 days prior to increase in MAOP. This report shall include; ▪ New MAOP ▪ Reasons for change ▪ Steps taken to determine the capability of the pipeline to withstand such an increase. Note: DOT requires same process but not the reporting. DOT would verify during normally scheduled audits.

17.10 MANAGEMENT of CHANGE (MOC)

17.10.1 References

This is a company requirement because it is considered best practices for pipeline operations and maintenance.

17.10.2 Purpose

This procedure establishes the minimum requirements to provide for the safety of Company personnel, the public, and Company pipeline facilities due to changes or modifications in product, equipment, technology, procedures, or personnel. The Company will analyze the potential impact of changes to the pipeline facilities and to modify pipeline procedures and programs as appropriate.

<u>**These procedures shall assure that the following considerations are addressed prior to any change:**</u>

- <u>**Impact of change on safety, health, and the environment**</u>
- Modifications to all appropriate procedures (O&M, Emergency, Operator Qualification, IMP, EHS)
- Necessary time period for the change, and
- Authorization requirements for the proposed change

17.10.3 Responsibility for Implementation

The (590)______________________ is responsible for implementation of this procedure.

17.10.4 Definitions

<u>In-Kind Change</u>

A replacement, repair, or modification that matches all existing conditions including design specifications, location, size, materials of construction, etc. (This does not mandate making replacements with the same manufacturer as the original piece of equipment or part.)

Management of Change (MOC)

Management of changes is the process of documenting and reviewing changes that potentially affect the safety and operation of the pipeline. MOC ensures that changes are recognized, documented, formally reviewed and approved prior to their implementation in order to avoid potential environmental, safety, and/or operational problems.

MOC Committee (Optional)

The individuals chosen to review proposed changes for their potential effects on pipeline safety and to propose safeguards, modifications, analyses, or other measures as required, ensuring the continued safe operation of the pipeline. Management of Change Committees may be appointed by the Pipeline Supervisor who is responsible for the process involving the proposed change. The members of the Management of Change Committee shall be chosen on the basis of their knowledge and expertise in the area(s) involving change, in the regulatory requirements, and in appropriate operations and maintenance procedures.

MOC Coordinator

The MOC Coordinator is the person assigned by the Company to implement and coordinate ongoing MOC activities.

MOC Covered Change

Any temporary or permanent action which results in one or more of the following:

- Replacement or modification of equipment with other than "in-kind"
- Operation of equipment outside of established design limits (e.g. pressures, temperatures, levels, etc.
- Change or addition of a new product which have not been previously used at a facility or are not discussed in the operating manual.
- Addition of new equipment, including piping, control systems, compressors, and any pipeline facility under DOT jurisdiction, etc.
- Modification of existing procedures or addition of a new procedure (O&M, Emergency Response, Operator Qualification, and Integrity Management)
- New personnel or personnel changes which may adversely affect the safety of remaining personnel or place the environment at undue risk.

- New technology
- Other changes that could affect the safety or operation of the pipeline facilities

Not-In Kind Change

A replacement, repair, or modification that does not match all existing conditions of design specifications, location, size, materials of construction, etc.

Temporary/Emergency Change

Any change that will not remain in effect indefinitely. Temporary changes shall not be planned for more than six (6) months.

Subject Matter Expert (SME)

Subject Matter Expert is the person with the required training, experience, and knowledge to perform the MOC review for their area of knowledge.

17.10.5 Training

Supervisors and management will provide training for all affected workers and contractors within their area of responsibility prior to startup of the affected process. The training shall include instruction on the scope and purpose of this MOC procedure as well as knowledge of the methods of employee participation in the Management of Change. Training on specific modified procedures will be included if appropriate.

17.10.6 MOC Process

At each pipeline facility, the Pipeline/Facility Manager or his designee will be the Facility MOC Coordinator. The Facility MOC Coordinator will be responsible for performing an initial review of any submitted MOC form. The Facility MOC Coordinator shall evaluate the complexity of the change to determine if review by an MOC committee is necessary, and if appropriate, assure appropriate personnel are assigned to the MOC Committee to assist in the review of the change.

Personnel (SMEs) assigned to review the MOC form shall have expertise in an area that The change involves (i.e., facility engineers, environmental engineers, safety engineers, Maintenance technicians, E&I technicians, measurement technicians, experienced operators, or experienced mechanics).

Each assigned SME will evaluate the change. They will either determine what actions shall be taken to safely implement the change or reject the change and issue an explanation for their rejection to the initiator. When an MOC has been approved by all the SMEs, it will be the responsibility of the Facility MOC Coordinator to provide the final verification that all of the review processes required to implement the change have been completed prior to submittal of the change for final approval by the Pipeline/Facility Manager. The change cannot be implemented without the final authorization and signature of the Pipeline/Facility Manager on the MOC form.

The Facility MOC Coordinator is responsible for ensuring that all post change documentation is completed in a timely manner.

17.10.7 Instructions for Completing Pipeline MOC Form

The following describes how the Management of Change process will work and how to complete each section on the MOC Form:

<u>Part I - Initiator</u>

Any of the following elements shall initiate the MOC process.

- Replacement or modification of equipment with other than "in-kind"
- Operation of equipment outside of established design limits (e.g. pressures, temperatures, levels, etc.
- Change or addition of a new product which have not been previously used at a facility or are not discussed in the operating manual.
- Addition of new equipment, including piping, control systems, compressors, and any pipeline facility under DOT jurisdiction, etc.
- Modification of existing procedures or addition of a new procedure (O&M, Emergency Response, Operator Qualification, and Integrity Management)
- New personnel or personnel changes which may adversely affect the safety of remaining personnel or place the environment at undue risk.
- New technology
- Other changes that could affect the safety or operation of the pipeline facilities

This section of the permit is to be completed by the Permit Initiator and reviewed by the Pipeline/Facility Supervisor. The Permit Initiator shall describe in detail the description of the proposed change. A complete description of the proposed task and work location must be identified. Attach any pertinent information useful to the reviewing parties.

The Pipeline Supervisor shall make an initial review of the MOC form and sign the form in the appropriate section of part I. The Pipeline Supervisor shall explain any MOC that is not approved. When the Pipeline/Facility Supervisor has completed their review, they shall forward the new MOC form to the MOC Coordinator.

If the change is Temporary/Emergency, the Pipeline/Facility Supervisor, after taking all necessary environmental, safety and operational precautions, and discussing the change with first line management may authorize the change. The anticipated date, not to exceed six months, when the facility will return to normal operations must be stated.

Part II – Reviews/Consultation

If the MOC Coordinator agrees that an MOC process is necessary, the MOC Coordinator will date and sign the MOC form in section two and forward the MOC form to the appropriate SMEs. The MOC Coordinator may consult with the Pipeline/Facility Supervisor for the date required. If the other box is checked, a description shall be written in the form to explain this other element.

Part III – SME Review

Each SME will date and initial their required action items when completed and forward a copy of the MOC form to the MOC Coordinator.

Part IV – Pipeline Manager Authorization

The MOC Coordinator will hold the MOC form until all required elements have been updated. Then the MOC Coordinator will sign and date the MOC Form in section four and forward the form to the appropriate person in the supervisor chain of command. The final approval shall be the Pipeline Manager or his designee.

17.10.8 Record Keeping

The following records shall be as noted below:

- MOC Form, #17.10 [5 years]
- MOC training [5 years]
- Changes and updates required by MOC form [Life of pipeline for repairs and construction records]

17.10.9 Related References and Documents

1. OSHA PSM, 29 CFR 1910.119

17.10.10 Roles & Responsibilities for MOC

It is the primary responsibility of the Pipeline/Facility Manager to oversee a safe and efficient MOC Program. The following table defines roles and responsibilities for MOC.

R = Responsible (person doing work)
A = Accountable (person in charge/oversight)
C = Consult
I = Inspect

	Description	Sect #	Mgr	MOC Coord	Eng	PL/ Fac. Supr	Pipe Oper	MOC Team
1.	Initial MOC	17.10.4	A	**R**	**R**	**R**	**R**	**R**
2.	Initial Review of MOC	17.10.4	A	**R**	C	C	C	C
3.	SME Review & Consultation	17.10.4	A	**R**	**R**	**R**	**R**	**R**
4.	Pipeline/Facility Supervisor Authorization	17.10.4	A	C	C	**R**	C	C
5.	MOC Coordinator Authorization	17.10.4	A	**R**	C	C	C	C
6.	Ensure completion of post change documentation (drawings, procedures, etc)	17.10.4	A	**R**	C	C	C	C

At the CVGS facilities, the following are the assigned roles:

Pipeline/Facility Supervisor:	The (590)_______________
MOC Coordinator:	The (590)_______________
Pipeline Manager	The (590)_______________

17.11 CONTROL ROOM MANAGEMENT

17.11.1 References

49 CFR, sections 192.605(b)(12), 192.631

17.11.2 Purpose

The purpose of this procedure is to provide guidelines for complying with control room management regulations.

17.11.3 Responsibilities for Updating Maps and Records

The (600)________________ is responsible for the upkeep of the CRM procedures. A copy of CRM procedures is maintained at the CVGS control room in Princeton, California.

Attachment 4

Central Valley Gas Storage Operator Qualification Plan

May 29, 2013

Letter of Transition
Operator Qualification Program

AGL Resources (AGLR) maintains Operator Qualification (OQ) Plans meeting the requirements identified in CFR192 Subpart N for all its Midstream Operations gas storage facilities. One of these facilities is located in Princeton, CA and operates under the name Central Valley Gas Storage (CVGS).

During construction and initial operations, CVGS utilized two OQ plans, one based on the Veriforce, LLC OQ program, and the other based on the OQ program of Compliance Services Inc. (CSI). Contractors working for or on behalf of CVGS have been OQ qualified under the guidelines and procedures outlined in the CSI OQ Plan for CVGS unless they already held the Veriforce-based OQ qualifications required for their work. CVGS company employees have current qualifications listed under the Veriforce-based OQ plan and will complete future re-qualifications under that plan.

Contractors who are qualified under the CSI OQ plan will be transitioned to the Veriforce supported OQ plan. This transition of qualifications to the Veriforce plan is expected to occur over a 12 month period. Once all contractor qualifications have been transitioned, the CSI OQ plan will be decommissioned allowing all AGLR Midstream Operations employees and contractors to be covered by the single AGLR Veriforce OQ plan.

AGL Resources

Jefferson Island Storage and Hub (JISH)
Golden Triangle Storage (GTS)
And
Central Valley Gas Storage (CVGS)

Operator Qualification Program

Written in Accordance with the

Operator Qualification Rule

49 CFR §192(N)
49 CFR §195(G)

Revision 2
Effective Date: 12/18/2012

TABLE OF CONTENTS

Program Revision History

Revision/Date	Description of Change	Justification for Change	Category of Change	Communication of Change
Revision 0 – 07/01/2010	Document Created	Wholesale change to include transition to Common Covered Tasks and program administration with Veriforce.	High	OQ Plan sent to Bobby Smith (OQ Specialist) on July 1, 2010.
Revision 1 – 09/21/2011	Added definition for “suspended qualification” Deleted sentence concerning “Failure to comply…” in section 1 Added WPHR discussion (6.1.3) Added PHMSA and state addresses (11.7.1) Added “and/or For Cause” (9.3)	Align OQ program to VF Policies and Procedures Manual Clarification Clarification Updated to reflect latest regulatory language Clarification	Low	Updated program sent to Program Admin. Per the Plan definition of “significant program change”, notification to Federal or State agencies is not required for any modifications made in this revision.
Revision 2 – 09/21/2012	Added the Central Valley Gas Storage location as an additional Operator location Added Program Manager, OQ Standards to section 4.1 as a responsible person	Clarification Clarification	Low Low	Updated program sent to Program Admin. Per the Plan definition of “significant program change”, notification to Federal or State agencies is not required for any modifications made in this revision.

PHMSA Enforcement Protocols

DOT/PHMSA utilizes enforcement protocols designed to standardize enforcement of the OQ Rule throughout the pipeline industry. While these protocols are subject to change, the following table is based on the version of protocols most current as of the effective date of these procedures and is provided as a reference to illustrate which parts of these procedures address corresponding protocol requirements.

#	Title	Protocol Question	Verification Items	*Company OQ Reference*
1.01	**Application and Customization of "Off-the-Shelf" Programs**	Does the Operator's plan identify covered tasks and does it specify task-specific reevaluation intervals for individuals performing covered tasks? [Enforceable] (Associated Protocols: 1.05, 2.01, 5.02)	NA	Section 3.0 Exhibit A
1.02	**Contractor Qualification**	Does the Operator employ contractor organizations to provide individuals to perform covered tasks? If so, what are the methods used to qualify these individuals and how does the Operator ensure that contractor individuals are qualified in accordance with the Operator's OQ program plan? [Enforceable] (Associated Protocols: 1.05, 2.02, 3.02)	Verify that the Operator's written program includes provisions that require all contractor and subcontractor individuals be evaluated and qualified prior to performing covered tasks, unless the covered task is performed by a non-qualified individual under the direction and observation of a qualified individual.	Section 1.0 Section 3.0 Section 4.0 Section 5.0 Section 6.0 Section 8.0 Section 12.0 Exhibit A Exhibit C Exhibit D
1.03	**Management of Mutual Assistance Programs**	Has the Operator's OQ program included provisions that require individuals from any other entity performing covered task(s) on behalf of the Operator (e.g., through mutual assistance agreements) be evaluated and qualified prior to task performance? [Enforceable] (Associated Protocols: 1.05, 2.02)	Verify that other entities that perform covered task(s) on behalf of the Operator are addressed under the Operator's OQ program and that individuals from such other entities performing covered tasks on behalf of the Operator are evaluated and qualified consistent with the Operator's program requirements.	Section 1.0 Section 3.0 Section 4.0 Section 5.0 Section 6.0 Section 8.0 Section 12.0 Exhibit A Exhibit C Exhibit D ("Other Entities" held to same standards as contractors.)
1.04	**Training Requirements (Initial Qualification, Remedial if Initial Failure, and Reevaluation)**	Does the Operator's OQ program plan contain policy and criteria for the use of training in initial qualification of individuals performing covered tasks, and are criteria in existence for re-training and reevaluation of individuals if qualifications are questioned? [Enforceable] (Associated Protocols: 5.02)	NA	Section 7.0
1.05	**Written Qualification Program**	Did the Operator meet the OQ Rule requirements for establishing a written Operator qualification program and completing qualification of individuals performing covered tasks? [Enforceable] (Associated Protocols: 3.01, 7.01)	Verify that the Operator's written qualification program was established by April 27, 2001.	See Original Program Documentation
			Verify that the written qualification program identified all covered tasks for the Operator's operations and maintenance functions being conducted as of October 28, 2002.	Section 3.0. Exhibit A.
			Verify that the written qualification program established an evaluation method(s) to be used in the initial qualification of individuals performing covered tasks as of October 28, 2002.	Section 3.0 Exhibit A Exhibit B Exhibit C

#	Title	Protocol Question	Verification Items	Company OQ Reference
			Verify that all individuals performing covered tasks as of October 28, 2002, and not otherwise directed or observed by a qualified individual were qualified in accordance with the Operator's written qualification program.	Section 12
2.01	**Development of Covered Task List**	How did the Operator develop its covered task list? [Enforceable] (Associated Protocols: 8.01)	Verify that the Operator applied the four-part test to determine whether 49 CFR Part 192 or 49 CFR Part 195 O&M activities applicable to the Operator are covered tasks.	Section 3.0 Exhibit D Exhibit E
			Verify that the Operator has identified and documented all applicable covered tasks.	Section 3.0 Exhibit D Exhibit E
2.02	**Evaluation Method(s) (Demonstration of Knowledge, Skill and Ability) and Relationship to Covered Tasks**	Has the Operator established and documented the evaluation method(s) appropriate to each covered task? [Enforceable] (Associated Protocols: 3.01, 3.02)	Verify what evaluation method(s) has been established and documented for each covered task.	Section 6.0 Exhibit A Exhibit B Exhibit C
			Verify that the Operator's evaluation program ensures that individuals can perform assigned covered tasks.	Section 6.0 Exhibit A Exhibit B Exhibit C
			Verify that the evaluation method is not limited to observation of on-the-job performance, except with respect to tasks for which OPS has determined that such observation is the best method of examining or testing qualifications. The results of any such observations shall be documented in writing.	Section 3.0 Section 6.0 Exhibit A Exhibit B Exhibit C
2.03	**Planning for Mergers and Acquisitions**	Does the operator have a process for managing qualifications of individuals performing covered tasks during program integration following a merger or acquisition (applicable only to operators engaged in merger and acquisition activities)? [Enforceable] (Associated Protocols: 3.01, 3.02)	Verify that the OQ program describes the process for ensuring OQ qualifications, evaluations, assignment and performance of covered tasks during the merger with or acquisition of other entities.	Section 13 Exhibit D
3.01	**Development and Documentation of Areas of Qualification for Individuals Performing Covered Tasks**	Does the Operator's program document the evaluation and qualifications of individuals performing covered tasks, and can the qualification of individuals performing covered tasks be verified at the job site? [Enforceable] (Associated Protocols: 4.02, 7.01)	Verify that the Operator's qualification program has documented the evaluation of individuals performing covered tasks.	Section 12.0
			Verify that the Operator's qualification program has documented the qualifications of individuals performing covered tasks.	Section 12.0
3.02	**Covered Task Performed by Non-Qualified Individual**	Has the Operator established provisions to allow non-qualified individuals to perform covered tasks while being directed and observed by a qualified individual, and are there restrictions and limitations placed on such activities? [Enforceable] (Associated Protocols: 2.01, 2.02)	Verify that the Operator's program includes provisions for the performance of a covered task by a non-qualified individual under the direction and observation by a qualified individual.	Section 8.0 Exhibit A Exhibit B Exhibit C
4.01	**Role of and Approach to "Work Performance**	Does the Operator use work performance history review as the sole method of qualification for individuals performing covered tasks prior to	Verify that after October 28, 2002, work performance history is not used as a sole evaluation method.	Section 6.0

#	Title	Protocol Question	Verification Items	Company OQ Reference
	History Review"	October 26, 1999, and does the Operator's program specify that work performance history review will not be used as the sole method of evaluation for qualification after October 28, 2002? [Enforceable] (Associated Protocols: 2.02)	Verify that individuals beginning work on covered tasks after October 26, 1999 have not been qualified using work performance history review as the sole method of evaluation.	Section 6.0
4.02	**Evaluation of Individual's Capability to Recognize and React to AOCs**	Are all qualified individuals able to recognize and react to AOCs? Has the Operator evaluated and qualified individuals for their capability to recognize and react to AOCs? Are the AOCs identified those that the individual may reasonably anticipate and appropriately react to during the performance of the covered task? Has the Operator established provisions for communicating AOCs for the purpose of qualifying individuals? [Enforceable] (Associated Protocols: 3.01)	Verify that individuals performing covered tasks have been qualified in recognizing and reacting to AOCs they may encounter in performing such tasks.	Section 6.0 Section 10.0 Section 11.0 Exhibit B Exhibit C
5.01	**Personnel Performance Monitoring**	Does the Operator's program include provisions to evaluate an individual if the Operator has reason to believe the individual is no longer qualified to perform a covered task based on: • Covered task performance by an individual contributed to an incident or accident. • Other factors affecting the performance of covered tasks. [Enforceable] (Specific Protocols: 2.02)	Verify that the Operator's program ensures evaluation of individuals whose performance of a covered task may have contributed to an incident or accident.	Section 9.0 Exhibit D
			Verify that the Operator has established provisions for determining whether an individual is no longer qualified to perform a covered task, and requires reevaluation.	Section 9.0 Exhibit D
5.02	**Reevaluation Interval and Methodology for Determining the Interval**	Has the Operator established and justified requirements for reevaluation of individuals performing covered tasks? [Enforceable] (Associated Protocols: None)	Verify that the Operator has established intervals for reevaluating individuals performing covered tasks.	Section 3.0 Exhibit A
6.01	**Program Performance and Improvement**	Does the Operator have provisions to evaluate performance of its OQ program and implement improvements to enhance the effectiveness of its program? (Associated Protocols: None)	NA	Section 10.0 Section 11.0
7.01	**Qualification "Trail"(i.e., covered task; individual performing; evaluation method(s); continuing performance evaluation; reevaluation interval; reevaluation records)**	Does the Operator maintain records in accordance with the requirements of 49 CFR 192, subpart N, and 49 CFR 195, subpart G, for all individuals performing covered tasks, including contractor individuals? [Enforceable] (Associated Protocols: 1.05, 3.01)	Verify that qualification records for all individuals performing covered tasks include the information identified in the regulations.	Section 12.0 Exhibit D
			Verify that the Operator's program ensures the retention of records of prior qualification and records of individuals no longer performing covered tasks for at least five years.	Section 12.0 Exhibit D
			Verify that the Operator's program ensures the availability of qualification records of individuals (employees and contractors) currently performing covered tasks, or who have previously performed covered tasks.	Section 12.0 Exhibit D

#	Title	Protocol Question	Verification Items	*Company OQ Reference*
8.01	**Management of Changes (to Procedures, Tools, Standards, etc.)**	Does the Operator's OQ program identify how changes to procedures, tools standards and other elements used by individuals in performing covered tasks are communicated to the individuals, including contractor individuals, and how these changes are implemented in the evaluation method(s)? [Enforceable] (Associated Protocols: 1.04)	Verify that the Operator's program identifies changes that affect covered tasks and how those changes are communicated, when appropriate, to affected individuals.	Section 11.0 Exhibit D
			Verify that the Operator's program identifies and incorporates changes that affect covered tasks.	Section 11.0 Exhibit D
			Verify that the Operator's program includes provisions for the communication of changes (e.g., who, what, when, where, why) in the qualification program to the affected individuals.	Section 11.0 Exhibit D
			Verify that the Operator incorporates changes into initial and subsequent evaluations.	Section 11.0 Exhibit D
			Verify that contractors supplying individuals to perform covered tasks for the Operator are notified of changes that affect task performance and thereby the qualification of these individuals.	Section 11.0 Exhibit D
8.02	**Notification of Significant Program Changes**	Does the operator have a process for identifying significant OQ written program changes and notifying the appropriate regulatory agency of these changes once the program has been reviewed? [Enforceable] (Associated Protocols: None)	Verify that the operator's written program contains provisions to notify OPS or the appropriate regulatory agency of significant modifications to a program that has been reviewed for compliance.	Section 11.0 Exhibit D

1.0 Background/Introduction

On August 27, 1999, the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation (DOT) promulgated regulations requiring all individuals who perform covered tasks on pipeline facilities "be qualified to operate and maintain the pipeline facilities" and have "the ability to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits".

These regulations, commonly referred to as the "Operator Qualification (OQ) Rule", were promulgated as amendments to 49 CFR §192 and 49 CFR §195, to cover pipeline transportation of natural gas and hazardous liquids, respectively.

The OQ Rule requires a pipeline Operator to ensure that all individuals who operate and maintain pipeline facilities are qualified to perform covered tasks and can adequately recognize and react to abnormal operating conditions identified by the Operator. Operators are held responsible not only for ensuring that their own employees are qualified to perform covered tasks, but that all contractors, subcontractors, or other entities performing covered tasks on their respective facilities are qualified as well.

This written program establishes the procedures, requirements and responsibilities for qualifying employees of Jefferson Island Storage & Hub (JISH), Golden Triangle Storage (GTS) and Central Valley Gas Storage (CVGS) ("Company") and any other individuals who perform covered tasks at the facilities for which the Company has responsibility. These procedures have been developed to ensure compliance with 49 CFR Part 192, Subpart N or 49 CFR 195 Subpart G (OQ Rule).

This written program applies to Company personnel, contractor personnel, sub-contractor personnel and personnel of all other entities who perform covered tasks on behalf of the Company. All personnel who perform covered tasks on facilities owned or operated by the Company must be qualified in accordance with this written program.

Veriforce, a third party service provider, has been contracted by the Company to administrate this written program. *Veriforce* will work directly with the Company's Management Personnel to implement and oversee all components of this program.

2.0 Definitions

Abnormal Operating Condition (AOC) – A condition identified by the Operator that may indicate a malfunction of a component or deviation from normal operations that may: (a) indicate a condition exceeding design limits; or (b) result in a hazard(s) to persons, property, or the environment.

Authentication – The act of attesting that information contained within a record is accurate, complete, legible, and appropriate to the work accomplished.

Authorized Evaluator – A Subject Matter Expert who has been formally approved by ***Veriforce*** with responsibility for evaluating a Candidate's knowledge, skills, and abilities to perform a specific covered task and ability to recognize and properly react to applicable abnormal operating conditions according to evaluation criteria defined by a specific Operator. An Authorized Evaluator is responsible for determining whether a Candidate is qualified to perform a covered task and is also authorized to conduct on-the-job training (OJT) as provided for in these procedures.

Candidate – A person whose knowledge, skills, and abilities are to be evaluated in order to determine whether that person is qualified to perform a specific covered task.

Common Covered Task List (CCTL) - A covered task list and supporting evaluation criteria developed by a consortium of subject matter experts (SMEs) from pipeline operators, contractors, organized labor, and nationally known training providers.

Construction – An activity that occurs to either a new pipeline, or a new pipeline component(s) or involves the expansion of service.

Contractor – An external organization whose employee(s) provide services to an Operator(s) for which the OQ rule applies and whose personnel are evaluated to determine qualification status.

Covered Task – An activity identified by the Operator, that:

1. Is performed on a pipeline facility;
2. Is an operation or maintenance task;
3. Is performed as a requirement of part 192, or 195; and
4. Affects the operation or integrity of the pipeline.

A covered task that does not technically meet this four-part test may also be defined by an Operator if the Operator determines that an activity poses significant risk to the integrity of pipeline facilities or if an activity is deemed a "covered task" through some other means or reference, including the Pipeline Integrity Rule or the Pipeline Safety Act.

Data Validation – The process of analyzing original quality records in order to identify specific and/or generic errors in particular data types (i.e.: signatures, completed forms, etc.)

Direct and Observe – The process by which a qualified individual oversees the work activities of a non-qualified individual(s) such that the individual overseeing the work is able to take immediate corrective action if necessary.

Disqualification – Permanent removal of an individual's qualified status relative to a specific covered task due to reasons related to individual's performance of the covered task such as an incident, accident, or other reason to believe the individual may no longer be qualified. In the case of disqualification, Candidate may not be re-evaluated until appropriate training requirements have been met and documented by ***Veriforce***.

Evaluation – A process established and documented by the Operator, to determine an individual's ability to perform a covered task. The tern can be used to refer to the process, instrument(s), or both. The process may entail one or more evaluation methods or one or more distinct evaluation instruments.

Evaluation Criteria – Knowledge criteria, performance criteria, AOCs, proper response to AOCs, and any other measurable criteria defined by an Operator which shall serve as the means by which one's qualification to perform a task is measured.

Evaluator – see "Authorized Evaluator".

Expired Qualification – Permanent removal of an individual's qualified status relative to a specific covered task due to the individual not being re-evaluated and re-qualified before expiration of the requalification interval established by the Operator. In the case of an expired qualification, Candidate may be re-evaluated (with or without receiving additional training) in order to reinstate qualified status.

Maintenance – An activity performed on pipeline or pipeline component(s) with the intent to sustain or improve the integrity of the pipeline. Examples of maintenance activities include (a) pipe replacements resulting from anomalies, (b) in-place repairs, (c) valve and regulator maintenance, and (d) annual corrosion surveys. Covered tasks related to maintenance activities are subject to the OQ rule.

On-the-Job Training (OJT) – Instruction, in accordance with written and structured training materials, by a Subject Matter Expert (SME) at or near the work setting.

Operator – One who operates a pipeline facility and, as a result, is required to comply with the OQ rule.

Operator Qualification (OQ) Rule – 49 CFR §192(N) and 49CFR §195(G)

Qualified Individual – A person who has been evaluated and deemed able to: (a) perform assigned covered tasks; and (b) recognize and react to abnormal operating conditions, and (c) maintains current qualification.

Quality Record – A record deemed by *Veriforce* or the Operator to be critical in documenting compliance with the OQ rule. Quality records are those to be maintained in accordance with applicable recordkeeping requirements set forth in the OQ rule.

Record of Evaluation (ROE) – A quality record originated by *Veriforce* which shall contain task description and Operator-specific evaluation criteria used by an Evaluator to conduct an evaluation and shall also include the following:

- Candidate name;
- Candidate identification;
- Candidate Employer identification;
- Evaluator identification;
- Signature of Candidate; and
- Signature of Evaluator

Revoked Qualification – Removal of an individual's qualified status relative to a specific covered task. Revocations occur due to reasons not related to individual's performance of the covered task such as improper evaluation, "High Impact" change, non-response to audit request, etc. Upon revocation, Candidate may be re-evaluated without training in order to reinstate qualified status.

Significant - As applicable to OQ program modifications, significant includes but is not limited to: increasing evaluation intervals, increasing span of control ratios, eliminating covered tasks, mergers and/or acquisition changes, evaluation method changes such as written vs. observation, and wholesale changes made to OQ plan.

Span of Control – The maximum number of non-qualified individuals that a Qualified Individual can direct and observe for the conditions under which the task is being performed.

Subject Matter Expert (SME) – An individual recognized as having a special skill or specialized knowledge of a process in a particular field, or of a piece of equipment.

Suspended Qualification – Removal or inactivation (usually temporary) of an individual's qualified status relative to a specific covered task. Qualifications are typically suspended pending investigations, audits, etc. – later to be reinstated, permanently revoked, or disqualified based on findings.

VeriSource – An internet-based database application that allows *Veriforce* customers/clients to review qualification status of individuals by task, by company, or by individual name.

3.0 Identification of Covered Tasks

3.1 As of the effective date of this plan, the Company has adopted the covered task list attached as Exhibit A for company and contractor personnel. Evaluation criteria for Company employees and selected contract employees are attached as Exhibit B. Evaluation criteria for most contract employees and other external personnel are attached as Exhibit C.

3.2 In 2003, a handful of pipeline Operators, supported by ***Veriforce***, Contractors and industry trade associations, took part in an effort to construct a covered task list and supporting evaluation criteria. This effort was undertaken over a period of eight months and included subject matter experts (SMEs) from pipeline operators, contractors, organized labor, and nationally known training providers. The "common" covered task list (CCTL) and associated evaluation criteria were created by comparing and reconciling existing covered task lists and evaluation criteria (including span of control and requalification intervals) that each Operator had developed or adopted individually. Each covered task and associated criteria was finalized only after SMEs present reached a consensus on the applicability of evaluation criteria, including span of control and requalification intervals.

3.3 For each of the current covered tasks identified in Exhibit A, the following have been identified:

- <u>Task ID</u> – the number assigned to the covered task
- <u>Task Description</u> – a description of the covered task
- <u>Regulatory Reference</u> – reference to applicable code requirements found in 49 CFR 192 and/or 49 CFR 195
- <u>Evaluation Method</u> – the mandated method of evaluation for the covered task
- <u>Performance by Non Qualified Individual Allowed?</u> – denotes whether the task may be performed by a non-qualified individual working under the direction and observation of a qualified individual
- <u>Span of Control (SOC) Limit</u> – ratio of non-qualified individuals who may perform a covered task under the direction and observation of a qualified person, provided such is allowed. The SOC for each covered task was established by SMEs representing various Operators and other organizations. The continued appropriateness of SOCs is evaluated in accordance with Section 10.0 of this plan.
- <u>Requalification interval</u> – the time period for which a qualification shall remain in effect before re-evaluation is required. The requalification interval for each covered task was established by SMEs representing various Operators and other organizations. The continued appropriateness of intervals is evaluated in accordance with Section 10.0 of this plan.

3.4 Initial requalification intervals and SOCs were established by the group of SMEs who worked to develop the original CCTL. These SMEs represented pipeline operating companies, contractors, organized labor, and national technical training organizations. Each covered task developed by this group included a requalification interval based on their estimate of task difficulty, task importance, the potential for loss of knowledge or skill over time, and/or manufacturer's recommendations. Maximum span of control limits were also established for each task taking into account the difficulty, importance, and other job-site factors related to the task in question.

3.4.1 Since original development, the CCTL has been updated several times and is used by many different pipeline Operators supported by ***Veriforce***. All ***Veriforce*** supported Operators can ask for revisions or additions to the CCTL and ***Veriforce*** will assist Operators in composing changes or revisions.

3.4.2 The procedure for adding or modifying any task on the CCTL first requires a draft submission to Veriforce by a pipeline Operator representative. Upon receipt, Veriforce submits the change proposal to all Veriforce supported Operators for review and comment. During the draft review phase, Operators are asked to have their respective SMEs review the proposed changes or new covered task and respond with technical comments related to the following:

- Name/description of covered task;
- Regulatory reference(s) of covered task;
- Evaluation criteria;
- Abnormal Operating Conditions and appropriate responses;
- Requalification interval; and
- Span of Control limit.

3.4.3 After the draft review phase is completed, Veriforce compiles all comments received and produces a written response. In cases where Operator comments propose a significant modification to the original proposal, Veriforce will send the revised proposal to all Operators for another review and comment period. After all comments have been received and any new major modification reviewed, then Veriforce will issue a final document that summarizes the original proposal, comments received, and final action taken.

3.5 Each covered task has been subjected to the "4-Part Test" in accordance with the OQ Rule. Tasks that **do not** fully meet the 4-Part Test may be included in the covered task list if they are determined to be sensitive tasks related to pipeline safety and integrity. Results of the 4-Part Test analysis are included in Exhibit E.

3.6 Underlying evaluation criteria have been established for each covered task. Exhibit B provides, for each covered task, evaluation criteria that includes task knowledge and skill requirements along with AOCs and proper AOC responses to be utilized for the evaluation of Company employees. Exhibit C provides evaluation criteria for use in evaluating contractors and/or other external personnel. The fact that evaluation criteria differs, regarding employees versus contractors, illustrates the manner in which a qualified individual is expected to respond to AOCs.

3.7 Each criteria component has been identified as either knowledge-based or skill-based. The method of evaluation for each covered task has been based on these designations.

4.0 Individuals Involved in Program Administration

4.1 The OQ Specialist/Administrator and Program Manager, OQ Standards shall:

- Act as administrator of the program,
- Develop and implement training needed to support the OQ program,
- Provide technical oversight for the program.
- Work directly with Veriforce as the Company's point of contact for all issues related to this written program,
- Advise Veriforce of changes in operating or maintenance technologies, procedures, best practices, and equipment for the purposes of updating the written program,
- Conduct review of program every fifteen months, but at least once each calendar year.
- Present program to inspecting agencies for review, as appropriate.
- Communicate to Veriforce feedback from regulatory agencies and other sources, as appropriate.
- Communicate to Veriforce changes from internal recommendations, as appropriate.

- Provide technical support to ensure that all revisions made to the Written Plan, Covered Task List, and Evaluation Criteria are commensurate with Company policies and procedures.
- Assign only qualified individuals to perform covered tasks or to direct and observe non-qualified individuals.
- Identify individuals who may be subject to re-evaluation and re-qualification due to concerns with performance of a covered task.

4.2 In circumstances where a Project Manager has been assigned oversight responsibilities for a specific project, the Project Manager shall determine through "scope-of-work" submitted by contractors, or by other means, the required OQ covered tasks to which contract personnel are performing on jurisdictional pipelines. The Project Manager, or his/her designee will ensure appropriate identification and obtainment of Field Verification Reports for OQ work being conducted or other appropriate documentation from VeriSource establishing the qualification of personnel performing covered tasks.

4.3 Evaluators are responsible for evaluating Candidates to determine whether they are qualified to perform covered tasks.

4.4 Company's designated supervision/field personnel are responsible for:

- Monitoring covered tasks to be performed at the job site;
- Verifying the identity of qualified personnel who will perform covered tasks at the job site;
- Validating through the use of Field Verification Reports or other appropriate resources that qualified personnel have been evaluated and qualified according to this written program;
- Ensuring that qualifications of personnel performing covered tasks at the job site are valid and current;
- Periodic observation of personnel performing covered tasks to ensure the covered task(s) is being performed according to Company procedures;
- Monitoring to ensure that "span of control" limits are observed; and
- Reporting to management any incident, accident, or other performance concern resulting from a qualified individual performing a covered task.

4.5 The Company has entered into a contractual relationship with Veriforce for support related to its OQ compliance program and administration of this written program. Veriforce will perform this function in accordance with its own procedures, included as Exhibit D. Generally, Veriforce is responsible for:

- Oversight and administration of evaluations and qualifications;
- Evaluator authorization;
- Quality records maintenance;
- Data management and reporting;
- Operator personnel and contractor communication support;
- Qualified personnel auditing; and
- Other services, as necessary.

5.0 Communication of Program Requirements

5.1 The Company or its designee will communicate program requirements to employees, contractors, and other affected parties who either perform covered tasks and/or have responsibilities associated with administering/implementing this program.

5.1.1 Program requirements shall be communicated via any or all of the following methods:

- VeriSource on-line Notification System,
- Veriforce website;
- Email;

- Fax;
- Direct telephone communications;
- Organizational meetings;
- Tailgate meetings; and/or
- Other means, as appropriate.

5.1.2 Veriforce is responsible for communication of program requirements to all affected parties, as directed by the Company.

5.2 Communication resulting from "Management of Change" efforts will be done in accordance with procedures outlined in Section 11.

6.0 Evaluation/Qualification of Individuals

6.1 All evaluations related to this written program shall be conducted in accordance with Veriforce Operator Qualification Personnel Evaluation Policies and Procedures, attached hereto as Exhibit D.

6.1.1 Those procedures shall govern all activities related to:

- Evaluator Authorization;
- Evaluation of Personnel;
- Training;
- Program Quality Management;
- Documentation and Record Keeping; and
- Management of Change.

6.1.2 Work Performance History Review (WPHR) is not an acceptable method of evaluation. At no time will WPHR be allowed as an acceptable method of evaluation for any task from the Common Covered Task List (CCTL).

6.1.3 All evaluations must be conducted by an Authorized Evaluator. The Authorized Evaluator must strictly follow evaluation criteria defined by the Company (as provided in Exhibits B and C). For the purpose of evaluating a Candidate's ability to recognize and respond appropriately to an AOC, the evaluator shall, to the extent practical, require the Candidate to describe the AOC and appropriate response in the context of the covered task being performed, the location where it will be performed, and according to Company procedures and requirements.

6.1.4 Non-Company Evaluators are required to be re-authorized on an annual basis at which time each must complete the Evaluator training program. Annually, the Evaluator training program will be updated to reflect changes implemented during the previous year. Internal Evaluators (employed by **JISH, GTS or CVGS)** are required to be re-authorized every **three** years.

7.0 Training

7.1 Prior to conducting an evaluation, supervision and the authorized evaluator shall be responsible for determining whether certain conditions exist indicating that training is required. This shall be documented on the Record of Evaluation. As related to this written program, and in accordance with Veriforce procedures attached hereto as Exhibit D, training shall be required in the following instances:

7.1.1 Candidate has been disqualified by Veriforce since last being evaluated. This shall apply to the specific covered task(s) for which the Candidate is to be evaluated.

7.1.2 Candidate was not successfully evaluated when most recently evaluated for the covered task(s) in question.

7.1.3 A "High Impact" change related to the covered task(s) in question has been initiated since the Candidate was last evaluated/qualified.

7.2 The Company will provide necessary training directly to Company employees through any number of means and/or sources, as deemed most appropriate on a case-by-case basis.

7.3 Although training may be required, the Company will not directly provide OQ-related training to external personnel such as contractors, subcontractors, or other individuals not employed by the Company. Veriforce will assist those individuals in identifying training resources, as appropriate, and documenting successful completion of training, when it is required.

8.0 Use of Nonqualified Persons to Perform Covered Tasks

8.1 Exhibit A identifies those covered tasks which may be performed by a non-qualified person under the direction and observation of a qualified individual.

8.2 Where allowed, a span of control limit has been established which sets forth the maximum number of non-qualified persons that may be directed and observed by a qualified individual. The qualified person directing and observing the non-qualified person must be able to intervene to either prevent or react to an AOC.

8.2.1 Company field personnel shall monitor performance of covered tasks at the job site to ensure that span of control limits are enforced.

8.2.2 Company field personnel may make span of control limits more restrictive in cases where safety, environmental, or other site-specific conditions exist that may affect safety of personnel and/or facilities.

8.3 Appropriateness and effectiveness of established span of control limits shall be evaluated as part of the Company's quality assurance and program evaluation efforts.

8.4 In emergency response situations, the first priority is to dispatch qualified individuals to respond to the emergency condition.

8.4.1 Individuals whose normal job responsibilities include emergency response shall be qualified for the covered tasks they perform in responding to, stabilizing, or terminating an emergency condition.

8.4.2 Tasks that are performed after the emergency condition has been stabilized or terminated shall be performed by qualified individuals or by non- qualified individuals under the direction and observation of qualified persons consistent with the span of control requirements identified in this standard.

8.4.3 Professional emergency responders, such as fire fighters, do not need to be qualified to perform covered tasks. Professional emergency responders who perform covered tasks under contract on behalf of the operator shall be qualified.

8.4.4 Individuals that perform covered tasks through a mutual aid arrangement shall perform emergency response tasks consistent with the qualification requirements for emergency responders as described above.

8.5 Where a qualified individual is directing and observing non-qualified individuals under span of control situations, the Company will ensure that no language barriers exist that would preclude the qualified person from communicating with non-qualified personnel.

9.0 Quality Assurance

9.1 Veriforce and the Company's Management will implement ongoing program quality management efforts in order to ensure accuracy of records, continued qualification of individuals, effective performance of Evaluators, to identify problems, and to identify opportunities for program improvements.

9.2 Veriforce will conduct audits of qualified personnel in order to determine if their performance has directly contributed to an incident or accident that may bring qualified status into question or whether there is any other reason to believe the individual is no longer qualified.

9.2.1 A minimum of **5%** of the individuals who are qualified for the Company will be selected to undergo a qualification audit each calendar year. The key purpose of the audit will be to ensure that the qualified individual is still qualified.

9.2.2 Audits will focus on individuals; therefore, when an individual is selected to undergo a qualification audit, Veriforce shall include all qualifications held by that individual. This may include multiple qualifications for a given Operator and/or qualifications related to multiple Operators.

9.2.3 Personnel qualification audits shall be conducted in accordance with Veriforce Operator Qualification Personnel Evaluation Policies and Procedures, attached as Exhibit D.

9.2.4 Veriforce will document all audits and manage associated documentation as a quality record(s) and shall provide the Company with access to this documentation.

9.2.5 The Company shall notify Veriforce in the event that a qualified individual contributes to an incident or accident while performing a covered task, or whether there is any reason to suspect a qualified individual may no longer be qualified.

9.2.5.1. Extended absence, physical injury, prolonged illness, and/or other factors may be cause to suspect a person may no longer be qualified. The Company shall review this on a case-by-case basis.

9.2.5.2. When notified of an incident, accident, or suspicion that a person may no longer be qualified, Veriforce shall immediately suspend those qualifications in question and work with Company to investigate more fully in accordance with Veriforce procedures described in Exhibit D.

9.3 In addition to Candidate auditing, Veriforce will conduct random and/or "for cause" audits of Evaluators' performance as a quality assurance measure to validate the Evaluators' continued competency and suitability. A minimum of **5%** of Authorized Evaluators will be audited each calendar year.

9.3.1 *Veriforce* will document all Evaluator monitoring and manage this documentation as a "quality record". The Company shall have access to this documentation.

9.4 For each qualification granted through Veriforce, a formal audit trail will be maintained which shall document:

- Documentation that the qualified individual was properly evaluated and qualified;
- Technical competency of the Evaluator of record;
- Documentation that the Evaluator has successfully completed the Veriforce Evaluator training program; and
- Documentation of auditing the qualified individual (as applicable).

9.4.1 At the conclusion of each qualification or evaluator audit, all Veriforce records associated with that individual's qualification(s) will be reviewed for completeness and accuracy. This shall include a formal audit of records applicable to the candidate in question as well as each Evaluator who has conducted an evaluation of the candidate.

10.0 Program Evaluation

10.1 Veriforce shall encourage all program participants (Operators, contractors, and Evaluators) to communicate difficulties encountered and ideas for program improvement whenever possible.

10.1.1 Veriforce shall be responsible for documenting such issues and communicating those issues to the Company for consideration.

10.2 The program shall be reviewed every fifteen months, but at least once each calendar year. This may include meeting with Veriforce as described in section 10.3.

10.3 Veriforce and the Company's Management will attempt to meet annually for the purpose of program monitoring and to discuss opportunities for program improvement. The annual meeting will include a review of each of the following:

- Compliance with the written program;
- Adequacy/currency of the written program;
- Adequacy/currency of the covered task list;
- Adequacy/currency of task-specific evaluation criteria;
- Appropriateness of task-specific re-qualification intervals;
- Appropriateness/effectiveness of task-specific span of control limits;
- Compliance with regulatory and other external requirements;
- Issues/challenges discovered as a result of Quality Assurance efforts;
- Other Issues/challenges encountered to date;
- Proposed program improvements/enhancements;
- Program performance related to the OQ rule and DOT/OPS enforcement-related activities; and
- Other issues.

11.0 Management of Change

11.1 Needed changes to this program may be identified through:

- Concerns with procedures,
- Field personnel input/feedback
- Evaluator input/feedback
- Change in regulatory or other requirements
- Change in technology
- Incidents/accidents/AOCs
- Program evaluation results from audits, etc.
- Annual review of O&M procedures and OQ program

11.2 There are five key activities which take place in the Veriforce process which provide opportunities to identify needed changes and/or to communicate program changes directly to impacted parties. Those are as follows:

1. Veriforce solicits input from Evaluators on a continuing basis regarding suggested program improvements and discussion of challenges faced;
2. Veriforce regularly meets with contractors to review program requirements, solicit input on program improvements, and discuss challenges faced;
3. Veriforce collects/reports information generated as a result of quality assurance and monitoring activities;
4. Veriforce holds regular meetings with other Operators it supports to discuss status, challenges faced, and program improvement ideas; and
5. Veriforce meets annually with the Company to review covered tasks, evaluation criteria, program requirements, etc.

11.3 On a continuing basis, all applicable parties will be encouraged to voice concerns, problems, or other issues and to present ideas on how the process might be improved.

Veriforce will solicit input; document issues raised, and present all such issues to Operators.

11.4 At any time, the Company may determine that its covered task list, evaluation criteria, or other components of this program should be revised. Veriforce and the Company will work together to manage any such change or revision, including categorizing and communicating any such changes and taking necessary steps to document and implement these changes such that compliance with the OQ rule can be properly demonstrated.

11.5 Upon reaching the decision to initiate a program change(s), the change(s) will be categorized as follows:

11.5.1 **Low Impact** – requires no formal communication. Low impact changes may include grammatical, formatting, or other modifications that result in no material effect on the administration and implementation of the OQ Program.

11.5.2 **Medium Impact** – requires formal communication to affected parties. "Medium Impact" changes are changes that affect the implementation and administration of the OQ program **but do not require the re-qualification of individuals previously qualified on the applicable covered task(s).** Examples of "Medium Impact" changes may include revisions to administrative procedures, evaluation methods, operating procedures, or other items – but only if those changes specifically affect the implementation and administration of the OQ program.

11.5.3 **High Impact** – requires formal communication to affected parties. "High Impact" changes are changes that affect the implementation and administration of the OQ program **and require the re-qualification of individuals previously qualified on the applicable covered task(s).** Examples of "High Impact" changes may include revisions to administrative procedures, evaluation methods, operating procedures, or other items – but only if those changes specifically affect the implementation and administration of the OQ program – **and** only if the change is so substantial that it renders an individual no longer qualified on the specific covered task(s). The only distinction between "Medium Impact" and "High Impact" changes is the affect each has on existing qualifications. It should be noted that introduction of a new covered task is not designated as a "High Impact" change. Because it is a new task, it is not a change that rendered anyone no longer qualified – therefore, it does not meet the definition of "High Impact" change.

11.5.3.1. In the case of a change(s) categorized as a High Impact, the Company shall define the date by which qualified individuals must be re-evaluated/qualified. If the impacted individual(s) has not been re-evaluated/qualified by the established date, he/she shall be deemed "not qualified".

11.6 Veriforce will be responsible for communicating change in accordance with the Veriforce Operator Qualification Personnel Evaluation Policies and Procedures, attached as Exhibit D.

11.6.1 In the case of a change categorized as a "Low Impact", Veriforce will communicate the change via any one or all of the following methods:

- An appropriate communication will be posted on the Veriforce website;
- A communication notification will be linked to the VeriSource login and password of all affected parties and will be displayed upon the individual logging into VeriSource,
- An appropriate communication will be sent to the Company contact, Contractors and Evaluators directly via email; and/or

- The change will be discussed during regular contractor and employee meetings.

11.6.2 Where a change is categorized as a “Medium Impact”, Veriforce will communicate the change as follows:

- Communication will be posted at the Veriforce website;
- A communication notification will be linked to the VeriSource login and password of all affected parties and will be displayed upon the individual logging into VeriSource;
- Change will be discussed at the appropriate “OQ Meeting”;
- Direct communication will be sent to affected parties as follows:
  1. Email in those cases where a valid email address is available;
  2. Fax in those cases where a valid email address is not available and a valid fax number is available; and/or;
  3. US Postal Service or other courier service in those cases where neither email nor fax is possible.

11.6.2.1. In cases a where a “Medium Impact” change is to be made effective on some future date, direct communication will be made as early as possible in advance of the effective date and a second communication will be sent on the effective date.

11.6.2.2. In those cases where a “Medium Impact” change is to be made immediately effective, direct communication will be sent immediately and a second communication reminding affected parties of the change will be sent within 10 business days.

11.6.3 For changes categorized as “High Impact”, Veriforce will immediately implement all changes in order to ensure that upcoming evaluations are conducted according to the most current task description and evaluation criteria. The change(s) will be communicated to applicable employees, contractors, Evaluators, and other impacted parties in the same manner as that described for a “Medium Impact” change.

11.6.4 Each change communication will be documented in an electronic communication log maintained by Veriforce. The communication log will document:

- the date of the communication;
- recipient of the communication;
- communication subject; and
- method by which communication was sent to the affected party.

11.6.5 Veriforce will provide toll-free telephone support to applicable parties so that changes can be communicated directly to those who utilize that support and assistance can be provided to those trying to address a specific issue or change.

11.7 In cases where the Company implements a significant change (as defined below), a description of the change will be submitted to appropriate federal and state regulatory agencies responsible for enforcing the Company’s OQ program. A significant program change is defined as a modification to the Company’s OQ program that would materially reduce or eliminate any part of the program that has been reviewed by the Administrator and adopted by the Company to address a performance requirement of the regulation. Examples of significant program changes include but are not limited to the following:

- Inactivation of a covered task that was/is performed by the Company;
- Increase in the requalification interval for a covered task;
- Increase in the SOC for a covered task;

- The wholesale elimination of evaluation criteria from a covered task;
- Mergers and/or acquisitions changes; or
- The addition of any new program element(s) designed to comply with a new regulatory requirement that has become effective after the date of the last review by the Administrator.

Examples of changes that the Company may make to their OQ program that would not be classified as significant include but are not limited to the following:

- The addition of new covered tasks;
- Decrease in the requalification interval of a covered task;
- Decrease in the SOC for a covered task;
- The addition of new or updated evaluation criteria to an existing covered task; or
- General program additions or clarifications that do not replace an existing part of the program that has been verified by the Administrator or are not intended to comply with a new regulatory requirement enacted since the date of the last review by the Administrator.

11.7.1 When appropriate, notifications of significant changes shall be sent to the OPS Information Resource Manager by e-mail at:

InformationResourcesManager@phmsa.dot.gov or mail to:

U.S. Department of Transportation,
Pipeline and Hazardous Materials Safety Administration,
Office of Pipeline Safety, Information Resources Manager,
1200 New Jersey Avenue, SE.,
East Building, 2nd Floor (PHP-10), Room E22-321,
Washington, DC 20590.

11.7.2 When appropriate, the following state agencies shall also be notified:

State of Louisiana
Department of Natural Resources
Office of Conservation
Pipeline Safety
P. O. Box 94275
Baton Rouge, LA 70804-9275

State of Texas
Railroad Commission of Texas
Pipeline Safety Section
P. O. Box 12967
Austin, TX 78711-2967

12.0 Documentation and Record Keeping

12.0 Documentation and record keeping shall be done in accordance with *Veriforce* Operator Qualification Personnel Evaluation Policies and Procedures, attached hereto as Exhibit D.

12.1 For each qualification granted through the Veriforce process, the following documents will be on file as supporting documentation:

- Record of Evaluation (ROE);
  - Identifies qualified individual;
  - Identifies the covered task the individual is qualified to perform;
  - Identifies all evaluation criteria;
  - Identifies any required supporting documentation;

    - Identifies Evaluator;
    - Identifies date of qualification; and
    - Identifies method of evaluation.
  - Audit Documentation (as appropriate); and
  - Evaluator Information
    - Original Evaluator application received by Veriforce;
    - Results of Evaluator's reference check;
    - Documentation that the Evaluator has successfully completed the Veriforce Evaluator Training Program (as applicable),; and
    - Documentation of all Evaluator monitoring (as appropriate).

12.2 Reporting of each qualification shall be done on a "real-time" basis through *VeriSource* that details:

- qualified individuals by task;
- qualified individuals by organization;
- qualified individuals by name; and
- other reports to aid the Company in analyzing the qualification status of specific individuals.

12.2.1 *VeriSource* shall also provide the name of the Evaluator associated with each qualification, date of qualification, method of qualification, and date that qualification is set to expire.

12.3 Quality records will be maintained in accordance with the recordkeeping requirements of the OQ rule. The Company shall have access to these records, as required.

12.3.1 Documents related to an individual's qualification(s) shall be maintained for five (5) years after the qualification expires.

12.3.2 Other OQ program documents shall be retained for five (5) years from the date the documents are generated.

13.0 Mergers and Acquisitions

13.1 In the event the Company acquires or merges with all or part of another Operator's facilities, and in the event such an acquisition results in Company being responsible for OQ compliance related to the newly acquired assets, the following process will be followed.

13.1.1 The Company shall conduct or oversee an in-depth review of the OQ program in effect for the newly integrated facilities/organization.

13.1.2 The review will be conducted by the Company and Veriforce, as requested.

13.1.3 The in-depth review will include a comparison of OQ-related processes, covered task list, and underlying evaluation criteria.

13.1.4 A written analysis will be developed that highlights differences that exist between the two programs (gap analysis).

13.1.5 Based on this gap analysis, the Company shall determine the best approach to integrating the two programs and shall construct a written transition plan that describes what actions are to be taken and a proposed schedule for taking those actions.

13.1.5.1. If procedures or other issues warrant such, the Company may determine that the best course of action is to maintain and operate separate OQ programs.

EXHIBIT A

COVERED TASK LIST

AGL Services Company Internal Covered Task List

Last updated 11/8/2012

Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
007OP	Operate Valves	N/A	N/A	Observation & Oral Exam.	Yes	1:3	3
008OP	Measurement of Wall Thickness with Ultrasonic Device	N/A	N/A	Observation & Oral Exam.	Yes	1:3	3
213OP	Joining of Steel Pipe - Threaded and Flanged Connections	192.271 192.273	195.126	Observation & Oral Exam.	Yes	1:3	3
214OP	Joining of Steel Pipe - Threaded Connections	192.271 192.273	N/A	Observation & Oral Exam.	Yes	1:3	3
215OP	Joining of Steel Pipe - Flanged Connections	192.271 192.273	195.126	Observation & Oral Exam.	Yes	1:3	3
217OP	Small Diameter Metal Tubing and Fitting Installation	192.271 192.273	N/A	Observation & Oral Exam.	Yes	1:3	3
401OP	Examination of Buried Pipelines When Exposed	192.459 192.328(a)(1)	195.569	Oral Examination	Yes	1:3	3
402OP	Apply Approved Coatings to Above Ground Piping	192.461(a)	195.581	Observation & Oral Exam.	Yes	1:3	3
403OP	Apply Approved Coatings to Below Ground Piping	192.461(a)	195.557 195.559	Observation & Oral Exam.	Yes	1:3	3
404OP	Protection of Coating When Backfilling and From Below Ground Supports	192.461(d) 192.614(c)(6) 192.461(c)	195.252 195.422	Oral Examination	Yes	1:3	3
405OP	Protection of Coatings From Above Ground Structures	192.461(d)	N/A	Oral Examination	Yes	1:3	3
407OP	Perform Cathodic Protection Survey	192.465(a) 192.465(e) 192.328(e) 192.620(d)(6)	195.573(a)	Observation & Oral Exam.	Yes	1:3	3
408OP	Inspect Cathodic Protection Rectifier	192.465(b)	195.573(c)	Observation & Oral Exam.	Yes	1:3	3
417OP	Atmospheric Corrosion Monitoring	192.481	195.581	Oral Examination	Yes	1:3	3
421OP	Measurement of Depth of Pitting with Pit Gage	192.485	195.569 195.585	Observation & Oral Exam.	Yes	1:1	3
426OP	Inspect Pipe Coating with Holiday Detector	192.455(a) 192.461 192.457(a) 192.479	195.561 195.569	Observation & Oral Exam.	Yes	1:1	3
427OP	Inspection of the Application of Above or Below Ground Coatings	192.461 (a)	195.561 195.569 195.557 195.559	Observation & Oral Exam.	Yes	1:3	3
501OP	Conduct Pressure Test to Substantiate MAOP / MOP	192.505 192.507 192.513 192.328(d)	195.304 195.305 195.306	Observation & Oral Exam.	No	1:0	3
502OP	Conduct Pressure Test on Pipe that is to be Operated at a Pressure <100 psig	192.509 192.511 192.513(b)	N/A	Observation & Oral Exam.	Yes	1:3	3

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AGL Services Company Internal Covered Task List

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
601OP	Start-up/Shut-down of Pipeline to Assure Operation Within MAOP / MOP	192.605(b)(5) 192.751	195.402 195.406	Oral Examination	No	1:0	3
602OP	Monitoring Pipeline Pressure	192.605(b)(5) 192.619	195.402(c)(9) 195.406	Oral Examination	Yes	1:3	3
603OP	Compressor Units/Stations: Start-up, Operation, Shutdown, and Purging Before Returning to Service	192.605(b)(6) 192.605(b)(7) 192.751	195.402(c)(7) 195.402(c)(8)	Observation & Oral Exam.	Yes	1:3	3
605OP	Locate Line/Install Temporary Marking of Buried Pipeline	192.614(c)(5)	195.442(c)(5)	Observation & Oral Exam.	Yes	1:1	3
606OP	Locate and Mark Submerged Pipelines	192.614(c)(5)	N/A	Oral Examination	No	1:0	3
607OP	Damage Prevention: Observation of Excavating and Backfilling	192.614(c)(6) 192.328(a)(1)	195.252 195.442(c)(6)	Oral Examination	Yes	1:3	3
608OP	Damage Prevention for Blasting Near a Pipeline	192.614(c)(6)	195.442(c)(6)	Oral Examination	Yes	1:3	3
611OP	Hot Tap (Steel Pipe)	192.627 192.751	195.422	Observation & Oral Exam.	Yes	1:1	3
613OP	Purge Pipeline Facilities With Gas	192.629(a) 192.751	N/A	Oral Examination	Yes	1:3	3
614OP	Purge Pipeline Facilities With Air or Inert Gas	192.629(b) 192.751	195.402(c)(10)	Oral Examination	Yes	1:3	3
616OP	Atmospheric Monitoring during Hot Work Operations	192.751	195.402(c)(11)	Observation & Oral Exam.	Yes	1:1	3
701OP	Patrolling Pipeline and Leakage Survey without Instrument	192.705 192.613 192.706 192.620(d)(4) 192.721	195.412(a)	Oral Examination	Yes	1:3	3
702OP	Leakage Survey with Leak Detection Device	192.706	N/A	Observation & Oral Exam.	Yes	1:3	3
703OP	Placing/Maintaining Line Markers	192.707	195.410(a) 195.410(c)	Oral Examination	Yes	1:3	3
709OP	Inspection and Testing of Relief Devices (Compressor Stations, Meter Stations, Regulating Stations)	192.731(a) 192.731(b) 192.739 192.743	195.428	Observation & Oral Exam.	Yes	1:3	3
710OP	Inspect/Test Compressor Station Remote Control Shutdown Devices (ESD/EBD)	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:3	3
711OP	Inspect, Test, and Maintain Control Systems	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:3	3
712OP	Programmable Logic Controllers	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:1	3
713OP	Test/Maintain Gas Detection and Alarm Systems	192.736(c)	N/A	Observation & Oral Exam.	Yes	1:3	3
714OP	Inspect and Maintain Pressure Limiting and Regulating Devices	192.739 192.743(a) 192.619(b)	195.428	Observation & Oral Exam.	Yes	1:3	3

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
715OP	Test and Maintain Pressure Switches and Transmitters in Pressure Limiting and Regulating Service	192.739 192.743(a) 192.619(b)	195.428	Observation & Oral Exam.	Yes	1:3	3
716OP	Inspect, Maintain, and Operate Valves	192.745 192.747	195.420(a) 195.420(b)	Observation & Oral Exam.	Yes	1:3	3
725OP	Aerial Leakage Survey: Transmission	192.706	195.412(a)	Observation & Oral Exam.	Yes	1:3	3
AGL-019A-OP	Hazard Control	192.751	N/A	Oral Examination	Yes	1:3	5

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
007	Operate Valves	N/A	N/A	Observation & Oral Exam.	Yes	1:3	3
008	Measurement of Wall Thickness with Ultrasonic Device	N/A	N/A	Observation & Oral Exam.	Yes	1:3	3
103	Nondestructive Testing (Other than testing of welds) -- Mag Particle	N/A	195.452(h)	Observation & Oral Exam.	Yes	1:1	3
201	Abnormal Operating Conditions Related to Welding on Pipelines	192.225 192.227 192.715 192.717 192.751 192.713 192.245 192.328(a)(1)	195.222 195.214 195.230 195.224 195.226	Oral Examination	No	1:0	3
202	Monitoring of Welding Process	192.241(a) 192.241(c) 192.231 192.235 192.245 192.328(a)(1)	195.204 195.224 195.228 195.234	Oral Examination	No	1:0	3
203	Visual Inspection of Welds not Non-Destructively Tested	192.241(b) 192.241(c)	195.204	Oral Examination	No	1:0	3
204	Non-Destructive Testing (Dye Penetrant)	192.243 192.328(b)	195.234	Certificate and Oral Examination	No	1:0	3
205	Non-Destructive Testing (Mag Particle)	192.243 192.328(b)	195.234	Certificate and Oral Examination	No	1:0	3
206	Non-Destructive Testing (Ultrasonic)	192.243 192.328(b)	195.234	Certificate and Oral Examination	No	1:0	3
207	Non-Destructive Testing (X-Ray)	192.243 192.328(b)	195.234	Certificate and Oral Examination	No	1:0	3
208	Plastic Pipe Joining: Butt Fusion	192.281 192.283 192.285 192.287	N/A	Observation & Oral Exam.	No	1:0	1
209	Plastic Pipe Joining: Mechanical Joining	192.281 192.283 192.285 192.287	N/A	Observation & Oral Exam.	No	1:0	1
210	Plastic Pipe Joining: Electrofusion Joining	192.281 192.283 192.285 192.287	N/A	Observation & Oral Exam.	No	1:0	1
211	Perform Plastic Fusion Inspection	192.287	N/A	Oral Examination	No	1:0	3
213	Joining of Steel Pipe - Threaded and Flanged Connections	192.271 192.273	195.126	Observation & Oral Exam.	Yes	1:3	3
214	Joining of Steel Pipe - Threaded Connections	192.271 192.273	N/A	Observation & Oral Exam.	Yes	1:3	3

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
215	Joining of Steel Pipe - Flanged Connections	192.271 192.273	195.126	Observation & Oral Exam.	Yes	1:3	3
216	Joining of Steel Pipe - Compression Couplings	192.271 192.273	N/A	Observation & Oral Exam.	Yes	1:3	3
217	Small Diameter Metal Tubing and Fitting Installation	192.271 192.273	N/A	Observation & Oral Exam.	Yes	1:3	3
401	Examination of Buried Pipelines When Exposed	192.459 192.328(a)(1)	195.569	Oral Examination	Yes	1:3	3
402	Apply Approved Coatings to Above Ground Piping	192.461(a)	195.581	Observation & Oral Exam.	Yes	1:3	3
403	Apply Approved Coatings to Below Ground Piping	192.461(a)	195.557 195.559	Observation & Oral Exam.	Yes	1:3	3
404	Protection of Coating When Backfilling and From Below Ground Supports	192.461(d) 192.614(c)(6) 192.461(c)	195.252 195.422	Oral Examination	Yes	1:3	3
405	Protection of Coatings From Above Ground Structures	192.461(d)	N/A	Oral Examination	Yes	1:3	3
406	Conduct Test to Determine Cathodic Protection Current Requirements	192.465(a) 192.620(d)(6)	195.571	Observation & Oral Exam.	Yes	1:3	3
407	Perform Cathodic Protection Survey	192.465(a) 192.465(e) 192.328(e) 192.620(d)(6)	195.573(a)	Observation & Oral Exam.	Yes	1:3	3
408	Inspect Cathodic Protection Rectifier	192.465(b)	195.573(c)	Observation & Oral Exam.	Yes	1:3	3
409	Inspect Interference Bonds	192.465(c)	195.573(c)	Observation & Oral Exam.	Yes	1:3	3
410	Clear Shorted Casing	192.467(c)	N/A	Oral Examination	Yes	1:3	3
411	Inspect/Test to Assure Electrical Isolation is Adequate	192.467(d) 192.620(d)(6)	195.575	Observation & Oral Exam.	Yes	1:3	3
412	Install CP Leads on Pipeline Using Exothermic Weld	192.471	195.567	Observation & Oral Exam.	Yes	1:3	3
413	Anode Installation on Submerged Pipeline or Facilities	192.471	N/A	Oral Examination	No	1:0	3
414	Inspect for Internal Corrosion Whenever Pipe is Removed	192.475(b)(1) 192.751	195.579(c)	Oral Examination	Yes	1:3	3
415	Monitoring for Internal Corrosion with Probes and Coupons	192.477 192.751 192.620(d)(5)	195.579(b)	Observation & Oral Exam.	Yes	1:1	3
416	Monitoring for Internal Corrosion with Gas Samples	192.477 192.751	N/A	Observation & Oral Exam.	Yes	1:3	3
417	Atmospheric Corrosion Monitoring	192.481	195.581	Oral Examination	Yes	1:3	3
418	General and Localized Corrosion Measurement (Remedial Measures)	192.485(a)(b)	195.585(b) 195.587	Observation & Oral Exam.	Yes	1:1	3
419	Test Point Survey	192.465(a) 192.620(d)(8)	195.573(a)	Observation & Oral Exam.	Yes	1:3	3

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
420	Soil Resistivity	N/A	N/A	Observation & Oral Exam.	Yes	1:3	3
421	Measurement of Depth of Pitting with Pit Gage	192.485	195.569 195.585	Observation & Oral Exam.	Yes	1:1	3
422	Assessment of Pipeline Segments Using Long Range Guided Wave UT			Observation & Oral Exam.	Yes	1:3	3
423	Perform Direct Current Voltage Gradient (DCVG) Survey	192.490 192.620(d)(7)	N/A	Observation & Oral Exam.	Yes	1:3	3
424	Perform AC Current Attenuation (ACCA) Survey	192.490 192.328(e) 192.620(d)(7)	N/A	Observation & Oral Exam.	Yes	1:3	3
425	Perform Alternating Current Voltage Gradient (ACVG) Survey	192.112(h)(3) 192.620(d)(7)	N/A	Observation & Oral Exam.	Yes	1:3	3
426	Inspect Pipe Coating with Holiday Detector	192.455(a) 192.457(a) 192.461 192.479	195.561 195.569	Observation & Oral Exam.	Yes	1:1	3
427	Inspection of the Application of Above or Below Ground Coatings	192.461 (a)	195.557 195.559 195.561 195.569	Observation & Oral Exam.	Yes	1:3	3
428	Pin Brazing to Install CP Leads on Pipeline	192.471	195.244 195.416 (b)	Observation & Oral Exam.	Yes	1:1	3
501	Conduct Pressure Test to Substantiate MAOP / MOP	192.505 192.507 192.513 192.328(d)	195.304 195.305 195.306	Observation & Oral Exam.	No	1:0	3
502	Conduct Pressure Test on Pipe that is to be Operated at a Pressure <100 psig	192.509 192.511 192.513(b)	N/A	Observation & Oral Exam.	Yes	1:3	3
601	Start-up/Shut-down of Pipeline to Assure Operation Within MAOP / MOP	192.605(b)(5) 192.751	195.402 195.406	Oral Examination	No	1:0	3
602	Monitoring Pipeline Pressure	192.605(b)(5) 192.619	195.402(c)(9) 195.406	Oral Examination	Yes	1:3	3
603	Compressor Units/Stations: Start-up, Operation, Shutdown, and Purging Before Returning to Service	192.605(b)(6) 192.605(b)(7) 192.751	195.402(c)(7) 195.402(c)(8)	Observation & Oral Exam.	Yes	1:3	3
604	Locate, Mark, and Remediate Exposed Pipelines in the Gulf of Mexico	192.612(b)	195.413	Observation & Oral Exam.	Yes	1:3	3
605	Locate Line/Install Temporary Marking of Buried Pipeline	192.614(c)(5)	195.442(c)(5)	Observation & Oral Exam.	Yes	1:1	3
606	Locate and Mark Submerged Pipelines	192.614(c)(5)	N/A	Oral Examination	No	1:0	3
607	Damage Prevention: Observation of Excavating and Backfilling	192.614(c)(6) 192.328(a)(1)	195.252 195.442(c)(6)	Oral Examination	Yes	1:3	3
608	Damage Prevention for Blasting Near a Pipeline	192.614(c)(6)	195.442(c)(6)	Oral Examination	Yes	1:3	3

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
609	Inspect and Maintain Odorization Equipment	192.625(e)	N/A	Observation & Oral Exam.	Yes	1:3	3
610	Monitor Odorant Concentration	192.625(f)	N/A	Observation & Oral Exam.	Yes	1:3	3
611	Hot Tap (Steel Pipe)	192.627 192.751	195.422	Observation & Oral Exam.	Yes	1:1	3
612	Hot Tap (Plastic Pipe)	192.627 192.751	N/A	Observation & Oral Exam.	Yes	1:1	3
613	Purge Pipeline Facilities With Gas	192.629(a) 192.751	N/A	Oral Examination	Yes	1:3	3
614	Purge Pipeline Facilities With Air or Inert Gas	192.629(b) 192.751	195.402(c)(10)	Oral Examination	Yes	1:3	3
616	Atmospheric Monitoring during Hot Work Operations	192.751	195.402(c)(11)	Observation & Oral Exam.	Yes	1:1	3
701	Patrolling Pipeline and Leakage Survey without Instrument	192.705 192.613 192.706 192.620(d)(4) 192.721	195.412(a)	Oral Examination	Yes	1:3	3
702	Leakage Survey with Leak Detection Device	192.706	N/A	Observation & Oral Exam.	Yes	1:3	3
703	Placing/Maintaining Line Markers	192.707	195.410(a) 195.410(c)	Oral Examination	Yes	1:3	3
704	Permanent Field Repair by Grinding	192.713	195.226 195.230	Observation & Oral Exam.	Yes	1:1	3
705	Permanent Field Repair Using Composite Materials (Clockspring)	192.713	195.422(a) 195.585(a)(2)	Certificate and Oral Examination	Yes	1:3	1
706	Permanent Field Repair Using Composite Materials (Armor Plate)	192.713	195.422(a) 195.585(a)(2)	Certificate and Oral Examination	No	1:0	3
707	Permanent Field Repair Using Bolt-On Clamp or Sleeve	192.717	195.422(a) 195.585(a)(2)	Observation & Oral Exam.	Yes	1:3	3
708	Permanent Field Repair Using Full Encirclement Weld Sleeve	192.717	195.585(a)(2) 195.422(a)	Observation & Oral Exam.	Yes	1:3	3
709	Inspection and Testing of Relief Devices (Compressor Stations, Meter Stations, Regulating Stations)	192.731(a) 192.731(b) 192.739 192.743	195.428	Observation & Oral Exam.	Yes	1:3	3
710	Inspect/Test Compressor Station Remote Control Shutdown Devices (ESD/EBD)	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:3	3
711	Inspect, Test, and Maintain Control Systems	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:3	3
712	Programmable Logic Controllers	192.731(c)	N/A	Observation & Oral Exam.	Yes	1:1	3
713	Test/Maintain Gas Detection and Alarm Systems	192.736(c)	N/A	Observation & Oral Exam.	Yes	1:3	3

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Task ID	Task Description	49 CFR 192	49 CFR 195	Evaluation Method	Perf by Non Qualified Indiv Allowed?	Span of Control Limit	Requal Interval (Years)
714	Inspect and Maintain Pressure Limiting and Regulating Devices	192.739 192.743(a) 192.619(b)	195.428	Observation & Oral Exam.	Yes	1:3	3
715	Test and Maintain Pressure Switches and Transmitters in Pressure Limiting and Regulating Service	192.739 192.743(a) 192.619(b)	195.428	Observation & Oral Exam.	Yes	1:3	3
716	Inspect, Maintain, and Operate Valves	192.745 192.747	195.420(a) 195.420(b)	Observation & Oral Exam.	Yes	1:3	3
717	Maintaining Vaults With Pressure Regulating and Pressure Limiting Equipment	192.749	N/A	Observation & Oral Exam.	Yes	1:3	3
718	Monitoring for Internal Corrosion with Liquid Samples	192.751 192.477	N/A	Observation & Oral Exam.	Yes	1:3	3
719	Permanent Field Repair Using Composite Materials (Wrapmaster)	192.713	195.422(a) 195.585(a)(2)	Certificate and Oral Examination	Yes	1:3	1
722	Permanent Field Repair Using Composite Materials (Aqua Wrap)	192.713	195.422(a) 195.585(a)(2)	Certificate and Oral Examination	Yes	1:3	3
723	Leakage Survey with Remote Laser Leak Detection Device	192.706	195.412(a)	Observation & Oral Exam.	No	1:1	3
724	Permanent Field Repair Using Composite Materials (Pipe Wrap A+)	192.713	195.422(a) 195.585(a)(2)	Certificate and Oral Examination	Yes	1:3	1
725	Aerial Leakage Survey: Transmission	192.706	195.412(a)	Observation & Oral Exam.	Yes	1:3	3
728	Aerial Leakage Survey: Transmission (UV/IR)	192.706	N/A	Observation & Oral Exam.	Yes	1:3	3
AGL-019A	Hazard Control	192.751	N/A	Oral Examination	Yes	1:3	5

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EXHIBIT B

EVALUATION CRITERIA
(COMPANY PERSONNEL)

Evaluation Criteria

Covered Task 007OP - Operate Valves

49 CFR 192 Reference
N/A

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S Note: An individual qualified on Covered Task 716 will automatically be qualified for this task. Therefore, an individual qualified on Covered Task 716 need not be evaluated on this task.

K 1. Identify the most common types of pipeline valves.
* Ball valve
* Plug valve
* Gate valve

S 2. Demonstrate how to open and close a valve:
a. Identify the proper valve (by tag, sign, or other means)
b. Unlock the valve, if required
c. Determine valve position
d. Operate valve. Include in operation both manual valve and valve with operator.
e. Verify the valve is in the desired position

Abnormal Operating Conditions

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 008OP - Measurement of Wall Thickness with Ultrasonic Device

49 CFR 192 Reference
N/A

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate calibration of Ultrasonic device according to manufacturer's guidelines
- Device must typically be calibrated for the material to be tested (mild steel, stainless steel, etc.)

K 2. Describe the proper surface preparation required for the test area
- Ensure surface is clean

S 3. Demonstrate the proper use of the Ultrasonic device according to manufacturer's guidelines
- Obtain proper wall thickness from a known sample

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 213OP - Joining of Steel Pipe - Threaded and Flanged Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
195.126

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining steel pipe with threaded connection.
* Verify fitting to be installed is the proper size, pressure rating, and material.
* Ensure the fitting is clean and free of obstruction, inspect for nicks or damage in the thread area that could effect sealing properly.
* Apply sealing material to threaded end connections.
* Screw Threaded connections together making a tight leak free joint.
* Check for leaks

S 2. Demonstrate joining of steel pipe by flanged connection
* Verify fitting and gasket to be installed are the proper size, rating and material.
* Ensure flange faces are clean, inspect for nicks or damage on flange faces that may prevent proper sealing.
* Align flanges and insert bolts in bottom portion of flange.
* Insert gasket between flange faces and insert remaining bolts
* Snug bolts around flange.
* Torque flange bolts to specified value using proper sequence of tightening.
* Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Insulator does not work
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 214OP - Joining of Steel Pipe - Threaded Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining steel pipe with threaded connection.
a. Verify fitting to be installed is the proper size, pressure rating, and material.
b. Ensure the fitting is clean and free of obstruction, inspect for nicks or damage in the thread area that could effect sealing properly.
c. Apply sealing material to threaded end connections to the proper depth. Ensure sealing material is compatible with the intended application (i.e. temperature range, pipe materials, contents of carrier pipe).
d. Screw threaded connections together making a tight leak free joint.
e. Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 215OP - Joining of Steel Pipe - Flanged Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
195.126

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining of steel pipe by flanged connection:
a. Verify fitting and gasket to be installed are the proper size, rating and material.
b. Ensure flange faces are clean, inspect for nicks or damage on flange faces that may prevent proper sealing.
c. Align flanges and insert bolts in bottom portion of flange.
d. Insert gasket between flange faces and insert remaining bolts
e. Snug bolts around flange.
f. Torque flange bolts to specified value using proper sequence of tightening, per manufacturer or Operator specifications.
g. Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Insulator does not work
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 217OP - Small Diameter Metal Tubing and Fitting Installation

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe general practices around tube routing design and fabrication.
a. Joints and fittings should be left as accessible as possible,
b. Tubing should be routed around components that require regular maintenance,
c. Consideration should be given to movement of components between connections (whether thru expansion and contraction or vibration); candidate should be able to describe the proper application of a "U" bend to allow for component movement.

K 2. Explain the importance of tubing support systems and when they would be used.
a. When left unsupported, shock and vibration will cause the tubing to shake and fittings to loosen or leak
b. Vibration could cause a leak in tubing where it comes into contact with other hard surfaces
c. A support system should be used anytime there is a chance for movement in a tubing run.

S 3. Demonstrate the proper design and fabrication of a tubing component system with at least one 90 degree bend.
a. Tube routing was designed to account for component movement, accessibility of other components.
b. Tubing was successfully bent utilizing the proper tool without wrinkling or excessive tube flattening.

S 4. Demonstrate the installation of a tube fitting, per manufacturer's instructions.
a. Tubing is inserted to the proper depth inside the fitting and rests on the shoulder of the fitting body,
b. The compression nut is tightened in accordance with tube size and manufacturers specifications.
c. Thread sealant is used on all NPT fittings, per manufactures specifications.
d. Check for leaks.

Abnormal Operating Conditions

Tubing of insufficient wall thickness to install fitting
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 401OP - Examination of Buried Pipelines When Exposed

49 CFR 192 Reference
192.328(a)(1)
192.459

49 CFR 195 Reference
195.569

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe when an inspection of coating on buried pipe must be performed.
* Whenever the pipe is exposed for any reason

K 2. Identify and describe the types of defects that might be discovered during a coating inspection.
* Disbonded coating
* Cracks
* Appearance of moisture under coating
* Lack of coating
* Soil stress

K 3. Identify and describe the types of defects that might be discovered during inspection of the exposed pipe.
* Pitting
* Scale
* Rust
* Discoloration
* Corrosion by-product
* Wrinkle
* Buckle
* Gouge
* Dent
* Damaged coupling
* Defective weld patches
* Groove
* Scratch
* Arc burns

K 4. Describe conditions that may warrant extending the inspection beyond the exposed area.
* Anytime the following conditions extend beyond the wall of the excavation:
* Continuation of an individual pitting area
* Coating failure
* Significant general corrosion
* Any mechanical defect or exposed metal surface

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Covered Task 402OP - Apply Approved Coatings to Above Ground Piping

49 CFR 192 Reference
192.461(a)

49 CFR 195 Reference
195.581

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe which factors must be considered when selecting proper coating.
a. Operator's requirements
b. Temperature range of pipeline
c. Weather conditions, (temperature, relative humidity, etc.)
d. Compatibility with existing coating
e. Surface preparation

K 2. Describe the methods of surface preparation.
a. Solvent cleaning
b. Hand tool cleaning
c. Power tool cleaning
d. Abrasive blasting
e. Water blasting

K 3. Describe what environmental conditions may affect coating application.
a. Dew point reading
b. Moisture on pipe surface
c. Ambient and surface temperature
d. Wind
e. Dust
f. Airborne particles

K 4. Describe the terms typically used in general manufacturer's recommendations pertaining to the application of coatings:
a. Pot life
b. Mixing ratios
c. Curing / drying times
d. Re-coating
e. Shelf life

K 5. Describe the following coating application methods and use of the related equipment.
a. Brush
b. Roller
c. Spray

S 6. Demonstrate proper surface preparation and the application of selected coating system(s).
a. Test temperature of pipe.
b. Obtain atmospheric temperature and humidity.
c. Clean and prepare area to be coated.
d. Apply primer, intermediate coat (if required), and topcoat according to Manufacturer's specifications.
e. Measure coating thickness to confirm proper application thickness using wet film and dry film.

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 403OP - Apply Approved Coatings to Below Ground Piping

49 CFR 192 Reference
192.461(a)

49 CFR 195 Reference
195.557
195.559

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Describe what factors must be considered when selecting proper coating.
a. Operator's requirements
b. Temperature range of pipeline
c. Soil type/conditions
d. Weather conditions, (temperature, relative humidity, etc.)
e. Compatibility with existing coating
f. Surface preparation

K 2. Describe the methods of proper surface preparation.
a. Solvent cleaning
b. Hand tool cleaning
c. Power tool cleaning
d. Abrasive blasting
e. Water blasting

K 3. Describe what environmental conditions may affect coating application.
a. Dew point reading
b. Moisture on surface of pipe
c. Ambient and surface temperature
d. Wind
e. Dust
f. Airborne particles

K 4. Describe the terms typically used in general manufacturer's recommendations pertaining to the application of coatings:
a. Pot life
b. Mixing ratios
c. Curing / drying times
d. Re-coating
e. Shelf life

K 5. Describe the following coating application methods and use of the related equipment.
a. Brush
b. Roller
c. Spray
d. Swab
e. Flock
f. Wrap

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K 6. Identify types of underground coatings:
a. Coal tar
b. Waxes
c. Tapes
d. Fusion Bond Epoxy (FBE)
e. Shrink sleeves
f. Mastics
g. Epoxies
h. Plastic
i. Rubber
j. Enamels

S 7. Demonstrate proper surface preparation and the application of selected coating system(s)
a. Test temperature of pipe.
b. Obtain atmospheric temperature and humidity.
c. Clean and prepare area to be coated.
d. Apply coating according to manufacturer's specifications.
e. Measure coating thickness to confirm proper application thickness with wet film and dry film.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 404OP - Protection of Coating When Backfilling and From Below Ground Supports

49 CFR 192 Reference
192.461(c)
192.461(d)
192.614(c)(6)

49 CFR 195 Reference
195.252
195.422

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe ditch and soil conditions that may adversely affect pipe coating.
a. Rock
b. Moisture
c. Foreign Material

K 2. Describe the most common methods of protecting pipe coating where pipe and supports come into contact.
a. Sandbags
b. Rock shield
c. Felt wrap
d. Concrete coatings
e. Grout or abrasion resistant coatings

K 3. Describe how to prevent damage to coating during backfill operations
a. Use rock shield as needed
b. Ensure pad dirt is free of rocks and other foreign material and compacted as appropriate
c. Ensure suitable pad dirt surrounds pipeline, as per Operator's policies & procedures
d. Ensure backfill material is free of large rocks and other foreign material
e. Do not fill directly on pipeline

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Abnormal loading of a pipeline that has impaired or is likely to impair the serviceability of the pipeline. Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 405OP - Protection of Coatings From Above Ground Structures

49 CFR 192 Reference
192.461(d)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Describe the most common methods of protecting pipe coating where pipe and permanent supports come into contact.
a. Composite materials (e.g.: Micarta)
b. Neoprene
c. PVC
d. Epoxy chocks

K 2. Describe the most common methods of protecting pipe coating where pipe and temporary supports come into contact.
a. Wood
b. Carpet
c. Rubber
d. Rope

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 407OP - Perform Cathodic Protection Survey

49 CFR 192 Reference	49 CFR 195 Reference	Evaluation Method:
192.328(e) 192.465(a) 192.465(e) 192.620(d)(6)	195.573(a)	Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required — **Span of Control**

(If training is required, appropriate training documentation must be submitted with this ROE.) — 1:3

None

K/S

K 1. Identify types of CP Surveys
a. Test point survey
b. Close interval survey
c. AC Potential survey
d. Hot Spot survey

K 2. Identify and describe the test equipment used to complete a cathodic protection survey
a. Digital or analog high impedance voltmeter
b. Reference cell (copper-copper/sulfate, silver-silver/chloride, zinc)
c. Ammeter (direct or indirect)
d. Current interrupter (if required)
e. Datalogger or other data recording device

S 3. Demonstrate the proper calibration, setup, and use of the equipment during an actual or simulated survey.

K 4. Identify and describe measurements that may be required at a given test point:
a. Structure-to-electrolyte potential
* Pipe-to-soil
* Pipe-to-water
* Structure-to-soil
* Casing-to-soil
* Foreign line-to-soil
b. AC potentials
c. Current flow measurements on pipelines
d. Galvanic anode output measurement

K 5. Describe use of interrupters
a. Verify calibration of all test equipment.
b. Locate/isolate the piping to be surveyed.
c. Set up and perform a survey using interrupters on rectifiers so interruptions are synchronous according to operator requirements.
d. If applicable, use appropriate equipment to verify that all current sources are properly interrupted.
e. Verify that the readings are in the desired range.

K 6. Identify common methods of determining IR drop:
a. Measure instant-off potential
b. Measure pipe-to-soil potential at pipe-to-soil interface

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Absence of CP current.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Discovery of unidentified shorted casing.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Stray current on pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 408OP - Inspect Cathodic Protection Rectifier

49 CFR 192 Reference
192.465(b)

49 CFR 195 Reference
195.573(c)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K&S 1. Describe and demonstrate steps for testing/inspecting rectifier for proper operation.

a. Verify the calibration of the meter or data logger
b. Check rectifier cabinet for electrical shorts
c. Verify and interpret output of DC voltage using an appropriate instrument
d. Verify and interpret output of DC current using an appropriate instrument

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 417OP - Atmospheric Corrosion Monitoring

49 CFR 192 Reference
192.481

49 CFR 195 Reference
195.581

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify indications of atmospheric coating damage and/or corrosion damage.
a. Coating Damage
* Coating deterioration
* Flaking
* Cracking
b. Corrosion Damage
* Rust
* Scale
* Pitting
* Thinning.

K 2. Identify steps required to conduct an atmospheric corrosion inspection
a. Clean loose soil or other debris with a non-metallic brush to expose coating.
b. Visually inspect condition of coating
c. Assess extent of coating deterioration or defect(s)

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 421OP - Measurement of Depth of Pitting with Pit Gage

49 CFR 192 Reference
192.485

49 CFR 195 Reference
195.569
195.585

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe the two most common types of pit gages
· Mechanical-type pit gage
· Dial-type pit gage

S 2. Demonstrate how to zero the pit gage.
· Ensure that pit gage is in proper and usable condition (flat base, no damage).
· Ensure gage reads zero when measuring an unblemished flat surface

S 3. Demonstrate how to measure pit depth
· Ensure that all coating and other contaminates have been removed from both the pit and the area surrounding the pit.
· Ensure base of pit gage spans the pitted area and rests upon unblemished pipe.

Abnormal Operating Conditions

1. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

2. Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

3. Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

4. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 426OP - Inspect Pipe Coating with Holiday Detector

49 CFR 192 Reference
192.455(a)
192.457(a)
192.461
192.479

49 CFR 195 Reference
195.561
195.569

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe the use and calibration of equipment required for holiday detection,

K 2. Describe the voltage limitations of the equipment being used.

S 3. Demonstrate the use of a holiday detector as follows:
* Ensured the pipeline is properly grounded.
* Placed the Holiday Detector on the pipeline to be inspected ensuring the detector ground cable is properly connected to the detector and the other end lying on the ground (not hooked to the ground rod).
* Attached HVDC probe positive (+) side to the detector coil and the negative (-) side to the pipeline.
* Set the voltage to the correct setting as per company specification.
* Turned on the Holiday Detector
* Inspected coating,
* Marked holidays for repair.

Abnormal Operating Conditions

1. Improper selection and/or application of coating system
Response: Follow appropriate procedures for notification, documentation, and remedial action.

2. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

3. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

4. Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

5. Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

6. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 427OP - Inspection of the Application of Above or Below Ground Coatings

49 CFR 192 Reference
192.461 (a)

49 CFR 195 Reference
195.557
195.559
195.561
195.569

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate surface preparation.

S 2. Demonstrate the coating application systems used in the area of responsibility.

S 3. Demonstrate the use of a sling psychrometer and the ability to determine relative humidity and dew point.

S 4. Demonstrate the use of wet film thickness gauge and dry film thickness gauge.

S 5. Demonstrate the use of wet film thickness gauge, dry film thickness gauge and sling psychrometer.

K 6. Describe factors that must be considered when selecting coatings.
a.Operators Requirements,
b.Temperature range of the pipeline,
c.Soil type/conditions,
d.Weather conditions (temperature, humidity),
e.Compatibility with existing coatings,
f.Surface preparation.

K 7. Describe the process for determining proper surface temperature prior to applying the coating.
a.Measure substrate that will be painted surface temperatures on all sides
b.Use all temperatures to determine worst case surface temperatures measured before blasting or painting.
c.Surface preparation or the application of a coating shall not be allowed when there is 5 degrees or less between the surface temperature and the dew point.

K 8. Describe the terms used in paint manufacturer's product data sheets.
a.Finish - description of coating appearance when cured. (example - Gloss, Semi-Gloss, Flat etc.)
b.Solids Content - Volume of solids typically reported as a percent of a packaged coating. Coating contents minus VOC's.
c.VOC - Volatile Organic Compounds - liquids that have high enough vapor pressure under normal conditions to significantly vaporize and enter the atmosphere.
d.Flash Point - The flash point of a flammable liquid is the lowest temperature at which it can form an ignitable mixture in air.
e.Surface Preparation - the removal of foreign matter from a metal by many of several means. The condition of the substrate surface can be described measured in mils.
f.Substrate - Surfaces to be painted

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K 9. Describe the use and calibration of equipment required for holiday detection.
a.Thin Film Wet Sponge Detector - A low voltage (67.5 volts) jeep or holiday detector used to find pinholes or thin coating in coatings up to 20 mils thick.
b.Thick film High Voltage Holiday Detection. Gradually move over cured coating. An audible signal will sound on the detector where a holiday exist. The inspector shall mark all holidays detected.
c.Test Voltage for holiday detectors - voltage for a specific coating shall be set to the voltage specified in the coating data sheet. All voltages are DC.
d.Calibrate by testing instrument on a coated surface with known holidays and by testing battery voltage.

K 10. Describe the use and calibration of equipment required for paint inspection.
a.Surface temperature thermometers - Two or more thermometers may be needed for full sun/shaded surfaces.
b.Sling psychrometers - Determine relative humidity and dew point from wet and dry bulb readings. Calibrate using an unused thermometer comparing temperatures before wetting sock on wet bulb.
c.Wet film thickness gauge - To use press gage against wet coating and remove. Read gage by identifying last (greatest) calibrated tab that has wet coating. Clean gage before storage and reuse. Calibrate against new equipment that has not been used.
d.Dry film thickness gauge - Type 1 magnetic pull-off gauges should be calibrated with card mounted standard metal plates. If a Positector 2000 gauge is used, then plastic shims should be used for its calibration.
e.Testex tape - use either coarse for 0.8-2.0 mils or x-coarse for 1.5-4.5 mils. Peel protective cover off of tape, apply tape to substrate, rub center circular piece in a circular motion with a clean smooth round object. Remove the tape and measure the rubbed surface
f.Spring micrometer - Place testex tape between measuring jaws of meter and release spring. Read placement of needle on calibrated face of micrometer.
g.Blast nozzle orifice gauge - Apply a grease pen marking on the gauge calibrated table. Insert orifice gage into threaded end of blast nozzle until nozzle bottoms out. Twist gage and remove from nozzle. Grease markings will be removed at point of contact. Read calibration at point of contact for nozzle size. No calibration. If wear is observed, discard and replace with new gage or compare to an un-used gage.

Abnormal Operating Conditions

1. Improper selection and/or application of coating system
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 501OP - Conduct Pressure Test to Substantiate MAOP / MOP

49 CFR 192 Reference
192.328(d)
192.505
192.507
192.513

49 CFR 195 Reference
195.304
195.305
195.306

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify common test mediums.
a. Water
b. Air or Inert gas
c. Natural Gas

K 2. Describe considerations when water is used as a test medium
a. Pre- or post-test sampling
b. Filtering
c. Prevention of Freezing

K&S 3. Describe and simulate required preparation for conducting a pressure test:
a. Obtain plan which will provide details of pressure test parameters, target test pressures, pressure ranges +/-, location of manifolds, test medium, duration, holds if any, MAOP / MOP of facilities and confirmation of material design specifications
b. Confirm all required calibration reports for test equipment is available and current.
c. Verify test equipment certification is current and re-certify if required.
d. Confirm that strength of existing and temporary piping and components will withstand test pressure specified in testing plan.
e. Confirm all valves are in manufacturer's recommended position or per Operator's specifications and have been blown down or drained as required
f. Confirm that all fittings, flanges, unions and threaded joints have been checked to insure they are tight and properly sealed.
g. Place all testing equipment as far as practical from facility to be tested, locate opposite side of any seams, keep in mind elevation constraints
h. Setup and check all equipment for proper operation, confirm understanding of proper operation of all appropriate equipment including, Deadweights, electronic pressure monitor/recorders, mechanical pressure, temperature recorders, hoses, fittings, high and low-pressure pumps, stroke counters, etc.
i. Ensure the recording gauge is level and plumb.
j. If a recording pressure gauge is not available, an adequate spring gauge or deadweight gauge may be used with pressure readings taken at operator prescribed intervals throughout the duration of the test and properly documented the pressures in the appropriate format. . The test pressure gauge shall be verified at the test pressure with a deadweight check before and after the test.
k. Obtain and record the ambient temperature.
l. Confirm appropriate surveillance activities are conducted in order to minimize number of persons near the tests
m. Fill test segment with test medium

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K&S 4. Describe and simulate activities required to conduct test:
a. If recording chart is used, place the static pressure recording chart and pen at the correct time when the test officially begins.
b. After pressure stabilizes, begin test and ensure pressures remain within desired range for prescribed duration of test.
c. Monitor potential effects of sun and temperature on pressures.
d. Adjust test pressures to account for elevation at the gauge site in the test segment.
e. Monitor pressure variations and document causes and mitigation.
f. Record required pressure, temperature and pump stroke readings at intervals specified in the test plan.

K&S 5. Describe and simulate steps involved in depressurizing:
a. Confirm acceptance of test by authorized Operator's representative
b. Relieve pressure according to Operator specifications.
c. Remove test medium in accordance with Operator approved method to ensure minimal impact to the environment and according to any required permits.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 502OP - Conduct Pressure Test on Pipe that is to be Operated at a Pressure <100 psig

49 CFR 192 Reference
192.509
192.511
192.513(b)

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and simulate the steps necessary to conduct a leak test where pressure is less than 100 p.s.i.:
a. Isolate the segment to be tested in accordance with Operator requirements.
b. Install/maintain calibrated test instruments/components in order to collect required test data
c. Setup appropriate equipment to introduce pressure and test medium into the segment to be tested.
d. Introduce test medium
e. Perform leak test in accordance with Operator procedures:
f. Ensure no leakage discovered
g. Remove isolation

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 601OP - Start-up/Shut-down of Pipeline to Assure Operation Within MAOP / MOP

49 CFR 192 Reference
192.605(b)(5)
192.751

49 CFR 195 Reference
195.402
195.406

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify the key components of a pipeline shutdown and startup procedure.
a. Identification of pipeline segment to be shutdown
b. Lockout/tagout procedure
c. Notification requirements such as Pipeline control center or outside agencies
d. Line cleaning
e. Leakage survey, as applicable
f. Valve maintenance
g. Isolation
h. Pulldown/blowdown
i. MAOP/MOP limitations of the pipeline segment(s)
j. Purging
k. Packing
l. Return to service

K 2. Describe the steps required for isolation of segment:
a. Operate valves in proper sequence including all receipt and delivery points.
b. Lockout/tagout of valves
c. Monitor pressures in adjacent sections to ensure MAOP / MOP is not exceeded, as applicable

K 3. Identify the steps required for pulldown/blowdown of isolated section:
a. Perform pulldown, if applicable, to reduce pressure and minimize gas loss.
b. Identify and remove potential ignition sources.
c. Perform blowdown according to procedure.
d. Check for downdraft at blow-off valve at completion of the blow-down to keep air out of depressurized section.

K 4. Identify the steps required for purging with air or inert gas:
a. Review purge procedure
b. Ensure adequate supply of air or inert gas.
c. Perform purge according to procedure

K 5. Identify the steps required for purging with gas
a. Review purge procedure
b. Ensure adequate supply of gas
c. Notify pipeline control center and/or other appropriate personnel
d. Perform purge according to procedure.

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K 6. Identify the steps required for re-pressurizing pipeline:
a. Notify Pipeline control center
b. Control flow rates during pressurization
c. Ensure pressure does not exceed MAOP / MOP
d. When pressure is equalized assure all valves are returned to designated operating position
e. Notify Pipeline control center

K 7. Using facility drawings as necessary, identify the steps required for pipeline startup:
a. Startup procedure must be verified with designated Operator's representative prior to beginning startup
b. Identify section to startup
c. Identify valves to be operated (opened or closed) and the correct position of all valves
d. Open valves and pack pipeline at prescribed rate
e. Monitor pressures in section to be startup and adjacent sections to ensure MAOP / MOP is not exceeded
f. Review the receipt/delivery points into the pipeline and verify with Pipeline control center

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 602OP - Monitoring Pipeline Pressure

49 CFR 192 Reference
192.605(b)(5)
192.619

49 CFR 195 Reference
195.402(c)(9)
195.406

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify common methods of monitoring pipeline pressure:
a. Network/location monitors
b. Deadweight reading
c. Pressure gauge

K 2. Explain steps to take if you suspect a false reading
a. Verify using another method(s)

K 3. Identify potential causes of unintended pipeline pressure increase, decrease, or differential.
a. Incorrect valve operation
b. Valve leakage
c. Line obstruction
d. Change in throughput
e. Rupture
f. Leak

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Loss of communication.
Response: Find alternate means of communication, if not possible, suspend activities and follow appropriate procedures for notification, documentation, and remedial action.

Unexplained high pressure deviation exceeding design limits.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 603OP - Compressor Units/Stations: Start-up, Operation, Shutdown, and Purging Before Returning to Service

49 CFR 192 Reference
192.605(b)(6)
192.605(b)(7)
192.751

49 CFR 195 Reference
195.402(c)(7)
195.402(c)(8)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps associated with pre-startup:
a. Notify local station personnel prior to start attempt (if applicable).
b. Review the posted startup procedure for the unit
c. Review and verify knowledge of starting unit
* Ensure unit and station valves are properly positioned for the selected mode of operation.
* Verify all critical operating variables are within the safe limits of the unit.
* Confirm the unit is safe and ready to run (all safety alarms and shutdown devices are properly set and functional)

S 2. Simulate the proper procedures for start-up of a unit at your location.
a. Start the unit in accordance with posted procedure.
b. Follow manufacturer's instructions for operating the equipment after it has been started
c. Verify unit successfully starts and runs unloaded for the specific warm-up period described in the unit starting procedure.
d. Monitor all alarm conditions during warm-up.
E. Verify station suction and discharge pressures and calculate unit load

K 3. Describe the operating parameters and monitoring requirements for a specific unit(s):
a. Unit loads
b. Unit operating temperatures, pressures, and speeds
c. Monitor for unusual noises, vibrations, leaks
d. Surge margin, fuel ratio, and fluid levels
e. Monitor to ensure that MAOP(s) is not exceeded

S 4. Simulate the proper procedures for shutting down a unit at your location:
a. Slow the unit down to minimum speed
b. Unload the unit, open bypass valve
c. Let unit cool down
d. Shut off the fuel supply or initiate the stop
e. Close suction and discharge valves
f. Leave unit pressurized if the unit may be returned to service within a reasonable period of time

K 5. Identify the steps required in isolating/purging a compressor unit or a section of station piping.
a. Develop a shutdown and purge procedure utilizing the station drawings for proper isolation and get the procedure approved.
b. Receive approval from Pipeline control center to begin required work.
c. Operate valves in accordance with the shutdown or purge procedures.

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Excessive vibration on unit or associated piping that has impaired or is likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Loss of communication.
Response: Find alternate means of communication, if not possible, suspend activities and follow appropriate procedures for notification, documentation, and remedial action.

Unexplained high flow rate and low pressure deviation.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unexplained high pressure deviation exceeding design limits.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 605OP - Locate Line/Install Temporary Marking of Buried Pipeline

49 CFR 192 Reference
192.614(c)(5)

49 CFR 195 Reference
195.442(c)(5)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe what details should be considered in selecting the proper line-locating device.
a.Electrical interference
b.Depth of pipe
c.Access to pipe
d.Line size
e.Line material
f.Presence of other facilities

K 2. Explain the different types of ways to use a locating device to place a signal or locate a signal on a target line and explain the advantage of each type
a.Conductive - direct connect method - metal to metal contact from transmitter to target should provide the best signal to detect
b.Inductive - induced signal on the target, set transmitter in line with the target pipeline and generates an electromagnetic field best method to use when a direct connection is not available
c.Passive - locate signals from foreign metallic conductors

K 3. Identify common problems with locate signals
a.Air coupling - Transmitter and receiver are too close; picking up the induced signal from the transmitter not the target pipeline.
b.Electromagnetic field from transmitter is distorted due to attracted/repelled signal from other buried facilities
c.Electrical interference from overhead or buried power lines
d.Inadequate connection or grounding when utilizing the conductive method.

K 4. Identify methods used to perform a inductive sweep search
a.In accordance with Operator procedures and/or manufacturer's instructions such as:
i.Circle sweep - hold the transmitter in the center point of the excavation area while the receiver is moved around the point at a distance not affected by air coupling, keep transmitter and receiver facing each other.
ii.Perimeter sweep - at a set distance apart the transmitter and receiver are walked parallel to the excavation on both sides of the located line and across the line at the ends of the excavation area.
iii.Spoke sweep - Transmitter and receiver transverse the excavation area at 90 Degrees, 45 Degrees, to create a wagon wheel spoke pattern for the search.

K 5. Explain how to determine the temporary marking requirements for the area to be located/marked.
a.Operator procedures
b.State or local marking requirements (i.e.; state internet home page)
c.Environmental conditions (weather, soil condition, etc.)
d.Terrain type (urban, rural, road, etc)

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K 6. Describe the national color code requirements for marking (APWA Uniform Color Code).
a.White - proposed
b.Pink - temporary survey markings
c.Red - electric power lines, cables, conduit and lighting cables
d.Yellow - gas, oil, petroleum or gaseous materials
e.Orange - communication, alarm or signal lines
f.Blue - potable water
g.Purple - reclaimed water, irrigation and slurry lines
h.Green - sewer and drain lines

K 7. Identify acceptable types of temporary markings:
a.Stakes
b.Flags
c.Paint
d.Chalk
e.Whiskers

K 8. Describe methods of documenting and communicating locate per:
a.Operator procedures
b.State or one call requirements

S 9. Demonstrate how to use maps, as-built survey information, and/or drawings to identify the general location of the pipeline and possible conditions that may affect the ability to locate the pipeline accurately.
a.Recognize crossovers
b.Multiple lines in ROW
c.Identified Foreign Facilities
d.Pipeline size and depth

S 10. Demonstrate the ability to operate the device and perform initial start up operation and verification activity as indicated in manufacturer's user information
a.Turn on the device
b.Check battery level
c.Verify device is operating within design parameters
i.Check locate at a predetermined location with a known posted depth

S 11. Demonstrate use of the line locator
a.Locate a pipeline in a ROW containing a single line, identify known foreign facilities
i.Demonstrate direct connection mode and inductive mode to locate facility
b.Locate a pipeline in a ROW or facility, containing a more complex pipeline configuration. (i.e.; multiple lines, a crossover, diverging pipe segments)
c.Demonstrate verification methods to ensure the locate signal is not distorted
i.Locate signal matches in peak and null modes
ii.Depth check method - locate peak signal take depth at ground level, raise receiver 1 foot retake depth- depth reading should concur with initial depth plus raise.
d.Perform a passive sweep to identify any unmarked facilities in the area of excavation
i.Identify the frequencies used to conduct the passive sweep and explain the specific characteristics of each
1.CPS - indicates the presence of Cathodic Protection
2.Power - indicates induces AC electrical frequencies from power lines, etc.
3.Radio - indicates other frequencies being carried that are transmitted from various sources.

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S 12. Demonstrate how to determine the vertical depth of the pipeline
a.Utilize appropriate methods (i.e.; T-bar, locator, etc)
b.Review precautions as to using these methods and potential accuracy concerns for establishing actual depth

S 13. Demonstrate how to properly place appropriate temporary line markings
a.Appropriate method(s) (stakes, flags, paint, etc)
b.Required information included on markings
c.Appropriate location(s) and/or distance

Abnormal Operating Conditions

1. Unreported encroachment activities that have impaired or are likely to impair the serviceability of the pipeline.
Reaction:
*Stop the activity immediately.
*Describe in detail the appropriate procedures for notification, documentation, and actions to protect the public, property, and the environment.

2. Improperly marked and/or unmarked pipeline.
Reaction:
*Remark as appropriate, if qualified to do so

3. Locator equipment not operating properly.
Reaction:
*Troubleshoot in accordance with the manufacturer's literature.
*Verify the operation of the locator by locating a known source.

4. Incorrect drawings or schematics.
Reaction:
*Verify the accuracy of drawings or schematics.
*If the drawings or schematics are incorrect, make notification.

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Evaluation Criteria

Covered Task 606OP - Locate and Mark Submerged Pipelines

49 CFR 192 Reference
192.614(c)(5)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:0

K/S

K 1. Describe how to use maps, as-built survey information, GPS, and/or drawings to identify the location of the pipeline.

K 2. Describe what things should be considered in selecting the proper line-locating device.
a. Depth of water
b. Depth of pipe
c. Access to pipe
d. Line size
e. Line/coating material

K 3. Describe common methods of locating underwater pipeline:
a. Bottom sweeps
b. Probe
c. Water probing
d. Jetting
e. Scanning sonar

K 4. Describe common methods of installing temporary markers for submerged pipelines:
a. Cane poles
b. Buoys
c. Sonar reflector
d. Sonar pinger

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Unreported activities that have impaired or are likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 607OP - Damage Prevention: Observation of Excavating and Backfilling

49 CFR 192 Reference
192.328(a)(1)
192.614(c)(6)

49 CFR 195 Reference
195.252
195.442(c)(6)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe steps that must take place prior to excavation (including trenchless activities such as boring and directional drilling) activities:
a. Verification of One-Call
b. Provide excavator with guidelines for construction near pipelines
c. Identification of pipeline markers
d. Identification of foreign structures and utilities
e. Verify location and elevation of affected structures
f. Pot hole when appropriate to ensure adequate clearance
g. Provide for standby personnel as needed

K 2. Identify considerations during excavation of pipelines:
a. Ensure bucket teeth are barred and side cutters removed as applicable
b. Maintain clearance between bucket and pipeline according to operator guidelines
c. Hand excavate as required
d. Anticipate encountering unidentified foreign structures and pipeline appurtenances (i.e.., taps, valves, etc.)

K 3. Describe how to prevent damage during backfill operations:
a. Use rock shield as needed
b. Ensure pad dirt is free of rocks and other foreign material and compacted as appropriate
c. Ensure suitable pad dirt surrounds pipeline, as per Operator's policies & procedures
d. Ensure backfill material is free of large rocks and other foreign material
e. Do not fill directly on pipeline

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 608OP - Damage Prevention for Blasting Near a Pipeline

49 CFR 192 Reference
192.614(c)(6)

49 CFR 195 Reference
195.442(c)(6)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the steps necessary to prevent pipeline damage caused by nearby blasting activities:
a. Obtain the blasting plan
b. Ensure that all information is included in the blasting plan and that it has been properly reviewed by Operator representatives
c. Monitor blasting operations to ensure that the blasting plan is followed
d. Monitor pipeline pressure and perform a leakage survey, as appropriate.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 611OP - Hot Tap (Steel Pipe)

49 CFR 192 Reference
192.627
192.751

49 CFR 195 Reference
195.422

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe the information which must be known prior to beginning a hot tapping operation:
a. Diameter and wall thickness of pipe
b. Pressure
c. Size of tap
d. Size and type of fitting

S 2. Simulate performance of a hot tap:
a. Set tapping machine up, verifying proper cutter and adapter.
b. Attach machine to valve
c. Run cutter in by hand until pilot bit touches pipe, and verify prior measurements.
d. Retract cutter to verify the tap valve will close.
e. Calculate boring distances and mark travel to bore on appropriate equipment.
f. Start the bore with bleed valve open.
g. Bore until bleed through occurs.
h. Shut in bleed valve. Let pressure equalize, and check all equipment for leaks.
i. Stop bore until any leaks are eliminated.
j. Bore to pre-marked depth, stop machine, and verify that entire cut has been made.
k. Slowly back out the cutter/perforator
l. Shut tap valve and bleed pressure off machine.
m. Remove machine
n. Examine cutter to verify presence of coupon, if shell cutter used.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unable to remove cutter and/or coupon
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 613OP - Purge Pipeline Facilities With Gas

49 CFR 192 Reference
192.629(a)
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps required to prepare for purging with gas
a. Review Operator-approved purge procedure
b. Ensure adequate supply of gas
c. Obtain authorization from pipeline control center and/or other appropriate personnel.

K 2. Identify and describe the steps necessary to complete a purge of air or inert gas with gas:
a. Electrically bond the segment to be purged.
b. Remove or take precautions for handling liquid in the line.
c. Ensure that the blow-off valve at the downstream end of the section to be purged was opened and secured.
d. Install calibrated pressure gauge immediately downstream of the purge pressure control valve
e. Open the control point valve to the position where the gas purging pressure reached the pre-determined value in the purge plan and maintain pressure at all points required by the plan
f. Monitor weather conditions to ensure safe working environment during the purge.
g. Upon completion of purge, close the downstream blowoff.
h. Record purge times and pressures.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 614OP - Purge Pipeline Facilities With Air or Inert Gas

49 CFR 192 Reference
192.629(b)
192.751

49 CFR 195 Reference
195.402(c)(10)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps required to prepare for purging with air or inert gas.
a. Review Operator-approved purge procedure
b. Ensure adequate supply of air or inert gas
c. Obtain authorization from pipeline control center and/or other appropriate personnel

K 2. Identify and describe the steps necessary to complete a purge of gas with an air mover:
a. Ensure an adequate supply of air is available for the air mover.
b. Establish the direction of the purge and mount air movers on the appropriate blowoff.
c. Ensure that air mover is grounded in accordance with Company procedures.
d. Remove or take precautions for handling liquid in the line, if necessary
e. Monitor weather conditions to ensure a safe working environment during the purge
f. Open air inlet.
g. Turn on the required supply to the air mover.
h. Sample the atmosphere in the pipeline at work location to verify a safe atmosphere.
i. Maintain the flow of air away from the workspace.

K 3. Identify and describe the steps necessary to complete a purge with pig or slug:
a. Ensure an adequate supply of air or inert gas is available for the purge.
b. Remove or take precautions for handling liquid in the line, if necessary.
c. Disconnect and physically isolate the pipeline sections to be purged.
d. Install calibrated pressure gauge immediately downstream of the purge pressure control valve
e. Open outlet.
f. Purge by injecting slug or running a pig through the section using air or inert gas.
g. Sample at outlet for presence of air or inert gas.
h. After pig has been received or slug has been detected, continue purge as specified in the plan.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 616OP - Atmospheric Monitoring during Hot Work Operations

49 CFR 192 Reference
192.751

49 CFR 195 Reference
195.402(c)(11)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe when atmospheric monitoring for combustible gas is required and the appropriate equipment to use:
a. Prior to and during welding or cutting operations on any pipe or components that previously contained flammable material,
b. Anytime hot work is done in areas were there is a potential for gas to be present,
c. Combustible gas indicators (CGIs) not flame ionization detectors (FIDs).

K 2. Describe the general steps during hot work operations:
a. If required, obtain 'hot work permit' from appropriate operations and/or construction personnel each day hot work will be performed or per applicable company procedure,
b. Remove all flammable products from the work area,
c. Establish combustible gas monitoring points, in accordance with site specific procedures (as required),
d. Ensure some method of communicating between gas monitoring points and employees performing hot work,
e. Ensure continuous monitoring at specified locations, per applicable company procedures.
f. Devise means to ensure air movers (if installed) are working properly at all times (flagging, alarms),
g. Cover equipment, grating, etc. as needed to protect inaccessible areas from sparking/ignition sources,
h. Ensure appropriate fire suppressant materials (fire extinguisher(s), blankets, etc.) and fire monitoring personnel (fire watch) are present and in good working condition, as required

S 3. Demonstrate the use of a CGI according to manufacturer's guidelines.
a. State the type of equipment that will be used,
b. Demonstrate calibration and start up of CGI, according to manufacturer guidelines.
c. Demonstrate operation of a CGI.

Abnormal Operating Conditions

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 701OP - Patrolling Pipeline and Leakage Survey without Instrument

49 CFR 192 Reference
192.613
192.620(d)(4)
192.705
192.706
192.721

49 CFR 195 Reference
195.412(a)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify methods of pipeline patrol:
a. Aerial
b. Vehicular
c. Walking rights of way

K 2. Identify the items that may be observed while patrolling:
a. General condition of rights of way
b. Encroachments
c. Signs of gas leakage
* Dead or discolored vegetation
* Smell
* Ice accumulation
* Dust cloud
* Bubbles in water
d. Soil slips, subsidence, washouts, and erosion over pipeline
e. Condition of pipeline markers and information contained thereon to ensure markers comply with Operator requirements and DOT requirements.
f. Exposed pipe
g. Construction within an area that may impact class location (building, parks, recreational areas, etc. within 660 feet of pipeline)

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 702OP - Leakage Survey with Leak Detection Device

49 CFR 192 Reference
192.706

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Describe means of identifying leaks:
a. Leak detection device
b. Smell
c. Dead vegetation
d. Ice accumulation
e. Dust cloud
f. Bubbles in water

S 2. Demonstrate use of the leak detection device according to manufacturer's guidelines.
a. State the type of equipment that will be used.
b. Demonstrate calibration and start up of leak detection device, according to manufacturer guidelines.
c. Demonstrate operation of leak detection device.

K 3. Describe how to test casing vents with gas detector.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 703OP - Placing/Maintaining Line Markers

49 CFR 192 Reference
192.707

49 CFR 195 Reference
195.410(a)
195.410(c)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Identify appropriate locations for line markers:
a. Stream crossings
b. Public road crossings
c. Railroad crossings
d. Above ground pipelines accessible to the public
e. Compressor and meter stations
f. Other locations designated by the operator (e.g.., fence lines)

K 2. Describe steps required to safely install a line marker:
a. Verify location of pipeline
b. Verify depth of pipeline
c. Install marker in order to maintain a safe distance from the pipeline.

K 3. Identify the information that must be correct and legible on the markers:
a. Emergency 24-hour Phone Number
b. Operator Identification
c. 'Warning' or 'Danger'
d. Name of gas transported

K 4. Describe what to look for when inspecting pipeline markers:
a. Verify proper location of pipeline marker
b. Verify accuracy of information on pipeline marker
c. Verify that pipeline marker is visible
d. Verify that pipeline marker is legible

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unreported activities that have impaired or are likely to impair the serviceability of the pipeline.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 709OP - Inspection and Testing of Relief Devices (Compressor Stations, Meter Stations, Regulating Stations)

49 CFR 192 Reference
192.731(a)
192.731(b)
192.739
192.743

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify the following types of relief devices and describe how they work:
* Spring loaded
* Pilot operated

K 2. Identify steps required to inspect/test a relief device:
a. Notify appropriate personnel (i.e.: customers, pipeline control center).
b. Record setpoint “as found”.
c. Assure that pipeline operations will not be jeopardized during testing/inspection of relief device and remove from service.
d. Monitor system pressure while relief device is isolated from the system.
e. Visually inspect valve for correct operation and signs of leakage, corrosion, damage, deterioration, and to ensure the outlet is clear of obstructions and in a safe location.
f. Verify setpoint pressures by observing a calibrated pressure indicating device while applying pressure greater than the set point to the device.
g. Verify capacity requirement of the relief device has not changed.
h. In the event that capacity of the relief device is insufficient, replace device or install additional device to provide for additional capacity requirement.
i. Return to service after completion of successful test and, if applicable, lock the isolation valve in the open position.
j. Record setpoint 'as left'.

S 3. Demonstrate how to test/inspect a relief device.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unexplained high pressure deviation exceeding design limits.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 710OP - Inspect/Test Compressor Station Remote Control Shutdown Devices (ESD/EBD)

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and simulate the steps to be followed for inspecting/testing compressor station remote control shutdown device.
a. Review and follow site-specific test plans
b. Block gas flow into and out of compressor station.
c. Activate a remote or manual ESD shutdown trigger.
d. Confirm that valves cycled in proper sequence and time
e. Confirm all compressor units within the tested system shutdown and AC power, and DC power as applicable, are shut down.
f. Ensure that each ESD trigger is inspected and tested for proper actuation
g. Return system to normal operation

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Unexplained high pressure deviation exceeding design limits.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 711OP - Inspect, Test, and Maintain Control Systems

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate how to calibrate each of the following:
a. Pressure transmitter
b. I/P transducer

S 2. Demonstrate how to maintain/inspect recorders.

K 3. Describe the importance of 4-20 shielding, grounding, and load balancing as it pertains to analog loops.

K 4. Explain the operating principle of a pressure switch, including dead band.

K 5. Explain what is meant by the phrase 'closes on rising pressure'.

K 6. Explain how class B shutdowns are bypassed during startup.

S 7. Use ladder drawings to identify shutdown limits.

K 8. Explain PLC hardware, software, and structure.

K 9. Draw and explain starting/shutdown string using 2-NO and 3-NC shutdown contacts (end-devices) and preset a latching shutdown coil with timer to set and panel reset, if applicable.

K 10. Draw and explain how to energize and latch a starter coil with a momentary push button, 2-NO and 3-NC permissive contacts, with engagement starter timer and shutdown to unlatch, if applicable.

K 11. Define and provide examples of Class A, Class B, and Class C shutdowns per the Instrument Society of America (ISA) standard.

K 12. Explain six alarms/shutdowns, including end device type, setpoint, purpose or safeguard, and action resulting from the alarm/shutdown.

K 13. Explain an alarm or shutdown from end device to SCADA display, including identification of end device, associated wiring, PLC input, local annunciation, HMI annunciation, and SCADA annunciation.

K 14. Explain voted shutdowns and give examples.

K 15. Explain redundancy and give examples.

K 16. Explain Company operating procedures regarding training, testing, and record keeping as it applies to shutdown systems.

K 17. Identify types of end-devices and the purpose of each.

K 18. Define which systems are fail-safe and non fail-safe.

K 19. Define the types of alarm indicators, i.e., audible lights, etc.

K 20. Explain the advantages and disadvantages of each alarm indicator.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 712OP - Programmable Logic Controllers

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Identify and describe the function of programmable logic controllers.

K 2. Describe possible concerns when installing a new PLC.

K 3. Explain maintenance of a Programmable Logic Controller.

K 4. Explain the Programmable Logic Controller's hardware, including:
a. Field terminations
b. I/O modules
c. Interface modules
d. Processors/co-processors
e. Modems
f. Communications hubs
g. Power supply
h. Power distribution, and
i. Grounding system

K 5. Describe the Programmable Logic Controller's software.

S 6. Demonstrate the following tasks, if applicable, using your PLC:
a. Utilize diagnostics to check PLC status
b. Download and upload PLC program
c. Display PLC logic and tasks (explain the operation), and
d. Stop and start PLC program execution

S 7. Demonstrate your ability to modify a PLC program, including:
a. Main line sequence control
b. Flow simulation
c. Remote operations
d. Tank level control
e. Remote alarming
f. Meter accumulation
g. Control loop

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 713OP - Test/Maintain Gas Detection and Alarm Systems

49 CFR 192 Reference
192.736(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and demonstrate how to test/maintain gas detection and alarm systems:
a. Visually inspect system in accordance with the company approved procedures. Inspect for signs of dirt, paint, wasp nests, or contamination. Clean system in accordance with manufacturer's specifications.
b. Isolate the gas detection system from the station shutdown, ESD/EBD system.
c. Connect gas detection system test equipment
d. Calibrate all sensors per manufacturer's instructions and check 'percent of LEL' levels in accordance with Operator requirements.
e. Verify that alarms and shutdown circuits activate at appropriate “percent of LEL”, as required by operator
f. Clear alarms and shutdowns and return system to service.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 714OP - Inspect and Maintain Pressure Limiting and Regulating Devices

49 CFR 192 Reference
192.619(b)
192.739
192.743(a)

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe how the following types of pressure regulating devices work:
* Spring loaded
* Pilot operated

K 2. Identify the steps in inspecting/maintaining a pressure limiting/regulating device:
a. Verify required setpoint pressures
b. Record setpoint “as found”.
c. Determine the test media to be applied
d. Isolate from system and bypass, if necessary.
E. Monitor pressure if bypass is non-regulated.
F. Inspect for good mechanical condition, proper installation and protection from dirt, liquids or other conditions that might prevent proper operation.
g. Clean, repair or replace the device as necessary following the manufacturer's guidelines.
h. Inspect for any leakage
i. Test the device to insure proper operation over its intended operating range and is set to function at the correct pressure.
j. Verify the proper operation and set pressure prior to returning to service.
k. Place the device back in service and return the station to normal operating conditions.
l. Record setpoint “as left”.

S 3. Demonstrate how to determine current setpoint.

S 4. Demonstrate how to test and inspect a spring-loaded pressure regulating device.

S 5. Demonstrate how to test and inspect a pilot-operated pressure regulating device.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 715OP - Test and Maintain Pressure Switches and Transmitters in Pressure Limiting and Regulating Service

49 CFR 192 Reference
192.619(b)
192.739
192.743(a)

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe how pressure switches, pressure transmitters, and pressure transducers work in pressure limiting and regulating service.
a. Pressure switches shut down compression and activate other protection devices at predetermined set points
b. Pressure transmitters/transducers provide a variable signal based upon varying pressure on the pipeline to other logic devices that can shut down compression and activate other protection devices at predetermined set points

K 2. Identify the steps in testing/maintaining pressure switches and transmitters:
a. Verify required setpoint pressures
b. Record setpoint “as found”.
c. Determine the test media to be applied
d. Inspect for good mechanical condition, proper installation and protection from dirt, liquids or other conditions that might prevent proper operation.
e. Clean, repair or replace the device as necessary following the manufacturer's guidelines.
f. Inspect for any leakage
g. Test the device to insure proper operation and to ensure that it is set to function at the correct pressure.
h. Place the device back in service and return to normal operating conditions.
i. Record setpoint “as left”.

S 3. Demonstrate how to adjust setpoint on a pressure switch.

S 4. Demonstrate how to calibrate a pressure transmitter/transducer loop/system.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

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Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 716OP - Inspect, Maintain, and Operate Valves

49 CFR 192 Reference
192.745
192.747

49 CFR 195 Reference
195.420(a)
195.420(b)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the most common types of pipeline valves.
* Ball valve
* Plug valve
* Gate valve

S 2. Demonstrate how to inspect a valve and associated components:
a. Verify valve is properly identified
b. Perform a physical inspection of valve body, flanges, bolts, operator, locking devices, lube fittings, chains, lock, etc. for leaks, corrosion, and damage
c. Operate valve (partially operate when full operation is not possible) to ensure valve operates properly. Include in operation both manual valve and valve with operator.

S 3. Demonstrate how to perform valve maintenance
a. Understand and follow manufacturer's specifications
b. Lubricate the valve according to valve type and manufacturer guidelines.
c. Identify pressure rating of valve and monitor grease pressure to ensure valve pressure rating is not exceeded during lubrication.
d. Clean stem threads, according to valve type.
e. Energize and/or replace stem packing to seal valve stem leaks or for predictive maintenance.
f. Bleed valve body, according to valve type.
g. Winterize valves subject to freezing.
h. Provide corrosion inhibitor (if applicable)
i. Operate valve (partially operate when full operation is not possible) to ensure valve operates properly. Include in operation both manual valve and valve with operator.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task 725OP - Aerial Leakage Survey: Transmission

49 CFR 192 Reference
192.706

49 CFR 195 Reference
195.412(a)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify leakage survey scope, method and requirements
The individual will be able to identify:
1. Leakage survey scope - utilize maps and records to identify segments to be surveyed
2. Method - aerial.
3. Requirements:
a. Transmission lines:
i. Take a continuous sampling of the atmosphere at 100 - 500 feet above ground level over buried gas facilities and above-ground gas facilities,
ii. Taking into account wind speed and direction, offset the aircraft downwind of pipeline and facilities such that leaking gas can still be detected by the instrumentation.
iii. The use of this survey method may be limited by adverse conditions (such as excessive wind, excessive soil moisture or frost or surface sealing by ice or water).
iv. The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained giving consideration to the location of gas facilities and any adverse conditions which might exist..

S 2. Perform equipment operation check
The individual will, prior to use and periodically if required, be able to:
1. Perform equipment operation check in accordance with manufacturer's instructions, including:
a. Verifying the sampling system is free of obstructions,
b. Verifying that nothing is obstructing the sample flow,
2. Verify recommended voltage requirements
3. Test Hydrogen the gas detection system for proper operations,
4. Initiate corrective action for equipment out of specification

S 3. Perform survey
The individual will be able to perform leakage surveys:
1. Operate the equipment in accordance with the manufacturer's instructions
2. Include all segments identified during Step 1
3. In accordance with the requirements identified during Step 1

Abnormal Operating Conditions

1. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

2. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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3. Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

4. Failure or malfunction of pipeline component(s).
Response: Protect the public, property, and the environment. Follow appropriate procedures for notification, documentation, and remedial action.

5. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Follow appropriate procedures for notification, documentation, and remedial action.

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Evaluation Criteria

Covered Task AGL-019A-OP - Hazard Control

49 CFR 192 Reference
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
5 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the requirements for hazard control
a.Taking steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion.
b.Removing each potential source of ignition from the area and providing a fire extinguisher when a hazardous amount of gas is being vented into open air.

K 2. Describe potential sources of ignition
a.Smoking and open flames.
b.Arcing from electrical devices in use.
c.Static electrical build-up or discharge.
d.Running engines.

K 3. Describe what factors to consider before blowing down, venting, or purging to help prevent accidental ignition
a.Proximity of houses, plants, or buildings.
b.Proximity of pedestrian, automotive, railroad or air traffic.
c.Proximity of electric transmission lines.

K 4. Describe what considerations/actions must be taken to prevent accidental ignition when responding to a gas leak or emergency call
a.Recognize when a hazardous amount of gas may be vented into open air
b.Monitor wind direction and velocity.
c.Restrict access to the area of operations.

K 5. With regard to accidental ignition of natural gas, explain possible actions an individual may take when it occurs
a.Eliminate fuel.
b.Determine the wind direction.
c.Use a fire extinguisher.
d.Eliminate sources of ignition.

K 6. Explain suitable precautions/actions to be taken prior to beginning any maintenance work on gas line systems.
a.Sniffing the air for the presence of natural gas.
b.Locate pipe.
c.Use Bonding cables when separating steel pipe
d.Post warning signs or barricades, where appropriate, when gas is being vented to the atmosphere

Abnormal Operating Conditions

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1. Occurrence of accidental ignition.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

2. Presence of hazardous amount of gas in an area.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

3. Indications of increasing amount of gas.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

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EXHIBIT C

EVALUATION CRITERIA
(CONTRACTORS AND OTHER EXTERNAL PERSONNEL)

Evaluation Criteria

Covered Task 007 - Operate Valves

49 CFR 192 Reference
N/A

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

Note: An individual qualified on Covered Task 716 will automatically be qualified for this task. Therefore, an individual qualified on Covered Task 716 need not be evaluated on this task.

K/S

K 1. Identify the most common types of pipeline valves.
* Ball valve
* Plug valve
* Gate valve

S 2. Demonstrate how to open and close a valve:
a. Identify the proper valve (by tag, sign, or other means)
b. Unlock the valve, if required
c. Determine valve position
d. Operate valve. Include in operation both manual valve and valve with operator.
e. Verify the valve is in the desired position

Abnormal Operating Conditions

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 008 - Measurement of Wall Thickness with Ultrasonic Device

49 CFR 192 Reference
N/A

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate calibration of Ultrasonic device according to manufacturer's guidelines
- Device must typically be calibrated for the material to be tested (mild steel, stainless steel, etc.)

K 2. Describe the proper surface preparation required for the test area
- Ensure surface is clean

S 3. Demonstrate the proper use of the Ultrasonic device according to manufacturer's guidelines
- Obtain proper wall thickness from a known sample

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 103 - Nondestructive Testing (Other than testing of welds) -- Mag Particle

49 CFR 192 Reference
N/A

49 CFR 195 Reference
195.452(h)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:1

K/S

K 1. Describe situations in which Mag Particle (MT) inspection may be appropriate:
- Presence of corrosion anomalies
- Presence of mechanical damage (i.e., dents and gouges)
- Presence of disbonded coating on lines where MAOP > 50% SMYS
- Monitoring for external stress corrosion cracking (SCC)

K 2. Identify equipment and supplies needed to conduct an MT inspection
- AC magnetic yoke
- Magnetic flux indicators
- Particle suspension medium
- Contrast medium (i.e., white paint)

S 3. Demonstrate proper preparation of pipe surface prior to MT inspection
- External coating removed in the area to be inspected
- Surface to be abrasive blasted, or otherwise prepared, in accordance with Operator specifications
- Inspection area free of oil, grease, or solids that may interfere with the MT process

S 4. Demonstrate proper inspection of a pipeline for SCC using MT

K 5. Describe documentation requirements in accordance with Operator requirements

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 201 - Abnormal Operating Conditions Related to Welding on Pipelines

49 CFR 192 Reference
192.225
192.227
192.245
192.328(a)(1)
192.713
192.715
192.717
192.751

49 CFR 195 Reference
195.214
195.222
195.224
195.226
195.230

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

NOTE:

1. Candidate must be currently qualified in accordance with API 1104 or ASME Section IX at the time of this evaluation.
2. Evaluation will cover Abnormal Operating Conditions (AOCs) only.
3. Candidate must meet specific pipeline operator welder testing/qualification requirements in addition to this evaluation.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 202 - Monitoring of Welding Process

49 CFR 192 Reference
192.231
192.235
192.241(a)
192.241(c)
192.245
192.328(a)(1)

49 CFR 195 Reference
195.204
195.224
195.228
195.234

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Describe the critical attributes of a welding procedure:
* Preheating
* Rod Selection
* Travel direction
* Travel speed
* Polarity
* Alignment
* Gap
* Cleanliness of surface
* Bevel Angle
* Amperage/Voltage Ranges
* Post-heat
* Control of the welding environment

K 2. Describe other procedures typically required by welding inspection:
* Operator-specific requirements
* Verification of Level II NDT Certification
* Acceptance criteria for welds per API-1104, Section 9 (19th Edition) or ASME Section IX

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 203 - Visual Inspection of Welds not Non-Destructively Tested

49 CFR 192 Reference
192.241(b)
192.241(c)

49 CFR 195 Reference
195.204

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Describe when visual inspection of a weld is allowed in lieu of NDT
* Pipeline less than or equal to 6" nominal diameter (OD); or
* Less than 40% SMYS and limited number of welds such that NDT is impractical

K 2. Describe when visual inspection must be performed during the welding process:
* Inspector must visually inspect the welding and confirm proper grinding and cleaning between each pass and at completion.

K 3. Describe visual inspection requirements prior to striking an arc:
* Alignment
* Gap
* Cleanliness of surface
* Bevel

K 4. Identify which of the following items may be identified visually:
* Inadequate penetration - yes, if interior of pipe is visible at welding area
* Inadequate penetration due to high-low - yes, if interior of pipe is visible at welding area
* Incomplete fusion - yes, if interior of pipe is visible at welding area
* Incomplete fusion due to cold lap - no
* Internal concavity - yes, if interior of pipe is visible at welding area
* Burnthrough - yes
* Slag inclusions - yes
* Individual or scattered porosity - yes, for external surface of each pass
* Cluster porosity - yes, for external surface of cap
* Hollow-bead porosity (root pass) - no
* Cracks - yes, under certain conditions
* External undercutting - yes
* Internal undercutting - yes, if interior of pipe is visible at welding area
* Accumulation of discontinuities - yes, under certain conditions

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

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Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 204 - Non-Destructive Testing (Dye Penetrant)

49 CFR 192 Reference
192.243
192.328(b)

49 CFR 195 Reference
195.234

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Level II or Greater Certificate (PT)

Span of Control
1:0

NOTE:
In order to be qualified on the task, you must also submit current (within 12 months) evidence of satisfactory near visual acuity (Jaeger J1 or equivalent) and color perception. This documentation must be submitted in a separate process by the company through the Submit Certification Report in Verisource

K/S
K&S 1. The individual must have a current Level II or greater NDE Certification (PT) in accordance with SNT-TC-1A.

Abnormal Operating Conditions
Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 205 - Non-Destructive Testing (Mag Particle)

49 CFR 192 Reference
192.243
192.328(b)

49 CFR 195 Reference
195.234

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
Level II or Greater Certificate (MT)

Span of Control
1:0

NOTE:
In order to be qualified on the task, you must also submit current (within 12 months) evidence of satisfactory near visual acuity (Jaeger J1 or equivalent) and color perception. This documentation must be submitted in a separate process by the company through the Submit Certification Report in Verisource

K/S
K&S 1. The individual must have a current Level II or greater NDE Certification (MT) in accordance with SNT-TC-1A.

Abnormal Operating Conditions
Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.
Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.
Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.
Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 206 - Non-Destructive Testing (Ultrasonic)

49 CFR 192 Reference
192.243
192.328(b)

49 CFR 195 Reference
195.234

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Level II or Greater Certificate (UT)

Span of Control
1:0

NOTE:
In order to be qualified on the task, you must also submit current (within 12 months) evidence of satisfactory near visual acuity (Jaeger J1 or equivalent) and color perception. This documentation must be submitted in a separate process by the company through the Submit Certification Report in Verisource

K/S
K&S 1. The individual must have a current Level II or greater NDE Certification (UT) in accordance with SNT-TC-1A.

Abnormal Operating Conditions
Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 207 - Non-Destructive Testing (X-Ray)

49 CFR 192 Reference
192.243
192.328(b)

49 CFR 195 Reference
195.234

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
Level II or Greater Certificate (RT)

Span of Control
1:0

NOTE:
In order to be qualified on the task, you must also submit current (within 12 months) evidence of satisfactory near visual acuity (Jaeger J1 or equivalent) and color perception. This documentation must be submitted in a separate process by the company through the Submit Certification Report in Verisource

K/S
K&S 1. The individual must have a current Level II or greater NDE Certification (RT) in accordance with SNT-TC-1A.

Abnormal Operating Conditions
Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 208 - Plastic Pipe Joining: Butt Fusion

49 CFR 192 Reference
192.281
192.283
192.285
192.287

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify the type of equipment being used in the fusion process.

K 2. Identify the material, size, type, grade, and age of pipe.

S 3. Demonstrate preparation of pipe ends for fusion.

S 4. Demonstrate proper Butt-Fusion procedure according to specific Operator procedure(s).

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Dissimilar material such as wall thickness, type, or grade.
Response: Verify materials. If not compatible, follow appropriate/approved joining procedures.

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Evaluation Criteria

Covered Task 209 - Plastic Pipe Joining: Mechanical Joining

49 CFR 192 Reference
192.281
192.283
192.285
192.287

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

S 1. Demonstrate the steps required to mechanically join plastic pipe.
a. Verify that mechanical fittings are suitable for the intended service.
b. Clean the ends of the pipe, and square as needed.
c. Install mechanical fitting with appropriate gaskets and bolts and nuts, as per manufacturer's specifications.
d. Ensure that insulated fittings are installed in the proper orientations.
e. Tighten fitting to manufacturer's specifications.
f. Verify that the fitting is not leaking.
g. Document installation of fitting as necessary.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Dissimilar material such as wall thickness, type, or grade.
Response: Verify materials. If not compatible, follow appropriate/approved joining procedures.

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Evaluation Criteria

Covered Task 210 - Plastic Pipe Joining: Electrofusion Joining

49 CFR 192 Reference
192.281
192.283
192.285
192.287

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify the type of equipment being used in the fusion process.

K 2. Identify the material, size, type, grade, and age of pipe.

S 3. Demonstrate preparation of pipe ends for fusion.

S 4. Demonstrate proper fusion procedure according to specific Operator procedure(s).

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Dissimilar material such as wall thickness, type, or grade.
Response: Verify materials. If not compatible, follow appropriate/approved joining procedures.

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Evaluation Criteria

Covered Task 211 - Perform Plastic Fusion Inspection

49 CFR 192 Reference
192.287

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:0

K/S

K 1. Describe when fusion of plastic pipe must be inspected and explain what must be verified.
* Each joint must be inspected and found to have the same appearance as a joint that is acceptable under the procedure being followed.

K 2. Describe when visual examination of a joint must be performed if inspecting a joint for the purpose of qualifying a person to make joints.
* The specimen joint must be visually examined during and after assembly or joining.

K 3. Identify specific inspection requirements, when inspecting a joint for the purpose of qualifying a person to make joints, specifically related to heat fusion, solvent cement, or an adhesive joint.
* Joint must be tested under any one of the appropriate test methods identified in the 49 CFR 192.283(a).
* Joint must be examined by ultrasonic inspection and found not to contain flaws that would cause failure.
* Joint must be cut into at least three (3) longitudinal straps, each of which is:
a. Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
b. Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Dissimilar material such as wall thickness, type, or grade.
Response: Verify materials. If not compatible, follow appropriate/approved joining procedures.

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Evaluation Criteria

Covered Task 213 - Joining of Steel Pipe - Threaded and Flanged Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
195.126

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining steel pipe with threaded connection.
* Verify fitting to be installed is the proper size, pressure rating, and material.
* Ensure the fitting is clean and free of obstruction, inspect for nicks or damage in the thread area that could effect sealing properly.
* Apply sealing material to threaded end connections.
* Screw Threaded connections together making a tight leak free joint.
* Check for leaks

S 2. Demonstrate joining of steel pipe by flanged connection
* Verify fitting and gasket to be installed are the proper size, rating and material.
* Ensure flange faces are clean, inspect for nicks or damage on flange faces that may prevent proper sealing.
* Align flanges and insert bolts in bottom portion of flange.
* Insert gasket between flange faces and insert remaining bolts
* Snug bolts around flange.
* Torque flange bolts to specified value using proper sequence of tightening.
* Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Insulator does not work
Response: Check installation of insulator.

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Evaluation Criteria

Covered Task 214 - Joining of Steel Pipe - Threaded Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining steel pipe with threaded connection.
a. Verify fitting to be installed is the proper size, pressure rating, and material.
b. Ensure the fitting is clean and free of obstruction, inspect for nicks or damage in the thread area that could effect sealing properly.
c. Apply sealing material to threaded end connections to the proper depth. Ensure sealing material is compatible with the intended application (i.e. temperature range, pipe materials, contents of carrier pipe).
d. Screw threaded connections together making a tight leak free joint.
e. Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 215 - Joining of Steel Pipe - Flanged Connections

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
195.126

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate joining of steel pipe by flanged connection:
a. Verify fitting and gasket to be installed are the proper size, rating and material.
b. Ensure flange faces are clean, inspect for nicks or damage on flange faces that may prevent proper sealing.
c. Align flanges and insert bolts in bottom portion of flange.
d. Insert gasket between flange faces and insert remaining bolts
e. Snug bolts around flange.
f. Torque flange bolts to specified value using proper sequence of tightening, per manufacturer or Operator specifications.
g. Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Insulator does not work
Response: Notify designated operator representative

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Evaluation Criteria

Covered Task 216 - Joining of Steel Pipe - Compression Couplings

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the factors to consider when selecting the proper compression coupling.
a. Pipe material (i.e. plastic, steel),
b. Material transported (liquids, gas)
c. Operating pressure,
d. Pipe diameter.

K 2. Identify and describe the purpose of the major parts associated with a compression coupling and discuss the appropriateness of mixing parts from different manufacturers.
a. Candidate can identify major components of compression couplings.
I. Studs (bolts) and nuts
II. Seals or sleeve,
III. Main fitting body or middle ring,
IV. Gasket (insulating or conductive).
b. Not acceptable to mix parts from different manufacturers or models, unless directed by the manufacturer. .

S 3. Demonstrate the proper application of a compression coupling to steel pipe:
a. Verify that mechanical fittings are suitable for the intended service and type of pipe (i.e. steel, plastic).
b. Clean and dry the ends of the pipe,
c. Square the ends of the pipe as needed
d. Install coupling with appropriate gaskets, bolts and nuts, as per manufacturer's specifications
e. Ensure that insulated fittings are installed in the proper orientations
f. Tighten fittings in proper sequence and to proper torque, per manufacturer's specifications
g. Check for leaks.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Pipe of insufficient wall thickness to install fitting
Response: Do not install fitting and contact designated operator representative.

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Evaluation Criteria

Covered Task 217 - Small Diameter Metal Tubing and Fitting Installation

49 CFR 192 Reference
192.271
192.273

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe general practices around tube routing design and fabrication.
a. Joints and fittings should be left as accessible as possible,
b. Tubing should be routed around components that require regular maintenance,
c. Consideration should be given to movement of components between connections (whether thru expansion and contraction or vibration); candidate should be able to describe the proper application of a “U” bend to allow for component movement.

K 2. Explain the importance of tubing support systems and when they would be used.
a. When left unsupported, shock and vibration will cause the tubing to shake and fittings to loosen or leak
b. Vibration could cause a leak in tubing where it comes into contact with other hard surfaces
c. A support system should be used anytime there is a chance for movement in a tubing run.

S 3. Demonstrate the proper design and fabrication of a tubing component system with at least one 90 degree bend.
a. Tube routing was designed to account for component movement, accessibility of other components.
b. Tubing was successfully bent utilizing the proper tool without wrinkling or excessive tube flattening.

S 4. Demonstrate the installation of a tube fitting, per manufacturer's instructions.
a. Tubing is inserted to the proper depth inside the fitting and rests on the shoulder of the fitting body,
b. The compression nut is tightened in accordance with tube size and manufacturers specifications.
c. Thread sealant is used on all NPT fittings, per manufactures specifications.
d. Check for leaks.

Abnormal Operating Conditions

Tubing of insufficient wall thickness to install fitting
Response: Do not install fitting. Notify designated operator representative.

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 401 - Examination of Buried Pipelines When Exposed

49 CFR 192 Reference
192.328(a)(1)
192.459

49 CFR 195 Reference
195.569

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Describe when an inspection of coating on buried pipe must be performed.
* Whenever the pipe is exposed for any reason

K 2. Identify and describe the types of defects that might be discovered during a coating inspection.
* Disbonded coating
* Cracks
* Appearance of moisture under coating
* Lack of coating
* Soil stress

K 3. Identify and describe the types of defects that might be discovered during inspection of the exposed pipe.
* Pitting
* Scale
* Rust
* Discoloration
* Corrosion by-product
* Wrinkle
* Buckle
* Gouge
* Dent
* Damaged coupling
* Defective weld patches
* Groove
* Scratch
* Arc burns

K 4. Describe conditions that may warrant extending the inspection beyond the exposed area.
* Anytime the following conditions extend beyond the wall of the excavation:
* Continuation of an individual pitting area
* Coating failure
* Significant general corrosion
* Any mechanical defect or exposed metal surface

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

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Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 402 - Apply Approved Coatings to Above Ground Piping

49 CFR 192 Reference
192.461(a)

49 CFR 195 Reference
195.581

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe which factors must be considered when selecting proper coating.
a. Operator's requirements
b. Temperature range of pipeline
c. Weather conditions, (temperature, relative humidity, etc.)
d. Compatibility with existing coating
e. Surface preparation

K 2. Describe the methods of surface preparation.
a. Solvent cleaning
b. Hand tool cleaning
c. Power tool cleaning
d. Abrasive blasting
e. Water blasting

K 3. Describe what environmental conditions may affect coating application.
a. Dew point reading
b. Moisture on pipe surface
c. Ambient and surface temperature
d. Wind
e. Dust
f. Airborne particles

K 4. Describe the terms typically used in general manufacturer's recommendations pertaining to the application of coatings:
a. Pot life
b. Mixing ratios
c. Curing / drying times
d. Re-coating
e. Shelf life

K 5. Describe the following coating application methods and use of the related equipment.
a. Brush
b. Roller
c. Spray

S 6. Demonstrate proper surface preparation and the application of selected coating system(s).
a. Test temperature of pipe.
b. Obtain atmospheric temperature and humidity.
c. Clean and prepare area to be coated.
d. Apply primer, intermediate coat (if required), and topcoat according to Manufacturer's specifications.
e. Measure coating thickness to confirm proper application thickness using wet film and dry film.

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 403 - Apply Approved Coatings to Below Ground Piping

49 CFR 192 Reference
192.461(a)

49 CFR 195 Reference
195.557
195.559

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe what factors must be considered when selecting proper coating.
a. Operator's requirements
b. Temperature range of pipeline
c. Soil type/conditions
d. Weather conditions, (temperature, relative humidity, etc.)
e. Compatibility with existing coating
f. Surface preparation

K 2. Describe the methods of proper surface preparation.
a. Solvent cleaning
b. Hand tool cleaning
c. Power tool cleaning
d. Abrasive blasting
e. Water blasting

K 3. Describe what environmental conditions may affect coating application.
a. Dew point reading
b. Moisture on surface of pipe
c. Ambient and surface temperature
d. Wind
e. Dust
f. Airborne particles

K 4. Describe the terms typically used in general manufacturer's recommendations pertaining to the application of coatings:
a. Pot life
b. Mixing ratios
c. Curing / drying times
d. Re-coating
e. Shelf life

K 5. Describe the following coating application methods and use of the related equipment.
a. Brush
b. Roller
c. Spray
d. Swab
e. Flock
f. Wrap

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K 6. Identify types of underground coatings:
a. Coal tar
b. Waxes
c. Tapes
d. Fusion Bond Epoxy (FBE)
e. Shrink sleeves
f. Mastics
g. Epoxies
h. Plastic
i. Rubber
j. Enamels

S 7. Demonstrate proper surface preparation and the application of selected coating system(s)
a. Test temperature of pipe.
b. Obtain atmospheric temperature and humidity.
c. Clean and prepare area to be coated.
d. Apply coating according to manufacturer's specifications.
e. Measure coating thickness to confirm proper application thickness with wet film and dry film.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 404 - Protection of Coating When Backfilling and From Below Ground Supports

49 CFR 192 Reference
192.461(c)
192.461(d)
192.614(c)(6)

49 CFR 195 Reference
195.252
195.422

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe ditch and soil conditions that may adversely affect pipe coating.
a. Rock
b. Moisture
c. Foreign Material

K 2. Describe the most common methods of protecting pipe coating where pipe and supports come into contact.
a. Sandbags
b. Rock shield
c. Felt wrap
d. Concrete coatings
e. Grout or abrasion resistant coatings

K 3. Describe how to prevent damage to coating during backfill operations
a. Use rock shield as needed
b. Ensure pad dirt is free of rocks and other foreign material and compacted as appropriate
c. Ensure suitable pad dirt surrounds pipeline, as per Operator's policies & procedures
d. Ensure backfill material is free of large rocks and other foreign material
e. Do not fill directly on pipeline

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Abnormal loading of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 405 - Protection of Coatings From Above Ground Structures

49 CFR 192 Reference
192.461(d)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the most common methods of protecting pipe coating where pipe and permanent supports come into contact.
a. Composite materials (e.g.: Micarta)
b. Neoprene
c. PVC
d. Epoxy chocks

K 2. Describe the most common methods of protecting pipe coating where pipe and temporary supports come into contact.
a. Wood
b. Carpet
c. Rubber
d. Rope

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 406 - Conduct Test to Determine Cathodic Protection Current Requirements

49 CFR 192 Reference
192.465(a)
192.620(d)(6)

49 CFR 195 Reference
195.571

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe the components used for a current requirement test.
a. Temporary Anode Bed - Used to simulate the current output of an installed cathodic protection system
b. DC Current Source - May consist of either a storage battery or a DC generator
c. Current Interrupter - Used to cycle the temporary groundbed current On and Off
d. Test Points - Identify the specific points where structure-to-electrolyte potentials will be recorded
e. Structure - Identify the structure to be cathodically protected - pipeline, platform, tower anchors, etc.
f. Ammeter
g. High impedance volt meter
h. Calibrated electrodes
i. Soil resistivity test device.

S 2. Perform the current requirement test procedure.
a. Identify system areas to be tested
b. Setup temporary groundbed
c. Calibrate electrodes
d. Record static (as found) structure-to-electrolyte potentials
e. Apply DC current from temporary groundbed, and cycle On and OFF using current interrupter
f. Record new ON and OFF structure-to-electrolyte potentials and record groundbed current output
g. Calculate or plot the apparent current requirement for the tested structure and interpolate the results.
h. Determine total quantity of additional current required and sites at which current should be applied.
i. Perform a soil resistivity test using an approved method.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 407 - Perform Cathodic Protection Survey

49 CFR 192 Reference
192.328(e)
192.465(a)
192.465(e)
192.620(d)(6)

49 CFR 195 Reference
195.573(a)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify types of CP Surveys
a. Test point survey
b. Close interval survey
c. AC Potential survey
d. Hot Spot survey

K 2. Identify and describe the test equipment used to complete a cathodic protection survey
a. Digital or analog high impedance voltmeter
b. Reference cell (copper-copper/sulfate, silver-silver/chloride, zinc)
c. Ammeter (direct or indirect)
d. Current interrupter (if required)
e. Datalogger or other data recording device

S 3. Demonstrate the proper calibration, setup, and use of the equipment during an actual or simulated survey.

K 4. Identify and describe measurements that may be required at a given test point:
a. Structure-to-electrolyte potential
* Pipe-to-soil
* Pipe-to-water
* Structure-to-soil
* Casing-to-soil
* Foreign line-to-soil
b. AC potentials
c. Current flow measurements on pipelines
d. Galvanic anode output measurement

K 5. Describe use of interrupters
a. Verify calibration of all test equipment.
b. Locate/isolate the piping to be surveyed.
c. Set up and perform a survey using interrupters on rectifiers so interruptions are synchronous according to operator requirements.
d. If applicable, use appropriate equipment to verify that all current sources are properly interrupted.
e. Verify that the readings are in the desired range.

K 6. Identify common methods of determining IR drop:
a. Measure instant-off potential
b. Measure pipe-to-soil potential at pipe-to-soil interface

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Absence of CP current.
Response: Notify designated operator representative.

Discovery of unidentified shorted casing.
Response: Notify designated operator representative.

Stray current on pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 408 - Inspect Cathodic Protection Rectifier

49 CFR 192 Reference
192.465(b)

49 CFR 195 Reference
195.573(c)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and demonstrate steps for testing/inspecting rectifier for proper operation.
a. Verify the calibration of the meter or data logger
b. Check rectifier cabinet for electrical shorts
c. Verify and interpret output of DC voltage using an appropriate instrument
d. Verify and interpret output of DC current using an appropriate instrument

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 409 - Inspect Interference Bonds

49 CFR 192 Reference
192.465(c)

49 CFR 195 Reference
195.573(c)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the equipment necessary for the proper inspection of a bond:
a. Calibrated resistor (shunt)
b. Calibrated meter capable of measuring millivolts
c. Calibrated electrode

S 2. Demonstrate how to check condition and operation of bonds, diodes and reverse current switches using proper equipment.
a. Measure structure-to-electrolyte potential
b. Measure voltage and calculate current flow across calibrated shunt

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 410 - Clear Shorted Casing

49 CFR 192 Reference
192.467(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Describe steps for clearing a shorted casing using insulators
a. Expose and inspect casing end seals
b. Install casing insulators, if possible
c. Install new casing end seals
d. Check for proper isolation

K 2. Describe steps for clearing a shorted casing by filling
a. Expose and inspect casing end seals
b. Install new casing end seals
c. Modify vent pipes to accept fill material
d. Inject fill material
e. Check for proper isolation

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 411 - Inspect/Test to Assure Electrical Isolation is Adequate

49 CFR 192 Reference
192.467(d)
192.620(d)(6)

49 CFR 195 Reference
195.575

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe types of insulators and where each is typically located.
a. Flange insulator - custody transfer points or other operator-designated locations
b. Union insulator - threaded connections
c. In-line insulator - custody transfer points or other operator-designated locations

S 2. Demonstrate how to inspect insulators for possible short:
a. Inspect insulator for evidence of electrical arcing or foreign material that could cause a short.
b. Determine that test equipment is working properly.
c. Demonstrate how to take a reading across an insulator to determine whether a short exists.

K 3. Describe common methods of subsequent testing if readings indicate a possible short.
a. Induce temporary current on one side
b. Depolarize one side
c. Temporary anode(s)

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 412 - Install CP Leads on Pipeline Using Exothermic Weld

49 CFR 192 Reference
192.471

49 CFR 195 Reference
195.567

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe how to verify pipeline wall thickness and location.
a.Consult with operator to verify product, line number, station number, location, and wall thickness

S 2. Demonstrate how to prepare pipe surface:
a. Remove coating, file and clean down to bare metal
b. Remove any film on pipeline with approved solvent

K 3. Describe how to select location of exothermic weld, exothermic weld size and appropriate furnace/mold
a. Ensure exothermic weld is a reasonable distance from any existing weld.
b. Appropriate charge size determined by wall thickness
c. Appropriate furnace/mold determined by pipe diameter and wire gauge

S 4. Demonstrate installation of CP leads using exothermic procedure and test integrity of weld/adhesion:
a. Select/prepare lead wire/cable (based on exothermic weld size)
b. Install lead with exothermic procedure
c. Test integrity of weld/adhesion

K 5. Describe final steps associated with CP lead installation:
a. Clean area and apply approved coating
b. Ensure CP leads are not damaged during backfill
c. Install test station
d. Take pipe to soil reading

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 413 - Anode Installation on Submerged Pipeline or Facilities

49 CFR 192 Reference
192.471

49 CFR 195 Reference
N/A

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Describe the key components of submerged cathodic protection systems:
a. Galvanic anode
b. Cathode
c. Electrical path
d. Electrolyte

K 2. Describe how to prepare pipe/facility surface
a. Remove coating
b. File and clean down to bare metal

K 3. Describe the use of 'bracelets', their purpose, and the process of installing them as part of a submerged cathodic protection system.

K 4. Describe the use of 'sleds', their purpose, and the process of installing them as part of a submerged cathodic protection system.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Exposed piping of an unsupported length that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 414 - Inspect for Internal Corrosion Whenever Pipe is Removed

49 CFR 192 Reference
192.475(b)(1)
192.751

49 CFR 195 Reference
195.579(c)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe areas that must be inspected once pipe is removed:
a. Internal surface of removed section of pipe
b. If internal corrosion is present in removed section of pipe, further investigation of adjacent pipe is required.

K 2. Describe how to perform internal corrosion inspection and describe what to look for when performing an internal corrosion inspection.
a. Clean internal pipe surface
b. Visually inspect for pitting
c. Visually inspect for erosion from liquids
d. Visually inspect for scale
e. Visually inspect for thinning
f. Visually inspect internal coating, if applicable

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 415 - Monitoring for Internal Corrosion with Probes and Coupons

49 CFR 192 Reference
192.477
192.620(d)(5)
192.751

49 CFR 195 Reference
195.579(b)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe corrosion coupons and explain how they are used to monitor internal corrosion.
a. Corrosion coupon - milled steel, reasonably close to the pipeline quality, used wherever a corrosive environment is known or suspected.
b. Coupons are inspected to determine if metal loss occurs. Periodic inspections will measure rate of metal loss

K&S 2. Describe and demonstrate the procedure for removing and inserting a coupon
a. Review manufacturer's procedures
b. Roll out coupon
c. Close tap valve
d. Blow down holder
e. Remove coupon and install new coupon
f. Open tap valve
g. Roll in coupon

K 3. Describe how electronic rate probes or monitors are used to monitor internal corrosion.
a. Systems of probes or electronic readout equipment are used to relate resistance change with time to indicate corrosion rate.
b. The resistance method is used in process monitoring to activate alarms where less rapid changes require monitoring.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 416 - Monitoring for Internal Corrosion with Gas Samples

49 CFR 192 Reference
192.477
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K&S 1. Describe and demonstrate the process of obtaining a gas sample:
a.Inspect and clear tap of any grease, oil, or dirt.
b.Inspect fittings connections externally for any defects
c.Verify whether a probe has been installed, use probe if possible
d.Obtain sample source process pressure
e.Install appropriate regulator to the specified tap source, as required
f.Obtain and use appropriate sample collection cylinder
g.Attach gas sample cylinder filter end to the regulator outlet (if appropriate) or connect the sample collection cylinder directly to the source valve.
h.Purge the sample collection cylinder for a period of time established by operator procedures.
i.Use fill and purge method as required by operator procedures until terminal sample is collected.
j.Close outlet valve and allow sample collection cylinder to build to final sample pressure as required by operator procedures.
k.Close source valve
l.Install plugs or caps to prevent leakage
m.Leak test the sample collection cylinder
n.Disconnect regulator (if appropriate) from supply source and secure tap.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 417 - Atmospheric Corrosion Monitoring

49 CFR 192 Reference
192.481

49 CFR 195 Reference
195.581

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify indications of atmospheric coating damage and/or corrosion damage.
a. Coating Damage
* Coating deterioration
* Flaking
* Cracking
b. Corrosion Damage
* Rust
* Scale
* Pitting
* Thinning.

K 2. Identify steps required to conduct an atmospheric corrosion inspection
a. Clean loose soil or other debris with a non-metallic brush to expose coating.
b. Visually inspect condition of coating
c. Assess extent of coating deterioration or defect(s)

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 418 - General and Localized Corrosion Measurement (Remedial Measures)

49 CFR 192 Reference
192.485(a)(b)

49 CFR 195 Reference
195.585(b)
195.587

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

S 1. Demonstrate how to calibrate a pit gauge and measure pit depth.
* Ensure pitted area is properly cleaned prior to taking measurements

S 2. Demonstrate how to calibrate an ultrasonic thickness meter and measure wall thickness.
* Ensure surface is clean prior to taking measurement with UT meter.

K 3. Describe required measurements for use in calculating remaining strength according to B31G.
a. Measure length of corrosion and effect of interconnected areas
b. Measure greatest depth(s) of the corrosion
c. Measure wall thickness

K 4. Describe required measurements for use in calculating remaining strength according to RSTRENG.
a. Measure length of corrosion
b. Measure greatest depth(s) of the corrosion
c. Measure wall thickness
d. Measure the effective length and width of interconnected areas
e. Layout a grid pattern for the corroded area
f. Collect profile data of the corroded area

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 419 - Test Point Survey

49 CFR 192 Reference
192.465(a)
192.620(d)(8)

49 CFR 195 Reference
195.573(a)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe the test equipment required to complete a test point survey:
a. Digital or analog high impedance voltmeter
b. Reference cell (copper-copper/sulfate)
Note: For individuals with test points in salt water: silver-silver/chloride
c. Current interrupter (as required)
d. Datalogger or other data recording device (if used)

K 2. Identify and describe measurements that may be required at a given test point:
a. Structure-to-electrolyte potential
1. Pipe-to-soil
2. Pipe-to-water
3. Structure-to-soil
4. Casing-to-soil
5. Foreign line-to-soil
b. Galvanic anode output measurement

S 3. Demonstrate the proper calibration, setup, and use of the equipment during an actual or simulated survey.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 420 - Soil Resistivity

49 CFR 192 Reference
N/A

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify equipment used to conduct a soil resistivity test

1. Soil resistivity test instrument
2. Metal pins
3. Wiring
4. Probe with two isolated electrodes
5. Volt meter
6. Amp meter
7. AC or DC current source
8. Soil box

K 2. Identify the different types of soil resistivity

1. Wenner method
2. Single probe method
3. Soil box method

S 3. Perform a soil resistivity test

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 421 - Measurement of Depth of Pitting with Pit Gage

49 CFR 192 Reference
192.485

49 CFR 195 Reference
195.569
195.585

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:1

K/S

K 1. Describe the two most common types of pit gages
· Mechanical-type pit gage
· Dial-type pit gage

S 2. Demonstrate how to zero the pit gage.
· Ensure that pit gage is in proper and usable condition (flat base, no damage).
· Ensure gage reads zero when measuring an unblemished flat surface

S 3. Demonstrate how to measure pit depth
· Ensure that all coating and other contaminates have been removed from both the pit and the area surrounding the pit.
· Ensure base of pit gage spans the pitted area and rests upon unblemished pipe.
· For isolated pitting, measure pit depth by inserting pit gage tip into base of pit and record the gage reading.
· For general pitting, measure pit depth at various points within the area and measure depth of the area with greatest visual depth and record the gage readings.

Abnormal Operating Conditions

1. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Reaction: Notify designated operator representative

2. Unintended fire and/or explosion on or near the pipeline.
Reaction: Leave immediate area and notify designated operator representative.

3. Failure or malfunction of pipeline component(s).
Reaction: Notify designated operator representative

4. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Reaction: Eliminate potential ignition sources and notify designated operator representative.

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Evaluation Criteria

Covered Task 422 - Assessment of Pipeline Segments Using Long Range Guided Wave UT

49 CFR 192 Reference
NA

49 CFR 195 Reference
NA

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Initial qualification requires proof that candidate successfully completed a minimum of 40 hours of training provided by a trainer accredited by the manufacturer.

Span of Control
1:3

K/S

K 1. Describe the four (4) steps typically associated with a Guided Wave UT Inspection (GWUT)

1. Pre-assessment of the pipeline segment
2. Inspection using GWUT
3. Verification of inspection results using direct examination of the pipe
4. Post assessment of the GWUT process

S 2. Demonstrate ability to calibrate equipment and perform necessary diagnostic checks in accordance with manufacturer instructions

S 3. Demonstrate how to perform a pipeline segment inspection using GWUT, following each of the steps below

1. Establish a reference location for all measurements on the pipeline
2. Select location for installation of the transducer assembly
3. Prepare pipe surface
4. Install transducer assembly onto pipe
5. Connect transducer assembly to laptop and/or guided wave UT instrumentation
6. Check system status and operation
7. Set system up for survey including frequency selection, length of shot, level of expected attenuation, and data averaging. Also make electronic record of pipe characteristics including location of reference point, site name, location of shot etc.
8. Perform the pipe survey
9. Identify and record location of all verifiable welds, flanges, or other pipe features
10. Record locations of transitions of pipe from exposed to buried, or exposed to cased segments
11. Set Distance Amplitude Curves (DAC)
12. Determine inspection range for the shot
13. Identify and set initial sizing and classification of reflections not addressed in steps 9 and 10.
14. Compare reflections to known features; verify system performance
15. Validate sizing and classification by direct examination of selected features
16. Revise feature sizing and classifications, if needed

Abnormal Operating Conditions

1. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

2. Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

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3. Failure or malfunction of pipeline component(s).
Respose: Notify designated operator representative.

4. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

5. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Resonse: Notify designated operator representative.

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Evaluation Criteria

Covered Task 423 - Perform Direct Current Voltage Gradient (DCVG) Survey

49 CFR 192 Reference
192.490
192.620(d)(7)

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the equipment used to perform a DCVG survey.
a. Current Interrupter,
b. DCVG Survey Meter or voltmeter,
c. Connection cables,
c. Copper Sulphate Reference Probes

K 2. Describe the action of the survey meter when approaching a defect.
a. As a defect is approached, the DCVG Survey Meter will begin to respond
b. If the defect is passed, the DCVG Survey Meter will respond in the reverse direction.

K 3. Discuss steps necessary to size a defect.
a. Locate the epicenter of the defect,
b. Record a series of lateral readings moving towards remote earth,
c. Measure the potential lost from the holiday to remote earth,
d. Divide the measured potential lost to remote earth to the total potential shift,

S 4. Demonstrate how to conduct a DCVG survey on a pipeline with a coating defect, including the set-up of necessary equipment.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 424 - Perform AC Current Attenuation (ACCA) Survey

49 CFR 192 Reference
192.328(e)
192.490
192.620(d)(7)

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Explain the purpose of conducting an AC Current Attenuation Survey
a. Assess overall pipeline coating quality over the survey length,
b. Identify coating holidays within the survey length.

K 2. Describe the equipment used to perform an ACCA survey.
a. A signal generator,
b. Proper grounding equipment (i.e. metal spike),
c. Chain or other device to accurately measure/designate survey intervals,
d. Detector or receiver unit.

S 3. Demonstrate how to conduct an ACCA survey on a pipeline with coating defects, including the set-up of necessary equipment.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 425 - Perform Alternating Current Voltage Gradient (ACVG) Survey

49 CFR 192 Reference
192.112(h)(3)
192.620(d)(7)

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the equipment used to perform an ACVG survey.
A.Power Source
b.Connection cables, wire
c.PCM transmitter & receiver
d.PCM A-frame
e.Independent Ground rods/system
f.Line locator
g.Water source (for dry soil conditions or over pavement)
h.Temporary markers
i.Data Logger

K 2. Describe the action of the survey meter when approaching a defect.
a.As a defect is approached, the ACVG Survey Meter will begin to respond in the direction towards the defect.
b.If the defect is passed, the ACVG Survey Meter will respond in the reverse direction.

K 3. Explain how excessive pipe depth limits the performance of the ACVG tool.

K 4. Discuss steps necessary to size a defect.
a.Locate the epicenter of the defect,
b.Record a series of lateral readings
c.Determine severity of faults identified according to equipment manufacturer's instructions.

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S 5. Demonstrate how to conduct an ACVG survey on a pipeline with a coating defect, including the set-up of necessary equipment.
a.Setup equipment and conduct survey in accordance with manufacturer's instructions.
b.Connect the transmitter to power supply, pipeline under test, and an electrically isolated ground.
c.Turn on transmitter and adjust to establish an adequate output signal level.
d.Ensure an adequate signal level on the entire section of pipeline under test. If unable to achieve an adequate signal to survey the entire section, the transmitter will have to be moved to ensure adequate coverage of the pipeline section.
e.Verify isolation of the signal from foreign pipelines and structures.
f.If not able to isolate the target pipeline, further care must be taken to avoid false indications that may occur because of shorts or bonds to other pipelines and structures.
g.Walk along the pipeline route and measure the voltage gradient at a consistent survey interval.
h.Walk in line with pipeline, making contact with ground surface every 5-10 ft.
i.If not able to walk directly over pipeline, record distance and direction off centerline
i.Ensure that conditions are maintained to achieve good results
j.When an indication is detected:
i.Backup and continue taking measurements, at shorter intervals, to determine location
ii.Turn electrode array 90 degrees and repeat above step to pinpoint location
iii.Document location, as appropriate
iv.Mark location, as required (flags, stakes, paint, etc)
k.Continue along entire pipeline segment until entire length is surveyed
l.Remove temporary survey and return existing pipeline equipment to original settings.

Abnormal Operating Conditions

1. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

2. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

3. Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

4. Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 426 - Inspect Pipe Coating with Holiday Detector

49 CFR 192 Reference
192.455(a)
192.457(a)
192.461
192.479

49 CFR 195 Reference
195.561
195.569

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe the use and calibration of equipment required for holiday detection,

K 2. Describe the voltage limitations of the equipment being used.

S 3. Demonstrate the use of a holiday detector as follows:
* Ensured the pipeline is properly grounded.
* Placed the Holiday Detector on the pipeline to be inspected ensuring the detector ground cable is properly connected to the detector and the other end lying on the ground (not hooked to the ground rod).
* Attached HVDC probe positive (+) side to the detector coil and the negative (-) side to the pipeline.
* Set the voltage to the correct setting as per company specification.
* Turned on the Holiday Detector
* Inspected coating,
* Marked holidays for repair.

Abnormal Operating Conditions

1. Improper selection and/or application of coating system
Response: Notify designated operator representative

2. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

3. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

4. Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

5. Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

6. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 427 - Inspection of the Application of Above or Below Ground Coatings

49 CFR 192 Reference
192.461 (a)

49 CFR 195 Reference
195.557
195.559
195.561
195.569

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S 1. Demonstrate surface preparation.

S 2. Demonstrate the coating application systems used in the area of responsibility.

S 3. Demonstrate the use of a sling psychrometer and the ability to determine relative humidity and dew point.

S 4. Demonstrate the use of wet film thickness gauge and dry film thickness gauge.

S 5. Demonstrate the use of wet film thickness gauge, dry film thickness gauge and sling psychrometer.

K 6. Describe factors that must be considered when selecting coatings.
a.Operators Requirements,
b.Temperature range of the pipeline,
c.Soil type/conditions,
d.Weather conditions (temperature, humidity),
e.Compatibility with existing coatings,
f.Surface preparation.

K 7. Describe the process for determining proper surface temperature prior to applying the coating.
a.Measure substrate that will be painted surface temperatures on all sides
b.Use all temperatures to determine worst case surface temperatures measured before blasting or painting.
c.Surface preparation or the application of a coating shall not be allowed when there is 5 degrees or less between the surface temperature and the dew point.

K 8. Describe the terms used in paint manufacturer's product data sheets.
a.Finish - description of coating appearance when cured. (example - Gloss, Semi-Gloss, Flat etc.)
b.Solids Content - Volume of solids typically reported as a percent of a packaged coating. Coating contents minus VOC's.
c.VOC - Volatile Organic Compounds - liquids that have high enough vapor pressure under normal conditions to significantly vaporize and enter the atmosphere.
d.Flash Point - The flash point of a flammable liquid is the lowest temperature at which it can form an ignitable mixture in air.
e.Surface Preparation - the removal of foreign matter from a metal by many of several means. The condition of the substrate surface can be described measured in mils.
f.Substrate - Surfaces to be painted

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K 9. Describe the use and calibration of equipment required for holiday detection.
a.Thin Film Wet Sponge Detector - A low voltage (67.5 volts) jeep or holiday detector used to find pinholes or thin coating in coatings up to 20 mils thick.
b.Thick film High Voltage Holiday Detection. Gradually move over cured coating. An audible signal will sound on the detector where a holiday exist. The inspector shall mark all holidays detected.
c.Test Voltage for holiday detectors - voltage for a specific coating shall be set to the voltage specified in the coating data sheet. All voltages are DC.
d.Calibrate by testing instrument on a coated surface with known holidays and by testing battery voltage.

K 10. Describe the use and calibration of equipment required for paint inspection.
a.Surface temperature thermometers - Two or more thermometers may be needed for full sun/shaded surfaces.
b.Sling psychrometers - Determine relative humidity and dew point from wet and dry bulb readings. Calibrate using an unused thermometer comparing temperatures before wetting sock on wet bulb.
c.Wet film thickness gauge - To use press gage against wet coating and remove. Read gage by identifying last (greatest) calibrated tab that has wet coating. Clean gage before storage and reuse. Calibrate against new equipment that has not been used.
d.Dry film thickness gauge - Type 1 magnetic pull-off gauges should be calibrated with card mounted standard metal plates. If a Positector 2000 gauge is used, then plastic shims should be used for its calibration.
e.Testex tape - use either coarse for 0.8-2.0 mils or x-coarse for 1.5-4.5 mils. Peel protective cover off of tape, apply tape to substrate, rub center circular piece in a circular motion with a clean smooth round object. Remove the tape and measure the rubbed surface
f.Spring micrometer - Place testex tape between measuring jaws of meter and release spring. Read placement of needle on calibrated face of micrometer.
g.Blast nozzle orifice gauge - Apply a grease pen marking on the gauge calibrated table. Insert orifice gage into threaded end of blast nozzle until nozzle bottoms out. Twist gage and remove from nozzle. Grease markings will be removed at point of contact. Read calibration at point of contact for nozzle size. No calibration. If wear is observed, discard and replace with new gage or compare to an un-used gage.

Abnormal Operating Conditions

1. Improper selection and/or application of coating system
Response: Notify designated operator representative

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Evaluation Criteria

Covered Task 428 - Pin Brazing to Install CP Leads on Pipeline

49 CFR 192 Reference
192.471

49 CFR 195 Reference
195.244
195.416 (b)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe how to determine pipeline wall thickness and location.
a.Consult with operator to determine product, line number, station number, location, and wall thickness verification process

K 2. Describe location requirements of the pin braze on the pipe surface.
a. Greater than one inch from a girth or longitudinal seam weld
b. Away from previous bonds or bond attempts

S 3. Demonstrate preparation of pipe surface for earth lead and brazing pin:
a. Remove coating
b. Clean surface of any oils or grease
c. Prepare surface - bring to a bright finish free of pits by means that will not jeopardize the integrity of the pipe

K 4. Describe selection of pin type and machine adjustment
a. Standard Pin
b. Threaded Pin
c. Load pin and ferrule in brazing gun
d. Hold gun flush against the pipe surface and adjust per manufacturer instructions.

S 5. Demonstrate installation of CP leads using pin brazing procedure:
a. Prepare and attach earth lead electrode to clean surface
b. Prepare and properly position cable connecting lug
1. Horizontal surface - pin should be placed in center of connecting lug
2. Vertical surface - Pin should be placed at top of connecting lug
c. Press brazing gun firmly to surface and hold trigger until fused connection breaks (nominally 2 seconds)
1.If the pin or lug is equipped with a fuse wire and the fuse does not break after normal time, keep trigger depressed and remove brazing gun from work surface; troubleshoot prior to attempting installation again
d. Continue to hold gun to surface for an additional few seconds to allow the braze to set
e. Remove gun by pulling straight from the surface in line with the pin and ferrule
f. Remove remaining pin and ferrule from gun

S 6. Test adhesion of braze
a. Standard Pin
1. Break shank of pin attached to the pipe with a hammer
2. Broken surface should be close to level with surface of lug.
b. Threaded Pin
1. Test with an approved torque device set to manufacturer instructions

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K 7. Describe final steps associated with CP lead installation:
a. Clean area and apply approved coating
b. Ensure CP leads are not damaged during backfill
c. Install test station
d. Take pipe to soil reading

Abnormal Operating Conditions

1. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Notify designated Operator representative

2. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated Operator representative

3. Unintended fire and/or explosion on or near the pipeline.
Response: Notify designated Operator representative

4. Failure or malfunction of pipeline component(s).
Response: Notify designated Operator representative

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Evaluation Criteria

Covered Task 501 - Conduct Pressure Test to Substantiate MAOP / MOP

49 CFR 192 Reference
192.328(d)
192.505
192.507
192.513

49 CFR 195 Reference
195.304
195.305
195.306

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify common test mediums.
a. Water
b. Air or Inert gas
c. Natural Gas

K 2. Describe considerations when water is used as a test medium
a. Pre- or post-test sampling
b. Filtering
c. Prevention of Freezing

K&S 3. Describe and simulate required preparation for conducting a pressure test:
a. Obtain plan which will provide details of pressure test parameters, target test pressures, pressure ranges +/-, location of manifolds, test medium, duration, holds if any, MAOP / MOP of facilities and confirmation of material design specifications
b. Confirm all required calibration reports for test equipment is available and current.
c. Verify test equipment certification is current and re-certify if required.
d. Confirm that strength of existing and temporary piping and components will withstand test pressure specified in testing plan.
e. Confirm all valves are in manufacturer's recommended position or per Operator's specifications and have been blown down or drained as required
f. Confirm that all fittings, flanges, unions and threaded joints have been checked to insure they are tight and properly sealed.
g. Place all testing equipment as far as practical from facility to be tested, locate opposite side of any seams, keep in mind elevation constraints
h. Setup and check all equipment for proper operation, confirm understanding of proper operation of all appropriate equipment including, Deadweights, electronic pressure monitor/recorders, mechanical pressure, temperature recorders, hoses, fittings, high and low-pressure pumps, stroke counters, etc.
i. Ensure the recording gauge is level and plumb.
j. If a recording pressure gauge is not available, an adequate spring gauge or deadweight gauge may be used with pressure readings taken at operator prescribed intervals throughout the duration of the test and properly documented the pressures in the appropriate format. . The test pressure gauge shall be verified at the test pressure with a deadweight check before and after the test.
k. Obtain and record the ambient temperature.
l. Confirm appropriate surveillance activities are conducted in order to minimize number of persons near the tests
m. Fill test segment with test medium

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K&S 4. Describe and simulate activities required to conduct test:
a. If recording chart is used, place the static pressure recording chart and pen at the correct time when the test officially begins.
b. After pressure stabilizes, begin test and ensure pressures remain within desired range for prescribed duration of test.
c. Monitor potential effects of sun and temperature on pressures.
d. Adjust test pressures to account for elevation at the gauge site in the test segment.
e. Monitor pressure variations and document causes and mitigation.
f. Record required pressure, temperature and pump stroke readings at intervals specified in the test plan.

K&S 5. Describe and simulate steps involved in depressurizing:
a. Confirm acceptance of test by authorized Operator's representative
b. Relieve pressure according to Operator specifications.
c. Remove test medium in accordance with Operator approved method to ensure minimal impact to the environment and according to any required permits.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 502 - Conduct Pressure Test on Pipe that is to be Operated at a Pressure <100 psig

49 CFR 192 Reference
192.509
192.511
192.513(b)

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and simulate the steps necessary to conduct a leak test where pressure is less than 100 p.s.i.:
a. Isolate the segment to be tested in accordance with Operator requirements.
b. Install/maintain calibrated test instruments/components in order to collect required test data
c. Setup appropriate equipment to introduce pressure and test medium into the segment to be tested.
d. Introduce test medium
e. Perform leak test in accordance with Operator procedures:
f. Ensure no leakage discovered
g. Remove isolation

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 601 - Start-up/Shut-down of Pipeline to Assure Operation Within MAOP / MOP

49 CFR 192 Reference
192.605(b)(5)
192.751

49 CFR 195 Reference
195.402
195.406

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Identify the key components of a pipeline shutdown and startup procedure.
a. Identification of pipeline segment to be shutdown
b. Lockout/tagout procedure
c. Notification requirements such as Pipeline control center or outside agencies
d. Line cleaning
e. Leakage survey, as applicable
f. Valve maintenance
g. Isolation
h. Pulldown/blowdown
i. MAOP/MOP limitations of the pipeline segment(s)
j. Purging
k. Packing
l. Return to service

K 2. Describe the steps required for isolation of segment:
a. Operate valves in proper sequence including all receipt and delivery points.
b. Lockout/tagout of valves
c. Monitor pressures in adjacent sections to ensure MAOP / MOP is not exceeded, as applicable

K 3. Identify the steps required for pulldown/blowdown of isolated section:
a. Perform pulldown, if applicable, to reduce pressure and minimize gas loss.
b. Identify and remove potential ignition sources.
c. Perform blowdown according to procedure.
d. Check for downdraft at blow-off valve at completion of the blow-down to keep air out of depressurized section.

K 4. Identify the steps required for purging with air or inert gas:
a. Review purge procedure
b. Ensure adequate supply of air or inert gas.
c. Perform purge according to procedure

K 5. Identify the steps required for purging with gas
a. Review purge procedure
b. Ensure adequate supply of gas
c. Notify pipeline control center and/or other appropriate personnel
d. Perform purge according to procedure.

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K 6. Identify the steps required for re-pressurizing pipeline:
a. Notify Pipeline control center
b. Control flow rates during pressurization
c. Ensure pressure does not exceed MAOP / MOP
d. When pressure is equalized assure all valves are returned to designated operating position
e. Notify Pipeline control center

K 7. Using facility drawings as necessary, identify the steps required for pipeline startup:
a. Startup procedure must be verified with designated Operator's representative prior to beginning startup
b. Identify section to startup
c. Identify valves to be operated (opened or closed) and the correct position of all valves
d. Open valves and pack pipeline at prescribed rate
e. Monitor pressures in section to be startup and adjacent sections to ensure MAOP / MOP is not exceeded
f. Review the receipt/delivery points into the pipeline and verify with Pipeline control center

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 602 - Monitoring Pipeline Pressure

49 CFR 192 Reference
192.605(b)(5)
192.619

49 CFR 195 Reference
195.402(c)(9)
195.406

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify common methods of monitoring pipeline pressure:
a. Network/location monitors
b. Deadweight reading
c. Pressure gauge

K 2. Explain steps to take if you suspect a false reading
a. Verify using another method(s)

K 3. Identify potential causes of unintended pipeline pressure increase, decrease, or differential.
a. Incorrect valve operation
b. Valve leakage
c. Line obstruction
d. Change in throughput
e. Rupture
f. Leak

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Loss of communication.
Response: Find alternate means of communication. If not possible, suspend activities and notify designated operator representative.

Unexplained high pressure deviation exceeding design limits.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 603 - Compressor Units/Stations: Start-up, Operation, Shutdown, and Purging Before Returning to Service

49 CFR 192 Reference
192.605(b)(6)
192.605(b)(7)
192.751

49 CFR 195 Reference
195.402(c)(7)
195.402(c)(8)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps associated with pre-startup:
a. Notify local station personnel prior to start attempt (if applicable).
b. Review the posted startup procedure for the unit
c. Review and verify knowledge of starting unit
* Ensure unit and station valves are properly positioned for the selected mode of operation.
* Verify all critical operating variables are within the safe limits of the unit.
* Confirm the unit is safe and ready to run (all safety alarms and shutdown devices are properly set and functional)

S 2. Simulate the proper procedures for start-up of a unit at your location.
a. Start the unit in accordance with posted procedure.
b. Follow manufacturer's instructions for operating the equipment after it has been started
c. Verify unit successfully starts and runs unloaded for the specific warm-up period described in the unit starting procedure.
d. Monitor all alarm conditions during warm-up.
e. Verify station suction and discharge pressures and calculate unit load

K 3. Describe the operating parameters and monitoring requirements for a specific unit(s):
a. Unit loads
b. Unit operating temperatures, pressures, and speeds
c. Monitor for unusual noises, vibrations, leaks
d. Surge margin, fuel ratio, and fluid levels
e. Monitor to ensure that MAOP(s) is not exceeded

S 4. Simulate the proper procedures for shutting down a unit at your location:
a. Slow the unit down to minimum speed
b. Unload the unit, open bypass valve
c. Let unit cool down
d. Shut off the fuel supply or initiate the stop
e. Close suction and discharge valves
f. Leave unit pressurized if the unit may be returned to service within a reasonable period of time

K 5. Identify the steps required in isolating/purging a compressor unit or a section of station piping.
a. Develop a shutdown and purge procedure utilizing the station drawings for proper isolation and get the procedure approved.
b. Receive approval from Pipeline control center to begin required work.
c. Operate valves in accordance with the shutdown or purge procedures.

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Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Excessive vibration on unit or associated piping that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Loss of communication.
Response: Find alternate means of communication. If not possible, suspend activities and notify designated operator representative.

Unexplained high flow rate and low pressure deviation.
Response: Notify designated operator representative.

Unexplained high pressure deviation exceeding design limits.
Response: Notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 604 - Locate, Mark, and Remediate Exposed Pipelines in the Gulf of Mexico

49 CFR 192 Reference
192.612(b)

49 CFR 195 Reference
195.413

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

S 1. Demonstrate proper calibration of line locating equipment.

S 2. Demonstrate use of locating device according to manufacturer's guidelines.

K 3. Describe proper survey technique:
a. How often is the line crossed?
b. How is the information plotted or recorded?
c. If shallow or exposed pipe is found, is the data verified?

K 4. Describe proper marking technique:
a. Mark the pipeline in accordance with 33 CFR part 64 at the ends of the segment and at intervals not over 500 yards long
b. Segments less than 200 yards long need only be marked in the center

K 5. Describe procedures for proper reburial of exposed pipelines:
a. Consider environmental conditions and permit requirements
b. Identify the steps that could be taken to protect the pipeline
c. Install Grout Bags
d. Mats
e. Rebury
f. Sand bags

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 605 - Locate Line/Install Temporary Marking of Buried Pipeline

49 CFR 192 Reference
192.614(c)(5)

49 CFR 195 Reference
195.442(c)(5)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe what details should be considered in selecting the proper line-locating device.
a.Electrical interference
b.Depth of pipe
c.Access to pipe
d.Line size
e.Line material
f.Presence of other facilities

K 2. Explain the different types of ways to use a locating device to place a signal or locate a signal on a target line and explain the advantage of each type
a.Conductive - direct connect method - metal to metal contact from transmitter to target should provide the best signal to detect
b.Inductive - induced signal on the target, set transmitter in line with the target pipeline and generates an electromagnetic field best method to use when a direct connection is not available
c.Passive - locate signals from foreign metallic conductors

K 3. Identify common problems with locate signals
a.Air coupling - Transmitter and receiver are too close; picking up the induced signal from the transmitter not the target pipeline.
b.Electromagnetic field from transmitter is distorted due to attracted/repelled signal from other buried facilities
c.Electrical interference from overhead or buried power lines
d.Inadequate connection or grounding when utilizing the conductive method.

K 4. Identify methods used to perform a inductive sweep search
a.In accordance with Operator procedures and/or manufacturer's instructions such as:
i.Circle sweep - hold the transmitter in the center point of the excavation area while the receiver is moved around the point at a distance not affected by air coupling, keep transmitter and receiver facing each other.
ii.Perimeter sweep - at a set distance apart the transmitter and receiver are walked parallel to the excavation on both sides of the located line and across the line at the ends of the excavation area.
iii.Spoke sweep - Transmitter and receiver transverse the excavation area at 90 Degrees, 45 Degrees, to create a wagon wheel spoke pattern for the search.

K 5. Explain how to determine the temporary marking requirements for the area to be located/marked.
a.Operator procedures
b.State or local marking requirements (i.e.; state internet home page)
c.Environmental conditions (weather, soil condition, etc.)
d.Terrain type (urban, rural, road, etc)

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K 6. Describe the national color code requirements for marking (APWA Uniform Color Code).
a.White - proposed
b.Pink - temporary survey markings
c.Red - electric power lines, cables, conduit and lighting cables
d.Yellow - gas, oil, petroleum or gaseous materials
e.Orange - communication, alarm or signal lines
f.Blue - potable water
g.Purple - reclaimed water, irrigation and slurry lines
h.Green - sewer and drain lines

K 7. Identify acceptable types of temporary markings:
a.Stakes
b.Flags
c.Paint
d.Chalk
e.Whiskers

K 8. Describe methods of documenting and communicating locate per:
a.Operator procedures
b.State or one call requirements

S 9. Demonstrate how to use maps, as-built survey information, and/or drawings to identify the general location of the pipeline and possible conditions that may affect the ability to locate the pipeline accurately.
a.Recognize crossovers
b.Multiple lines in ROW
c.Identified Foreign Facilities
d.Pipeline size and depth

S 10. Demonstrate the ability to operate the device and perform initial start up operation and verification activity as indicated in manufacturer's user information
a.Turn on the device
b.Check battery level
c.Verify device is operating within design parameters
i.Check locate at a predetermined location with a known posted depth

S 11. Demonstrate use of the line locator
a.Locate a pipeline in a ROW containing a single line, identify known foreign facilities
i.Demonstrate direct connection mode and inductive mode to locate facility
b.Locate a pipeline in a ROW or facility, containing a more complex pipeline configuration. (i.e.; multiple lines, a crossover, diverging pipe segments)
c.Demonstrate verification methods to ensure the locate signal is not distorted
i.Locate signal matches in peak and null modes
ii.Depth check method - locate peak signal take depth at ground level, raise receiver 1 foot retake depth- depth reading should concur with initial depth plus raise.
d.Perform a passive sweep to identify any unmarked facilities in the area of excavation
i.Identify the frequencies used to conduct the passive sweep and explain the specific characteristics of each
1.CPS - indicates the presence of Cathodic Protection
2.Power - indicates induces AC electrical frequencies from power lines, etc.
3.Radio - indicates other frequencies being carried that are transmitted from various sources.

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S 12. Demonstrate how to determine the vertical depth of the pipeline
a.Utilize appropriate methods (i.e.; T-bar, locator, etc)
b.Review precautions as to using these methods and potential accuracy concerns for establishing actual depth

S 13. Demonstrate how to properly place appropriate temporary line markings
a.Appropriate method(s) (stakes, flags, paint, etc)
b.Required information included on markings
c.Appropriate location(s) and/or distance

Abnormal Operating Conditions

1. Unreported encroachment activities that have impaired or are likely to impair the serviceability of the pipeline.
Reaction:
*Notify designated operator representative

2. Improperly marked and/or unmarked pipeline.
Reaction:
*Notify designated operator representative.
*Remark as directed by Operator, if qualified to do so

3. Locator equipment not operating properly.
Reaction:
*Notify designated operator representative.
*Troubleshoot in accordance with the manufacturer's literature.
*Verify the operation of the locator by locating a known source.

4. Incorrect drawings or schematics.
Reaction:
*Notify designated operator representative

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Evaluation Criteria

Covered Task 606 - Locate and Mark Submerged Pipelines

49 CFR 192 Reference
192.614(c)(5)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:0

K/S

K 1. Describe how to use maps, as-built survey information, GPS, and/or drawings to identify the location of the pipeline.

K 2. Describe what things should be considered in selecting the proper line-locating device.
a. Depth of water
b. Depth of pipe
c. Access to pipe
d. Line size
e. Line/coating material

K 3. Describe common methods of locating underwater pipeline:
a. Bottom sweeps
b. Probe
c. Water probing
d. Jetting
e. Scanning sonar

K 4. Describe common methods of installing temporary markers for submerged pipelines:
a. Cane poles
b. Buoys
c. Sonar reflector
d. Sonar pinger

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unreported activities that have impaired or are likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 607 - Damage Prevention: Observation of Excavating and Backfilling

49 CFR 192 Reference
192.328(a)(1)
192.614(c)(6)

49 CFR 195 Reference
195.252
195.442(c)(6)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe steps that must take place prior to excavation (including trenchless activities such as boring and directional drilling) activities:
a. Verification of One-Call
b. Provide excavator with guidelines for construction near pipelines
c. Identification of pipeline markers
d. Identification of foreign structures and utilities
e. Verify location and elevation of affected structures
f. Pot hole when appropriate to ensure adequate clearance
g. Provide for standby personnel as needed

K 2. Identify considerations during excavation of pipelines:
a. Ensure bucket teeth are barred and side cutters removed as applicable
b. Maintain clearance between bucket and pipeline according to operator guidelines
c. Hand excavate as required
d. Anticipate encountering unidentified foreign structures and pipeline appurtenances (i.e.., taps, valves, etc.)

K 3. Describe how to prevent damage during backfill operations:
a. Use rock shield as needed
b. Ensure pad dirt is free of rocks and other foreign material and compacted as appropriate
c. Ensure suitable pad dirt surrounds pipeline, as per Operator's policies & procedures
d. Ensure backfill material is free of large rocks and other foreign material
e. Do not fill directly on pipeline

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unintended movement of a pipeline that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 608 - Damage Prevention for Blasting Near a Pipeline

49 CFR 192 Reference
192.614(c)(6)

49 CFR 195 Reference
195.442(c)(6)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Oral Examination

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the steps necessary to prevent pipeline damage caused by nearby blasting activities:
a. Obtain the blasting plan
b. Ensure that all information is included in the blasting plan and that it has been properly reviewed by Operator representatives
c. Monitor blasting operations to ensure that the blasting plan is followed
d. Monitor pipeline pressure and perform a leakage survey, as appropriate.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 609 - Inspect and Maintain Odorization Equipment

49 CFR 192 Reference
192.625(e)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:3

K/S

K 1. Describe purpose of odorant systems.
a. Odorant systems are required in certain locations in order that leaks can be more readily detected.

K 2. Identify common types of odorization equipment
a. Injection pump odorizer
b. Non-injection type odorizer
* Wick
* Bypass

S 3. Demonstrate how to inspect odorization equipment:
a. Visually inspect fittings, connections, and odorization equipment for defects.
b. Determine odorant level
c. Calculate injection rate for flow conditions and make necessary adjustments
d. Repair/replace equipment, as necessary.
e. Fill odorant tank

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 610 - Monitor Odorant Concentration

49 CFR 192 Reference
192.625(f)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Describe requirements related to odorant concentration:
a. Odorant concentration must be such that gas is readily detectable at 1/5 of LEL.

K 2. Identify conditions that could interfere with obtaining accurate test results:
a. Wind
b. Presence of H_2S

S 3. Demonstrate how to use/operate an odorometer:
a. Ensure odorometer is calibrated
b. Properly connect and purge odorometer
c. Initiate flow until detectable by smell
d. Determine concentration
e. Record results
f. Shut off flow of gas to the odorometer and disconnect

K 4. Identify other methods for monitoring odorant concentration:
a. Sniff test
b. Obtain/analyze gas sample

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 611 - Hot Tap (Steel Pipe)

49 CFR 192 Reference
192.627
192.751

49 CFR 195 Reference
195.422

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:1

K/S

K 1. Describe the information which must be known prior to beginning a hot tapping operation:
a. Diameter and wall thickness of pipe
b. Pressure
c. Size of tap
d. Size and type of fitting

S 2. Simulate performance of a hot tap:
a. Set tapping machine up, verifying proper cutter and adapter.
b. Attach machine to valve
c. Run cutter in by hand until pilot bit touches pipe, and verify prior measurements.
d. Retract cutter to verify the tap valve will close.
e. Calculate boring distances and mark travel to bore on appropriate equipment.
f. Start the bore with bleed valve open.
g. Bore until bleed through occurs.
h. Shut in bleed valve. Let pressure equalize, and check all equipment for leaks.
i. Stop bore until any leaks are eliminated.
j. Bore to pre-marked depth, stop machine, and verify that entire cut has been made.
k. Slowly back out the cutter/perforator
l. Shut tap valve and bleed pressure off machine.
m. Remove machine
n. Examine cutter to verify presence of coupon, if shell cutter used.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unable to remove cutter and/or coupon.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 612 - Hot Tap (Plastic Pipe)

49 CFR 192 Reference
192.627
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe the information which must be known prior to beginning a hot tapping operation:
a. Diameter and wall thickness of pipe
b. Pressure
c. Size of tap
d. Size and type of fitting

S 2. Simulate performance of a tap with a self-tapping tee:
a. Set tapping machine up, verifying proper cutter and adapter.
b. Apply pressure reduction clamps.
c. Attach machine to pipe
d. Verify that perforator/cutter is in tee body. Make sure that top of cutter/perforator is even with top of tee body.
e. Run cutter in by hand until it touches tee, and verify prior measurements.
f. Retract cutter.
g. Screw in perforator/cutter until is pipe is perforated, proper pressure is achieved on tapping instrument and metal to metal seal is obtained
h. With outlet valve open, slowly back out the cutter
i. Verify the metal to metal seal was achieved, and hole was cut all the way through the wall of the pipe.
j. Purge tee if necessary
k. Perform leak test re-tap if leak is found
l. Remove cutting instrument and close the outlet valve
m. Run perforator cutter all the way out and allow full flow of gas.
n. Attach completion cap

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Unable to remove cutter and/or coupon.
Response: Notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 613 - Purge Pipeline Facilities With Gas

49 CFR 192 Reference
192.629(a)
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps required to prepare for purging with gas
a. Review Operator-approved purge procedure
b. Ensure adequate supply of gas
c. Obtain authorization from pipeline control center and/or other appropriate personnel.

K 2. Identify and describe the steps necessary to complete a purge of air or inert gas with gas:
a. Electrically bond the segment to be purged.
b. Remove or take precautions for handling liquid in the line.
c. Ensure that the blow-off valve at the downstream end of the section to be purged was opened and secured.
d. Install calibrated pressure gauge immediately downstream of the purge pressure control valve
e. Open the control point valve to the position where the gas purging pressure reached the pre-determined value in the purge plan and maintain pressure at all points required by the plan
f. Monitor weather conditions to ensure safe working environment during the purge.
g. Upon completion of purge, close the downstream blowoff.
h. Record purge times and pressures.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 614 - Purge Pipeline Facilities With Air or Inert Gas

49 CFR 192 Reference
192.629(b)
192.751

49 CFR 195 Reference
195.402(c)(10)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the steps required to prepare for purging with air or inert gas.
a. Review Operator-approved purge procedure
b. Ensure adequate supply of air or inert gas
c. Obtain authorization from pipeline control center and/or other appropriate personnel

K 2. Identify and describe the steps necessary to complete a purge of gas with an air mover:
a. Ensure an adequate supply of air is available for the air mover.
b. Establish the direction of the purge and mount air movers on the appropriate blowoff.
c. Ensure that air mover is grounded in accordance with Company procedures.
d. Remove or take precautions for handling liquid in the line, if necessary
e. Monitor weather conditions to ensure a safe working environment during the purge
f. Open air inlet.
g. Turn on the required supply to the air mover.
h. Sample the atmosphere in the pipeline at work location to verify a safe atmosphere.
i. Maintain the flow of air away from the workspace.

K 3. Identify and describe the steps necessary to complete a purge with pig or slug:
a. Ensure an adequate supply of air or inert gas is available for the purge.
b. Remove or take precautions for handling liquid in the line, if necessary.
c. Disconnect and physically isolate the pipeline sections to be purged.
d. Install calibrated pressure gauge immediately downstream of the purge pressure control valve
e. Open outlet.
f. Purge by injecting slug or running a pig through the section using air or inert gas.
g. Sample at outlet for presence of air or inert gas.
h. After pig has been received or slug has been detected, continue purge as specified in the plan.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 616 - Atmospheric Monitoring during Hot Work Operations

49 CFR 192 Reference
192.751

49 CFR 195 Reference
195.402(c)(11)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe when atmospheric monitoring for combustible gas is required and the appropriate equipment to use:
a. Prior to and during welding or cutting operations on any pipe or components that previously contained flammable material,
b. Anytime hot work is done in areas were there is a potential for gas to be present,
c. Combustible gas indicators (CGIs) not flame ionization detectors (FIDs).

K 2. Describe the general steps during hot work operations:
a. If required, obtain 'hot work permit' from appropriate operations and/or construction personnel each day hot work will be performed or per applicable company procedure,
b. Remove all flammable products from the work area,
c. Establish combustible gas monitoring points, in accordance with site specific procedures (as required),
d. Ensure some method of communicating between gas monitoring points and employees performing hot work,
e. Ensure continuous monitoring at specified locations, per applicable company procedures.
f. Devise means to ensure air movers (if installed) are working properly at all times (flagging, alarms),
g. Cover equipment, grating, etc. as needed to protect inaccessible areas from sparking/ignition sources,
h. Ensure appropriate fire suppressant materials (fire extinguisher(s), blankets, etc.) and fire monitoring personnel (fire watch) are present and in good working condition, as required

S 3. Demonstrate the use of a CGI according to manufacturer's guidelines.
a. State the type of equipment that will be used,
b. Demonstrate calibration and start up of CGI, according to manufacturer guidelines.
c. Demonstrate operation of a CGI.

Abnormal Operating Conditions

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

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Evaluation Criteria

Covered Task 701 - Patrolling Pipeline and Leakage Survey without Instrument

49 CFR 192 Reference
192.613
192.620(d)(4)
192.705
192.706
192.721

49 CFR 195 Reference
195.412(a)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify methods of pipeline patrol:
a. Aerial
b. Vehicular
c. Walking rights of way

K 2. Identify the items that may be observed while patrolling:
a. General condition of rights of way
b. Encroachments
c. Signs of gas leakage
* Dead or discolored vegetation
* Smell
* Ice accumulation
* Dust cloud
* Bubbles in water
d. Soil slips, subsidence, washouts, and erosion over pipeline
e. Condition of pipeline markers and information contained thereon to ensure markers comply with Operator requirements and DOT requirements.
f. Exposed pipe
g. Construction within an area that may impact class location (building, parks, recreational areas, etc. within 660 feet of pipeline)

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 702 - Leakage Survey with Leak Detection Device

49 CFR 192 Reference
192.706

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe means of identifying leaks:
a. Leak detection device
b. Smell
c. Dead vegetation
d. Ice accumulation
e. Dust cloud
f. Bubbles in water

S 2. Demonstrate use of the leak detection device according to manufacturer's guidelines.
a. State the type of equipment that will be used.
b. Demonstrate calibration and start up of leak detection device, according to manufacturer guidelines.
c. Demonstrate operation of leak detection device.

K 3. Describe how to test casing vents with gas detector.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 703 - Placing/Maintaining Line Markers

49 CFR 192 Reference
192.707

49 CFR 195 Reference
195.410(a)
195.410(c)

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify appropriate locations for line markers:
a. Stream crossings
b. Public road crossings
c. Railroad crossings
d. Above ground pipelines accessible to the public
e. Compressor and meter stations
f. Other locations designated by the operator (e.g.., fence lines)

K 2. Describe steps required to safely install a line marker:
a. Verify location of pipeline
b. Verify depth of pipeline
c. Install marker in order to maintain a safe distance from the pipeline.

K 3. Identify the information that must be correct and legible on the markers:
a. Emergency 24-hour Phone Number
b. Operator Identification
c. 'Warning' or 'Danger'
d. Name of gas transported

K 4. Describe what to look for when inspecting pipeline markers:
a. Verify proper location of pipeline marker
b. Verify accuracy of information on pipeline marker
c. Verify that pipeline marker is visible
d. Verify that pipeline marker is legible

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Unreported activities that have impaired or are likely to impair the serviceability of the pipeline. Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 704 - Permanent Field Repair by Grinding

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.226
195.230

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control
1:1

K/S

K 1. Describe the steps for making permanent repairs of imperfections or damage by grinding:
a. Verify wall thickness in defect area and establish minimum allowable wall thickness.
b. Verify that pressure is at safe level.
c. Grind the defect in a circumferential direction and monitor wall thickness during grinding process.
d. Contour the area around the defect to provide a smooth transition to the unaffected pipe surface.
e. Verify remaining wall thickness is within allowable limits.
f. Qualified person inspects area for cracking with wet mag particle or other operator-approved method.

S 2. Demonstrate the proper grinding procedure by removing a gouge from a piece of scrap pipe.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 705 - Permanent Field Repair Using Composite Materials (Clockspring)

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Manufacturer Certification

Span of Control
1:3

K/S

N/A 1. Obtain and maintain certification from manufacturer.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 706 - Permanent Field Repair Using Composite Materials (Armor Plate)

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Manufacturer Certification

Span of Control
1:0

K/S

N/A 1. Obtain and maintain certification from manufacturer.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 707 - Permanent Field Repair Using Bolt-On Clamp or Sleeve

49 CFR 192 Reference
192.717

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the steps for making field repairs using bolt-on clamp or bolt-on sleeve:
a. Verify that pressure is at safe level
b. Clean pipe surface to bare metal.
c. Place the clamp/sleeve around the pipe, over the leak, and tighten clamp/sleeve according to manufacturer's guidelines
d. Support pipe as required by operator.

S 2. Demonstrate installation of bolt-on clamp or bolt-on sleeve.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 708 - Permanent Field Repair Using Full Encirclement Weld Sleeve

49 CFR 192 Reference
192.717

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the steps for making field repairs using full encirclement weld sleeve:
a. Verify that pressure and flow rate are at acceptable levels
b. Clean pipe surface to bare metal.
c. Perform ultrasonic test
d. Install filler material, if applicable, according to operator requirements.
e. Prepare and fit top and bottom halves to the pipe
f. Ensure that a qualified welder welds side seams and ends in accordance with operator welding procedures
g. Ensure that welds are inspected or tested according to operator procedures.

S 2. Demonstrate how to properly align top and bottom halves to the pipe.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 709 - Inspection and Testing of Relief Devices (Compressor Stations, Meter Stations, Regulating Stations)

49 CFR 192 Reference
192.731(a)
192.731(b)
192.739
192.743

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the following types of relief devices and describe how they work:
* Spring loaded
* Pilot operated

K 2. Identify steps required to inspect/test a relief device:
a. Notify appropriate personnel (i.e.: customers, pipeline control center).
b. Record setpoint “as found”.
c. Assure that pipeline operations will not be jeopardized during testing/inspection of relief device and remove from service.
d. Monitor system pressure while relief device is isolated from the system.
e. Visually inspect valve for correct operation and signs of leakage, corrosion, damage, deterioration, and to ensure the outlet is clear of obstructions and in a safe location.
f. Verify setpoint pressures by observing a calibrated pressure indicating device while applying pressure greater than the set point to the device.
g. Verify capacity requirement of the relief device has not changed.
h. In the event that capacity of the relief device is insufficient, replace device or install additional device to provide for additional capacity requirement.
i. Return to service after completion of successful test and, if applicable, lock the isolation valve in the open position.
j. Record setpoint 'as left'.

S 3. Demonstrate how to test/inspect a relief device.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unexplained high pressure deviation exceeding design limits.
Response: Notify designated operator representative.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 710 - Inspect/Test Compressor Station Remote Control Shutdown Devices (ESD/EBD)

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K&S 1. Describe and simulate the steps to be followed for inspecting/testing compressor station remote control shutdown device.

a. Review and follow site-specific test plans
b. Block gas flow into and out of compressor station.
c. Activate a remote or manual ESD shutdown trigger.
d. Confirm that valves cycled in proper sequence and time
e. Confirm all compressor units within the tested system shutdown and AC power, and DC power as applicable, are shut down.
f. Ensure that each ESD trigger is inspected and tested for proper actuation
g. Return system to normal operation

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Unexplained high pressure deviation exceeding design limits.
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 711 - Inspect, Test, and Maintain Control Systems

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

S 1. Demonstrate how to calibrate each of the following:
a. Pressure transmitter
b. I/P transducer

S 2. Demonstrate how to maintain/inspect recorders.

K 3. Describe the importance of 4-20 shielding, grounding, and load balancing as it pertains to analog loops.

K 4. Explain the operating principle of a pressure switch, including dead band.

K 5. Explain what is meant by the phrase 'closes on rising pressure'.

K 6. Explain how class B shutdowns are bypassed during startup.

S 7. Use ladder drawings to identify shutdown limits.

K 8. Explain PLC hardware, software, and structure.

K 9. Draw and explain starting/shutdown string using 2-NO and 3-NC shutdown contacts (end-devices) and preset a latching shutdown coil with timer to set and panel reset, if applicable.

K 10. Draw and explain how to energize and latch a starter coil with a momentary push button, 2-NO and 3-NC permissive contacts, with engagement starter timer and shutdown to unlatch, if applicable.

K 11. Define and provide examples of Class A, Class B, and Class C shutdowns per the Instrument Society of America (ISA) standard.

K 12. Explain six alarms/shutdowns, including end device type, setpoint, purpose or safeguard, and action resulting from the alarm/shutdown.

K 13. Explain an alarm or shutdown from end device to SCADA display, including identification of end device, associated wiring, PLC input, local annunciation, HMI annunciation, and SCADA annunciation.

K 14. Explain voted shutdowns and give examples.

K 15. Explain redundancy and give examples.

K 16. Explain Company operating procedures regarding training, testing, and record keeping as it applies to shutdown systems.

K 17. Identify types of end-devices and the purpose of each.

K 18. Define which systems are fail-safe and non fail-safe.

K 19. Define the types of alarm indicators, i.e., audible lights, etc.

K 20. Explain the advantages and disadvantages of each alarm indicator.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

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Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 712 - Programmable Logic Controllers

49 CFR 192 Reference
192.731(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:1

K/S

K 1. Identify and describe the function of programmable logic controllers.

K 2. Describe possible concerns when installing a new PLC.

K 3. Explain maintenance of a Programmable Logic Controller.

K 4. Explain the Programmable Logic Controller's hardware, including:
a. Field terminations
b. I/O modules
c. Interface modules
d. Processors/co-processors
e. Modems
f. Communications hubs
g. Power supply
h. Power distribution, and
i. Grounding system

K 5. Describe the Programmable Logic Controller's software.

S 6. Demonstrate the following tasks, if applicable, using your PLC:
a. Utilize diagnostics to check PLC status
b. Download and upload PLC program
c. Display PLC logic and tasks (explain the operation), and
d. Stop and start PLC program execution

S 7. Demonstrate your ability to modify a PLC program, including:
a. Main line sequence control
b. Flow simulation
c. Remote operations
d. Tank level control
e. Remote alarming
f. Meter accumulation
g. Control loop

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

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Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 713 - Test/Maintain Gas Detection and Alarm Systems

49 CFR 192 Reference
192.736(c)

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and demonstrate how to test/maintain gas detection and alarm systems:
a. Visually inspect system in accordance with the company approved procedures. Inspect for signs of dirt, paint, wasp nests, or contamination. Clean system in accordance with manufacturer's specifications.
b. Isolate the gas detection system from the station shutdown, ESD/EBD system.
c. Connect gas detection system test equipment
d. Calibrate all sensors per manufacturer's instructions and check 'percent of LEL' levels in accordance with Operator requirements.
e. Verify that alarms and shutdown circuits activate at appropriate “percent of LEL”, as required by operator
f. Clear alarms and shutdowns and return system to service.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 714 - Inspect and Maintain Pressure Limiting and Regulating Devices

49 CFR 192 Reference
192.619(b)
192.739
192.743(a)

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe how the following types of pressure regulating devices work:
* Spring loaded
* Pilot operated

K 2. Identify the steps in inspecting/maintaining a pressure limiting/regulating device:
a. Verify required setpoint pressures
b. Record setpoint “as found”.
c. Determine the test media to be applied
d. Isolate from system and bypass, if necessary.
E. Monitor pressure if bypass is non-regulated.
F. Inspect for good mechanical condition, proper installation and protection from dirt, liquids or other conditions that might prevent proper operation.
g. Clean, repair or replace the device as necessary following the manufacturer's guidelines.
h. Inspect for any leakage
i. Test the device to insure proper operation over its intended operating range and is set to function at the correct pressure.
j. Verify the proper operation and set pressure prior to returning to service.
k. Place the device back in service and return the station to normal operating conditions.
l. Record setpoint “as left”.

S 3. Demonstrate how to determine current setpoint.

S 4. Demonstrate how to test and inspect a spring-loaded pressure regulating device.

S 5. Demonstrate how to test and inspect a pilot-operated pressure regulating device.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 715 - Test and Maintain Pressure Switches and Transmitters in Pressure Limiting and Regulating Service

49 CFR 192 Reference
192.619(b)
192.739
192.743(a)

49 CFR 195 Reference
195.428

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify and describe how pressure switches, pressure transmitters, and pressure transducers work in pressure limiting and regulating service.
a. Pressure switches shut down compression and activate other protection devices at predetermined set points
b. Pressure transmitters/transducers provide a variable signal based upon varying pressure on the pipeline to other logic devices that can shut down compression and activate other protection devices at predetermined set points

K 2. Identify the steps in testing/maintaining pressure switches and transmitters:
a. Verify required setpoint pressures
b. Record setpoint “as found”.
c. Determine the test media to be applied
d. Inspect for good mechanical condition, proper installation and protection from dirt, liquids or other conditions that might prevent proper operation.
e. Clean, repair or replace the device as necessary following the manufacturer's guidelines.
f. Inspect for any leakage
g. Test the device to insure proper operation and to ensure that it is set to function at the correct pressure.
h. Place the device back in service and return to normal operating conditions.
i. Record setpoint “as left”.

S 3. Demonstrate how to adjust setpoint on a pressure switch.

S 4. Demonstrate how to calibrate a pressure transmitter/transducer loop/system.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 716 - Inspect, Maintain, and Operate Valves

49 CFR 192 Reference
192.745
192.747

49 CFR 195 Reference
195.420(a)
195.420(b)

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify the most common types of pipeline valves.
* Ball valve
* Plug valve
* Gate valve

S 2. Demonstrate how to inspect a valve and associated components:
a. Verify valve is properly identified
b. Perform a physical inspection of valve body, flanges, bolts, operator, locking devices, lube fittings, chains, lock, etc. for leaks, corrosion, and damage
c. Operate valve (partially operate when full operation is not possible) to ensure valve operates properly. Include in operation both manual valve and valve with operator.

S 3. Demonstrate how to perform valve maintenance
a. Understand and follow manufacturer's specifications
b. Lubricate the valve according to valve type and manufacturer guidelines.
c. Identify pressure rating of valve and monitor grease pressure to ensure valve pressure rating is not exceeded during lubrication.
d. Clean stem threads, according to valve type.
e. Energize and/or replace stem packing to seal valve stem leaks or for predictive maintenance.
f. Bleed valve body, according to valve type.
g. Winterize valves subject to freezing.
h. Provide corrosion inhibitor (if applicable)
i. Operate valve (partially operate when full operation is not possible) to ensure valve operates properly. Include in operation both manual valve and valve with operator.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 717 - Maintaining Vaults With Pressure Regulating and Pressure Limiting Equipment

49 CFR 192 Reference
192.749

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

S Note: This covered task applies only to those vaults in which a pressure regulating device is used. Operator-specific procedures must be followed while working in permit-required confined spaces.

K 1. Identify the steps to be followed in inspecting a vault with a pressure regulating device.
a. Inspect physical condition of vault.
b. Ensure that vault is adequately ventilated that ventilation system is free from obstructions, and is operating properly.
c. Inspect cover to ensure that it does not present a hazard to public safety.
d. Inspect vault for presence of combustible gas (gas detection)

S 2. Demonstrate use of gas detection equipment according to manufacturer's guidelines.
a. State the type of equipment that will be used.
b. Demonstrate calibration and start up of gas detection equipment, according to manufacturer guidelines.
c. Demonstrate operation of gas detection equipment.

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 718 - Monitoring for Internal Corrosion with Liquid Samples

49 CFR 192 Reference
192.477
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Observation & Oral Exam.

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K&S 1. Describe and demonstrate the process of obtaining a liquid sample:
a.Obtain and prepare necessary equipment and sample kit for internal corrosion monitoring
b.Perform a visual inspection of the facility
c.Purge location from which sample is to be taken
d.Obtain necessary samples
e.Perform the necessary steps to prepare samples for testing and/or shipping

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 719 - Permanent Field Repair Using Composite Materials (Wrapmaster)

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Manufacturer Certification

Span of Control
1:3

K/S

K 1. Obtain and maintain certification from manufacturer

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 722 - Permanent Field Repair Using Composite Materials (Aqua Wrap)

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
3 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
Manufacturer Certification

Span of Control
1:3

K/S

K 1. Obtain and maintain certification from manufacturer

Abnormal Operating Conditions

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 723 - Leakage Survey with Remote Laser Leak Detection Device

49 CFR 192 Reference
192.706

49 CFR 195 Reference
195.412(a)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:1

K/S

K 1. Describe means of identifying leaks:
a. Leak detection device
b. Smell
c. Dead vegetation
d. Ice accumulation
e. Dust cloud
f. Bubbles in water

S 2. Demonstrate use of a remote laser leak detection device according to manufacturer's guidelines.
a. Demonstrate calibration and start up of leak detection device, according to manufacturer guidelines.
b. Demonstrate proper operation of the device.

K 3. Describe how to test casing vents with gas detector.

Abnormal Operating Conditions

1. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

2. Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

3. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

4. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

5. Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

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Evaluation Criteria

Covered Task 724 - Permanent Field Repair Using Composite Materials (Pipe Wrap A+)

49 CFR 192 Reference
192.713

49 CFR 195 Reference
195.422(a)
195.585(a)(2)

Evaluation Method:
Certificate and Oral Examination

Subsequent Qualification Interval
1 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)

Manufacturer Certification

Span of Control
1:3

K/S

K/S 1. Obtain and maintain certification from manufacturer.

Abnormal Operating Conditions

Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative.

Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 725 - Aerial Leakage Survey: Transmission

49 CFR 192 Reference
192.706

49 CFR 195 Reference
195.412(a)

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required

(If training is required, appropriate training documentation must be submitted with this ROE.)

None

Span of Control

1:3

K/S

K 1. Identify leakage survey scope, method and requirements
The individual will be able to identify:
1. Leakage survey scope - utilize maps and records to identify segments to be surveyed
2. Method - aerial.
3. Requirements:
a. Transmission lines:
i. Take a continuous sampling of the atmosphere at 100 - 500 feet above ground level over buried gas facilities and above-ground gas facilities,
ii. Taking into account wind speed and direction, offset the aircraft downwind of pipeline and facilities such that leaking gas can still be detected by the instrumentation.
iii. The use of this survey method may be limited by adverse conditions (such as excessive wind, excessive soil moisture or frost or surface sealing by ice or water).
iv. The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained giving consideration to the location of gas facilities and any adverse conditions which might exist..

S 2. Perform equipment operation check
The individual will, prior to use and periodically if required, be able to:
1. Perform equipment operation check in accordance with manufacturer's instructions, including:
a. Verifying the sampling system is free of obstructions,
b. Verifying that nothing is obstructing the sample flow,
2. Verify recommended voltage requirements
3. Test Hydrogen the gas detection system for proper operations,
4. Initiate corrective action for equipment out of specification

S 3. Perform survey
The individual will be able to perform leakage surveys:
1. Operate the equipment in accordance with the manufacturer's instructions
2. Include all segments identified during Step 1
3. In accordance with the requirements identified during Step 1

Abnormal Operating Conditions

1. Pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Eliminate potential ignition sources and notify designated operator representative.

2. Material defects, anomalies, or physical damage of pipe or a component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

3. Unintended fire and/or explosion on or near the pipeline.
Response: Leave immediate area and notify designated operator representative

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4. Failure or malfunction of pipeline component(s).
Response: Notify designated operator representative.

5. Corrosion on pipeline component that has impaired or is likely to impair the serviceability of the pipeline.
Response: Notify designated operator representative.

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Evaluation Criteria

Covered Task 728 - Aerial Leakage Survey: Transmission (UV/IR)

49 CFR 192 Reference
192.706

49 CFR 195 Reference
N/A

Subsequent Qualification Interval
3 Years

Evaluation Method:
Observation & Oral Exam.

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Identify leakage survey scope, method and requirements
The individual will be able to identify:
1. Leakage survey scope - utilize provided information and data to identify segments to be surveyed
2. Requirements:
a. Continually survey the atmosphere at the appropriate (as dictated by conditions and/or equipment) above ground level over buried gas facilities and above-ground gas facilities, taking into account wind speed and direction.
b. The survey may be limited by adverse conditions such as excessive wind and thunderstorms.
c. The survey should be conducted at speeds slow enough to allow adequate surveying to be continuously obtained giving consideration to the location of gas facilities and any adverse conditions.

S 2. Perform equipment operation check. The individual will, prior to use and periodically if required, be able to:
1. Perform an equipment operation check in accordance with manufacturer's instructions, including:
a. Verifying the surveying system functions as intended,
b. Verify the calibration of the system for the targeted gas
c. Verifying that nothing is obstructing the surveying device
2. Verify recommended operating parameters of the equipment (e.g., voltage, sensor response, laser power output):
3. Initiate corrective action for equipment that is out of specification

S 3. Perform survey. The individual will be able to perform leakage surveys:
1. Operate the equipment in accordance with the manufacturer's instructions.
2. In accordance with the requirements identified during step 1of this section.

Abnormal Operating Conditions

1. Significant pipeline leak, unauthorized release, vapors, or hazardous atmosphere.
Response: Quantify the leak. Leave the area immediately. Notify the operator.

2. Unintended fire and/or explosion on or near the pipeline.
Response: Leave the area immediately. Notify the operator.

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Evaluation Criteria

Covered Task AGL-019A - Hazard Control

49 CFR 192 Reference
192.751

49 CFR 195 Reference
N/A

Evaluation Method:
Oral Examination

Subsequent Qualification Interval
5 Years

Supporting Documentation Required
(If training is required, appropriate training documentation must be submitted with this ROE.)
None

Span of Control
1:3

K/S

K 1. Describe the requirements for hazard control
a.Taking steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion.
b.Removing each potential source of ignition from the area and providing a fire extinguisher when a hazardous amount of gas is being vented into open air.

K 2. Describe potential sources of ignition
a.Smoking and open flames.
b.Arcing from electrical devices in use.
c.Static electrical build-up or discharge.
d.Running engines.

K 3. Describe what factors to consider before blowing down, venting, or purging to help prevent accidental ignition
a.Proximity of houses, plants, or buildings.
b.Proximity of pedestrian, automotive, railroad or air traffic.
c.Proximity of electric transmission lines.

K 4. Describe what considerations/actions must be taken to prevent accidental ignition when responding to a gas leak or emergency call
a.Recognize when a hazardous amount of gas may be vented into open air
b.Monitor wind direction and velocity.
c.Restrict access to the area of operations.

K 5. With regard to accidental ignition of natural gas, explain possible actions an individual may take when it occurs
a.Eliminate fuel.
b.Determine the wind direction.
c.Use a fire extinguisher.
d.Eliminate sources of ignition.

K 6. Explain suitable precautions/actions to be taken prior to beginning any maintenance work on gas line systems.
a.Sniffing the air for the presence of natural gas.
b.Locate pipe.
c.Use Bonding cables when separating steel pipe
d.Post warning signs or barricades, where appropriate, when gas is being vented to the atmosphere

Abnormal Operating Conditions

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1. Occurrence of accidental ignition.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

2. Presence of hazardous amount of gas in an area.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

3. Indications of increasing amount of gas.
Response: Notify designated operator representative. If qualified to do so, correct the condition and make operator representative aware of action taken to correct condition.

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EXHIBIT D

VERIFORCE OPERATOR QUALIFICATION POLICIES AND PROCEDURES

Operator Qualification
Policies and Procedures Manual

Related to the Operator Qualification Rule
49 CFR §192(N)
49 CFR §195(G)

Revision: 13

Revision Date: June 1, 2012

The following document describes proprietary policies and procedures of ***Veriforce***, LLC and is recognized and offered by the company to individuals conditioned on their acceptance without disclosure, duplication, modification of the terms, conditions, and notices contained herein unless otherwise noted through contractual agreement(s) or unless otherwise provided in writing. Reading or otherwise accepting this document constitutes an agreement to all such terms, conditions, and notices. Any use of this document may also be subject to additional terms outlined elsewhere in associated agreements. In the event that any of the terms, conditions, and notices contained herein conflict with the additional agreement terms or other terms and guidelines contained within any particular ***Veriforce*** system component, then the terms reflected herein, shall control. This document may not be reproduced in any fashion without the expressed written consent of ***Veriforce***, LLC.

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Part I: Background/Introduction

These procedures outline acceptable practices, measures, and methods for evaluating, qualifying, and documenting qualifications of personnel who perform covered tasks for ***Veriforce*** Operator clients. These procedures outline processes implemented by ***Veriforce*** for Operator clients to comply with the Operator Qualification (OQ) Rule codified at 49 CFR 192 Subpart N and 49 CFR 195 Subpart G.

These procedures are separated into ten parts, as outlined below:
1. Background/Introduction;
2. Regulations/Requirements/Standards
3. Definitions;
4. Evaluator Authorization;
5. Training of Personnel;
6. Evaluation of Personnel;
7. Program Quality Management;
8. Documentation and Record Keeping;
9. Management of Change; and
10. ***Veriforce*** Program Management.

Veriforce will, by following the procedures outlined herein, assist in determining whether an individual(s) is qualified to perform a covered task identified by a specific Operator according to evaluation criteria defined by that Operator.

Veriforce is responsible for communicating the Operator's requirements, as well as subsequent changes to these requirements, to appropriate parties. As a result, ***Veriforce*** is in a unique position to communicate back to Operators those issues/challenges encountered in implementing their respective OQ programs and assist in identifying, recommending, and implementing program improvements.

Veriforce represents and assists its Operator clients in implementing their respective programs and assists them in ensuring and demonstrating compliance with the OQ rule. Specifically, the OQ-related services which ***Veriforce*** offers to Operators include the following:

Third Party Oversight/Management of Contractor Personnel Evaluations and Qualifications
- Review/analysis of qualifications put in place through other processes/organizations to determine equivalency to Operator client requirements,
- Assistance in solving OQ issues and/or arranging for expedited qualification of individuals in order to minimize interruptions to affected projects/work,
- Required execution of Professional Services Agreement by Contractors which sets forth obligations related to meeting Operator-specific OQ requirements,
- Implementation of Operator-defined covered tasks and underlying evaluation criteria.

Evaluator Authorization
- Reference-check process to ensure technical competence of Evaluator related to applicable covered tasks;
- ,Administer formal Evaluator Training Program;
- Tracking/reporting of Evaluator by employer and transferring applicable records when Evaluator changes employers; and
- Monitor Evaluator performance through a structured audit and investigation process.

Training
- Evaluators ensure that appropriate training requirements have been completed before conducting an evaluation,
- Provide resources to support on-the-job training (OJT) of pipeline personnel,

- Provide training and guidance to Evaluators on the use of ***Veriforce*** provided OJT resources,
- Develop, administer, and document customized training programs, per Operator request,
- Document personnel training conducted through other organizations, and
- Report personnel training via secure web accessible database.

Quality Records Maintenance

- Document current employer for each Qualified Individual
- Centralized maintenance of full audit trail to support each qualification including (a) Record of Evaluation and (b) documentation to support applicable Evaluator credentials,
- Self-audit of records for completeness/accuracy through a structured audit process,
- Maintenance of "Change Control History" relative to specific covered tasks and qualification requirements,
- Quality Assurance to ensure Evaluator of record has been properly authorized (per processes outlined herein) for applicable covered task(s),
- Transfer of individual qualifications/records when a Qualified Individual changes employers (portability), as allowed.

Data Management and Reporting

- Reporting of qualification records via secure web accessible database,
- Quality Assurance process to ensure validity of data and consistency with underlying quality records
- Customization of web-based reporting tool for Operator clients (as requested),
- Tracking, reporting, and automated notification of "soon to expire qualifications", "suspended qualifications", "revoked qualifications", and "disqualifications",
- Provide support to Operator's field personnel in verifying qualification status
- Tracking Contractors designated as Operator-approved "vendors" vs. "non-vendors".

Operator/Contractor Communication Support

- Initiate communication on behalf of Operator client, as requested, through web-based notification/tracking system, telephone, email, fax, and/or mail,
- On a daily basis, handle incoming requests/questions of Contractors on behalf of Operator client,
- Work with Operator clients to categorize/implement "Management of Change" documentation and communication to affected parties,
- Support Operator client's field personnel in search of Contractor/personnel qualification status and/or to address specific issues/problems,
- Post and maintain Operator-specific requirements, covered task list, evaluation criteria, and other documents.

Qualified Individual and Authorized Evaluator Audits

- Random and for cause auditing of Qualified Individuals to ensure continued qualification,
- Random and for cause auditing of Authorized Evaluators to ensure that evaluations are being conducted in accordance with these procedures and any other specific Operator requirements,
- Provide assistance to Operator in investigating incidents/accidents reported during audit process to determine need for re-evaluation.

Other Services

- Customized training programs to support Operators in OQ implementation,
- Technical support provided to Operator clients in preparing for and/or undergoing PHMSA/State OQ inspections/audits including being present at the inspection, if requested, to describe/document OQ qualification activities/procedures,
- Technical support in reviewing Operator OQ Program, covered task list and underlying evaluation criteria, and other documents/records,
- Develop and execute formal process for sharing best practices and/or compliance experience of individual Operator(s) with other Operator clients to improve compliance efforts.

Part II: Regulations/Requirements/Standards

The Operator Qualification Rule (49 CFR §192.801/§195.501)

The following table provides a reference to these procedures relative to specific provisions of the OQ rule.

Regulatory Citation	Title	Regulatory Requirement	*Veriforce Procedures*
§192.801 §195.501	Scope		
§192.801(a) §195.501(a)		This subpart prescribes the minimum requirements for Operator qualification of individuals performing covered tasks on a pipeline facility.	
§192.801(b) §195.501(b)		For the purpose of this subpart, a covered task is an activity, identified by the Operator, that: (1) Is performed on a pipeline facility; (2) Is an operations or maintenance task; (3) Is performed as a requirement of this part; and (4) Affects the operation or integrity of the pipeline.	Part III Part VI Part X
§192.803 §195.503	Definitions	Abnormal operating condition means a condition identified by the Operator that may indicate a malfunction of a component or deviation from normal operations that may: (a) Indicate a condition exceeding design limits; or (b) Result in a hazard(s) to persons, property, or the environment.	Part III
§192.803 §195.503		Evaluation means a process, established and documented by the Operator, to determine an individual's ability to perform a covered task by any of the following: (a) Written examination; (b) Oral examination; (c) Work performance history review; (d) Observation during: (e) Performance on the job, (f) On the job training, or (g) Simulations; or (h) Other forms of assessment.	Part III
§192.803 §195.503		Qualified means that an individual has been evaluated and can: (a) Perform assigned covered tasks; and (b) Recognize and react to abnormal operating conditions.	Part III
§192.805 §195.505	Qualification program	Each Operator shall have and follow a written qualification program. The program shall include provisions to:	Part I
§192.805(a) §195.505(a)		Identify covered tasks;	Part I Part VI Part X
§192.805(b) §195.505(b)		Ensure through evaluation that individuals performing covered tasks are qualified;	Part VI
§192.805(c) §195.505(c)		Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;	Part VI
§192.805(d) §195.505(d)		Evaluate an individual if the Operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;	Part VI Part VII
§192.805(e) §195.505(e)		Evaluate an individual if the Operator has reason to believe that the individual is no longer qualified to perform a covered task;	Part VI Part VII
§192.805(f) §195.505(f)		Communicate changes that affect covered tasks to individuals performing those covered tasks; and	Part IX
§192.805(g) §195.505(g)		Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.	Part X Part VI
§192.805(h) §195.505(h)		After December 16, 2004 provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operations of pipeline facilities	Part V
§192.805(i) §195.505(i)		After December 16, 2004 notify the administrator or a State agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or State agency has verified that it complies with this section.	Not Applicable to ***Veriforce***

Regulatory Citation	Title	Regulatory Requirement	***Veriforce* Procedures**
§192.807 §195.507	Recordkeeping	Each Operator shall maintain records that demonstrate compliance with this subpart.	Part VIII
§192.807(a) §195.507(b)		Qualification records shall include: 1) Identification of qualified individual(s); 2) Identification of the covered tasks the individual is qualified to perform; 3) Date(s) of current qualification; and 4) Qualification method(s).	Part VIII
§192.807(b) §195.507(b)		Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.	Part VIII
§192.809 §195.509	General		
§192.809(a) §195.509(a)		Operators must have a written qualification program by April 27, 2001.	Not Applicable to ***Veriforce***
§192.809(b) §195.509(b)		Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.	Not Applicable to ***Veriforce***
§192.809(c) §195.509(c)		Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999.	Part VI
§192.809(d) §195.509(d)		After October 28, 2002, work performance history may not be used as a sole evaluation method.	Part VI
§192.809(e) §195.509(e)		After December 16, 2004, observation of on-the-job performance may not be used as the sole evaluation method.	Part VI

The Alternative MAOP Rule (49 CFR §192.620)

The following table provides a reference to these procedures relative to specific provisions of the AMAOP rule as it relates to the qualification of personnel.

Regulatory Citation	Title	Regulatory Requirement	***Veriforce* Procedures**
§192.620(c)(6)	What is an operator electing to use the alternative maximum allowable operating pressure required to do?	If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a "covered task", notwithstanding the definition in §192.801(b) and implement the requirements of subpart N as appropriate.	Part I Part VI Part VIII Part X

PHMSA Enforcement Protocols

DOT/PHMSA utilizes enforcement protocols designed to standardize enforcement of the OQ Rule throughout the pipeline industry. While these protocols are subject to change, the following table is based on the version of protocols most current as of the effective date of these procedures (PHMSA Form 14 Rev. 5) and is provided as a reference to illustrate which parts of these procedures address corresponding protocol requirements.

#	Title	Protocol Question	Verification Items	*Veriforce* Procedures
1.01	**Application and Customization of "Off-the-Shelf" Programs**	Does the Operator's plan identify covered tasks and does it specify task-specific reevaluation intervals for individuals performing covered tasks? (Associated Protocols: 1.05, 2.01, 5.02)	NA	Part I (all) 6.1 10.1
1.02	**Contractor Qualification**	Does the Operator employ contractor organizations to provide individuals to perform covered tasks? If so, what are the methods used to qualify these individuals and how does the Operator ensure that contractor individuals are qualified in accordance with the Operator's OQ program plan? (Associated Protocols: 1.05, 2.02, 3.02)	Verify that the Operator's written program includes provisions that require all contractor and subcontractor individuals be evaluated and qualified prior to performing covered tasks, unless the covered task is performed by a non-qualified individual under the direction and observation of a qualified individual.	All
1.03	**Management of Other Entities Performing Covered Tasks**	Has the Operator's OQ program included provisions that require individuals from any other entity performing covered task(s) on behalf of the Operator (e.g., through mutual assistance agreements) be evaluated and qualified prior to task performance? (Associated Protocols: 1.05, 2.02)	Verify that other entities that perform covered task(s) on behalf of the Operator are addressed under the Operator's OQ program and that individuals from such other entities performing covered tasks on behalf of the Operator are evaluated and qualified consistent with the Operator's program requirements.	All ("other entities" to be held to meeting same requirements as contractors)
1.04	**Training Requirements (Initial Qualification, Remedial if Initial Failure, and Reevaluation)**	Does the Operator's OQ program plan contain policy and criteria for the use of training in initial qualification of individuals performing covered tasks, and are criteria in existence for re-training and reevaluation of individuals if qualifications are questioned? (Associated Protocols: 5.02)	NA	Part V (all) 6.1 6.3 6.4 6.6 6.8 6.9 6.10 7.1 8.1 9.3 10.2
1.05	**Written Qualification Program**	Did the Operator meet the OQ Rule requirements for establishing a written Operator qualification program and completing qualification of individuals performing covered tasks? (Associated Protocols: 3.01, 7.01)	Verify that the Operator's written qualification program was established by April 27, 2001.	NA – Operator Requirement
			Verify that the written qualification program identified all covered tasks for the Operator's operations and maintenance functions being conducted as of October 28, 2002.	NA – Operator Requirement
			Verify that the written qualification program established an evaluation method(s) to be used in the initial qualification of individuals performing covered tasks as of October 28, 2002.	NA – Operator Requirement.

#	Title	Protocol Question	Verification Items	*Veriforce* Procedures
			Verify that all individuals performing covered tasks as of October 28, 2002, and not otherwise directed or observed by a qualified individual were qualified in accordance with the Operator's written qualification program.	All
2.01	**Development of Covered Task List**	How did the Operator develop its covered task list? (Associated Protocols: 8.01)	Verify that the Operator applied the four-part test to determine whether 49 CFR Part 192 or 49 CFR Part 195 O&M activities applicable to the Operator are covered tasks.	6.1 10.1
			Verify that the Operator has identified and documented all applicable covered tasks.	6.1 10.1
2.02	**Evaluation Method(s) (Demonstration of Knowledge, Skill and Ability) and Relationship to Covered Tasks**	Has the Operator established and documented the evaluation method(s) appropriate to each covered task? (Associated Protocols: 3.01, 3.02)	Verify what evaluation method(s) has been established and documented for each covered task.	6.1 10.1
			Verify that the Operator's evaluation program ensures that individuals can perform assigned covered tasks.	Part I Part VI
			Verify that the evaluation method is not limited to on-the-job performance, except with respect to tasks for which OPS has determined that such observation is the best method of examining or testing qualifications. The results of any such observations shall be documented in writing.	6.1 10.1
2.03	**Planning for Mergers and Acquisitions (Due Diligence re: Acquiring Qualified Individuals)**	Does the operator have a process for managing qualifications of individuals performing covered tasks during program integration following a merger or acquisition (applicable only to operators engaged in merger and acquisition activities)? (Associated Protocols: 3.01, 3.02)	Verify that the OQ program describes the process for ensuring OQ qualifications, evaluations, assignment, and performance of covered tasks during the merger with or acquisition of other entities.	NA – Operator Requirement
3.01	**Development/ Documentation of Areas of Qualification for Individuals Performing Covered Tasks**	Does the Operator's program document the evaluation and qualifications of individuals performing covered tasks, and can the qualification of individuals performing covered tasks be verified at the job site? (Associated Protocols: 4.02, 7.01)	Verify that the Operator's qualification program has documented the evaluation of individuals performing covered tasks.	7.3 8.1 8.2
			Verify that the Operator's qualification program has documented the qualifications of individuals performing covered tasks.	7.3 8.1
3.02	**Covered Task Performed by Non-Qualified Individual**	Has the Operator established provisions to allow non-qualified individuals to perform covered tasks while being directed and observed by a qualified individual, and are there restrictions and limitations placed on such activities? (Associated Protocols: 2.01, 2.02)	Verify that the Operator's program includes provisions for the performance of a covered task by a non-qualified individual under the direction and observation by a qualified individual.	6.9 6.10
4.01	**Role of and Approach to "Work Performance**	Does the Operator use work performance history review as the sole method of qualification for individuals performing covered tasks prior to	Verify that after October 28, 2002, work performance history is not used as a sole evaluation method.	6.3

#	Title	Protocol Question	Verification Items	*Veriforce* Procedures
	History Review"	October 26, 1999, and does the Operator's program specify that work performance history review will not be used as the sole method of evaluation for qualification after October 28, 2002? (Associated Protocols: 2.02)	Verify that individuals beginning work on covered tasks after October 26, 1999 have not been qualified using work performance history review as the sole method of evaluation.	6.3 6.7 6.11
4.02	**Evaluation of Individual's Capability to Recognize and React to AOCs**	Are all qualified individuals able to recognize and react to AOCs? Has the Operator evaluated and qualified individuals for their capability to recognize and react to AOCs? Are the AOCs identified those that the individual may reasonably anticipate and appropriately react to during the performance of the covered task? Has the Operator established provisions for communicating AOCs for the purpose of qualifying individuals? (Associated Protocols: 3.01)	Verify that individuals performing covered tasks have been qualified in recognizing and reacting to AOCs they may encounter in performing such tasks.	6.7 6.10 6.11
5.01	**Personnel Performance Monitoring**	Does the Operator's program include provisions to evaluate an individual if the Operator has reason to believe the individual is no longer qualified to perform a covered task based on: • Covered task performance by an individual contributed to an incident or accident. • Other factors affecting the performance of covered tasks. (Specific Protocols: 2.02)	Verify that the Operator's program ensures evaluation of individuals whose performance of a covered task may have contributed to an incident or accident.	Part VII 6.10 10.3
			Verify that the Operator has established provisions for determining whether an individual is no longer qualified to perform a covered task, and requires reevaluation.	7.1 10.3
5.02	**Reevaluation Interval and Methodology for Determining the Interval**	Has the Operator established and justified requirements for reevaluation of individuals performing covered tasks? (Associated Protocols: None)	Verify that the Operator has established intervals for reevaluating individuals performing covered tasks.	6.1 10.1
6.01	**Program Performance and Improvement**	Does the Operator have provisions to evaluate performance of its OQ program and implement improvements to enhance the effectiveness of its program? (Associated Protocols: None)	NA	Part VII 9.1
7.01	**Qualification "Trail"(<u>i.e.</u>, covered task; individual performing; evaluation method(s); continuing performance evaluation; reevaluation interval; reevaluation records)**	Does the Operator maintain records in accordance with the requirements of 49 CFR 192, subpart N, and 49 CFR 195, subpart G, for all individuals performing covered tasks, including contractor individuals? (Associated Protocols: 1.05, 3.01)	Verify that qualification records for all individuals performing covered tasks include the information identified in the regulations.	Part VIII
			Verify that the Operator's program ensures the retention of records of prior qualification and records of individuals no longer performing covered tasks for at least five years.	8.6
			Verify that the Operator's program ensures the availability of qualification records of individuals (employees and contractors) currently performing covered tasks, or who have previously performed covered tasks.	8.1 8.5

#	Title	Protocol Question	Verification Items	*Veriforce* Procedures
8.01	**Management of Changes (to Procedures, Tools, Standards, etc.)**	Does the Operator's OQ program identify how changes to procedures, tools standards and other elements used by individuals in performing covered tasks are communicated to the individuals, including contractor individuals, and how these changes are implemented in the evaluation method(s)? (Associated Protocols: 1.04)	Verify that the Operator's program identifies changes that affect covered tasks and how those changes are communicated, when appropriate, to affected individuals.	Part IX
			Verify that the Operator's program identifies and incorporates changes that affect covered tasks.	Part IX
			Verify that the Operator's program includes provisions for the communication of changes (e.g., who, what, when, where, why) in the qualification program to the affected individuals.	9.3
			Verify that the Operator incorporates changes into initial and subsequent evaluations.	Part IX
			Verify that contractors supplying individuals to perform covered tasks for the Operator are notified of changes that affect task performance and thereby the qualification of these individuals.	9.3
8.02	**Notification of Significant Program Changes**	Does the operator have a process for identifying significant OQ written program changes and notifying the appropriate regulatory agency of these changes once the program has been reviewed? (Associated Protocols: None)	Verify that the operators written program contains provisions to notify OPS or the appropriate regulatory agency of significant modifications to a program that has been reviewed for compliance.	NA – Operator Requirement

Part III: Definitions

Abnormal Operating Condition (AOC) – A condition identified by the Operator that may indicate a malfunction of a component or deviation from normal operations that may: (a) indicate a condition exceeding design limits; or (b) result in a hazard(s) to persons, property, or the environment.

Authentication – The act of attesting that information contained within a record is accurate, complete, legible, and appropriate to the work accomplished.

Authorized Evaluator – A Subject Matter Expert who has completed the Veriforce Evaluator Authorization Process and is responsible for evaluating a Candidate's knowledge, skills and abilities to perform a specific covered task and ability to recognize and properly react to applicable abnormal operating conditions according to evaluation criteria defined by a specific Operator. An Authorized Evaluator is also authorized to conduct on-the-job training (OJT) as provided for in these procedures.

CCTL Steering Committee – Group consisting of representatives from ***Veriforce*** Operator clients tasked with the review and maintenance of the common covered task list. The group will meet, as required, to review proposed changes, additions, or deletions from the CCTL.

Candidate – A person whose knowledge, skills, and abilities are to be evaluated in order to determine whether that person is qualified to perform a specific covered task for a specific Operator.

Character Reference – An individual, either a representative of a pipeline Operator (direct employee or inspector) or a Supervisor/Owner of the prospective Evaluator's company, who will attest to the prospective Evaluator's character as part of the Evaluator Authorization Process.

Construction – An activity that occurs to either a new pipeline, or a new pipeline component(s) or involves the expansion of service.

Contractor – An organization whose employee(s) provide services to an Operator(s) for which the OQ rule applies and whose personnel are evaluated to determine qualification status.

Covered Task – An activity identified by the Operator, that:

1. Is performed on a pipeline facility;
2. Is an operation or maintenance task;
3. Is performed as a requirement of 192 and/or 195; and
4. Affects the operation or integrity of the pipeline.

A covered task may also be defined by an Operator that does not technically meet this four-part test if the Operator determines that an activity poses significant risk to the integrity of pipeline facilities or if an activity is deemed a "covered task" through some other means or reference.

Contractor Advisory Group – Group consisting of representatives from Contractor organizations who meet quarterly, or as needed, to review new/existing processes and systems. Feedback is provided to the Operator group following each meeting.

Direct and Observe – The process by which a Qualified Individual oversees the work activities of a non-qualified individual(s) such that the individual overseeing the work is able to take immediate corrective action if necessary.

Disqualification – Removal of an individual's qualified status relative to a specific covered task due to reasons related to individual's performance of the covered task such as an incident (as defined in Part 191), accident (as defined in Part 195), or other reason to believe the individual may no longer be qualified. In the case of disqualification, Candidate may not be re-evaluated until appropriate training requirements have been met and documented by ***Veriforce***.

Evaluation – A process established to determine whether an individual possesses the knowledge, skills, and abilities to perform a covered task. The term can be used to refer to the process, instrument(s) or both. The process may entail one or more evaluation methods or one or more distinct evaluation instruments.

Evaluation Criteria – Knowledge criteria, performance criteria, AOCs, proper response to AOCs, and any other measurable criteria defined by an Operator which shall serve as the means by which one's qualification to perform a task is measured.

Evaluator – See "Authorized Evaluator".

Expired Authorization – Removal of an Evaluator's authorized status for failure to successfully complete the ***Veriforce*** Evaluator Training Program within 12 months of his/her last successful completion of the Evaluator Training Program. An expired authorization will be reinstated upon successful completion of the Evaluator Training Program and associated testing.

Expired Qualification -- Removal of an individual's qualified status relative to a specific covered task due to the individual not being re-evaluated and requalified before expiration of the requalification interval established by the Operator. In the case of an expired qualification, Candidate may be re-evaluated (with or without receiving additional training) in order to reinstate qualified status.

Maintenance – An activity performed on a pipeline or pipeline component(s) with the intent to sustain or improve the integrity of the pipeline. Examples of maintenance activities include (a) pipe replacements resulting from anomalies, (b) in-place repairs, (c) valve and regulator maintenance, and (d) annual corrosion surveys. Covered tasks related to maintenance activities are subject to the OQ rule.

Observation – Method of evaluation an Evaluator can utilize to assess the skill and ability of a Candidate for a particular covered task by observing a Candidate perform or simulate performance of a particular system or process.

On-the-Job Training (OJT) – Instruction followed by allowed practice, in accordance, with written and structured training materials, by an instructor (i.e. SME, Qualified Individual, Evaluator, etc) at or near the work setting.

Operator – One who operates a pipeline facility and, as a result, is required to comply with the OQ rule.

Operator Qualification (OQ) Rule – 49 CFR §192(N) and 49 CFR §195(G)

Oral Examination – Method of evaluation an Evaluator can utilize to assess the knowledge of a Candidate for a particular covered task by asking either questions or asking a Candidate to describe a particular system or process.

Qualified Individual – A person who has been evaluated and deemed able to: (a) perform assigned covered tasks; (b) recognize and react to abnormal operating conditions, and (c) maintains current qualification. Qualified Individuals are documented and reported in the ***Veriforce*** online database, VeriSource.

Quality Record – A record deemed by ***Veriforce*** to be critical in documenting compliance with the OQ rule. Quality records are those to be maintained in accordance with applicable recordkeeping requirements set forth in the OQ rule.
Record of Evaluation (ROE) – A quality record originated by ***Veriforce*** that contains a task description and Operator-specific evaluation criteria used by an Evaluator to conduct an evaluation and shall also include the following:

- Candidate name;
- Candidate date of birth;
- Candidate identification;
- Candidate Employer identification;
- Evaluator identification;
- Signature of Candidate;
- Signature of Evaluator; and
- Evaluation date.

Rejected ROE – Rejection of ROE(s) submitted by Evaluator and not yet passed by ***Veriforce***. Rejected ROEs are not entered into VeriSource as valid qualifications. Rejection of ROE is not related to an individual's performance of a covered task. Following a rejected ROE, candidate may be re-evaluated without training in order to become qualified.

Revoked Authorization – Removal of an Evaluator's authorized status such that he/she is no longer authorized by ***Veriforce*** to evaluate and qualify Candidates. An Evaluator's authorized status may be revoked by ***Veriforce*** if investigation findings indicate that the Evaluator did not follow proper procedures in conducting and/or documenting evaluations. Under certain circumstances, Evaluators may be re-authorized following appropriate training and testing.

Revoked Qualification – Removal of an individual's qualified status relative to a specific covered task. Revocations occur due to reasons not related to individual's performance of the covered task such as improper evaluation, "High Impact" change, non-response to audit request, as a result of a records audit, etc. Upon revocation, Candidate may be re-evaluated without training (except in the case of a "High Impact" change) in order to reinstate qualified status.

Simulation – A method of observation as described in Section 6.7.8.1 of these procedures.

Span of Control (SOC) – The maximum number of non-qualified individuals that a Qualified Individual can direct and observe for the conditions under which the task is being performed. A span of control of 1:0 indicates that only qualified personnel may perform the task and that performance of the task by a non-qualified person is not allowed.

Subject Matter Expert (SME) – An individual recognized as having a special skill or specialized knowledge either through training and/or experience in a particular field or a piece of equipment.

Suspended Authorization – Temporary removal of an Evaluator's authorized status such that he/she is no longer authorized by ***Veriforce*** to evaluate and qualify Candidates. An Evaluator's authorized status is typically suspended pending investigations, later to be either re-instated or revoked based on findings.

Suspended Qualification – Removal or inactivation (usually temporary) of an individual's qualified status relative to a specific covered task. Qualifications are typically suspended pending investigations, audits, etc. – later to be reinstated, permanently revoked, or disqualified based on findings. Qualification(s) may also be suspended due to non-response to a Qualified Individual audit request or as a result of a records audit.

Technical Reference - A technical reference is a person who is skilled in and/or familiar with the task categories for which an Evaluator has requested to be authorized on. He/she must also be familiar with the knowledge, skills and abilities of the Evaluator as they pertain to each task category requested.

VeriSource – An internet-based database application that allows ***Veriforce*** customers/clients to review qualification status of individuals by task, by company, or by individual name.

Part IV: Evaluator Authorization

4.0 Purpose and Scope

4.0.1 The integrity of the ***Veriforce*** process depends on the quality of the individual who functions as the Evaluator. An Evaluator has the responsibility of evaluating a Candidate to determine whether that Candidate is qualified to perform a specific covered task and to adequately document the evaluation/qualification. Veriforce requires an Evaluator to be a person with the character to preserve the integrity of the Evaluator Authorization Process.

4.1 Roles of the Evaluator

4.1.1 An Evaluator is authorized by ***Veriforce*** to conduct either one or both of the following:

4.1.2 **Evaluation** – Evaluator is responsible for determining whether an individual is qualified to perform a covered task. This determination is made in accordance with Operator-defined covered tasks, evaluation criteria, and evaluation method. The Authorized Evaluator is responsible for conducting evaluations in strict accordance with the procedures outlined herein and following Operator-defined evaluation methods and criteria.

4.1.3 **Training** – The Evaluator is authorized to conduct training specifically related to a given covered task.

4.2 Evaluator Application

4.2.1 ***Veriforce*** will only authorize Evaluators who have appropriate technical competence relative to covered tasks for which they will be evaluating others.

4.2.1.1 Any person desiring to become an authorized Evaluator must submit an Evaluator Statement of Personal Commitment to ***Veriforce***. In addition, the prospective Evaluator must identify categories of covered tasks for which he/she wishes to be authorized to evaluate others through the use of the Evaluator Competency Verification form.

4.2.1.2 The prospective Evaluator is required to provide at least three technical references that can validate technical competence for each category of covered task and overall suitability. ***Veriforce*** will not authorize an Evaluator for a given covered task category(s) unless three references complete the ***Veriforce*** Technical Reference Verification form.

4.2.1.3 The prospective Evaluator is required to provide at least two character references. Each Character Reference must be from a supervisory representative of a pipeline Operator OR a supervisor/owner from the prospective Evaluator's company (past or present). ***Veriforce*** will not authorize an Evaluator for a given covered task category(s) unless two references complete the ***Veriforce*** Character Reference Verification form.

4.2.2 At the request of an Operator, ***Veriforce*** will manage Evaluator records for Operator's internal employee Evaluators. In this case, ***Veriforce*** will work with the individual Operator to define the specific parameters for processing Evaluator applications and authorizing covered tasks, which may differ from these procedures.

4.2.3 In cases where an Operator's internal Evaluator will evaluate Contractor personnel, ***Veriforce*** will require the Evaluator to submit an application with three technical references, two character references and complete the Evaluator Training Program before becoming authorized to evaluate Contractor employees if the Contractor qualifications will be valid for more than one Operator.

4.3 Evaluator Initial Training Program

4.3.1 In addition to determining suitability and technical competence of the prospective Evaluator, he/she must successfully complete the ***Veriforce*** Instructor-led Evaluator Training Program before being designated an Authorized Evaluator.

4.3.2 The ***Veriforce*** Instructor-led Evaluator Training Program consists of the following topics:

- Evaluator's role during the evaluation process
- VeriSource familiarization training
- Mock evaluations

4.3.3 Successful completion of the ***Veriforce*** instructor-led Evaluator Training Program requires passing the written exam, administered by ***Veriforce,*** and appropriate participation in class. If the prospective Evaluator ***does not*** successfully complete the ***Veriforce*** Evaluator Training Program, he/she will **not** be authorized as an Evaluator and will not be allowed to conduct evaluations through ***Veriforce***.

4.4 Documentation of Authorized Evaluators

4.4.1 ***Veriforce*** shall maintain an active electronic database of authorized Evaluators, cross-referenced to applicable covered tasks and specific Operators for which they are authorized to evaluate personnel. ***Veriforce*** will maintain all records associated with Evaluator authorization in accordance with recordkeeping requirements set forth in the Operator Qualification rule and these procedures.

4.4.2 Upon successfully completing the ***Veriforce*** instructor-led Evaluator Training Program, after the technical competence of the individual has been validated by three references, and two character references have been received, the Applicant shall be deemed authorized as an Evaluator for applicable covered tasks.

4.4.3 At the time of initial application, an Evaluator will be assigned a user name and password to access online data through *VeriSource*. Until authorized, the Evaluator can only use his/her user name and password to view authorization status and non-ROE documents. Once authorized, the Evaluator can access ROEs within the authorized task category(s) and submit qualification records only for those tasks for which the Evaluator is authorized.

4.5 Evaluator Re-Authorization

4.5.1 An Evaluator must be re-authorized annually on or before the anniversary date for which he/she was initially authorized or subsequently re-authorized.

4.5.2 To become re-authorized, the Evaluator must complete the ***Veriforce*** Evaluator Refresher Training Program or attend the Instructor-led Evaluator Training Course. This reauthorization requirement has been put in place to help ensure that Evaluators are exposed to changes in program requirements, Operator requirements, and/or ***Veriforce*** procedures at least annually. Veriforce may allow a grace period where an Evaluator may take the refresher course within thirty (30) days prior to the expiration date and retain the same authorization date.

4.5.2.1 Evaluators must pass the written exam with a score of 100%. This refresher training and exam will be available online. Each Evaluator will be given two attempts to pass the online exam. Each attempt will have an immediate re-test, if a score of 90% or better is achieved. If the Evaluator does not score a 100% on the online exam after two full attempts (which includes two immediate retests), he/she must attend and successfully pass the instructor-led Evaluator Training Course.

4.5.3 In the event the Evaluator's authorization period has lapsed, the Evaluator may be reauthorized upon successfully completing the ***Veriforce*** Evaluator Training Program, as outlined in this section, unless Evaluator authorization requirements have changed to the extent that ***Veriforce*** determines that existing records/documentation are not adequate. In this case, the Evaluator may be required to complete the full authorization process in accordance with current procedural/process requirements.

4.5.3.1 If an Evaluator's authorization has lapsed for more than one year and he/she has never attended the Instructor-led Evaluator Training Course, then the Evaluator will be required to attend the Instructor-led Evaluator Training Course in order to become reauthorized.

4.5.3.2 If an Evaluator's authorization has lapsed for more than two years and he/she has previously attended the Instructor-led Evaluator Training Course, then the Evaluator will be required to attend the Instructor-led Evaluator Training Course in order to become reauthorized.

4.6 Evaluator Transfer to another Company

4.6.1 In cases where an Authorized Evaluator is no longer employed by the company for which he/she worked at the time of becoming authorized, the previous employer may remove the Evaluator's access to the company's records. In this case, access to any qualification records of the previous employer will be removed and the Evaluator will be identified in the ***Veriforce*** database as "inactive".

4.6.1.1 In order to restore "active" status at a later date with the same company, the company OQ administrator must request such in writing. ***Veriforce*** will, upon receiving such a request, review the information for accuracy and reactivate the Evaluator's association with the company.

4.6.2 In cases where an Authorized Evaluator was once active with a company and moves to a new company, he/she may transfer Evaluator records to the new employer by completing a ***Veriforce*** Evaluator Transfer Form. ***Veriforce*** will, upon receiving such a request, review the information for accuracy and transfer the Evaluator's associated records to the new company.

4.6.2.1 Evaluator Transfers must be approved by the OQ administrator of the new company. The Evaluator's access will remain in a pending state until approved by the new company.

4.7 Removal of an Evaluator's Authorized Status

4.7.1 Once authorized, an Evaluator and any qualifications put in-place by that Evaluator may be suspended or revoked if ***Veriforce*** audit or investigation results demonstrate that the Evaluator did not follow procedures.

4.7.2 If ***Veriforce*** discovers evidence suggesting that an Evaluator did not:

a) Follow the mandated evaluation method for the task,
b) Include all of the evaluation criteria in the evaluation, or
c) Conduct evaluations in a one-on-one setting (unless a written exam was administered, as allowed);

Then ***Veriforce*** will immediately launch an audit following procedures outlined in Section 7.2 to determine if or to what extent the Evaluator failed to follow procedures.

4.7.3 In cases where the initial evidence strongly suggests that any of the above requirements were not followed, ***Veriforce*** may immediately suspend the Evaluator's authorized status, pending a formal audit.

4.7.4 Minor procedural infractions including not signing documentation where appropriate, signature dates of the Candidate and Evaluator not matching, etc. will result in the rejection by ***Veriforce*** of the ROE(s) in question and an explanation to the Evaluator of why the ROE(s) were rejected. If a pattern of minor procedural infractions emerges or if the minor infractions indicate that more serious infractions (as described in paragraph 4.7.2) could be occurring, ***Veriforce*** may, at its discretion, initiate an Evaluator audit.

4.7.5 Veriforce may remove an Evaluator's authorized status either temporarily or permanently as a result of audit findings, procedural violations, administrative issues, etc.

4.7.5.1 In the case of permanent removal of an Evaluator's authorized status, Veriforce will first confer with applicable Operator clients prior to taking such action.

4.8 Evaluator Reauthorization following Revocation

4.8.1 The first time an Evaluator's status is revoked, he/she may become re-authorized by attending an instructor-led ***Veriforce*** Evaluator Training Course and passing the written exam with a score of 100%. ***Veriforce*** will communicate the program costs to the Evaluator and will schedule these courses at least quarterly, or as needed.

4.8.2 The second time the Evaluator's status is revoked, authorized status can only be reinstated if a majority of the Operators are in agreement and he/she successfully completes the instructor-led ***Veriforce*** Evaluator Training Course. In this case, if an Operator does not respond to a ***Veriforce*** request for vote, then no response corresponds to a denial of reinstating the Evaluator.

4.8.3 The third time the Evaluator's status is revoked; the revocation will be permanent with NO possibility of becoming reauthorized.

4.8.4 If ***Veriforce*** discovers evidence that the integrity of an Evaluator is in question, ***Veriforce*** may, upon conferring with applicable Operator clients, permanently revoke the Evaluator's authorization regardless of whether it is a first, second, or third offense.

Part V: Training of Personnel

5.0 Purpose and Scope

5.0.1 This part describes procedures to be followed in determining when training of a Candidate is appropriate and how that training is to be conducted and documented.

5.1 Determining When Training is Appropriate

5.1.1 Training shall be required prior to the evaluation of a Candidate in the following instances:

5.1.1.1. Qualified Individual has been deemed "disqualified" by ***Veriforce*** since last being qualified. This shall apply to the specific covered task(s) for which the Candidate is to be evaluated.

5.1.1.2. Candidate was not successfully evaluated when most recently evaluated for the covered task(s) in question.

5.1.1.3. A High Impact change related to the covered task(s) in question has been initiated since the Qualified Individual was last qualified.

5.1.2 Individual Operators may dictate additional instances when training is required prior to the evaluation. ***Veriforce*** will work with Operators on an individual basis to capture their training requirements and communicate those requirements to Contractors and Evaluators.

5.1.3 Prior to conducting an evaluation, it is the responsibility of the Evaluator to determine whether appropriate training has been provided to the Candidate, as required, and to submit documentation of training in accordance with Section 5.4.

5.2 Use of Veriforce-Provided Training Materials

5.2.1 ***Veriforce*** may make training resources available for various covered tasks identified by its Operator clients.

5.2.2 Where training is specific to a given covered task, the learning objectives of the training shall be consistent with the knowledge, skills, and abilities described within the evaluation criteria for the corresponding covered task.

5.2.3 Best practices and processes associated with conducting ***Veriforce***-provided training shall be described in the ***Veriforce*** Evaluator Training Program.

5.3 Use of Training Materials Developed Through Other Organizations

5.3.1 A Candidate may choose to attend/complete training courses or programs offered through other organizations. If a Candidate utilizes training materials or courses other than those provided by ***Veriforce***, the Candidate (or Candidate's employer) assumes the responsibility for the applicability of the training to the task in question and is responsible for providing proof of training to the Evaluator. The Evaluator is responsible to ensure that the training received by the Candidate is applicable to the covered task in question.

5.3.2 The training shall be considered applicable so long as the learning objectives are consistent with the evaluation criteria associated with the covered task in question. ***Veriforce*** personnel will, as needed, review course outlines to ensure that course objectives match the corresponding evaluation criteria.

5.4 Documenting That Training Requirements Have Been Addressed

5.4.1 The Evaluator shall note on the Record of Evaluation whether training is required by virtue of one or more of the instances addressed in Paragraph 5.1.

5.4.2 In the event that training is required, the Evaluator is responsible to ensure that training has been successfully completed by the Candidate before proceeding with the evaluation.

5.4.3 The Evaluator shall require the Candidate to produce training documentation, as follows:

a) A valid Record of Training (ROT), if Veriforce-provided training resources are used;
b) An official training course/program attendance sheet; or
c) An official Certificate of Completion issued by the course provider/instructor.

For a training record to be acceptable, the document(s) must clearly identify:

a) Name/Title of training program;
b) Source of training;
c) Candidate name; and
d) Date of completion.

5.4.3.1. If training is required, but has not been completed by the Candidate, the Evaluator is authorized to conduct structured OJT, as appropriate, using training resources made available by ***Veriforce.***

5.4.4 Where required training has been completed by the Candidate, the Evaluator shall conduct the evaluation, and attach documentation of training described in Paragraph 5.4.3 to the Record of Evaluation submitted to ***Veriforce***.

5.4.5 ***Veriforce*** shall maintain the training documentation as a quality record.

Part VI: Evaluation of Personnel

6.0 Purpose and Scope

6.0.1 This part describes procedures to be followed in conducting a formal evaluation. The procedures described here are key in ensuring that evaluations are conducted properly, consistently, in a timely and efficient manner, and that proper documentation is put in place.

6.1 Defining/Communicating Covered Tasks, Evaluation Criteria, and Program Requirements

6.1.1 Each Operator is responsible for identifying covered tasks for which personnel must be qualified. In addition, each Operator must define the following relative to each covered task:

a) Evaluation criteria;
   - Knowledge/skill requirements,
   - Abnormal operating conditions (AOCs),
   - Proper response to identified AOCs.
b) Interval for re-evaluation of Qualified Individuals;
c) Indicate whether the covered task may be performed by non-qualified individuals; and
d) Span of Control limits or other directive, if nonqualified personnel are allowed to perform the covered task.

6.1.2 Each Operator shall provide its respective covered task list and underlying evaluation criteria to ***Veriforce***.

6.1.3 ***Veriforce*** shall communicate the list of covered tasks, evaluation criteria, and program requirements to employees, Contractors, subcontractors, and others, as appropriate. Method(s) of communication may include any or all of the following:

- Letter or other communication sent via the US Postal Service or other courier service;
- ***Veriforce*** OQ Meetings;
- Email;
- Fax;
- Posting on the ***Veriforce*** website; or
- Notification through *VeriSource.*

6.1.4 The list of covered tasks for each Operator client shall be posted and maintained on the ***Veriforce*** website.

6.1.5 Evaluation criteria shall be made available through *VeriSource*. These criteria are task specific intended for use by Evaluators, Candidates, and other interested parties in preparing for an evaluation.

6.1.6 Any other guidelines, documents, training materials, etc. that are to be made available at the request of the Operator shall be made available through *VeriSource.*

6.2 Approaches to Becoming Qualified

6.2.1 ***Veriforce*** offers three approaches to becoming qualified for a particular covered task(s).

6.2.1.1. Evaluation by a Third-Party Evaluator – Candidates or Candidate employers may choose to hire an independent, third-party Evaluator to conduct evaluations. Upon request, ***Veriforce*** may assist Candidate, or Candidate's employer, with finding a third-party Evaluator that has been authorized by ***Veriforce***. In this situation, ***Veriforce*** acts only as a referral source linking Contractors with third party Evaluators. Aside from the authorization process, ***Veriforce*** assumes no liability for any third-party Evaluators hired by Candidate/Candidate's employer.

6.2.1.1.1. It is the responsibility of the Candidate and Authorized Evaluator to establish date, time, location and other logistical arrangements necessary to schedule and conduct the evaluation. Candidate is responsible for all costs associated with hiring a third party Evaluator and must make arrangements directly with the Evaluator.

6.2.1.2. Evaluation by Internal Evaluator – Organizations may choose to have internal personnel authorized as an Evaluator(s) so that evaluations can be done internally. ***Veriforce*** will allow individuals to evaluate their own employees provided they have been authorized as an Evaluator according to these procedures.

6.2.1.3. Assessment of Qualification Through other Process /Organization – In the event that a Candidate has become qualified for a similar covered task through another process or organization, ***Veriforce*** will review that qualification for equivalency in order to determine whether the requested qualification can be granted through ***Veriforce***. Details of the assessment process are outlined in Paragraph 6.11 of these procedures.

6.2.2 ***Veriforce*** does not view work performance history review (WPHR) as an acceptable method of evaluation. Qualification of personnel based on this method will not be permitted unless specifically requested by an Operator in writing. At NO time will WPHR be allowed as an acceptable method of evaluation for any task from the Common Covered Task List (CCTL).

6.3 Pre-Evaluation Activities

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.3.1 Whenever needed, the Evaluator should assist in providing for special needs to be met during the evaluation. These may include language barriers, handicaps, or other issues that may require special provisions for conducting an evaluation.

6.3.2 In cases where a Candidate requests assistance in identifying training resources for the purpose of acquiring new knowledge, skills, or abilities or for the purpose of preparing for an evaluation, ***Veriforce*** may work to assist the Candidate in identifying possible training resources. This may include OJT resources made available by ***Veriforce***, web-based training, computer-based training, self-paced training, or traditional instruction from any number of sources.

6.3.3 An ROE will be made available to the appropriate Evaluator who shall use the document to record the results of the evaluation.

6.3.3.1. The ROE shall include Candidate information, information about the Candidate's employer, information about the Evaluator, and pertinent logistical details. It shall also include a full description of the task to be evaluated along with corresponding evaluation criteria. The Evaluator should ensure that required facilities, equipment, personnel, materials, etc., will be available at the scheduled time.

6.3.4 The Evaluator should make the appropriate evaluation criteria available to the Candidate prior to the evaluation; however, the Candidate is NOT allowed to use the evaluation criteria during the actual evaluation. The Candidate should know what will be expected during the evaluation and may use the evaluation criteria as a "study guide" so that he/she can be fully prepared for the evaluation. If a written test is required, the Evaluator shall NOT share the test with the Candidate prior to taking the exam; however, adequate study materials should be made available prior to the exam.

6.3.5 The Candidate is responsible for reviewing knowledge and/or performance requirements, abnormal operating conditions, and other criteria, prior to the evaluation.

6.3.6 The Candidate should review those cases in which training is required prior to conducting an evaluation and ensure that any required training has been completed, documented, and that documentation is available for the Evaluator to collect and submit.

6.4 The Evaluation Process

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.4.1 The purpose of an evaluation is to assess a Candidate's knowledge, skills, and abilities necessary to perform a covered task in accordance with predetermined evaluation criteria. This evaluation function is separate and distinct from training. During the evaluation, the Evaluator assesses the knowledge, skills, and abilities of the Candidate in order to determine whether the Candidate is qualified to perform the covered task in question.

6.4.2 The Evaluator shall utilize evaluation criteria identified by the applicable Operator(s) and these procedures in conducting the evaluation. Evaluations must be done following the method or combination of methods specified for the task by the applicable Operator(s). The proper method of evaluation is dictated by the Operator and is shown on the ROE.

6.4.3 The Evaluator will brief the Candidate, ensure that applicable training requirements have been met, conduct the evaluation, debrief the Candidate, and document the evaluation, per these procedures.

6.5 Briefing the Candidate

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.5.1 Prior to conducting an evaluation, the Evaluator will confirm the identity of the Candidate using government-issued photo identification.

6.5.2 The Evaluator will provide clear and complete instructions as to what the Candidate is allowed to do physically in order to complete the skill; or verbally in order to respond to questions or give explanation as to performance of the task.

6.5.3 The Evaluator will explain under what circumstances he/she will stop the Candidate (such as danger to personnel or equipment).

6.5.4 The Evaluator will review the task and corresponding evaluation criteria with the Candidate and explain the standards of acceptable performance.

6.5.5 The Evaluator will explain to the Candidate that any answer or action that would place personnel, the facility, or system in danger will be treated as an immediate failure regardless of the acceptability of other responses. The Evaluator will allow the Candidate to ask any questions about the process to be followed.

6.6 Ensuring that Applicable Training Requirements Are Met

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*
- *Assessment of Qualification Through Other Process/Organization*

6.6.1 The Evaluator shall determine whether training requirements may apply and whether those training requirements have been met. This shall be done in accordance with Part V of these procedures.

6.7 Conducting an Evaluation

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.7.1 The Evaluator shall immediately take over, if qualified to do so, or stop a process if a safety hazard is present.

6.7.2 The Evaluator will not coach or prompt the Candidate by giving hints, by asking leading questions, or by his/her actions.

6.7.3 If a task requires the Candidate to go to a location, the Evaluator shall not lead the way.

6.7.4 If evaluation criteria reference a procedure, that procedure should be available to the Candidate during the evaluation but should not be handed to the Candidate by the Evaluator. Part of the evaluation may be to assess the Candidate's ability to locate and use procedures and understand their importance.

6.7.5 The Evaluator will be able to determine if the Candidate is qualified to perform the task by comparing the Candidate's answers and/or actions to the Operator's evaluation criteria.

6.7.6 The Evaluator will note whether a given criterion is knowledge-based or skill-based and conduct the evaluation in strict accordance with the method(s) established by the Operator and defined on the ROE.

6.7.7 In the case of knowledge-based criterion, the appropriate evaluation method shall be oral examination unless otherwise noted on the ROE. The Evaluator shall ask the question as presented on the ROE and evaluate the Candidate's response according to information provided thereon.

6.7.8 With skill-based criteria, the Evaluator shall observe the Candidate performing that skill(s). Observation may be done in accordance with the OQ Rule through (a) actual performance on the job, (b) on the job training, or (c) simulation.

6.7.8.1. ***Veriforce*** and the OQ regulations allow an Evaluator to ask a Candidate to "simulate" the observation portion of a covered task. It is highly recommended that the Evaluator require the candidate to perform the function described in the task criteria; however, if it is not possible, or acceptable (due to span of control limits), to observe the candidate perform the actual work then simulation can be used. To ensure that the simulated task function is applicable, all instances of "simulation" should meet the following characteristics:

- Simulations should reflect the actual work setting sufficiently to reflect work performance. This could include the use of equipment or equipment replicas in a shop or at a yard; and
- Simulations must require the candidate perform some type of "hands-on" activity that imitates the actual skill to be measured (i.e. walking through the task and simulating all actual manipulations of valves, switches, tools, etc. with the use of visual aids, models and/or replicas.

6.7.8.2. Simulation cannot be limited to or defined as any of the following:

- Oral "talk-through" or "walk-through" of the steps of a task;
- Using hand gestures;
- "Imagining" there are tools/equipment present to aid verbal descriptions;
- Observing other individuals perform a task while describing their activities.

6.7.8.3. In cases where actual performance on the job is used as a means to observe the candidate, and in cases where this will occur on an active jurisdictional pipeline facility, and where the candidate is not currently "qualified" to perform this covered task, the Evaluator shall ensure that appropriate span of control requirements are followed.

6.7.9 In order to judge a Candidate's ability to appropriately recognize and react to AOCs, the Evaluator shall utilize either a written or oral examination, per applicable Operator requirements. If oral examination is used, the Evaluator shall follow the questioning techniques defined in the ***Veriforce*** Evaluator Training Program.

6.8 Questions during an Evaluation

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.8.1 Usually it is not enough for a Candidate to possess the skills to operate a tool, a component, or a system. Knowledge of the underlying theory/principles of operation, interactions with other systems, recognition of AOCs, and ability to respond to those AOCs is also required.

6.8.2 To assess a Candidate's knowledge, the Evaluator is required to ask questions to verify the Candidate's understanding of the knowledge-based evaluation criteria associated with a covered task.

6.8.3 All questions asked during an evaluation will be related to the covered task and corresponding evaluation criteria.

6.8.4 The questions asked during the evaluation should be designed to test understanding and judgment as well as factual knowledge. If detailed questions have been developed by the Operator with detailed answers, the Evaluator shall ask all pre-determined questions.

6.8.5 While questions asked by the Evaluator during the evaluation may be restricted to those included verbatim in the evaluation criteria, the Evaluator must keep in mind that the Candidate's answer may not be a verbatim answer.

6.8.6 In some instances, evaluation criteria do not contain specific questions for knowledge criteria, but rather instruct the Evaluator to have the Candidate "describe" a process or procedure. In this case, the Evaluator is responsible for ensuring that the Candidate adequately describes whatever is asked.

6.8.7 Questions asked during an evaluation shall be directly related to the Operator's evaluation criteria, and may include theory, system equipment, routine and/or emergency procedures, and questions related to abnormal operating conditions. Most Operators require the Candidate to memorize the immediate actions of an emergency procedure and expect the Candidate to be able to rapidly locate the supplementary or follow-up actions in the procedures.

6.8.8 When a Candidate answers a question incorrectly during the course of an evaluation, the Evaluator's response to the wrong answer must be as neutral as possible. The Evaluator may rephrase the question and if the Candidate still does not know the correct answer, move on. At the completion of the evaluation, the Evaluator may clarify any misconceptions or have the Candidate look up what he/she did not know. In this case, the Candidate would have failed the evaluation.

6.9 Debriefing the Candidate

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.9.1 At the completion of an evaluation, the Evaluator and the Candidate will conduct a detailed review of the Candidate's performance.

6.9.2 Candidates who meet all (100%) evaluation criteria defined by an Operator for a specific covered task shall be considered "Qualified Individuals" by ***Veriforce*** and the Operator.

6.9.3 The Evaluator will tell the Candidate if he/she passed or failed the evaluation. Based on that outcome, the Evaluator is encouraged to discuss with the Candidate the knowledge or performance criteria not successfully met, if applicable.

6.9.4 If unsuccessful, the Evaluator shall inform the Candidate that he/she is only allowed to perform the covered task if directed and observed by a qualified person, as allowed by the Operator in accordance with established "span of control" limits.

6.9.5 If unsuccessful, the Candidate will be required to successfully complete appropriate training before a subsequent evaluation is allowed. The Evaluator shall notify the Candidate of this requirement during the debriefing.

6.10 Post-Evaluation Activities

Applicable Approaches:

- *Evaluation by Third Party Evaluator*
- *Evaluation by Internal Evaluator*

6.10.1 If successful, the Candidate will achieve "Qualified" status relative to the task(s) **AND** Operator(s) for which he/she was successfully evaluated.

6.10.2 If successful, "Qualified" status shall remain in effect for a period of time defined by the applicable Operator for the covered task in question. "Qualified" status may be in effect for a period **less** than this in cases where there is evidence that an individual is no longer qualified. This evidence could come from a ***Veriforce*** audit or notification from a Contractor or Operator. Section 6.12 of these procedures describes in detail how an individual's qualified status could be removed early.

6.10.3 If unsuccessful, the Candidate will be deemed unqualified and the evaluation will be documented as a failure.

6.11 Assessment of Qualification Achieved Through Other Processes or Organizations

Applicable Approaches:

- *Assessment of Qualification Through Other Processes/Organizations*

6.11.1 ***Veriforce*** will assess evaluations conducted by (or through) other processes or organizations in order to determine whether it is sufficient to meet qualification requirements of a specific ***Veriforce*** Operator client(s).

6.11.2 The assessment will be conducted to determine equivalency of:

- Evaluation criteria (performance criteria and abnormal operating conditions);
- Evaluation methodology; and
- Suitability of the individual who performed the evaluation. (Regardless of granting organization/process, the Evaluator must become authorized in accordance with ***Veriforce*** procedures in order for a qualification to be valid.)

6.11.3 Based on the above three factors, ***Veriforce*** will determine whether the individual should be granted "qualified" status for the Operator(s) in question.

6.11.4 Even though documentation may originate on a record or form other than an ROE, the Evaluator is still required to ensure that training requirements have been adequately addressed.

6.11.5 Where it is determined that an existing qualification is not equivalent to the covered task for whom the Candidate is pursuing qualification, the Candidate and/or Candidate's employer will be informed that qualification through this approach is not possible.

6.11.6 For all assessments where qualification is deemed equivalent, ***Veriforce*** will create and maintain documentation adequate to demonstrate compliance with these procedures, the Operator's written OQ program, and the OQ rule.

6.11.7 At the written direction of an Operator, ***Veriforce*** will accept qualifications from another process or organization provided that the qualifications are valid for only the requesting Operator (i.e. not an Operator who has adopted the CCTL).

6.12 Removal of an Individual's Qualified Status

6.12.1 Operators and Contractors shall agree to notify ***Veriforce*** immediately of any incident or accident involving a Qualified Individual that may bring that individual's qualified status into question or if they have any reason to believe that an individual is no longer qualified to perform the covered task. ***Veriforce*** may suspend an individual's qualifications at the verbal direction of an Operator with the understanding that the Operator will follow-up with written confirmation. All other requests must be in writing or email with the name and pertinent contact information of the individual requesting the suspension.

6.12.1.1. ***Veriforce*** will immediately suspend all applicable qualifications held by the individual pending further investigation. To protect the interests of other Operators, ***Veriforce*** will also suspend all other qualifications held by the individual that are in the same task category (outlined in the ***Veriforce*** Evaluator Authorization Process) as the suspended qualification(s).

6.12.1.2. Any investigation into the qualification status of an individual will be completed either by ***Veriforce*** or the Operator requesting the removal of the qualifications.

6.12.1.3. If, based on the results of the investigation, the Qualified Individual becomes disqualified, he/she shall successfully complete appropriate training and be subject to the full evaluation process set forth in these procedures if he/she wishes to become qualified at a later date. If disqualified on one task, the individual will also become disqualified on all other tasks from the same task category, as outlined above.

6.12.1.4. If the investigation yields no evidence that the individual should be disqualified, all suspended qualifications will be reinstated.

6.12.2 In the event that a Qualified Individual becomes disqualified, for whatever reason, the individual's employer and/or the applicable Operator(s) will be immediately notified by ***Veriforce***. The notification will include instructions that the individual can only perform the covered task if under the direction and observation of a Qualified Individual, as allowed by the Operator. The notification will also include instructions that the individual must complete appropriate training before being evaluated for the covered task in the future.

6.12.3 Qualifications may also be revoked as a result of a Qualified Individual or Evaluator audit, as described in Section 7 of these procedures.

Part VII: Program Quality Management

7.0 Purpose and Scope

7.0.1 ***Veriforce*** will implement ongoing program quality management efforts in order to ensure the accuracy of records, continued qualification of individuals, effective performance of Evaluators, problem identification, and that program improvement opportunities are identified.

7.0.2 ***Veriforce*** will treat all program quality management-related documentation as quality records and will ensure ongoing communication of results with applicable Operators in accordance with these procedures.

7.1 Monitoring Qualified Individuals

7.1.1 ***Veriforce*** will conduct audits of Qualified Individuals in order to determine if their performance has directly contributed to an incident or accident that may bring qualified status into question or whether there is any other reason to believe the individual is no longer qualified.

7.1.2 A minimum of **5%** of the individuals who are qualified for each Operator will be selected to undergo a qualification audit each year. Selection of Qualified Individuals to be audited may be either random or for cause. The purpose of the audit is to ensure that a Qualified Individual is still qualified.

7.1.2.1. In conjunction with the ***Veriforce*** semi-annual Contractor billing cycle, ***Veriforce*** will count the number of Qualified Individuals that were active for each Operator over the previous 6 month period and select 2.5% of those individuals for audit.

7.1.2.2. Audited Qualified Individuals who are qualified for more than one Operator will count towards all Operators for whom they are qualified.

7.1.3 Audits will focus on individuals; therefore, when a Qualified Individual is selected to undergo an audit, ***Veriforce*** will review all qualifications held by that individual. This may include multiple qualifications for a given Operator and/or qualifications related to multiple Operators.

7.1.4 When an individual is selected to be audited, ***Veriforce*** will notify the company representative and request that someone from the company who is familiar with the Qualified Individual and his/her work respond to the audit to determine the following:

1. Has the individual performed the covered task since being qualified?
2. If so, for what Operator(s)?
3. Has the individual been involved in any incident or accident related to performing the covered task?
4. Does the supervisor/company representative have any reason to believe the individual is no longer qualified to perform the covered task?

7.1.5 In cases where the individual has been employed by more than one Contractor since the date of qualification, ***Veriforce*** will attempt to contact <u>all</u> Contractors for whom the Qualified Individual has qualifications. If ***Veriforce*** is unable to contact a Contractor or the Contractor refuses to cooperate with the audit, then ***Veriforce*** will suspend all of the individual's qualifications for that Contractor only. Qualifications for those Contractors who participate in the audit will be left active, unless the audit uncovers evidences suggesting that the Qualified Individual should no longer be qualified.

7.1.5.1. ***Veriforce*** will allow each Contractor one chance to re-instate a suspended qualification due to non-response to an audit if they complete the audit.

7.1.5.2. Following suspension/reinstatement of qualifications, future instances of where a Contractor does not respond to an audit will result in revocation of qualifications for applicable Qualified Individuals. In this case, re-evaluation of the Qualified Individual will be required. Requalification due to non response to an audit does not require training prior to the evaluation.

7.1.6 In cases where the Qualified Individual has performed the covered task for an identified Operator, ***Veriforce*** will attempt to contact that Operator to determine the following:

1. Has the individual performed the covered task for the Operator since being qualified?
2. Has the individual been involved in any incident or accident related to performing the covered task?
3. Does the Operator representative have any reason to believe the individual is not qualified to perform the covered task?

7.1.7 In cases where the individual has performed the covered task for more than one Operator, ***Veriforce*** will attempt to contact each Operator.

7.1.8 ***Veriforce*** will make two attempts to contact Operators. If an Operator cannot be contacted, then the audit will be closed as complete and the audit report will note who the Operator's contact is and when the attempts were made.

7.1.9 Each audit results in either no further action required or the suspension of qualifications pending further investigation, as described below.

7.1.9.1. No further action or investigation required – Nothing was discovered that calls qualified status into question.

7.1.9.2. Individual's qualification(s) suspended pending further investigation – Further investigation is necessary to determine whether the individual is still qualified.

7.1.9.2.1. The investigation procedures outlined in Section 6.12.1 will be followed whenever an audit results in the need for further investigation. Notification procedures described at 6.12.2 will be followed in the event a Qualified Individual becomes disqualified.

7.1.10 In cases where an incident/accident was caused, or contributed to, by the performance of the covered task, the investigation shall consider the following:

a) Adequacy of the covered task evaluation criteria and abnormal operating conditions;
b) Appropriateness of the evaluation interval;
c) Adequacy of the evaluation method;
d) Adequacy of the evaluation (to ensure that evaluation was conducted in accordance with Operator requirements and these procedures); and
e) Evaluator credentials, technical competence, and suitability.

7.1.11 ***Veriforce*** will manage all documentation associated with audits and investigations as Quality Records.

7.2 Monitoring Authorized Evaluators

7.2.1 ***Veriforce*** will regularly review Evaluator performance as a quality assurance measure to validate the Evaluator's suitability and conformance with applicable procedures and Operator requirements.

7.2.2 Annually, ***Veriforce*** will audit 5% of the Authorized Evaluators, as measured on January 1 of each calendar year. The audit selection process will be weighted towards new Evaluators and/or those who have exhibited suspect performance (recommendations from Operators or

Contractors, unusually high number of qualifications submitted in a 24 hour period). ***Veriforce*** may also select Evaluators for audit at random.

7.2.2.1. ***Veriforce*** may also conduct additional audits of Evaluators based on Operator direction or under special circumstances.

7.2.3 Refusal to cooperate with the audit process outlined herein may result in suspension of qualifications and/or the Evaluator's authorization. Suspended qualifications and/or Evaluator authorization may be reinstated upon compliance with the Evaluator audit process or revoked in the case of continued non-response.

7.2.4 Like Qualified Individual audits, Evaluator audits will focus on individuals; therefore, the overall suitability applicable to all Operators will be assessed during the audit. The goal of the Evaluator audit is to determine if the Evaluator is following ***Veriforce*** procedures and Operator-specific criteria when conducting Candidate evaluations. To accomplish this goal, ***Veriforce*** may utilize either a "desktop" and/or "field" audit, as described below.

7.2.5 A desktop Evaluator audit involves a review of the Evaluator's file for completeness followed up by telephone discussions with 25% but no more than five (5) of the Qualified Individuals that were evaluated by the Evaluator. During the telephone interview, ***Veriforce*** will utilize a standard audit checklist to gather the following information:

1. Can the Qualified Individual confirm that he/she was evaluated for the covered task by the authorized Evaluator and on the date noted on the Record of Evaluation?
2. Did the Evaluator correctly assess the need for training prior to the evaluation?
3. Did the Evaluator follow <u>all</u> evaluation criteria for the task in question?
4. Did the Evaluator follow the appropriate method as outlined by the Operator(s) for the task in question?
5. Did the Evaluator conduct the evaluation in a one-on-one setting (unless a written test was administered, as allowed)?
6. Did the Evaluator ask the Qualified Individual to identify and appropriately respond to AOCs associated with the task in question? (if applicable)

7.2.6 If the information gathered during the desktop and/or field audit clearly indicates that one or more evaluations were not conducted properly and the Qualified Individual should not be qualified on specific tasks, ***Veriforce*** may suspend or revoke individual qualifications and/or the authorized status of the Evaluator immediately. Individuals may also be immediately disqualified if evidence suggests the individual does not possess the knowledge, skills and ability to perform a task(s). In most cases; however, action on the status of qualifications or Evaluator status will not be taken until the audit has been completed.

7.2.7 After ***Veriforce*** has interviewed all Qualified Individuals and clarified any questions raised during those interviews with the Evaluator, ***Veriforce*** will prepare an audit report. Each desktop audit results either in (1) no further action required, (2) the initiation of an Evaluator field audit, or (3) actions to be taken without need for Evaluator field audit.

7.2.7.1. <u>No further action or investigation required; audit closed.</u> If all of the Qualified Individuals contacted answer the above questions in a manner indicating that the Evaluator followed ***Veriforce*** procedures and any associated Operator-specific evaluation criteria, then the audit will be closed with no further action required. If only one of the Qualified Individuals contacted indicates that the Evaluator either did not follow ***Veriforce*** procedures or any Operator-specific evaluation criteria, then ***Veriforce*** will contact at least one additional Qualified Individual to either refute or corroborate the original allegation(s). If the Qualified Individual's allegation(s) cannot be corroborated after speaking with at least one other Qualified Individual and the Evaluator in-question then the audit will be closed with no further action required.

However, if the issues identified with the original Qualified Individual remain unresolved, then ***Veriforce*** may take action against that individual's qualifications as described in section 7.2.6. The final report will be prepared within 15 business days of audit completion and will be submitted to the Evaluator.

7.2.7.2. <u>Initiation of an Evaluator field audit (investigation); audit remains open.</u> If more than one Qualified Individual or any person representing an Operator indicates that the Evaluator either did not follow ***Veriforce*** procedures or any Operator-specific evaluation criteria, then ***Veriforce*** will communicate the results of the desktop audit to the Evaluator for a response and may initiate an Evaluator field audit.

7.2.7.3. <u>Field audit deemed unnecessary; actions to be taken.</u> In cases where further action is required, but a field audit is deemed unnecessary, ***Veriforce*** will proceed to section 7.2.7.2, step 4. Field audits may be deemed unnecessary due to overwhelming evidence of procedural violations such as Evaluator statements indicating procedures were not followed, instances of a majority or all Qualified Individuals involved in the desktop audit indicated they were not evaluated properly, etc.

7.2.8 The goal of the Evaluator field audit is the same as the desktop audit – to determine if the Evaluator is following ***Veriforce*** procedure and Operator-specific criteria when conducting evaluations. An Evaluator field audit involves a ***Veriforce*** representative visiting the Evaluator and Qualified Individuals in the field to conduct in-person interviews. A field audit will either be conducted as a result of a failed desktop audit, in the place of a desktop audit (depending upon logistical considerations, for cause, etc.), or at the specific request of an Operator.

7.2.8.1. When a field audit is initiated, ***Veriforce*** will first contact the Evaluator to be audited for a pre-audit conference and to inform him/her that they have been selected to undergo a field audit and to explain why they were selected for an audit. A company representative and/or the Evaluator will also be presented with a list of Qualified Individuals that ***Veriforce*** would like to meet with and ask that the Evaluator (or the Qualified Individuals' employer) make at least two of them available for in-person interviews. Veriforce will endeavor to interview individuals who did not participate in the prior desktop audit pertaining to the Evaluator in question.

7.2.8.2. The general steps of an Evaluator field audit are as follows:

1. ***Veriforce*** schedules a pre-audit conference with the Evaluator to describe the purpose of the audit and the reason(s) the field audit is taking place (i.e., desktop audit results, Operator request, etc.)

2. ***Veriforce*** will contact a company representative and/or the Evaluator in order to schedule a location, time, and date of the field audit. A list of Qualified Individuals to be interviewed will be provided.

3. ***Veriforce*** will interview each Qualified Individual in-person and ask them detailed questions regarding the evaluation process. A formal audit checklist will be used. ***Veriforce*** will focus on the description(s) given by the Evaluator as to how the evaluations were conducted to determine if the Qualified Individual can substantiate the account(s) given by the Evaluator. ***Veriforce*** may, after interviewing the Qualified Individuals, contact additional personnel involved with the evaluations (other Evaluators, Qualified Individuals, field supervisors, etc) to substantiate information gathered during the field interviews.

4. After ***Veriforce*** has interviewed all Qualified Individuals, the results will be communicated to the Evaluator in an exit interview. The Evaluator will be given the opportunity to clarify and/or resolve any potential issues identified in the desktop and/or field audit. If the potential issues cannot be resolved with the Evaluator, ***Veriforce*** will prepare a preliminary report detailing the audit finding. The Evaluator will be given 5 business days from the time ***Veriforce*** sends the preliminary report to the Evaluator to provide a written response to any audit findings. Evaluator comments will be considered in preparing the final field audit report.

5. ***Veriforce*** prepares a final audit report that details ***Veriforce*** findings, any response/comments from the Evaluator, and a description of the final actions to be taken by ***Veriforce***.

6. The final report will be prepared within 15 business days of audit completion and will be submitted to the Evaluator. In cases where action is to be taken against qualifications and/or Evaluator authorized status, the final report will be sent on the date of audit closure.

7.2.9 Each Evaluator field audit can result in the following outcomes: (1) no further action required; audit closed, (2) selected ROEs rejected, (3) all ROEs rejected, (4) revoke selected qualifications, (5) revoke all active qualifications put in-place by the Evaluator, and/or (6) revoke the Evaluator's authorized status. In cases where the field audit results from a failed desktop audit, ***Veriforce*** will consider all evidence gathered during both audits when determining the appropriate outcome.

7.2.9.1. <u>No further action required; audit closed</u>. Applied to those cases where the desktop audit results could not be substantiated or where a field audit was initiated with no desktop audit and there were no findings during the field audit.

7.2.9.2. <u>Selected ROEs rejected.</u> If ***Veriforce*** concludes (based on results of both the desktop and/or field audit) that an Evaluator did not follow procedures or Operator-specific evaluation criteria for a group of submitted ROEs that have not yet been passed, ***Veriforce*** will reject the affected pending ROEs and the Evaluator will be informed that they will not be entered into VeriSource as valid. ROEs will be rejected as soon as the audit report is finalized.

7.2.9.3. <u>All ROEs rejected.</u> If ***Veriforce*** concludes (based on results of the desktop and/or field audit) that an Evaluator repeatedly did not follow procedures or Operator-specific evaluation criteria for multiple groups and/or lengths of time, for submitted ROEs that have not yet been passed by ***Veriforce***, then ***Veriforce*** will reject all pending ROEs and the Evaluator will be informed that they will not be entered into VeriSource as valid. ROEs will be rejected as soon as the audit report is finalized.

7.2.9.4. <u>Selected qualifications revoked.</u> If ***Veriforce*** definitively concludes (based on results of the desktop and/or field audit) that an Evaluator did not follow procedures or Operator-specific evaluation criteria for a defined group of people over a specific period of time (i.e. one project or job), then ***Veriforce*** will revoke only the affected qualifications. Notice will be given to all affected parties that qualifications will be revoked, in most cases, 30 calendar days from the time that the audit report is finalized. .

7.2.9.5. <u>All active qualifications put in-place by the Evaluator since the last Evaluator Audit was conducted by ***Veriforce*** revoked.</u> If ***Veriforce*** concludes (based on results of the desktop and/or field audit, if applicable) that an Evaluator repeatedly did not follow procedures or Operator-specific evaluation criteria for multiple groups and/or lengths of time, then ***Veriforce*** will revoke all active qualifications put in-place by the Evaluator since his/her last Evaluator Audit that was conducted following the audit procedures outlined herein. Notice will be give to all affected parties that qualifications will be revoked, in most cases, 30 calendar days from the time that the audit report is finalized.

7.2.9.6. Evaluator's authorized status revoked. Anytime ***Veriforce*** revokes all active qualifications put in-place by an Evaluator, then the Evaluator's authorized status will also be revoked. In addition, ***Veriforce*** may revoke an Evaluator's authorized status anytime qualifications are revoked or ROEs are rejected due to an improperly conducted evaluation. An Evaluator's authorized status will be revoked as soon as the audit report is finalized.

7.2.10 ***Veriforce*** will document all Evaluator monitoring and manage this documentation as a quality record.

7.3 Data QA/QC

7.3.1 ***Veriforce*** may be required to enter data into an electronic database in support of various OQ processes and procedures. When performing data entry, ***Veriforce*** will implement data quality assurance/quality control (QA/QC) procedures to ensure that:

1. Information (applications, ROEs, forms, etc.) received is completed accurately, per the instructions outlined in the particular document or form,
2. Any data from these documents that requires manual transcription to an electronic database is accurately entered, and
3. Data entered via web interfaces by Evaluators or other outside parties is accurate and completed following specific procedures.

7.3.2 ***Veriforce*** will develop and execute data QA/QC protocols, depending upon the specific process in question. Specific QA/QC procedures and, where necessary, checklists will be developed for critical data entry processes that highlight the important items to be reviewed. These procedures will include audit frequency and problem correction protocols.

7.4 Review of Veriforce Records

7.4.1 For each qualification granted through ***Veriforce***, there will be a formal audit trail as described in Section 8.1.

7.4.2 At the conclusion of any audit, all ***Veriforce*** records associated with that individual (Qualified Individual or Evaluator) will be reviewed for completeness and accuracy.

7.4.3 If applicable supporting documentation cannot be found, then ***Veriforce*** will contact (if known) the originator of the record and request a copy of any missing records. If the record cannot be produced, then ***Veriforce*** will give the Qualified Individual, in most cases, 30 days to be re-evaluated at which time ***Veriforce*** will revoke the qualification in question.

7.5 Program Review

7.5.1 ***Veriforce*** encourages all program participants (Operators, Contractors, Evaluators, and others) to communicate difficulties encountered and ideas for program improvement whenever possible.

7.5.2 ***Veriforce*** will document issues and communicate those issues to the applicable Operator(s) for consideration.

7.5.3 ***Veriforce*** will host, at least quarterly, a meeting to be attended by its Operator clients for the purpose of program monitoring and to discuss options for program improvement.

7.5.4 ***Veriforce*** will work with individual Operator clients, at their request, to review their program for improvement opportunities

7.6 Annual 3rd-Party Audit of Veriforce

7.6.1 Annually, ***Veriforce*** will contract with a 3rd party auditing firm who will perform a business process compliance audit. The goal of this audit will be to provide assurances to client Operators that ***Veriforce*** is following the processes and procedures outlined herein.

7.6.2 ***Veriforce*** will work with client Operators to select an appropriate audit firm. Annually, ***Veriforce*** will prepare a scope of work and will solicit recommendations from Operators for audit vendors. Unless an alternate approach is approved by ***Veriforce*** Operators, ***Veriforce*** will submit a RFP to at least two different vendors (including any recommendations from client Operators) and will select one to perform the work.

7.6.3 ***Veriforce*** will submit a copy of the final audit report to all client Operators. Any reports or other documentation required as part of the final audit report will also be shared with Operators.

Part VIII: Documentation and Record Keeping

8.0 Purpose and Scope

8.0.1 This part describes the methods by which ***Veriforce*** will create, manage, and maintain quality records.

8.1 Documentation Supporting Each Qualification

8.1.1 For each qualification granted by ***Veriforce*** , the following documents will be maintained as supporting documentation:

1. Candidate Information
    a. ROE;
        i. Identifies Qualified Individual;
        ii. Identifies the covered task the individual is qualified to perform;
        iii. Identifies applicable evaluation criteria;
        iv. Identifies any required supporting documentation;
        v. Identifies required documentation of training;
        vi. Identifies the Evaluator;
        vii. Identifies the date of qualification; and
        viii. Identifies the method of evaluation.

2. Audit Documentation (if an audit has been completed); and

3. Evaluator Information
    a. Evaluator application received by ***Veriforce***,
    b. Complete Evaluator reference forms;
    c. Documentation that the Evaluator has successfully completed the Veriforce Evaluator Training Program; and
    d. Documentation of all Evaluator auditing (as appropriate).

8.1.2 Each of these records shall be treated as a quality record and maintained in accordance with the recordkeeping requirements of the OQ Rule. Applicable Operator(s) shall have access to these records.

8.2 Documenting the Evaluation

8.2.1 At the conclusion of an evaluation and after the Evaluator has determined whether the Candidate has successfully met applicable evaluation criteria, the ROE shall be signed and dated by the Evaluator. This signature serves as certification by the Evaluator that all appropriate ***Veriforce*** procedures were followed during the course of that evaluation.

8.2.2 At the conclusion of the evaluation, the Candidate shall also sign the ROE acknowledging (1) his/her identity, (2) that the evaluation took place, and (3) that the Candidate has a full understanding of the outcome of the evaluation.

8.2.3 At the conclusion of an evaluation, the Evaluator should relay any difficulties encountered in conducting the evaluation related to structure of task, criteria, questions, or any procedural issues that, if corrected, will improve the process of evaluating personnel back to ***Veriforce***. Significant issues will be reported back to applicable Operators in order to identify process improvement opportunities.

8.3 Documentation of Qualified Individual/Evaluator Monitoring

8.3.1 At the conclusion of each audit, a report will be created and archived. All resultant documentation generated from an audit will be maintained as a quality record.

8.3.2 All documentation pertaining to investigations resulting from an audit or any other incident investigation shall be maintained as a quality record and archived as part of the Qualified Individual's or Authorized Evaluator's file.

8.4 Documentation Related to an Evaluator

8.4.1 ***Veriforce*** shall maintain the following Evaluator records:

- Documentation of technical competence relative to the task(s) in question; and
- Documentation that the Evaluator has successfully completed the ***Veriforce*** Evaluator Training Program.

8.4.2 All quality records related to a specific Evaluator will be archived as part of the Evaluator's permanent file and maintained for a period of at least five (5) years following the date on which an Evaluator's authorization becomes inactive, expires, or is revoked.

8.5 Reporting

8.5.1 On a real-time basis, ***Veriforce*** will provide its Operator clients and Contractors access to *VeriSource*, a web-based reporting system that details

- Qualified Individuals by task;
- Qualified Individuals by organization;
- Qualified Individuals by name; and
- Other reports.

8.5.2 *VeriSource* also provides the name of the Evaluator associated with each qualification, date of qualification, method of qualification, and date that qualification is set to expire.

8.5.3 Password access will be given to appropriate parties in order that they have access to continually updated information.

8.5.4 ***Veriforce*** provides toll-free telephone access for Operator and Contractor personnel 24 hours per day, 7 days per week.

8.5.5 Those with password access are permitted to print qualification documentation directly from *VeriSource*.

8.5.6 ***Veriforce*** will endeavor to ensure that electronic data reporting is available through *VeriSource* at all times and will communicate any scheduled downtime at least 24 hours in advance. Notice of such shall be provided to each Operator client via email and as an electronic notification through *VeriSource* to both Operators and Contractors.

8.6 Management/Maintenance of Quality Records

8.6.1 Individuals responsible for the creation of records shall ensure that they are legible, accurate, completed appropriately, and traceable to the item(s) and/or activity(s) to which they apply.

8.6.2 Quality records may be originals, photocopies, faxes or scanned images.

8.6.3 All quality records shall be authenticated by ***Veriforce*** upon receipt. Authentication is the act of ensuring that the information contained within a record is accurate, complete, legible, and appropriate to the work accomplished.

8.6.4 Documents generated for an individual's qualifications shall be maintained for at least five (5) years after the qualification expires. All other quality records shall be retained while they are effective and for five years from the date the documents revisions become obsolete.

8.6.5 Documents generated for an individual's qualification for covered tasks required for Alternative Maximum Allowable Operating Pressure (AMAOP) projects shall be retained for life of the pipeline facility.

8.7 Submitting Records

8.7.1 All quality records shall be submitted to ***Veriforce*** either by fax, electronically, or as scanned images via email.

8.7.2 Records should be submitted to ***Veriforce*** as soon as possible after completion.

8.7.3 Quality records shall be submitted to ***Veriforce***, who shall authenticate, enter, and subsequently store/archive those records in accordance with this procedure.

8.8 Electronic Records

8.8.1 Digital or other non-paper records shall, at all times, be protected from magnetic fields, heat, moisture, light, or anything that would cause deterioration to the media and/or the information it contains.

8.9 E-Mail Records

8.9.1 Any quality record submitted via e-mail will be stored electronically by ***Veriforce*** and backed up in accordance with these procedures.

8.10 Protection of Records

8.10.1 Any person who generates or holds a quality record shall protect it from damage or loss. This includes protection from liquids, fire, and moisture. In-process records should be kept in a secure area when not in use.

8.10.2 Quality records placed in long-term storage must be stored in an appropriate container such that reasonable assurance can be made that the record will not be damaged or destroyed during the life of the record.

8.11 Supplementing, Changing, or Correcting Records

8.11.1 Corrections to records which require a change to a prior entry will include the initials or signature of the authorized person making the correction. Corrections to quality records shall be made such that the prior entry is not obliterated. Quality records shall not be corrected through the use of corrections fluids or tapes.

8.11.2 Records that are incomplete or illegible will be sent back to the generator and may be corrected by transcribing, regenerating or enhancing the illegible portion of the record.

8.12 Data/Records Backup

8.12.1 To avoid loss of data/records, a backup copy of data is made daily. On a weekly basis, all data shall be backed-up and stored off-site. CD-ROM (or other appropriate media) backup copies of entered data shall be made monthly and stored in a second location.

Part IX: Management of Change

9.0 Purpose and Scope

9.0.1 The OQ rule mandates that Operators put in place a structure by which to manage changes in task descriptions, evaluation criteria, methods/processes for evaluating personnel, and other program requirements. This part addresses the means by which ***Veriforce*** will support Operators in managing such changes.

9.1 Definition/Initiation of Change

9.1.1 There are several key activities which take place that provide opportunities to identify needed changes and/or to communicate program changes directly to impacted parties:

1. ***Veriforce*** solicits input from Evaluators regarding suggested program improvements and discussion of challenges faced;
2. ***Veriforce*** solicits input from Contractors to review program requirements, provide input on program improvements, and discuss challenges faced;
3. ***Veriforce*** collects/reports information generated as a result of quality assurance and monitoring activities;
4. ***Veriforce*** solicits input from Operator clients to discuss status, challenges faced, and program improvement ideas; and
5. ***Veriforce*** attempts to meet individually with each Operator annually to review covered tasks, evaluation criteria, and program requirements.

9.1.2 All applicable parties are encouraged to voice concerns, problems, or other issues and to present ideas on how the process might be improved. ***Veriforce*** will solicit input, document issues raised, and present all such issues to Operators.

9.1.3 On a periodic basis, ***Veriforce*** will host Operator OQ meetings for the purpose of reviewing requirements, communicating change, and soliciting input from Operators regarding issues, challenges, and ideas for improving the ***Veriforce*** process. The purpose of these meetings is:

- To discuss any problems/issues encountered. All such problems/issues identified will be communicated to applicable Operators for consideration in making any process improvements or changes in requirements in their respective OQ programs;
- To communicate any procedural issues or changes implemented by ***Veriforce***; and
- To communicate any changes in OQ requirements, covered tasks, evaluation criteria, or other changes initiated by the Operator(s) in support of the Operator's "Management of Change" efforts.

9.1.4 On a periodic basis, ***Veriforce*** will host Contractor Advisory Group (CAG) meetings. The purpose of the CAG is to identify process/VeriSource improvements, demonstrate product or system changes prior to implementation, and provide feedback to the Operator group.

9.1.5 As part of its efforts in monitoring Qualified Individuals and Evaluators, ***Veriforce*** will document issues raised by Qualified Individuals, Contractor representatives, Evaluators, and Operator personnel and communicate those issues to Operator clients.

9.1.6 At least annually, ***Veriforce*** will host a meeting of all Contractors and Operator clients where issues can be shared and discussed.

9.1.7 At any time, an Operator may determine that its program, covered task list, or corresponding evaluation criteria should be revised. ***Veriforce*** will assist the Operator in communicating any such changes and taking necessary steps to document and implement these changes such that compliance with the OQ rule can be properly demonstrated.

9.2 Categorization of Change

9.2.1 Upon being notified by an Operator of any change or alteration that impacts the currency of task descriptions, evaluation criteria, or program requirements, ***Veriforce*** and the applicable Operator will categorize the change(s) as follows:

9.2.1.1. **Low Impact** – requires no formal communication. Low impact changes may include grammatical, formatting, or other modifications that result in no material effect on the administration and implementation of the OQ Program.

9.2.1.2. **Medium Impact** – requires formal communication to affected parties. Medium impact changes may include revisions to administrative procedures, evaluation methods, operating procedures, or other items that affect the implementation and administration of the OQ program but **do not require** the requalification of individuals previously qualified on the applicable task(s).

9.2.1.3. **High Impact** – requires formal communication to affected parties. High impact changes may include revisions to administrative procedures, evaluation methods, operating procedures, or other items that affect the implementation and administration of the OQ program that **require** the requalification of individuals previously qualified on the applicable task(s).

9.2.1.3.1. In the case of a change(s) categorized as a High Impact, if the impacted individual(s) has not been re-evaluated/requalified by the date required, he/she shall be deemed “not qualified”.

9.3 Communication of Change

9.3.1 In the case of a change categorized as a Low Impact, ***Veriforce*** may communicate the change electronically or through discussion at a quarterly Operator or Contractor meeting. Depending on the nature of the change, formal communication may not be necessary.

9.3.2 Where a change is categorized as either Medium or High Impact, ***Veriforce*** will communicate the change as follows:

a. Electronic notification will be posted through *VeriSource*;
b. The change(s) will be discussed at the appropriate quarterly Operator meeting;
c. For High Impact changes, direct communication will be sent to affected parties as follows:
    1. Email in those cases where a valid email address is available;

2. Fax in those cases where a valid email address is not available and a valid fax number is available; and;
3. Communication via US Postal Service or other courier service in those cases where neither email nor fax is possible.

9.3.2.1. In those cases a where either a Medium or High Impact change is to be made effective on some future date, communication will be made to affected parties as early as possible in advance of the effective date (depending on the nature of the change) and a second communication will be sent on the date the change becomes effective.

9.3.2.2. In those cases where either a Medium or High Impact change is to be made immediately effective, communication will be sent to affected parties as soon as possible.

9.3.3 When a change is communicated to an affected party, that communication will be documented in an electronic communication log maintained by ***Veriforce***. The communication log will document (a) the date of the communication, (b) recipient of the communication, (c) communication subject, and (d) method by which communication was sent to the affected party.

9.3.4 ***Veriforce*** provides toll-free telephone support to applicable parties so that changes can be communicated directly to those who utilize that support and assistance can be provided to those trying to address a specific issue or change.

Part X: *Veriforce* Program Management

10.0 Purpose and Scope

10.0.1 ***Veriforce*** provides various OQ compliance services to a large and diverse number of pipeline Operator clients; each with a common goal of ensuring compliance with the OQ Rule yet each with unique needs. This section describes the various documents and programs that ***Veriforce*** employs to help ensure OQ compliance while accommodating the needs of various pipeline Operators.

10.1 Common Covered Task List

10.1.1 In 2003, various OQ stakeholder groups including Operating clients, pipeline Contractors, other third-party OQ service vendors, and unions took part in an effort to construct a covered task list and supporting evaluation criteria that could be adopted by ***Veriforce*** Operators. The goal of this effort was to produce a “common covered task list” (CCTL) so that Contractors qualified for a common task would be qualified for all Operators who had adopted the list as their own.

10.1.2 The CCTL and associated evaluation criteria were created by comparing and reconciling the existing covered task lists and criteria each Operator had developed/adopted individually. This effort took place over a period of several months in 2003. SMEs utilized data from their respective individual plans to decide on evaluation method, evaluation criteria, span of control, and requalification intervals for each of the common covered tasks.

10.1.3 The CCTL is regularly updated as Operators have the opportunity to request additional covered tasks or modifications to existing covered tasks.

10.1.3.1. ***Veriforce*** will facilitate the establishment of and the work of the CCTL Steering Committee. The purpose of this committee is to review the adequacy of the CCTL (and underlying task evaluation criteria) on an ongoing basis and to review potential changes to the CCTL. The CCTL steering committee will make recommendations to the larger group of Operators who have adopted the CCTL.

10.1.3.2. Any changes made to the CCTL will be managed in accordance with Part IX of these procedures.

10.1.4 Any ***Veriforce*** Operator can choose to adopt the CCTL into their OQ plan. Each Operator who chooses to adopt the CCTL has the opportunity to add or remove tasks from their individual covered task list.

10.1.5 If an Operator chooses to adopt the CCTL to replace or supplement an existing covered task list, the following steps will be followed, as appropriate, to effect an orderly transition that ensures continued compliance with the OQ Rule:

10.1.5.1. ***Veriforce*** will work with the Operator to document which “common” covered tasks will replace existing covered tasks. This will be accomplished by comparing evaluation criteria within the “common” evaluation criteria;

10.1.5.2. ***Veriforce*** will ensure that all impacted Evaluators are authorized for appropriate “common” covered tasks based on existing authorization relative to Operator-specific covered tasks;

10.1.5.3. ***Veriforce*** will send communication to all impacted parties describing the upcoming transition;

10.1.5.4. Existing qualifications will be converted to appropriate “common” qualifications within *VeriSource*;

10.1.5.5. A second communication will be sent to all impacted parties announcing that the conversion has taken place;

10.1.5.6. ***Veriforce*** shall document all communication in accordance with Part IX of these procedures.

10.1.6 New ***Veriforce*** Operators who do not have a covered task list can adopt the CCTL. ***Veriforce*** will work with those Operators to ensure that the CCTL describes all Covered Tasks performed by the Operator. If the Operator identifies Covered Tasks (as defined in the OQ Rule) that are applicable to their operation and are NOT on the CCTL, then ***Veriforce*** will work with the Operator to develop new covered task(s) and associated evaluation criteria for the Operator to be adopted into their OQ Plan.

10.1.6.1. After a new task is developed for a specific Operator, ***Veriforce*** may propose the new task to the CCTL Steering Committee for possible adoption into the CCTL.

10.2 CCTL Training Guides

10.2.1 ***Veriforce*** provides training documents, known as *Training Guides* (TGs), for each task listed in the CCTL that can be used by Authorized Evaluators to assist in the delivery of OJT. The TGs are offered in good faith and anyone choosing to utilize them is doing so at their own discretion and choice. Although every attempt has been made to ensure the correctness and suitability of TGs and to correct any errors brought to our attention, no representation or guarantee is being made regarding correctness or suitability, either directly or indirectly, or regarding correctness or suitability of information referenced or implied. It is intended that this training tool be used exclusively by an Authorized Evaluator, who shall comply with all safety requirements and Company and/or Operator operating procedures, as applicable. In no event shall ***Veriforce*** be liable for any special, incidental or consequential damages or any damages whatsoever, including but not limited to, death, personal injury, damage, loss of use, loss of revenues, whether in an action of contract, negligence, or other action, arising out of the use or misuse of this document. All critical information should be independently verified. The subject matter included in TGs has been compiled from a variety of sources, and is subject to change without notice.

10.2.2 During the course of use, Authorized Evaluator's may encounter improvements or other changes that they feel should be made to the TGs. Proposed changes to the TGs should be submitted to ***Veriforce.***

10.2.3 Any requests to change or modify TGs will be considered by ***Veriforce*** who may, at their discretion, modify the TGs as recommended. ***Veriforce*** may ask other SMEs to review the proposed change for accuracy prior to modifying a particular TG.

10.3 Professional Services Agreement

10.3.1 Prior to establishing an internal Evaluator or putting any qualification in place, the Candidate (or his/her employer) must execute a Professional Services Agreement (PSA), or similar agreement if Evaluator/Candidate represents an Operator client.

10.3.2 The PSA sets forth obligations of the Candidate/Candidate's employer, as listed below:

10.3.2.1. All statements, certifications, and actions shall be in full accordance with ***Veriforce*** procedures, applicable pipeline Operator requirements, and the OQ Rule. It shall be understood that, in the event these obligations are not met, previously Qualified Individuals may be disqualified at the discretion of ***Veriforce*** and/or the applicable pipeline Operator(s).

10.3.2.2. The PSA will constitute an agreement to notify ***Veriforce*** immediately of any case in which performance of a Qualified Individual contributes to an incident or accident or if there is any reason to suspect that a Qualified Individual may no longer be qualified. Candidate's employer shall also agree to cooperate during ***Veriforce*** audits of Authorized Evaluators, Qualified Individuals, or other activities/persons, as applicable.

10.3.2.3. In the event that a representative or employee becomes an Evaluator, that Evaluator/employer agrees to ensure that all activities of that Evaluator are done in full accordance with ***Veriforce*** procedures. It shall be understood that, in the event this obligation is not met, existing qualifications may be revoked and the Evaluator's authorized status may be suspended or revoked at the discretion of ***Veriforce*** and/or the applicable pipeline Operator(s).

10.4 Operator Qualification Policy and Procedures Document

10.4.1 The ***Veriforce*** Policies and Procedures Manual describes the processes employed to manage OQ for client Operators. Because of program improvements and other regulatory changes, these procedures must be updated on a regular basis, as described below.

10.4.2 Changes to the ***Veriforce*** Policies and Procedures Manual can be proposed by either ***Veriforce*** or an Operator client. So that the procedures are not modified too frequently, ***Veriforce*** will make every effort to consolidate changes into an annual program review and update.

10.4.2.1. If changes are proposed by an Operator, ***Veriforce*** will review the proposal for any negative impacts to other processes or procedures.

10.4.2.2. If conflicts are noted that would negatively affect other procedures or processes, ***Veriforce*** will describe the conflict in writing and notify the Operator that the proposal cannot be implemented as proposed.

10.4.2.3. If no conflicts are noted, ***Veriforce*** will proceed with the proposal. In doing so, ***Veriforce*** may elect to hold the proposed change until the procedures are up for annual review and modification. Every effort will be made to combine all proposed changes into one annual revision.

10.4.2.4. Operators will be given three weeks (unless speed is of the essence) to review and provide comment on the proposed changes.

10.4.2.5. At the end of three weeks, ***Veriforce*** will compile comments into one document and issue a Response to Comments communication to all Operators summarizing any comments received and the ***Veriforce*** response along with the decision to either approve or disapprove of the change.

10.4.2.6. If issues are uncovered that could significantly affect the proposal, then ***Veriforce*** may change the proposal and re-submit with an additional three week review and comment period.

10.4.3 In most cases, changes will be approved if greater than half of the Operators either approve the change or do not respond to the ***Veriforce*** request for approval. No response by an Operator will be considered an approval vote.

10.4.4 Periodically, ***Veriforce*** will review and update the entire Manual to keep current with regulatory trends or other industry best practices. Many updates may be proposed, some of which are not significant. In this case, it may not be practical to summarize every change made; therefore, ***Veriforce*** will edit the document in “track changes” mode and circulate the modified manual as the change summary document.

Document Revision History

Rev No.	Rev Date	Description of Change	Justification For Change
0	10/01/2001	Effective date of ***Veriforce*** Policies and Procedures - Rev 0.	Initial Revision
1	12/19/2001	Added/revised definitions and added Management of Change procedures to ***Veriforce*** Policies and Procedures	MOC procedures added to capture requirements of the OQ Rule
2	1/24/2002	Added language related to conduct of evaluator background checks. Allowed for contractor personnel evaluating their own employees. Allowed for assessment of qualifications achieved via other processes/organizations. Added language to make distinction between training and evaluation. Added requirement that Evaluator must provide identification. Added provision that ***Veriforce*** would assist in meeting "special needs" of candidate in conducting evaluation.	Various changes made to better align procedures with the OQ Rule and to account for experiences gained in implementation.
3	2/28/2002	Reorganized procedures into multiple Parts. Created appendices to provide examples of quality records. Expanded definitions.	Re-organized for greater clarity and logical flow.
4	10/22/2002	Made ***Veriforce*** responsible for technical approval of prospective evaluators. Removed Part IX (renumbered) to remove "Assessment of Other Internal Programs". Removed specific reference to "Personnel Evaluation by Proctor" (Part VI - renumbered). Removed appendices.	Changes made to reflect experience gained in program implementation.
5	11/22/2002	Added specific language related to revocation of evaluator/proctor authorization. Removed reference to "Affidavit of Qualification".	Changes made to reflect experience gained in program implementation.
6	2/24/2003	Added flow diagrams to supplement each section. Added details on defining and communicating program requirements to contractors, integration of evaluation criteria, and approaches to becoming qualified. Added specific language related to the Professional Services Agreement required of contractors. Removed specific reference to proctor-driven evaluations. Added section on "Program Quality Management". Re-inserted appendix showing sample quality records.	Changes made to synchronize procedures with OPS Enforcement Protocols.

Rev No.	Rev Date	Description of Change	Justification For Change
7	11/7/2003	Added a detailed list of services/functions performed by ***Veriforce***. Added Part II (New) – References applicable parts of the procedures to (a) OQ Rule, (b) OPS Enforcement Protocols (OQ2), and (c) ASME B31Q. Added definition of "Construction". Added definition of "Maintenance". Evaluator Authorization Flow Diagram revised to reflect change in Evaluator Training Program. . ***Veriforce*** to convert its Evaluator training course to "no cost" self-paced training course. ***Veriforce*** to no longer approve or accept Evaluator training programs of other organizations. 100% passing grade required on Evaluator Training examination. Evaluator reauthorization required annually. Evaluation of Personnel Flow Diagram revised to (1) remove reference to "integrated tasks". Removed reference to "Integrated Covered Tasks". Added discussion relative to "Common Covered Tasks". Strengthened discussion of knowledge (K) and skill (S) based criteria and mandated "method" of evaluation. Removed requirement that candidate's employer would be notified, in writing, of an unsuccessful evaluation. Removed requirement that all "assessments" must be overseen by ***Veriforce*** Project Manager. Management of Change Flow Diagram revised to reflect re-definition of Change Categories. Added details to description of activities where ***Veriforce*** will solicit input from program participants. Re-defined "categories" of change. Removed Appendix A. Strengthened language related to communication of change to describe more clearly (a) how communication will take place, based on change category, and (b) documenting communication.	Changes made to reflect experience gained in program implementation.
8	12/17/2004	Added table to illustrate document revision history for ***Veriforce*** procedures. Incorporated training requirements in accordance with Pipeline Safety Improvement Act of 2002. Various revisions and additions in definitions section. Explanation that only Authorized Evaluators may conduct structured on-the-job training (OJT) through ***Veriforce***. Added explanation that personnel may be selected for audit based on "random" selection or "for cause".	Changes made to comply with statutory requirements set forth in Pipeline Safety Improvement Act of 2002, to add clarification for a number of issues, and to improve the ***Veriforce*** program.

Rev No.	Rev Date	Description of Change	Justification For Change
9	10/1/2006	Miscellaneous – Editorial revisions to provide clarification. Part II -- Tables updated to reflect current requirements set forth in OQ Rule and PHMSA enforcement protocols. Part III -- Added definition of "Subject Matter Expert" and removed definitions for "***Veriforce*** Project Manager" and "***Veriforce*** Records Administrator". Part IV – Clarified to require **at least** 3 references for evaluator applicants (4.2.3). Revised process to allow for assignment of evaluator login and password at time of application (4.4.4). Revised to allow for reauthorization of expired evaluator through training only provided retraining takes place within one calendar year of expiration (4.6.3). Part V – Clarified to establish evaluator responsibility for determining training requirements prior to evaluation (5.1.2 and 6.8.1). Established that Candidate's employer assumes responsibility for applicability of training through sources other than ***Veriforce*** (5.3.1). Part VI – Established responsibility of Operator to define covered task-specific requirements related to "span of control" (6.1.1). Clarification added that applicable documents are to be provided through VeriSource (6.1.6). Clarified role of third-party evaluators (6.3.1). Clarified the "Assessment" approach (6.13). Part VII – Added clarification for monitoring of candidates and monitoring of evaluators as separate processes (7.1 and 7.2). Clarified steps to be followed when there is evidence to suggest an individual may no longer be qualified (7.1.8.2). Allowance for bypassing monitoring of certain evaluators where sufficient data suggests acceptable performance (7.2.2). Part VIII – Clarified timeframe for which certain quality records are to be maintained (8.6.4). Part IX – Added examples of "High Impact Change" (9.2.1.3).	Changes made to add clarification for a number of issues and to improve the ***Veriforce*** program.

Rev No.	Rev Date	Description of Change	Justification For Change
10	9/4/2007	Miscellaneous – Editorial revisions to provide clarification. Part II – Tables updated to reflect current requirements set forth in OQ Rule and PHMSA enforcement protocols. Part III – Modified the following definitions: "Authorized Evaluator", "Direct and Observe", "Evaluation Criteria", and "Evaluator". Added the following definitions: "Expired Authorization", "Revoked Authorization", "Suspended Authorization". Deleted the following definitions: "Internal Evaluator", "Trainer", "Data Evaluation". Part IV – Clarified that Operator's internal Evaluators may submit Operator-specific Evaluator Applications (4.2). Clarified expired Evaluator reauthorization requirements (4.5). New section describing circumstances warranting removal of an Evaluator's authorized status (4.7). New section describing Evaluator reauthorization following a revocation (4.8). Part V – Clarified that individual Operators may dictate additional instances when training is required prior to an Evaluation (5.1). Part VI – Clarified that proper response to AOCs are part of the evaluation criteria (6.1). Clarified that candidates art not allowed to use evaluation criteria documents during an evaluation (6.3). Section 6.2 moved to 10.1. Section 6.4 moved to 10.3. Language added to allow for Operator-specific qualifications at the written direction of the Operator (6.11). Detail added on removal of an individual's qualifications (6.12). Part VII – Detail added to Qualified Individual audit procedures (7.1). Detail added to Authorized Evaluator audit procedures (7.2). New section describing internal data entry QA/QC (7.3). Clarify ***Veriforce*** response to missing records (7.4). New section describing annual ***Veriforce*** program audit (7.6). Part X – New part describing various OQ program elements.	Changes made to add clarification for a number of issues and to improve the ***Veriforce*** program.

Rev No.	Rev Date	Description of Change	Justification For Change
11	5/20/2009	Miscellaneous – Editorial revisions to provide clarification. Part III – Added the following definitions: "CCTL Steering Committee", "Rejected ROE", and "Simulation". Part IV – Removed requirement that Evaluator must be reauthorized within 12 months of expired authorization in order to avoid full authorization process (4.5.3). Added language allowing for permanent revocation of Evaluator authorization in certain cases (4.8.4). Part VI – Added procedural requirements related to "simulation" (6.7.8.1. and 6.7.8.2). Added procedural guidance related to use of "performance on the job" (6.7.8.3). Removed wording requiring completion of an investigation within 5 working days and requirement to invite all operators to participate in such investigations (6.12.1.2). Part VII – Added allowance for suspension of qualifications and/or Evaluator authorization based on refusal to cooperate with a ***Veriforce*** audit (7.2.3.). Clarified field audit process description (7.2.6. through 7.2.8.). Added reference to rejecting ROEs not yet passed due to evaluator audit findings (7.2.8). Clarified ***Veriforce*** responsibility to work with Operator clients to review and improve individual OQ programs (7.5.4). Part VIII – Revision requiring that Veriforce shall provide toll-free telephone technical support on a 24/7 basis (8.5.4.) Part X – Added provision for establishing the CCTL Steering Committee (10.1.3.1. through 10.1.3.2. and 10.1.6.1.)	Changes made to add clarification for a number of issues and to improve the ***Veriforce*** program.

Rev No.	Rev Date	Description of Change	Justification For Change
12	5/1/2011	Miscellaneous – Editorial revisions to provide clarification. Part II – Added table for AMAOP reference Part III – Updated the definitions of the following: Authorized Evaluator, Evaluation, Maintenance, OJT, Qualified Individual, Revoked Authorization, Suspended Authorization and SOC. Added definitions: Character Reference, Contractor Advisory Group, Technical Reference. Removed definition of Data Validation. Part IV – Added requirement for character references (4.2.1.3). Updated New Evaluator training description (4.3). Updated Evaluator Reauthorization process (4.5). Added description to explain transfers (4.6.2). Added section 4.7.5. Part V – Removed requirement for training to be conducted by authorized evaluator (5.2.2). Added requirement for candidates' name (5.4.3). Part VI – Removed allowance for not reviewing ID (6.5.1.1). Updated simulation description (6.7.8.1). Removed discussion concerning written questions (6.8.4). Part VII – Added discussion concerning non-response to audit (7.1.5.2). Added discussion concerning final report delivery (7.2.8.2) Part VIII – Added statement for AMAOP record retention (8.6.5) Part IX – Added CAG discussion (9.1.4)	Changes made to add clarification for a number of issues and to improve the ***Veriforce*** program.
13	6/1/2012	Miscellaneous – Editorial revisions to provide clarification. Part III – Updated "Disqualification" to include references to Parts 191 &195. Updated "Revoked Qualification" to clarify training requirement for High Impact changes Part IV – Added discussion for character references (4.2.1.3). Added descriptions for lapsed evaluator authorizations (4.5.3.1&2) Part VI – Added evaluation failure discussion (6.10.2) Part VII – Added additional audits discussion (7.2.2) Part IX – Edited communication requirements for high & medium impact changes (9.3.2)	Changes made to add clarification for a number of issues and to improve the ***Veriforce*** program.

EXHIBIT E

4-PART TEST ANALYSIS

4-Part Test Analysis
Covered Task List
Jefferson Island Storage and Hub (JISH), Golden Triangle Storage (GTS), & Central Valley Gas Storage (CVGS)

Task ID (Incl. OP)	Task Description	Performed on a Pipeline Facility	Operations or Maintenance	Required by 192 or 195	Affects Pipeline Operation or Integrity
007	Operate Valves	Yes	Yes	No	Yes
008	Measurement of Wall Thickness with Ultrasonic Device	Yes	Yes	Yes	Yes
103	Nondestructive Testing (Other than testing of welds)--Mag Particle	Yes	Yes	Yes	Yes
201	Abnormal Operating Conditions Related to Welding on Pipelines (Maintenance, Tie-Ins, and Repair)	Yes	Yes	Yes	Yes
202	Monitoring of Welding Process	Yes	Yes	Yes	Yes
203	Visual Inspection of Welds not Non-Destructively Tested	Yes	Yes	Yes	Yes
204	Non-Destructive Testing of Welds (Dye Penetrant)	Yes	Yes	Yes	Yes
205	Non-Destructive Testing of Welds (Mag Particle)	Yes	Yes	Yes	Yes
206	Non-Destructive Testing of Welds (Ultrasonic)	Yes	Yes	Yes	Yes
207	Non-Destructive Testing of Welds (X-Ray)	Yes	Yes	Yes	Yes
208	Plastic Pipe Joining: Butt Fusion	Yes	Yes	Yes	Yes
209	Plastic Pipe Joining: Mechanical Joining	Yes	Yes	Yes	Yes
210	Plastic Pipe Joining: Electrofusion Joining	Yes	Yes	Yes	Yes
211	Perform Plastic Fusion Inspection	Yes	Yes	Yes	Yes
213	Joining of Steel Pipe – Threaded and Flanged Connections	Yes	Yes	Yes	Yes
214	Joining of Steel Pipe – Threaded Connections	Yes	Yes	Yes	Yes
215	Joining of Steel Pipe – Flanged Connections	Yes	Yes	Yes	Yes
216	Joining of Steel Pipe – Compression Couplings	Yes	Yes	Yes	Yes
217	Small Diameter Tubing and Fitting Installation	Yes	Yes	Yes	Yes
401	Examination of Buried Pipelines When Exposed	Yes	Yes	Yes	Yes
402	Apply Approved Coatings to Above Ground Piping	Yes	Yes	Yes	Yes
403	Apply Approved Coatings to Below Ground Piping	Yes	Yes	Yes	Yes
404	Protection of Coating When Backfilling and From Below Ground Supports	Yes	Yes	Yes	Yes
405	Protection of Coatings From Above Ground Structures	Yes	Yes	Yes	Yes
406	Conduct Test to Determine Cathodic Protection Current Requirements	Yes	Yes	Yes	Yes
407	Perform Cathodic Protection Survey	Yes	Yes	Yes	Yes
408	Inspect Cathodic Protection Rectifier	Yes	Yes	Yes	Yes
409	Inspect Interference Bonds	Yes	Yes	Yes	Yes
410	Clear Shorted Casing	Yes	Yes	Yes	Yes
411	Inspect/Test to Assure Electrical Isolation is Adequate	Yes	Yes	Yes	Yes
412	Install CP Leads on Pipeline Using Exothermic Weld	Yes	Yes	Yes	Yes
413	Anode Installation on Submerged Pipeline or Facilities	Yes	Yes	Yes	Yes
414	Inspect for Internal Corrosion Whenever Pipe is Removed	Yes	Yes	Yes	Yes
415	Monitoring for Internal Corrosion with Probes and Coupons	Yes	Yes	Yes	Yes
416	Monitoring for Internal Corrosion with Gas Samples	Yes	Yes	Yes	Yes
417	Atmospheric Corrosion Monitoring	Yes	Yes	Yes	Yes
418	General and Localized Corrosion Measurement (Remedial Measures)	Yes	Yes	Yes	Yes

4-Part Test Analysis
Covered Task List
Jefferson Island Storage and Hub (JISH), Golden Triangle Storage (GTS), & Central Valley Gas Storage (CVGS)

Task ID (Incl. OP)	Task Description	Performed on a Pipeline Facility	Operations or Maintenance	Required by 192 or 195	Affects Pipeline Operation or Integrity
419	Test Point Survey	Yes	Yes	Yes	Yes
420	Soil Resistivity	Yes	Yes	Yes	Yes
421	Measurement of Depth of Pitting with Pit Gauge	Yes	Yes	Yes	Yes
423	Perform Direct Current Voltage Gradient (DCVG) Survey	Yes	Yes	Yes	Yes
424	Perform AC Current Attenuation (ACCA) Survey	Yes	Yes	Yes	Yes
425	Perform Alternating Current Voltage Gradient (ACVG) Survey	Yes	Yes	Yes	Yes
426	Inspect Pipe Coating with Holiday Detector	Yes	Yes	Yes	Yes
427	Inspection of the Application of Above or Below Ground Coatings	Yes	Yes	Yes	Yes
428	Pin Brazing to Install CP Leads on Pipeline	Yes	Yes	Yes	Yes
501	Conduct Pressure Test to Substantiate MAOP	Yes	Yes	Yes	Yes
502	Conduct Pressure Test (<100 p.s.i.)	Yes	Yes	Yes	Yes
601	Start-up/Shut-down of Pipeline to Assure Operation Within MAOP	Yes	Yes	Yes	Yes
602	Monitoring Pipeline Pressure	Yes	Yes	Yes	Yes
603	Compressor Units/Stations: Start-up, Operation, Shutdown, and Purging Before Returning to Service	Yes	Yes	Yes	Yes
604	Locate, Mark, and Remediate Exposed Pipelines in the Gulf of Mexico	Yes	Yes	Yes	Yes
605	Locate Line/Install Temporary Marking of Buried Pipeline	Yes	Yes	Yes	Yes
606	Locate and Mark Submerged Pipelines	Yes	Yes	Yes	Yes
607	Damage Prevention: Observation of Excavating and Backfilling	Yes	Yes	Yes	Yes
608	Damage Prevention for Blasting Near a Pipeline	Yes	Yes	Yes	Yes
609	Inspect and Maintain Odorizer	Yes	Yes	Yes	Yes
610	Monitor Odorant Concentration	Yes	Yes	Yes	Yes
611	Hot Tap (Steel Pipe)	Yes	Yes	Yes	Yes
612	Hot Tap (Plastic Pipe)	Yes	Yes	Yes	Yes
613	Purge Pipeline Facilities With Gas	Yes	Yes	Yes	Yes
614	Purge Pipeline Facilities With Air or Inert Gas	Yes	Yes	Yes	Yes
615	Inspect Odorizer	Yes	Yes	Yes	Yes
616	Atmospheric Monitoring During Hot Work Operations	Yes	Yes	Yes	Yes
701	Patrolling Pipeline and Leakage Survey without Instrument	Yes	Yes	Yes	Yes
702	Leakage Survey with Leak Detection Device	Yes	Yes	Yes	Yes
703	Placing/Maintaining Line Markers	Yes	Yes	Yes	Yes
704	Permanent Field Repair by Grinding	Yes	Yes	Yes	Yes
705	Permanent Field Repair Using Composite Materials (Clockspring)	Yes	Yes	Yes	Yes
706	Permanent Field Repair Using Composite Materials (Armor Plate)	Yes	Yes	Yes	Yes
707	Permanent Field Repair Using Bolt-On Clamp or Sleeve	Yes	Yes	Yes	Yes
708	Permanent Field Repair Using Full Encirclement Weld Sleeve	Yes	Yes	Yes	Yes
709	Inspection and Testing of Relief Devices (Compressor Stations, Meter Stations, Regulating Stations)	Yes	Yes	Yes	Yes

4-Part Test Analysis
Covered Task List
Jefferson Island Storage and Hub (JISH), Golden Triangle Storage (GTS), & Central Valley Gas Storage (CVGS)

Task ID (Incl. OP)	Task Description	Performed on a Pipeline Facility	Operations or Maintenance	Required by 192 or 195	Affects Pipeline Operation or Integrity
710	Inspect/Test Compressor Station Remote Control Shutdown Devices (ESD/EBD)	Yes	Yes	Yes	Yes
711	Inspect, Test, and Maintain Control Systems	Yes	Yes	Yes	Yes
712	Programmable Logic Controllers	Yes	Yes	Yes	Yes
713	Test/Maintain Gas Detection and Alarm Systems	Yes	Yes	Yes	Yes
714	Inspect and Maintain Pressure Limiting and Regulating Devices	Yes	Yes	Yes	Yes
715	Test and Maintain Pressure Switches and Transmitters in Pressure Limiting and Regulating Service	Yes	Yes	Yes	Yes
716	Inspect, Maintain, and Operate Valves	Yes	Yes	Yes	Yes
717	Maintaining Vaults With Pressure Regulating and Pressure Limiting Equipment	Yes	Yes	Yes	Yes
718	Monitoring for Internal Corrosion with Liquid Samples	Yes	Yes	Yes	Yes
719	Permanent Field Repair Using Composite Materials (PermaWrap/Weld Wrap)	Yes	Yes	Yes	Yes
721	Permanent Field Repair Using Composite Materials (Black Diamond)	Yes	Yes	Yes	Yes
722	Permanent Field Repair Using Composite Materials (Aqua Wrap)	Yes	Yes	Yes	Yes
723	Leakage Survey with Remote Laser Leak Detection Device	Yes	Yes	Yes	Yes
724	Permanent Field Repair Using Composite Materials (Pipe Wrap A+)	Yes	Yes	Yes	Yes
725	Aerial Leakage Survey: Transmission	Yes	Yes	Yes	Yes
728	Aerial Leakage Survey: Transmission (UV/IR)	Yes	Yes	Yes	Yes
AGL-019a	Hazard Control	Yes	Yes	Yes	Yes

Attachment 5

Central Valley Gas Storage Emergency Response Plan

Central Valley Gas Storage

*An **AGL Resources** Company*

Emergency Response Plan

June 2013 Version

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
Emergency Plan – Summary Table of Contents

Reference: 49 CFR 192.615 **Date Revised: April 2012**

Summary Contents

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
Emergency Plan

Reference: 49 CFR 192.615 **Date Revised: April 2012**

INTRO & PRE-PLANNING

CENTRAL VALLEY GAS STORAGE

Natural Gas Transmission Pipeline
Emergency Response Procedures

Reference: 49 CFR 192.615 **Date Revised: April 2012**

APPROVAL DOCUMENT

Company Pipeline Emergency Plan Approval:	Brian K. Jones Director, Storage & Peaking Ops - West Region (approval name & title) Brian K Jones 6/13/12 (approval signature) (date)
Site/Facility Plan Approval:	DG. Woodward Manager Storage Operations - CVGS (approval name & title) D G Woodward 6/13/12 (approval signature) (date)
Original Effective Date:	April 1, 2012
Revised Em Plan Effective Date:	
Plan Review:	These pipeline Emergency Response Procedures shall be reviewed and updated at an interval not to exceed 15 months, but at least once each calendar year. Also, when major revisions to the plan occur, the appropriate Managers/Supervisors shall re-approve this plan.
Purpose:	This Emergency Response Plan outlines the procedures and methods CVGS will utilize in complying with the DOT gas pipeline regulations written in 49 CFR 192.615.
Applies To:	This Plan applies to the DOT jurisdictional gas transmission pipeline located in Princeton, California.

CENTRAL VALLEY GAS STORAGE

Natural Gas Transmission Pipeline
Emergency Response – Record of Revisions

Reference: 49 CFR 192.615 **Date Revised: June 2013**

	April 2012
1.	CVGS Facilities authorized by the CPUC in Decision 10-01-001 are placed into commercial service with 9 injection and withdrawal wells receiving natural gas from PG&E facilities on McAusland Road with associated metering and regulation facilities along with safety and emergency shut-down devices. CVGS' USDOT Operator ID number is 32603.
	June 2012
2.	Revisions are made to the Emergency Response Plan including Approval Document (tab 1), Record of Revisions (tab 2), Introduction, Scope and Responsibilities (tab 3), and Emergency Phone Numbers (tab 8). Additional CVGS Facilities authorized by the CPUC in Decision 10-01-100 are placed into service including 14.7 miles of 24 inch pipeline, 1400 feet of dual 16 inch gathering lines, 3-3,500 horsepower (hp) natural gas engine-driven compressors; 3 gas fired dehydration units; associated metering and regulation facilities along with safety and emergency shut-down devices for the additional facilities.
	March 2013
3.	Revisions are made to the Emergency Response Plan including the Record of Revisions (tab 2), Pipeline Emergency Plan Distribution List (tab 3), and Emergency Phone Numbers (tab 8).
	June 2013
4.	Emergency valve list was revised. Also, revised the following: • Distribution list in the intro section • Emergency contact list

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
Emergency Response Procedures

Ref: 192.615	Date Revised: June 2013

Introduction, Scope, Responsibilities, and Distribution

Scope of Manual:

The purpose of this manual is to provide procedures to be followed by pipeline operating personnel in any emergency involving the DOT jurisdictional pipelines. These procedures are written to assure the welfare and safety of the public and all emergency response personnel. Property is to be protected, but only after it is ascertained that the public is adequately protected from any consequences of the failure or accident. This plan is designed to meet the requirements of the Department of Transportation (DOT) for natural gas pipeline operations as outlined in 49 CFR 192.615.

Description of Pipeline:

See attached "Fact Sheet."

Responsibilities:

This DOT pipeline emergency response plan is established by Central Valley Gas Storage (CVGS). The CVGS Operations Manager is responsible for handling emergencies utilizing its resources. In the event that an emergency requires outside resources, a Unified Command will be utilized. CVGS will make the initial response and ensure that safeguarding of people and property are given first priority.

The CVGS OPERATIONS MANAGER is designated as the initial "Incident Commander" under the incident command system (ICS) format. The CVGS OPERATIONS MANAGER may designate personnel to perform emergency response training, but utilimately has the responsibility to ensure completion of all emergency plan action items and responses.

The on-call employee will normally make the initial response to the emergency and then notify the CVGS OPERATIONS MANAGER of the status and resources needed. The CVGS OPERATIONS MANAGER will also call the appropriate company personnel as listed in the emergency contact list.

PIPELINE EMERGENCY PLAN DISTRIBUTION LIST

CVGS

Name	Title	Location	Manual #, Location
Brian Hackney	Manager, Operations	Princeton, CA	Office / Vehicle
	CVGS Office	Princeton CA	Control Room
Robert Cornell	Director, Storage & Peaking Ops – West Region	Beaumont, TX	Vehicle / Electronic
Tim Hermann	V.P. Storage & Peaking Ops	Lisle, IL	Office
Princeton Fire Dept.	Fire Chief	Princeton, CA	Office
Maxwell Fire Dept.	Fire Chief	Maxwell, CA	Office

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
Emergency Response Procedures

Ref: 192.615	**Date Revised: April, 2012**

PRE-EMERGENCY PLANNING

This Emergency Response Plan shall be reviewed and updated at least once per calendar year not to exceed 15 months. In addition to updating the Plan, several additional activities shall be completed before responding to emergencies. Below is a summary list of these activities followed by a detailed description of these items.

Summary of Potential Pre-Emergency Activities

- Review and update emergency plan. [192.605(a)]
- Emergency drills and training. [192.615(b)]
- Liaison with public officials. [192.615(c)]
- Public education program. [192.616]
- One call center. [192.614]
- Verification of Approved Contractors [199.21, 192.801-809, 29 CFR 1910.120]
- Operator Qualification [192.801-809]

Emergency Drills and Training

Periodically, a simulated emergency shall be conducted to test the Emergency Plan, train personnel, and test their competency in implementing the plan. These drills shall be as realistic as possible without endangering any lives or property or reducing services to any party on the pipeline systems. These drills may be field exercises, table top drill, or class room training, or a combination of these methods. Note, actual emergencies may be used as a drill or training method if the actual emergency is reviewed and documented as required.

Appropriate emergency response groups and agencies may be invited to partake in the drill when appropriate. These groups may include local fire departments, county emergency response agencies, State Police or Highway Patrol, and local police departments. All aspects of the Emergency Plan shall be tested including inter-agency cooperation.

The CVGS OPERATIONS MANAGER will verify that employee training is effective by administering a written exam, oral interviews, or table top drills. [192.615(b)(2)] After verification is completed, a record of each persons training shall be placed in the DOT files.

Liaison With Public Officials & Other Emergency Response Agencies

The Company will establish and maintain liaison with appropriate fire, police and other emergency response agencies as required by 49 CFR 192.615(c). Face to face meetings with representatives from these agencies is the preferred method. The purpose of the meeting includes the following purposes:

- Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency.
- Acquaint the officials with the operator's ability in responding to a gas pipeline emergency.
- Identify the types of gas pipeline emergencies of which the operator notifies the officials.
- Plan how the operator and officials can engage in mutual assistance to minimize the hazards to life or property.

The Company will provide the agencies with a copy of this Emergency Plan or an abbreviated version applicable to emergency response personnel.

Public Education Program

The Company will conduct a continuing education program for the general public residing within our pipeline right-of-way. A notification brochure is sent or delivered to each residence located within the pipeline right-of-way. Information that is communicated in the brochures includes the following:

- Description of facts and information about the natural gas pipeline transportation industry.
- Explanation on how to recognize and report a gas emergency.
- Necessary actions to be taken in an emergency or when gas leaks are discovered.
- How to contact CVGS using the 24 hour number **(1-855-303-2847)** to report an emergency or discovery of a natural gas leak
- Importance of reporting any signs of leaks, or odor of gases no matter how slight.
- How to identify a pipeline marker.
- Importance of reporting any gas pipeline damage or movement.

See the Company Operations & Maintenance Manual for additional details on public education and damage prevention requirements. A copy of the letter and damage prevention/public awareness brochures is located in the DOT files.

One-Call Center

The Company is a member of the California One Call system (Underground Service Alert, USA North) whose purpose is to reduce damage from outside forces. Primarily this would include damage from any contractors performing excavation activities near the pipeline right-of-way. Excavators must notify Dig Alert North at least two (not more than ten) business days prior to digging, (other rules apply to emergency digs). Any underground facilities within the planned work area will be located and marked by the appropriate Company employee or representative.

One-Call Center:

Underground Service Alert
E-mail usanorth@usan.org
4090 Nelson Avenue, Suite A,
Concord CA 94520-1232

(800) 227-2600	Call Before You Dig Tickets
(925) 798-9504	Utility Notification Center Office
(925) 798-9506	Fax
811	National One Call Before You Dig

Hazardous Substances Emergency Response Training

Company personnel and/or contractors and sub-contractor personnel who are called upon to respond to emergencies involving releases of hazardous materials must comply with OSHA regulations in 29 CFR 1910.120. Further, company employees shall receive appropriate Cal/OSHA training based upon 8 CCR 5192(q). Company employees shall not work beyond their level of training during an emergency. Company personnel will ensure contract personnel have received proper training appropriate for the job being performed.

Verification of Approved Contractors

The Company shall verify and approve emergency contractors before contractors are called upon at the scene of an emergency. Approved contractors shall meet the following compliance criteria:

- Drug Plan and testing [49 CFR 199.21]
- Operator Qualification [49 CFR 192.801-809]
- HAZWOPER [29 CFR 1910.120] (as necessary for the job being performed)

Operator Qualification

The Company shall implement the standards in its Operator Qualification Plan. This Plan defines how each person performing a "covered task" will be qualified by the Company to ensure he/she can perform the task in a safe and efficient manner. The Plan includes the following "covered tasks" that relate to emergency response operations:

- Leak Survey
- Pipeline Shutdown, Startup or Pressure Change
- Emergency Valves
- Prevention of Accidental Ignition
- Abnormal Operating Conditions (AOCs)

See the Operator Qualification Plan for details.

POST EMERGENCY ACTIVITIES

Once the emergency has been stabilized and the hazards have been eliminated or controlled, the post emergency response phase begins. Below is a summary list of these activities followed by a detailed description of how to perform these items.

Summary of Potential Post Emergency Activities

- Reporting safety related condition [191.23 & 25]
- Transmission pipeline incident report [191.15]
- Annual report for gas transmission pipeline [191.17]
- Emergency response critique and report [192.615(b)(3), Em Manual section 32.1]
- Updating and revising emergency procedures [192.615, 192.605]
- Training & verification of appropriate personnel [192.615(b)(2)]
- Drug testing [199.11(b)]
- Cleanup, disposal, and restoration

Reporting Safety Related Condition [191.23 & 25]

It is the obligation of all Company pipeline personnel who are aware of an unsafe or potentially unsafe condition to immediately report the matter to the attention of the employee's supervisor. Refer to the Company Operations and Maintenance Manual for details on safety related condition reporting guidelines. Please note that an emergency may or may not result in a safety related condition report.

Transmission Pipeline Incident Report [191.15]

This procedure describes the criteria for reporting certain natural gas leaks and facility failures involving the Company. The CVGS OPERATIONS MANAGER shall be responsible for making certain that the appropriate federal, state, and local offices are notified if appropriate. Refer to the Company Operations and Maintenance Manual for details on incident reporting

Annual Report for Gas Transmission Pipeline [191.17]

If an emergency response incident results in a leak and/or repair of the pipeline, it must be included in the transmission pipeline annual report. This report is due March 15th for the previous calendar year. Refer to the Company Operations and Maintenance Manual for details on incident reporting

Emergency Response Critique and Report [192.615(b)(3)]

All major emergencies are to be critiqued by the key supervisors involved as soon as possible after the emergency is concluded. All aspects of the emergency shall be reviewed to determine if changes shall be made. A report shall be prepared which outlines the procedure followed in solving the emergency and forwarded to Manager for distribution to the appropriate employees.

Measures shall be employed to analyze the accident or failure and to determine the cause. In some instances, especially in the case of material failure, laboratory analysis may be required. Review "Failure Investigation" procedures as a guideline for reviewing the incident. Refer to the Company Operations and Maintenance Manual for details on failure investigation.

In addition, after each emergency, the Company will conduct a post accident review of employee activities to determine whether the emergency response procedures were effective. If deficiencies are found in the emergency response plan or in the actions taken by employees, the Company will take appropriate action.

Actions taken by other response groups shall be included in the post accident critique. Critique results shall be discussed with these groups so they will be aware of any deficiencies in their response.

The review shall be approved by the CVGS OPERATIONS MANAGER as soon as possible after the end of the emergency.

Updating and Revising Emergency Procedures [192.615, 192.605(b)(3)]

After completion of the emergency response critique, emergency procedures shall be updated and revised as appropriate. Emergency response agencies and contractors shall be informed of any procedure changes that affect how they would respond to a Company pipeline event.

Training & Verification on Revised Emergency Plan [192.615(b)(2)]

After completion of the emergency response critique, the appropriate Company personnel will be trained to assure they are knowledgeable of the emergency procedures. The CVGS

OPERATIONS MANAGER or the DOT Compliance Specialist will verify that employee training is effective by administering a written exam and/or oral review.

Drug Testing [199.11(b)]

49 CFR 199.11(b) requires pipeline operators to test employees for the presence of prohibited drugs after an accident. According to 199.11(b) (Post-accident testing.) , an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a factor to the accident. These drug tests shall be administered as soon as possible, but no later than 32 hours after an accident. An operator may decide not to test, but such a decision must be based on the best information available after the accident. This information must indicate that the employee's performance could not have contributed to the accident or, because of the time between that performance and the accident, a drug test would not be effective in determining whether that performance was affected by drug use.

Cleanup, Disposal, and Restoration

Following any emergency involving a release of hazardous fluid (i.e., natural gas condensate) from a pipeline, the Company will clean up any damaged or polluted areas, dispose of any residual hazardous liquid, and restore the affected area to its pre-emergency condition. The amount of cleanup involved will depend largely on the properties of the released fluid, the quantity of fluid released, and the characteristics of the area in which the release occurred. In general, low volatility liquids will cause the most soil and water pollution since they will not evaporate rapidly.

Much of the released liquid may be recovered directly by use of vacuum trucks and skimmers. However, these techniques are seldom 100% effective. Sorbent materials will be used on small releases and as a secondary liquid recovery technique. Any recovered liquid and materials contaminated with the liquid will be disposed of properly. It may be necessary to take contaminated soil, water, or absorbent materials to a licensed hazardous materials recovery or disposal facility.

Activities associated with emergency response, cleanup, and pipeline repair may alter the local soil contours, waterways, and vegetation. Following all cleanup and repair activities and effort shall be made to restore the affected area to its pre-emergency condition.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
Emergency Plan – Summary Table of Contents

Reference: 49 CFR 192.615 **Date Revised: April 2012**

ONSCENE RESPONSE

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
First on Scene Response Activities

Ref: 192.615	Date Revised: April 2012

Overview:

Regardless of the nature and /or severity of an incident, there are general tasks to be performed by the first company employee on the scene. These tasks are listed below and included in the "First On Scene Checklist", Form #EM-2.

No two accidents or emergencies are identical. Therefore, it is not possible to write a checklist or procedure of responses for all emergency incidents, or even to a particular event. Appropriate action to be taken when an emergency situation occurs will be dictated by the conditions existing at the place and time of the incident. However, certain responses will be common to all emergencies. This section discusses only those responses that should be considered by the First Responder.

First Responder Responsibilities:

Scope and Assessment:

- Identify the type, form, nature, quantity and hazards involved in the incident.
- Protection of the public, responders, and company personnel are 1st **Priority**

Notifications:

- Call 911 for any emergency, if not done already
- Call supervisor and appropriate company personnel

Mitigation

- Develop a proper course of action (evacuating, traffic control, prevention of accidental ignition, etc.)
- Determine action needed to stop the incident (closing a valve, emergency shutdown of all or part of the pipeline, etc.)

First Responder Checklist:

"First On Scene Checklist", Form #EM-2, is located at the end of this section or in the FORMS section of this Em. Response manual.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
First on Scene Response Activities

Ref: 192.615	**Date Revised: April 2012**

Scope and Assessment

Scope and Assessment Overview:	Upon arriving at the emergency scene, the First Responder should quickly assess the situation. This assessment would include the status of the emergency, an estimation of how the incident might progress, and an evaluation of the manpower, equipment, and materials needed to adequately cope with the situation. The assessment must be based on the physical evidence, the behavior of the released fluid, and the results of the hazards analysis. The following questions illustrate the types of information you should be able to determine on-site.
Information Gathering:	❑ Is the fluid being released as a liquid, an aerosol, or a gas? ❑ Is there a visible vapor cloud? ❑ Has a liquid pool started to form? ❑ How large is the visible cloud or pool? ❑ Is the liquid pool likely to spread and enter a body or water? ❑ Is the vapor likely to enter nearby buildings? ❑ If already ignited, how large is the fire? ❑ Is the situation immediately dangerous to persons or property? ❑ Is the situation likely to get worse? ❑ What can be done to reduce the risk to persons and property? ❑ Are there ignition sources that need to be removed?

Mitigation

Mitigation Overview:	Mitigation can be loosely defined as any procedure, practice, or act that decreases the likelihood of an accident causing injuries to persons or damage to property. There are several mitigation methods that may be of use during a pipeline release emergency. Training on possible mitigation methods will be conducted with all personnel who may be called upon to respond. This should be done before, not during, the emergency.
Evacuate or Shelter-in-Place	It is also possible to reduce risk to persons by removing them from a potentially hazardous area, or by shielding them from the effects of a particular hazard. When considering how best to protect people from a hazardous material release, one of the methods commonly suggested is evacuation. However, there are some disadvantages to evacuation. Evacuation takes time and personnel. In some cases, such as release of flammable, non-toxic gas from a pipeline, the time period of greatest danger is the first few minutes of the release. After emergency shutdown and isolation, the vapor cloud hazard zone will begin to decrease in sizes. It is doubtful if evacuation can be accomplished quickly enough to be of much help in this type of situation. The number of persons needed to carry out the evacuation will rarely be available quickly enough. Evacuation can expose people to the very hazard you are trying to protect them from. Due to the time required to begin an evacuation, the hazardous condition (fire, flammable vapor cloud, or toxic vapor cloud) may already pose a danger to persons who are outdoors and have not sought shelter. People who leave their homes or place of business will be most vulnerable to effects of the release during the period they are outdoors. In some cases, it is better to recommend shelter-in-place. With the shelter-in-place method, people are requested to remain indoors, and should not go outside unless absolutely necessary. A home or other building can provide a significant degree of protection

from the heat effects of fires and even from the effects of toxic vapor clouds. The choice between evacuation and sheltering-in-place should be based on the results of a hazards analysis and the specific situation.

Ignition Source Control:

A flammable, non-toxic vapor cloud may pose a danger to a large area. If ignited, the cloud might explode, or may simply burn back to the source of the flammable vapor. The explosion or burning cloud can injure exposed persons and cause widespread property damage. If un-ignited, the vapor cloud will eventually be diluted below the lower flammable limit and dissipate harmlessly. The potential danger of a flammable, non-toxic vapor cloud is realized only if it is ignited.

Similarly, a release of flammable liquid that results in a liquid pool may cause some localized environmental damage, but will cause fire-related damage only if ignited. In many situations, it will be beneficial to prevent ignition of the released fluid.

To prevent ignition, it will be necessary to remove all potential ignition sources in or near the flammable vapor cloud or liquid pool, and prevent other potential ignition sources from entering the hazardous area. Potential ignition sources include automobiles, matches, cigarette lighters, internal combustion engines, electric motors, pilot lights on gas-burning appliances, electric switches, static electricity, etc. Under some circumstances, it will be difficult to exclude all ignition sources from the hazardous area. Actually, it may be impossible under any set of circumstances since you cannot control all sources of static electricity. However, you should attempt to reduce the number of potential ignition sources to a minimum.

Be particularly careful when first responding to the scene so your vehicles or equipment does not ignite the release. The same precaution holds true for response personnel involved in hazard mitigation activities. Some of these activities, such as using vacuum trucks to collect spilled liquid, will introduce potential ignition sources to the area. Whenever possible, use intrinsically safe equipment or explosion-proof equipment during mitigation and cleanup activities. Intrinsically safe walkie-talkies and air powered tools are recommended.

If an emergency occurs near a road or highway, control of traffic may be desirable to prevent ignition. The same is true if the accident occurs near a railroad right-of-way or navigable waterway. Control of railroad or waterway traffic may be more difficult than controlling normal roadway traffic. Trains and ships require very long distances to stop. Companies and government agencies that control railroad and waterborne traffic in the area may need to be contacted for assistance.

Emergency Shutdown And Isolation:

One method for reducing the area threatened by the release of a hazardous fluid is the prompt shutdown of pumps or compressors maintaining pressure in the failed system, and closing selected isolation or block valves to isolate the release point. An emergency shutdown of pumps and compressors will cause the pressure at the release point to decrease, decreasing the release rate. Closing of isolation/block valves will reduce the total quantity of fluid released. In some cases, it may not be possible to initiate emergency shutdown from the emergency scene. However, you should be able to contact the control room or dispatch center and have operations personnel initiate the shutdown.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT Emergency Classification

Ref: 192.615	Date Revised: April 2012

Emergency Classification

General Information & Procedures

The purpose of this procedure is to provide guidance and information to company employees involved in incident investigation and emergency situations resulting from the transportation of natural gas.

Although the types of emergencies that might occur in a gas system are widely varied, there are certain common actions, which can be taken regardless of the type of emergency. Regardless of the type of incident, the company will make safe any actual or potential hazard to life or property. [192.615(a)(7)]

This plan is not intended to be an all-encompassing plan of action for emergencies, because certain types of emergencies may occur which would make it impractical to follow the guidelines established in this Plan. The necessary preparatory planning, procurement of certain equipment and supplies and training shall be completed. Each supervisor or employee who may have duties and responsibilities in emergency situations shall be furnished a copy of this Plan. [192.615(b)(1)] Employees shall be trained in their areas of responsibility, and familiar with the total Plan. Employees shall attend annual review sessions, emergency drills, table top drills, or classroom training as noted in the pre-emergency planning section.

Classification of Emergency: [192.615(a)(1)]

The On-Duty Person receiving the call shall identify and classify the potential emergency including events which require immediate response by the company. There is the possibility of a situation that could be classified under more than one type of emergency. Thus, personnel must be sufficiently familiar with the Emergency Plans to be able to combine the relevant requirements of the appropriate plans.

1. *Minor Emergency*: If the call appears to be "minor" (one that is not reportable), the On-Duty Person will dispatch to investigate the emergency call and report the findings. If the On-Duty Person determines that the condition found could be remedied without assistance from other personnel, the On-Duty Person will handle and document as required.

   If additional personnel or assistance is required, the On-Duty Person will notify the OM. The On-Duty Person shall give all pertinent information so the OM may notify other personnel if applicable.

2. *Major Emergency*: A major emergency would be a reportable incident or any other incident in the judgment of the On-Duty Person that required immediate response by the company and additional notification. If the On-Duty Person has been notified of a call that appears to be "major" in nature, the information will be immediately relayed to OM and the On-Duty Person will be dispatched to the scene. A supervisor will also be dispatched to take charge and evaluate the situation.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT Emergency Communications & Responsibilities

Ref: 192.615	**Date Revised: June 2012**

Emergency Communications

General Information & Procedures

Effective internal and external communications with the emergency responders, regulatory agencies, public, and media is essential to ensure the effective management of an emergency event.

Although the types of emergencies that might occur in a gas system are widely varied, there are certain <u>common actions</u>, which can be taken regardless of the type of emergency. Regardless of the type of emergency, the company will <u>make safe any actual or potential hazard to life or property</u>. [192.615(a)(7)]

<u>Each supervisor who may have duties and responsibilities in emergency situations shall be furnished a copy of this Plan.</u> [192.615(b)(1)] Employees shall be trained in their areas of responsibility, and familiar with the total Plan. Employees shall attend annual review sessions, emergency drills, table top drills, or classroom training as noted in the pre-emergency planning section.

Emergency Communications [192.615(a)(2) & (a)(8)]

The Supervisor or designee shall designate one person at the emergency scene as "<u>Supervisor in Charge", or "Incident Commander</u>" (IC). The IC will coordinate all of the field activities. The IC shall communicate with the Fire Department and other public officials to keep them informed about all work planned. Refer to the Incident Command section of this Plan for more details.

When possible, a supervisor shall be designated, as Public Information Officer (PIO) to receive and transmit needed information to the On-Duty Person and key personnel not on the scene. All contacts with persons on the scene shall be made through the PIO. In the absence of a person designated PIO, the IC will act as the public relations representative. The PIO shall make reports of activities at the emergency.

The IC shall ensure that communications are maintained until the emergency is past. All company personnel will avoid unnecessary radio traffic during an emergency condition. In the event radio communications are not available cellular telephones shall be used.

Supervisor Responsibilities

The Supervisor is responsible for the training and equipping of personnel in the investigation of leak and incident complaint reports and responding to pipeline emergencies. The Supervisor has the primary responsibility for identifying each of the potential emergency situations, and when necessary, declaring a gas emergency. The Supervisor also has the responsibility to ensure availability of personnel, instruments, tools, and material required at the scene of an emergency. [192.615(a)(4)] When an emergency condition arises that could seriously affect the normal, safe operation of a gas system, it is essential that a predetermined course of action be implemented to ensure protection to the public, Company employees, and protection of public and Company property. In an emergency, protection of people first [192.615(a)(5)] and property second must receive paramount consideration.

The ability to adequately respond to potential emergency situations will be determined by the familiarity of the employees with emergency plans and the extent of preplanning. The Supervisor is responsible to see that all employees in the Company are able to recognize what constitutes a gas emergency, how to classify incidents, and what information shall be obtained.

The Supervisor will ensure the failure/accident investigation is conducted as soon as is reasonable possible. [192.615(a)(10)] The company will follow the failure investigation procedures in the DOT pipeline O&M manual.

On-Duty Operator/Person Responsibilities

The On-Duty Person shall upon notification of a potential gas emergency, dispatch to the scene to identify the extent of the emergency and to take those steps immediately necessary to protect people and property. The On-Duty Person shall, when conditions warrant, notify the local police, fire, civil officials, and the company Supervisor.

The On-Duty Person will do everything possible to ***protect life and property*** while help is arriving. He will advise the public on safety measures to take, depending upon the nature of the emergency. He will try to find the source of the leak. He will work with agency emergency personnel until order is restored. He will advise the Supervisor of conditions as they progress.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT Emergency Communications & Responsibilities

Ref: 192.615	**Date Revised: June 2012**

Communication & Receiving Information General

Leaks, fires, explosions, or other emergencies may be reported by the public 24 hours per day, seven days per week, by calling **(1-855-303-2847)**, which is the phone number listed on pipeline markers, and station markers. After hours, these calls are received by the 24 hour answering service and forwarded to the on-duty supervisor. A written record shall be maintained of all calls received and actions taken. The 24-hour answering service is responsible for maintaining the written log of all calls received and actions taken to ensure that no hazardous conditions exists.

All personnel receiving leak complaints are trained in asking appropriate questions to determine the location and potential hazard of each leak. Reports received might contain much of the information needed. However, in most instances, this information may not be volunteered; therefore, emergency calls shall be received by, or referred to, a person knowledgeable in reacting to such situations. This person shall attempt to obtain and record the following information:

Communication & Information to Obtain during Initial Notification (see Form #Em-1)

1. The address where the emergency has occurred. If the address is given as a rural route, box number of general area, obtain additional information to further identify the location.
2. The name of the caller.
3. The telephone number of the caller and location of the telephone
4. Personal estimate of the information from the caller as to the severity of the situation.
5. What is happening?

    a. Gas odor inside structure
    b. Gas odor outside structure
    c. Line break
    d. Gas blowing (hissing sound)
    e. Explosion
    f. Fire
    g. Natural disaster
    h. Civil disorder

6. Types of structures or area involved; i.e. school buildings, public assembly areas, critical area locations, etc.
7. Action that has already been taken by persons at the emergency site.
8. An estimate of how long the problem has existed.
9. The traffic situation in the area involved.
10. Any other information that might be helpful.
11. Time of the call and the date.

Communication and Advice to Caller

For a leak inside building and strong gas odor
- Evacuate building
- Warn against operating light switches
- Warn against lighting matches
- Warn against using telephone
- Warn against re-entering building

For blowing gas leak keep people away from the immediate vicinity.

Communication and Notification of Local Emergency Units

Depending on the nature of the emergency, assistance may be requested of the Fire Department and/or Emergency Rescue, the Police/Sheriff Department, State Police, an Ambulance Unit, or Civil Defense; all of these can be reached by dialing 911. The type of emergency involved will dictate the type of assistance to be requested. We have informed these organizations of our abilities in responding to emergencies, identified the type of emergencies of which we will notify these organizations, and discussed how these organizations can assist us in minimizing hazards to life or property. These organizations have been informed of our planned responses and actual responses during an emergency. See agency notification section for details.

Notification of Other Company Pipeline Personnel and Utility Company Personnel

In the event that additional information is needed on company facilities, the On-Duty person will furnish system information. Facilities outside the system may require further assistance from other natural gas companies and utilities to operate facilities that are not under the control of their office. Refer to the telephone numbers listed in this Plan. See "Emergency Phone Numbers" tab for more detail.

Log of Events (see Form #Em-5)

Depending on the scope of the emergency, a log of events shall be maintained as designated by the IC. Use Form #EM-5, Emergency Log of Miscellaneous Activities.

The IC shall be responsible for making certain that the Commission and Department of Transportation are properly notified of reportable accidents, leaks or incidents. See the DOT O&M Manual for specific procedures. The IC shall be responsible for reporting in writing, a summary of each accident or incident to the Supervisor. The report shall be submitted as soon as practicable, but not more than 30 days after the incident. On-Duty Supervisor and other employees as directed will complete a report.

Media and Public Communications

One person shall be designated as the company spokesperson. This will usually be the Supervisor, Incident Commander, or Public Information Officer. The following are dos and don'ts for the designated spokesperson when talking with reporters.

Dos	Don'ts
Be Calm	Don't speculate on cause of crisis or accident
Be Truthful	Don't estimate damages
Identify yourself as the designated company spokesperson	Don't discuss identities or medical conditions of injured or missing
Speak only for the company, not contractors or clients	Don't guess about number of victims
Give a brief list of facts	Don't allow reporters or "sightseers" to wander around the scene
End interviews promptly after giving brief facts	Don't say anything you don't consider media material
Advise other employees to refer all inquiries to you	Remember that nothing is off the record
Set up a safe secure area where reporters can be briefed	

The company is committed to communicating in a clear, concise and timely manner by providing accurate and detailed information.

The news media can provide valuable assistance to the company and play an important public service role during an incident, conveying important information to the public through radio, television, the Internet, and print.

It is important to understand that the media operates independently; each news organization competes with other news organizations. Their p[primary concern is to get the story, not resolve the issue. The easier it is for them to get the story, the more favorable their coverage is likely to be. It is also important to note that news is about change and conflict, drama and emotion. Those elements make better stories. That is why the media will focus on the negative and the sensational. It is the communicator's job to deliver a succinct message of order and calm.

It is important to develop and maintain a good working relationship with the news media from the outset of any emergency. The manner in which both field and corporate personnel interface with reporters will affect the public perception of both the effectiveness of the response and the company. Always insist the media talk with the incident commander or assigned public information officer (PIC).

Ref: 192.615	Date Revised: June 2012

PREMLIMINARY MEDIA STATEMENT

Date: _________
Time: _________

My name is ______________________ (The company Job Title). At ____________(time) on ______________(date) a ____________________ (nature of incident) occurred at (The company's) __________________ (plant, well site, pipeline) located approximately _______ kilometers (east, west, sough, north) of ______________(nearest town or city).

The __________________ (plant, pipeline) has been shut down and isolated. The company has activated its emergency response plan to protect the public, our employees and the environment.

The cause of the ___________________ (nature of accident) is not yet known and we do not have an estimate of damage. A subsequent investigation will determine those facts.

I will release further information as it becomes available at ______________ (field office).

CENTRAL VALLEY GAS STORAGE

Gas Transmission Pipeline Emergency Phone Numbers

Ref: 192.615	Date Revised: June 2013

******** FOR ANY EMERGENCY – CALL "911" ********

855-303-2847
When called this number it will be received by the CVGS 24 hour answering service. The answering service will call CVGS on-duty employees in the priority given.

Central Valley Gas Storage

Name	Title	Office	Cellular
Brian Hackney	Manager, Storage Operations	(530) 439-2606	(530) 919-4783
Bill Wolf	Operator	(530) 439-2619	(530) 722-7806
Daniel Perez	Operator	(530) 439-2612	(530) 722-7951
John Dale	I&E Technician	(530) 439-2604	(530) 632-4753
James DeGroodt	Mechanic	(530) 439-2614	(530) 333-5326
TBD	Maintenance Specialist		
Felecia Roe	Administrative Assistant III	(530) 439-2607	(337) 777-8165
Robert Cornell	Director, Storage & Peaking Ops – West Region	(409) 835-0233	(409) 739-9631
Tim Hermann	V.P. Storage & Peaking Ops	(630) 245-7822	(312) 446-7106
Oscar Towne	CVGS Trading	(630) 245-7814	(630) 470-8791
John Fortman	Director, Commercial Services	(630) 245-7845	(630) 399-1022

Public Utilities

PG&E Power Distribution (for power outages)	(800) 743-5000
PG&E Gas Control	(415) 973-3214

Fire Departments

Andy Ferndely Princeton FD	(530) 701-4389
Maxwell FD	(530) 438-2320

CENTRAL VALLEY GAS STORAGE

Gas Transmission Pipeline Emergency Phone Numbers

Ref: 192.615	Date Revised: June 2013

Ambulance

Willows Ambulance	(530) 934-4556

Law Enforcement

Willows Police	(530) 934-3456
California Highway Patrol Dispatch in Willows	(530) 934-5424
Colusa County Sheriff	(530) 458-0200

Safety Equipment and Supplies

American Safety, Bakersfield	(661) 589-7635

Pipeline Emergency Contractor

ARB, Bakersfield	(805) 589-5070

CENTRAL VALLEY GAS STORAGE
Emergency Response Procedures
Agency Notifications and Reporting

Ref: 192.615	Date Revised: April 2012

Scope:

This procedure covers the release reporting requirements for a release of natural gas, or natural gas condensate from a DOT jurisdictional pipeline such as CVGS. Multiple federal, state, and local authorities may require notification depending on the location and severity of the event. Agencies that may require notification include:

Federal:
- National Response Center per DOT [49 CFR 191.5]
- Office of Pipeline Safety [49 CFR 191.25]
- OSHA [29 CFR 1904.39]
- National Response Center per USCG [33 CFR 153.203 & 40 CFR 110.10]

State:
- OES [HSC 25507(a) & Water Code 13271(a)]
- California State Lands Commission [2 CCR 2142]
- CHP [Vehicle Code 23112.5(a)]
- Ca. Dept. of Fish & Game [Ca. Gov. Code 8670.25-27]

Local:
- 911 for any emergency
- Administering agency for hazardous material releases [HSC 25507(a)]

Reporting Procedures:

After the necessary emergency steps are taken to stop, contain, and control the release to protect public safety, environmental resources, and minimize damage:

1. Determine whether there is a reporting requirement. Review the reporting criteria listed on the "Agency Notification and Reporting" form. (Form #Em-3)
2. Notify the appropriate agencies and document using the following "Agency Notification and Reporting" form. (Form #Em-3)
3. Conduct repairs and clean up measures as appropriate and document.
4. Submit follow up reports as appropriate.

Ref: 192.615	**Date Revised: April 2012**

Record Keeping:	All reportable releases shall be documented using the attached "Agency Notification and Reporting" form. Completed forms shall be forwarded to the DOT Compliance Supervisor for filing into the DOT record keeping system.

CENTRAL VALLEY GAS STORAGE
Emergency Response Procedures
Incident Command and Emergency Response

Ref: 192.615	Date Revised: June 2012

Incident Command Description

The Incident Command System (ICS) is an organization system widely used for emergency management by federal, state, and local emergency response organizations. The Company has adopted ICS as the base organizational system for responding to pipeline emergencies.

ICS Flexibility

ICS allows the base organization structure to be adapted for different situations depending on the type and complexity of the incident. Two situations may occur that rely upon this flexibility when determining needed ICS positions.

The first situation involves "first responders." A fundamental premise of ICS is that positions are initially filled based upon available personnel. Position replacements occur as more experienced, trained, and qualified personnel become available. The replacement transition requires briefings and exchange of incident status information.

The second situation that relies upon the flexibility of ICS occurs when more than one legal entity has responsibility for managing the incident. This often occurs in oil spill situations but can occur in other emergency situations such as a fire that impacts public areas. ICS accommodates these situations through implementation of a Unified Command. The Unified Command can include various agency and regulatory groups in addition to Company personnel.

ICS Responsibilities

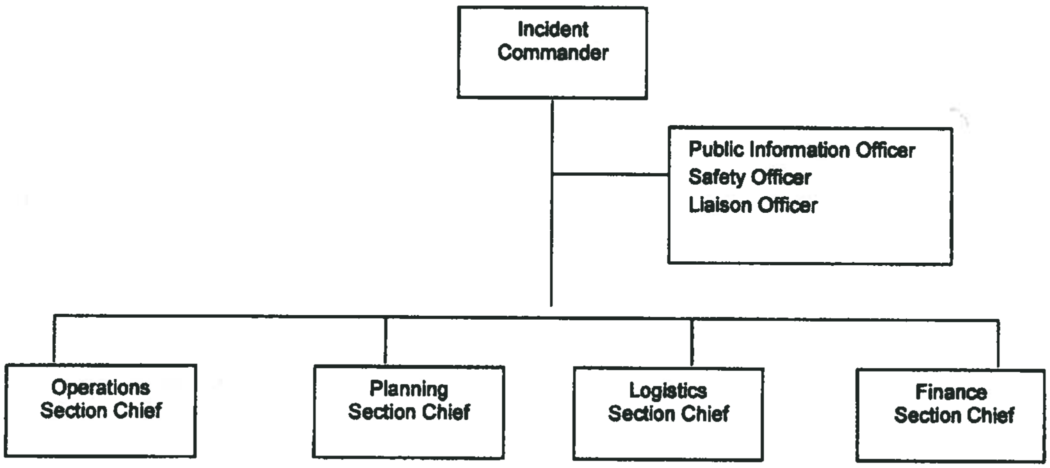
At each emergency, a company staff employee will be responsible for directing and coordinating the overall emergency response, referred to as Incident Commander. For emergencies that do not involve a fire or explosion, the ranking employee at the scene will be designated the Incident Commander. If a fire, explosion, or major event is involved, this position is usually assigned to the local fire department.

Incident Command Authority

During a declared emergency, the company staff employee acting as the Incident Commander will have the authority to take required immediate action to protect the public and the environment. As soon as more personnel arrive at the scene, Incident Commander duties can be shifted to more qualified personnel.

Ref: 192.615	Date Revised: June 2012

INCIDENT COMMAND SYSTEM (ICS)



The following Position Descriptions and Task Checklists for the ICS provide general guidance to fulfill organizational roles:

Included are:

- **General Role Definitions**
- **Listing of Suggested Candidates**
- **Critical Task Checklist**

Position Descriptions for:

- **Incident Commander (IC)**
- **Public Information Officer (PIO)**
- **Safety Officer**
- **Liaison Officer**
- **Operations Section Chief**
- **Planning Section Chief**
- **Logistics Section Chief**
- **Finance Section Chief**

Ref: 192.615	**Date Revised: June 2012**

Incident Commander

IC Role:

The Incident Commander is responsible for overall incident response and control of all activities. The IC establishes the "Command Post" at the incident location or other appropriate location. Authorization of action plans and resources are key activities of the IC.

IC Position Candidate Examples:

- Initial Responder
- Operations Manager
- Plant Operator
- Director, Storage & Peaking Ops – West Region

IC Checklist:

- ❑ Identify and isolate incident area; establish perimeters and control points.
- ❑ Establish a command post and staging areas.
- ❑ Notify and request assistance from dispatch, immediate supervisor, or appropriate higher ranking officials.
- ❑ Initiate incident command system and coordinate scene activities.
- ❑ Appoint command staff – safety liaison and information officers- and begin operations.
- ❑ Implement standard operating procedures or emergency response plan; develop and release incident action plan; revise and disseminate operational plans.
- ❑ Provide policy, direction, and control for emergency operations; set priorities and establish response strategies.
- ❑ Implement site safety plan; revise and disseminate plan.
- ❑ Establish site perimeter and control points.
- ❑ Reroute traffic and control access to site
- ❑ Establish work zones
  - Exclusion zone (hot zone)
  - Contamination reduction zone (decon zone)
  - Support zone
- ❑ Conduct operations; eliminate potential for airborne dispersion, terminate release of hazardous materials, reduce exposure of personnel and equipment.
- ❑ Monitor and sample site
- ❑ Determine type of evacuation: immediate, precautionary, and scheduled.

Ref: 192.615	**Date Revised: June 2012**

Public Information Officer

Information Officer Role:	The Public Information Officer is responsible for providing on-site contact with news media and furnishing the media with Company approved news release information.
Information Officer Position Candidate Examples:	• Company Public Affairs Manager • Public Affairs Consultant • Operations Manager • EHS Specialist
Information Officer Checklist:	❑ Obtain briefing from incident commander. ❑ Contact the jurisdictional agency to coordinate public information activities. ❑ Establish single-incident information center whenever possible. ❑ Arrange for necessary work space, material, telephones, and staffing. ❑ Prepare initial information summary as soon as possible after arrival. ❑ Obtain approval for release from incident commander. ❑ Release information to news media. ❑ Post information in command post and other appropriate locations. ❑ Attend meetings to update information releases. ❑ Arrange for meetings between media and incident personnel. ❑ Provide escort service to the media and VIP's ❑ Respond to special request for information. ❑ Maintain log.
Information Officer Hints:	**Specifically, the Information Officer should address the following:** ❑ Name, title, and what the Info Officer function is. ❑ What has happened in simple terms. ❑ Injuries (no names unless family has been notified). ❑ Major concerns (Safety of people and protection of environment) **Watch for Red Flag questions:** ❑ What is the cause? Who is at fault? ❑ How much will it cost? ❑ How much was released? **Do not speculate. Stick to the known facts.**

Ref: 192.615	**Date Revised: June 2012**

Safety Officer

Safety Officer Role:	The Safety Officer is responsible for providing a "Site Safety Plan" and assessing activities for hazardous and/or unsafe situations and developing means for assuring the safety of response personnel.
Safety Officer Position Candidate Examples:	• Initial Responder • Operations Manager • Plant Operator • EHS Specialist • EHS Consultant
Safety Officer Checklist:	☐ Obtain briefing from incident commander. ☐ Identify hazardous situations associated with the incident ☐ Identify control measures: (engineering administrative/PPE). ☐ Initiate evacuation procedures. ☐ Develop decontamination procedures. ☐ Conduct safety meetings. ☐ Participate in planning meetings. ☐ Review incident action plan. ☐ Review and approve medical plan ☐ Investigate accidents that have occurred within incident areas. ☐ Maintain a log. **Note:** Exercise emergency authority to stop and prevent unsafe acts.

Ref: 192.615	Date Revised: June 2012

Liaison Officer

Liaison Officer Role:	The Liaison Officer is responsible for conducting initial regulatory contacts and coordinating required government reports and inquires. Ensure that The Company is tracking regulatory agency response and potential for incidents of non-compliance.
Liaison Officer Position Candidate Examples:	• Initial Responder • Operations Manager • Director, Storage & Peaking Ops – West Region • EHS Specialist
Liaison Officer Checklist:	❑ Obtain briefing from incident commander. ❑ Provide a point of contact for agency representatives. ❑ Identify agency representative from each agency. ❑ Establish communications link and location. ❑ Provide inter-organizational contacts for incident personnel. ❑ Monitor incident operations for inter-organizational problems. ❑ Maintain log.

Ref: 192.615	**Date Revised: June 2012**

Operations Section Chief

Operations Section Chief Role:	The Operations Section Chief is responsible for directing tactical emergency response, incident control actions, and recovery/clean-up operations. Also, request needed resources and prepares operational plans if needed.
Operations Section Chief Position Candidate Examples:	• Initial Responder • Operations Manager • Director, Storage & Peaking Ops – West Region • EHS Specialist
Operations Section Chief Checklist:	❑ Obtain briefing from incident commander. ❑ Develop operations portion of Incident Action Plan. ❑ Brief and assign operations personnel in accordance with Incident Action Plan. ❑ Supervise Operations. ❑ Determine need and request additional resources. ❑ Review suggested list of resources to be released and initiate recommendation for release of resources. ❑ Assemble and disassemble strike teams assigned to operations section. ❑ Report information about special activities, events, and occurrences to incident commander.

Planning Section Chief

Planning Section Chief Role:

The Planning Section Chief is responsible for development of "Incident Action Plans" and management of incident status reports. Role includes assessing the situation, predicting outcomes and resource status, and initiating planning meetings.

Planning Section Chief Position Candidate Examples:

- Initial Responder
- Operations Manager
- Plant Operator
- Director, Storage & Peaking Ops – West Region
- EHS Specialist

Planning Section Chief Checklist:

- ☐ Obtain briefing from incident commander.
- ☐ Activate planning section units.
- ☐ Reassign initial attack personnel to incident positions as appropriate.
- ☐ Establish information requirements and reporting schedules for all ICS organizational elements for use in preparing the incident action plan.
- ☐ Establish a weather data collection system when necessary.
- ☐ Supervise preparation of incident action plan.
- ☐ Assemble information on alternative strategies.
- ☐ Assemble and disassemble strike teams not assigned to operations.
- ☐ Identify need for use of specialized resources.
- ☐ Provide periodic predictions on incident potential.
- ☐ Compile and display incident status summary information.
- ☐ Advise general staff of any significant changes in incident status.
- ☐ Provide incident traffic plan.
- ☐ Supervise planning section units.
- ☐ Prepare and distribute incident commander's orders.
- ☐ Insure that normal agency information collection and reporting requirements are being met.
- ☐ Prepare recommendations for release of resources for submission to the incident commander.

Ref: 192.615	**Date Revised: June 2012**

Logistics Section Chief

Logistics Section Chief Role:	The Logistics Section Chief is responsible for identifying needed resources and supplies and on-scene delivery and management of supply facilities, services, and materials.
Logistics Section Chief Position Candidate Examples:	• Initial Responder • Operations Manager • Plant Operator • Director, Storage & Peaking Ops – West Region • Mechanic • Maintenance Specialist
Logistics Section Chief Checklist:	☐ Obtain briefing from incident commander. ☐ Plan organization of logistics section. ☐ Assign work locations and preliminary work tasks to section personnel. ☐ Participate in preparation of Incident Action Plan. ☐ Identify service and support requirements for planned and expected operations. ☐ Provide input to and review communications plan, medical plan, and traffic plan. ☐ Coordinate and process request for additional resources. ☐ Review incident action plan and estimate section needs for next operational period. ☐ Insure incident communications plan is prepared. ☐ Advise on current service and support capabilities. ☐ Prepare service and support elements of the incident action plan. ☐ Estimate future service and support requirements. ☐ Receive demobilization plan from planning section. ☐ Recommend release of unit resources in conformity with demobilization plan. **Insure general welfare and safety of logistics section personnel.**

Finance Section Chief

Finance Section Chief Role:

The Finance Section Chief is responsible for management of cost control and critical manpower planning.

Finance Section Chief Position Candidate Examples:

- Operations Manager
- Administrative Assistant
- Supply Chain Specialist
- Plant Operator
- Director, Storage & Peaking Ops – West Region

Finance Section Chief Checklist:

- ❑ Obtain briefing from incident commander.
- ❑ Attend briefing with responsible agency to gather information.
- ❑ Attend planning meeting to gather information.
- ❑ Identify needs, order supplies, and support needs for finance section.
- ❑ Develop an operating plan for finance function on incident.
- ❑ Prepare work objectives for staff.
- ❑ Determine need for commissary operation.
- ❑ Inform command staff and general staff when section is fully operational.
- ❑ Meet with agency representatives as required.
- ❑ Provide input in all planning sessions on financial and cost analysis matters.
- ❑ Maintain daily contact with agency(s) administrative headquarters on finance matters.
- ❑ Insure that all personnel time records are transmitted to appropriate locations.
- ❑ Participate in all demobilization planning.
- ❑ Insure that all obligation documents initiated at the incident are properly prepared and completed.
- ❑ Brief agencies on all incident related business management issues needing attention and follow-up prior to leaving incident.

Material Safety Data Sheet

May be used to comply with

OSHA's Hazard Communication Standard, 29 CFR 1910.1200. Standard must be consulted for specific requirements.

U.S. Department of Labor

Occupational Safety and Health Administration
(Non-Mandatory Form)
Form Approved
OMB No. 1218-0072

IDENTITY *(As Used on Label and List)* *Natural Gas*	Note: Blank spaces are not permitted. If any item is not applicable, or no information is available, the space must be marked to indicate that.

Section I

Manufacturer's Name Nicor Gas	Emergency Telephone Number 630-983-7405
Address *(Number, Street, City, State, and ZIP Code)* *P.O. Box 190* Aurora, IL 60507-0190	Telephone Number for Information 630-844-2040 Extension 319
1844 Ferry Road, Naperville, IL 60563	Date Prepared November 1, 2002
	Signature of Preparer *(optional)*

Section II - Hazard Ingredients/Identity Information

Hazardous Components (Specific Chemical Identity; Common Name(s))	OSHA PEL	ACGIH TLV	Other Limits Recommended	%(optional)
Methane	N.E.*	N.E.		ca 94.2% V/V
Ethane	N.E.	N.E.		ca 3.0% V/V
Propane	1000 ppm	N.E.		ca 0.2% V/V
Butane	N.E.	800 ppm		ca 0.2% V/V
Nitrogen	N.E.	N.E.		ca 1.6% V/V
Carbon Dioxide	5000 ppm	5000 ppm		ca 0.8% V/V
Natural gas is classified	Hazardous Materials Identification System:			
as a simple asphyxiant.	Health	1		
*N.E. = None Established	Fire	4		
N.A. = Not Applicable	Reactivity	0		

Section III - Physical/Chemical Characteristics

Boiling Point	-259° F	Specific Gravity ($H_2O = 1$)	N.A.
Vapor Pressure (mm Hg.)	N.A.	Melting Point	-297° F
Vapor Density (AIR = 1)	0.6	Evaporation Rate (Butyl Acetate = 1)	N.A.

Solubility in Water
Insoluble

Appearance and Odor
Colorless, tasteless, extremely flammable gas with added mercaptan odor.

Section IV - Fire and Explosion Hazard Data

Flash Point (Method Used) -306° F (Open Cup)	Flammable Limits	LEL 5% V/V	UEL 15% V/V

Extinguishing Media
Dry chemical, CO2, water fog. Water spray may be used to cool adjacent property.

Special Fire Fighting Procedures
Wear a self-contained breathing apparatus (SCBA) with a full face piece operated in the pressure-demand or positive-pressure mode.

Unusual Fire and Explosion Hazards
The best fire-fighting technique may be simply to let the burning gas escape from the pressurized system. Never extinguish the burning gas without first sealing its source.

Section V - Reactivity Data

Stability	Unstable		Conditions to Avoid Avoid uncontrollable exposure to ignition sources. Prevent uncontrollable rapid release from high pressure systems.
	Stable	X	

Incompatibility *(Materials to Avoid)* *Bromine Pentafluoride, Chlorine Dioxide, Nitrogen Trifluoride, Liquid Oxygen, Oxygen Difluoride.*

Hazardous Decomposition or Byproducts Thermal oxidative degradation can produce carbon dioxide and carbon monoxide.

Hazardous Polymerization	May Occur		Conditions to Avoid
	Will Not Occur	X	

Section VI - Health Hazard Data

Route(s) of Entry:	Inhalation? Yes	Skin? No	Ingestion? No

Health Hazards *(Acute and Chronic)*
Natural gas is a simple asphxiant in high concentrations.

Carcinogenicity:	NTP? No	IARC Monographs? No	OSHA Regulated? No

Signs and Symptoms of Exposure
Oxygen deficiency can cause diminished alertness, fatigue, nausea, vomiting, unconsciousness, coma and death

Medical Conditions
Generally Aggravated by Exposure None reported

Emergency and First Aid Procedures
Move victim to fresh air. Start artificial respiration if necessary. Seek medical assistance if needed.

Section VII - Precautions for Safe Handling and Use

Steps to Be Taken in Case Material is Released or Spilled Eliminate all sources of heat or ignition and ventilate area. Locate and seal the source of the leaking gas if necessary.

Waste Disposal Method Vent gas to atmosphere.

Precautions to Be taken in Handling and Storing Follow NFPA No. 54 and local codes.

Other Precautions
Never smoke in any work area where the possibility of exposure to fire hazard levels of natural gas exist.

Section VIII - Control Measures

Respiratory Proctection *(Specify Type)* Wear a NIOSH-approved SCBA if necessary.

Ventilation N.A.	Local Exhaust If necessary use local explosion-proof ventilation to maintain airborne concentrations of natural gas below the LEL (5 % V/V).	Special N.A.
	Mechanical *(General) N.A.*	Other N.A.

Protective Gloves N.A.	Eye Protection N.A.

Other Protective Clothing or Equipment N.A.

Work/Hygienic Practices N.A.

2008 EMERGENCY RESPONSE GUIDEBOOK

Natural Gas, Natural Gas Liquids, Natural Gasoline, Propane, n-Butane, Iso-Butane

GUIDE
115
GASES - FLAMMABLE (Including Refrigerated Liquids)

POTENTIAL HAZARDS

FIRE OR EXPLOSION

- **EXTREMELY FLAMMABLE.**
- Will be easily ignited by heat, sparks or flames.
- Will form explosive mixtures with air.
- Vapors from liquefied gas are initially heavier than air and spread along ground.

CAUTION: Hydrogen (UN1049), Deuterium (UN1957), Hydrogen, refrigerated liquid (UN1966) and Methane (UN1971) are lighter than air and will rise. Hydrogen and Deuterium fires are difficult to detect since they burn with an invisible flame. Use an alternate method of detection (thermal camera, broom handle, etc.)

- Vapors may travel to source of ignition and flash back.
- Cylinders exposed to fire may vent and release flammable gas through pressure relief devices.
- Containers may explode when heated.
- Ruptured cylinders may rocket.

HEALTH

- Vapors may cause dizziness or asphyxiation without warning.
- Some may be irritating if inhaled at high concentrations.
- Contact with gas or liquefied gas may cause burns, severe injury and/or frostbite.
- Fire may produce irritating and/or toxic gases.

PUBLIC SAFETY

- **CALL Emergency Response Telephone Number on Shipping Paper first. If Shipping Paper not available or no answer, refer to appropriate telephone number listed on the inside back cover.**
- As an immediate precautionary measure, isolate spill or leak area for at least 100 meters (330 feet) in all directions.
- Keep unauthorized personnel away.
- Stay upwind.
- Many gases are heavier than air and will spread along ground and collect in low or confined areas (sewers, basements, tanks).
- Keep out of low areas.

2008 EMERGENCY RESPONSE GUIDEBOOK

Natural Gas, Natural Gas Liquids, Natural Gasoline, Propane, n-Butane, Iso-Butane

PROTECTIVE CLOTHING

- Wear positive pressure self-contained breathing apparatus (SCBA).
- Structural firefighters' protective clothing will only provide limited protection.
- Always wear thermal protective clothing when handling refrigerated/cryogenic liquids.

EVACUATION

Large Spill

- Consider initial downwind evacuation for at least 800 meters (1/2 mile).

Fire

- If tank, rail car or tank truck is involved in a fire, ISOLATE for 1600 meters (1 mile) in all directions; also, consider initial evacuation for 1600 meters (1 mile) in all directions.

EMERGENCY RESPONSE

FIRE

- **DO NOT EXTINGUISH A LEAKING GAS FIRE UNLESS LEAK CAN BE STOPPED.**

CAUTION: Hydrogen (UN1049), Deuterium (UN1957) and Hydrogen, refrigerated liquid (UN1966) burn with an invisible flame. Hydrogen and Methane mixture, compressed (UN2034) may burn with an invisible flame.

Small Fire

- Dry chemical or CO_2.

Large Fire

- Water spray or fog.
- Move containers from fire area if you can do it without risk.

Fire involving Tanks

- Fight fire from maximum distance or use unmanned hose holders or monitor nozzles.
- Cool containers with flooding quantities of water until well after fire is out.
- Do not direct water at source of leak or safety devices; icing may occur.
- Withdraw immediately in case of rising sound from venting safety devices or discoloration of tank.
- ALWAYS stay away from tanks engulfed in fire.

- For massive fire, use unmanned hose holders or monitor nozzles; if this is impossible, withdraw from area and let fire burn.

SPILL OR LEAK

- ELIMINATE all ignition sources (no smoking, flares, sparks or flames in immediate area).
- All equipment used when handling the product must be grounded.
- Do not touch or walk through spilled material.
- Stop leak if you can do it without risk.
- If possible, turn leaking containers so that gas escapes rather than liquid.
- Use water spray to reduce vapors or divert vapor cloud drift. Avoid allowing water runoff to contact spilled material.
- Do not direct water at spill or source of leak.
- Prevent spreading of vapors through sewers, ventilation systems and confined areas.
- Isolate area until gas has dispersed.

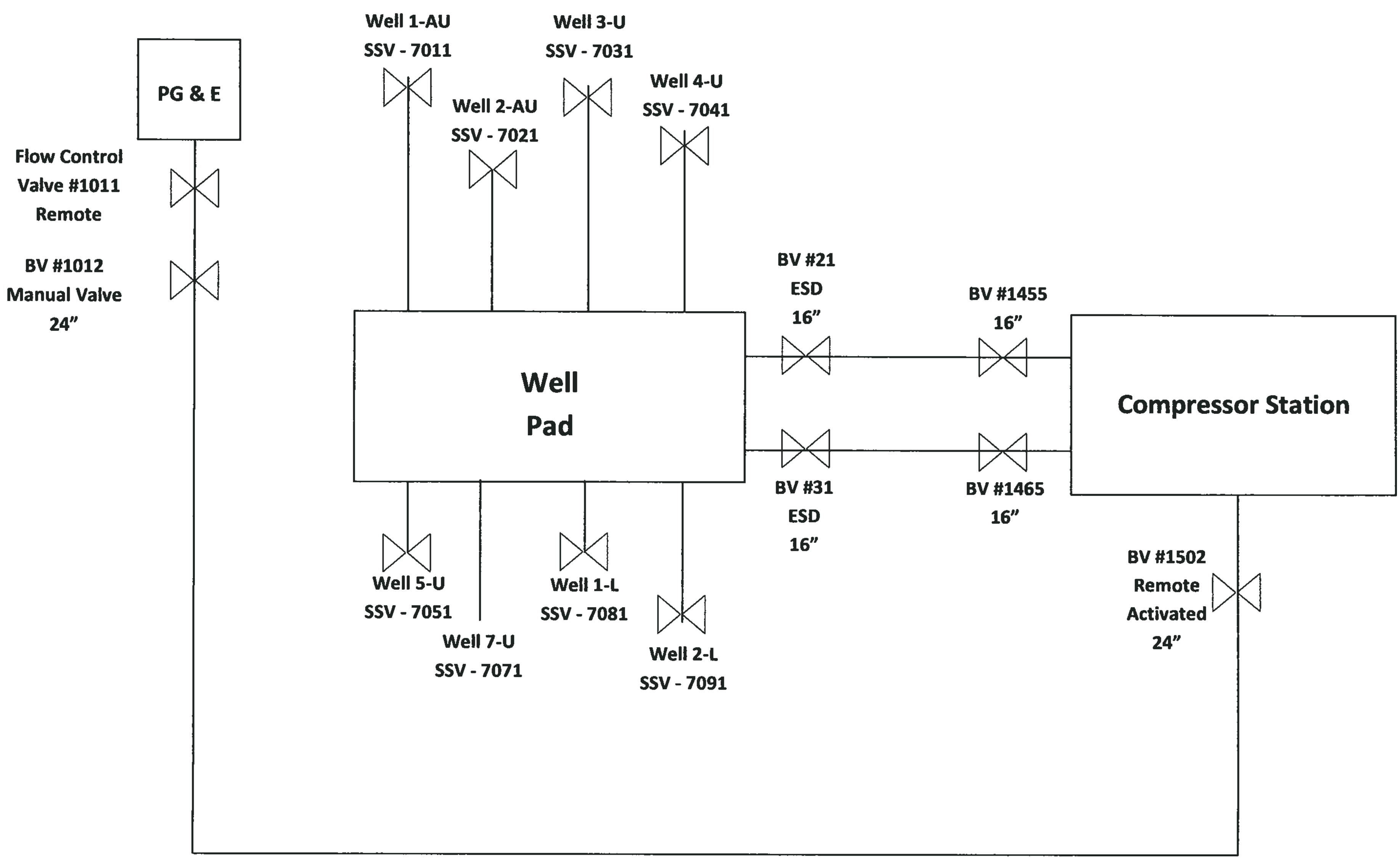
CAUTION: When in contact with refrigerated/cryogenic liquids, many materials become brittle and are likely to break without warning.

FIRST AID

- Move victim to fresh air.
- Call 911 or emergency medical service.
- Give artificial respiration if victim is not breathing.
- Administer oxygen if breathing is difficult.
- Remove and isolate contaminated clothing and shoes.
- Clothing frozen to the skin should be thawed before being removed.
- In case of contact with liquefied gas, thaw frosted parts with lukewarm water.
- In case of burns, immediately cool affected skin for as long as possible with cold water. Do not remove clothing if adhering to skin.
- Keep victim warm and quiet.
- Ensure that medical personnel are aware of the material(s) involved and take precautions to protect themselves.

CVGS

Emergency Valve Diagram



RESPONSE TO SPECIFIC TYPES OF EMERGENCIES

13. Gas Inside or Near a Building
14. Fire and Explosion
15. Natural Disaster
16. Civil Disturbance

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT General Emergency Response Procedures

Ref: 192.615	Date Revised: April 2012

Types of Emergencies: [192.615(a)(3]

Four types of natural gas emergencies are defined and a plan for each type of emergency is established. The responsibility for declaring an emergency is defined. The liaison between the Company and public officials is outlined and guidelines for educating public officials and the general public are provided.

The company will provide prompt response to each of the following types of emergencies:

- **escaping gas and/or gas detected inside a building**
- fire or explosion
- natural disaster (including earthquakes, etc.)
- civil disturbance.

This section of the emergency response plan describes "Emergency Response for Escaping Gas Including Gas Detected Inside a Building."

Emergency Response for Escaping Gas Including Gas Detected Inside a Building [192.615(a)(3]

A major leak or gas detected inside or near a building must be given immediate attention to protect the general public and property.

1. When information is received which indicates a major leak or a pipeline break exists, appropriate personnel must be dispatched to the job site immediately as provided in Receiving Information and Notification. While these employees are in route to the emergency, they shall be given all available information about the emergency by radio so they can begin assessment of the danger involved as soon as they arrive at the job site. The On-duty Person and Supervisor shall, when arriving at the job site, report to the Fire Department officials or other civil authorities that might be on the scene and become appraised of the situation. After this is accomplished, determination shall be made of the area affected by the uncontrolled gas. The evaluation of the situation shall include the following:
   a. The first employees on the site shall determine with a leak detector whether or not escaping gas is present in or under the building involved or in any adjacent buildings. If gas is detected, the affected buildings shall be evacuated, the gas meter shall be turned off, open flames shall be extinguished, electrical switches and telephones shall not be operated and all necessary precautions shall be taken to prevent the gas from being ignited.

b. Determine if traffic shall be stopped or rerouted to prevent possible ignition of the escaping gas. If it is determined that traffic shall be rerouted, the Police or Fire Department should be requested to direct the flow of traffic.

c. It shall be determined whether or not the gas is migrating into storm or sanitary sewers. If gas is found in either type of sewer, then necessary precautions shall be taken to prevent ignition. When gas is found in a sanitary sewer, the buildings in the immediate area shall be checked with a leak detector to determine if any gas is present under or in the buildings. Normally, gas in a sanitary sewer will vent from the sewer stack unless there is a leak in the sewer system under the building. At times, gas will get under the building by following the sewer ditch. If gas from a sewer is found under a building the dangerous condition can usually be eliminated by opening a hole in the sanitary sewer line and the gas will then vent to atmosphere. When gas is found in storm sewers, it will usually vent out at the nearest sewer inlets at the curb. Precautions shall be taken to prevent this gas from being ignited by either flames or vehicles.

2. During an investigation, reports of conditions found and precautions taken will be communicated to the On-Duty Person. Company personnel at the leak will describe the intensity of the leak, probable hazards involved, and back up needed, such as welders, equipment operators and fire or police. The On-Duty Person will notify supervisory, Claims, and Public Relations personnel if the seriousness of the leak warrants or when injury or personal property damage results. If the leak occurs after regular working hours, On-Duty Person will notify the on call supervisor and call overtime personnel in accordance with standard practice. Upon arrival, all personnel will be briefed by the supervisor on the situation and proceed with repair of the emergency.

a. The On-Duty Person shall determine the expected consequences of lowering the gas pressure or taking the pipeline out of service. Before a decision is made to take a line out of service or to isolate a section of the system, an analysis will be made of the system maps to determine which valves must be closed. The On-Duty Person will normally plan this.

b. Gas Operation will pay particular attention to leaks that may compromise the integrity of the Gas System. Compressors may be started or Pressures of remotely controlled regulators may be raised as required to maintain an adequate supply of gas to the system. Remotely controlled block valves will not be closed without supervisory approval.

c. After the decision is made as to how the escaping gas will be controlled, the "Supervisor in Charge" will request any additional personnel, equipment, and materials needed for the repair. The supervisor at the dispatch office will arrange for dispatching employees to the valve locations and will coordinate the isolation.

d. While the repair is being made on a pipeline or a section of the system that has had the flow of gas interrupted, the On-duty Persons will ensure that all laterals are turned off in the isolated section.

e. After repairs are completed and the line has been purged, if necessary, and placed in service, additional checks shall be made in the immediate area by accepted leak detection methods to determine if other leaks exist in the immediate area.

f. Upon completion of repairs, notification will be made to the "Supervisor in Charge" so gas may be restored to the affected area; buildings reoccupied, and traffic returned to normal. In addition all previously notified public agencies, company personnel, and insurance representatives will be informed that emergency conditions have been corrected.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT General Emergency Response Procedures

Ref: 192.615	Date Revised: April 2012

Types of Emergencies: [192.615(a)(3]

Four types of natural gas emergencies are defined and a plan for each type of emergency is established. The responsibility for declaring an emergency is defined. The liaison between the Company and public officials is outlined and guidelines for educating public officials and the general public are provided.

The company will provide prompt response to each of the following types of emergencies:

- escaping gas and/or gas detected inside a building
- **fire or explosion**
- natural disaster (including earthquakes, etc.)
- civil disturbance.

This section of the emergency response plan describes "Emergency Response for Fire or Explosion."

Emergency Response for Major Fires and Explosions [192.615(a)(3)]

Emergency precautions must be taken after explosions and during major fires to protect system facilities and to ensure that the presence of gas will not create additional problems for fire-fighting and damage control personnel. Refer to Emergency Shutdown and Pressure Reduction Procedure.

1. When responding to a report of a major fire or explosion, the primary consideration shall be the safety of the public and employees. A fire or explosion resulting from the leakage of natural gas requires immediate and urgent attention by all the company personnel involved. A On-duty Person will be dispatched to the area immediately. The following actions and procedures shall be considered:
    a. Immediately upon arrival, establish contact with any fire and police personnel on the scene. If company personnel precede fire and police arrival, verify with the On-Duty Person that proper notice has been given these agencies. The On-duty Person will describe the nature and scope of the emergency to the On-Duty Person by radio and request emergency back-up crews and equipment to handle the emergency. Gas Operation will dispatch the requested personnel and equipment to the area and notify other supervisory, emergency, and interested personnel in accordance with standard practice.

b. It must be determined immediately if gas is directly involved in the fire or explosion. If gas is not involved, but is in close proximity, action shall be taken to ensure the protection of the public and the affected facilities.

c. If gas is involved and the presence is such that there is immediate danger to public and property, proceed to evacuate the areas. Request the Fire/Police Department's assistance in evacuation efforts if needed. The On-duty Person, or his supervisor at the scene, will do what is necessary to eliminate any remaining hazard to persons or structures in the vicinity. Occupants of adjacent structures will be advised to evacuate if there is danger of additional fire or explosion. They will be advised against turning on light switches or any appliance, which would likely cause a spark. Gas and electric meters may be turned off to prevent ignition of trapped gas if present. Traffic will be detoured around the area until the danger has cleared. Coordination and cooperation with the Fire and Police Departments by company personnel is imperative.

d. The On-duty Person at the scene of the emergency shall immediately attempt to locate the source of the leak. The On-duty Person will have Gas Leak Repair Persons dispatched to the area without delay. At the same time, the On-duty Person will continue to search for the leak using a combustible gas indicator. He will investigate such things as sewer vents, manholes, curb lines, and cracks in sidewalks, driveways or pavement. Edges of sidewalks, driveways, or building foundations and any other discontinuity of the ground surface are also places to investigate.

e. Measurement & Regulator Persons will be dispatched if the area requires isolation to prevent further leakage or pressure reduction to repair the leak. These operations will be planned and executed by the Operations Person.

f. Tests shall be made by accepted leak detection methods to determine the presence of gas. A detailed schematic showing readings and where readings were taken along with calibration of instruments shall be documented.

2. After initial action has been completed to assure the safety of the public, and to prevent damage to property, there are certain investigative actions that shall be considered by the supervisor in charge of the investigation.

   a. Record all information concerning actions taken, so that necessary reports might be prepared. Refer to Checklist for Supervisors -- (Form EM-5).

   b. Ensure that all persons necessary to conduct a completed investigation have been notified.

   c. See that no action is taken that might disturb evidence necessary to conduct a complete investigation. Evidence shall be recorded with notes, photographs, and videotape, if possible. At times certain components shall be brought to the Main Operations Office.

   d. Review maintenance work and results of previous leakage surveys in the area. Review the level of cathodic protection on the system. Determine if there has been recent construction work in the area by the company or others, which may have contributed to the emergency.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT General Emergency Response Procedures

Ref: 192.615	Date Revised: April 2012

Types of Emergencies: [192.615(a)(3]

Four types of natural gas emergencies are defined and a plan for each type of emergency is established. The responsibility for declaring an emergency is defined. The liaison between the Company and public officials is outlined and guidelines for educating public officials and the general public are provided.

The company will provide prompt response to each of the following types of emergencies:

- escaping gas and/or gas detected inside a building
- fire or explosion
- **natural disaster (including earthquakes, etc.)**
- civil disturbance.

This section of the emergency response plan describes "Emergency Response for Natural Disaster (including earthquakes, etc.)"

Emergency Response for Natural Disasters [192.615(a)(3)]

Disasters such as floods, tornadoes, earthquake, and high winds might cause various operating problems within the gas system. Emergency procedures must be employed to survey the system and eliminate conditions that might endanger life or property.

1. Immediately upon learning of such an occurrence, the appropriate Supervisor shall assess the severity of the situation and decide whether it is necessary to initiate action. When a disaster does occur, civil authorities may declare a state of emergency. Under a state of emergency the civil authorities have control over the actions of all persons and equipment in the area. After the immediate hazardous conditions have been corrected, essential services shall be restored on the priorities established by the public officials.

   Notification shall be given to the appropriate personnel to report for work and equip their vehicles with emergency tools and stand by for further instructions. It is most important to utilize radio-equipped vehicles and make maximum usage of portable radios or telephones.

2. Action shall be taken upon arrival at the scene of the emergency.
   a. Communications shall be established with all rescue squads, police and fire departments, and the National Guard. Full advantage shall be taken of the services that these organizations can render.

b. One radio-equipped vehicle shall be staffed and located in a conspicuous and convenient location in the emergency area. The Supervisor will appoint an employee at the scene to locate the person or persons in charge of each emergency agency that is present, and establish communications with them. The Supervisor will inform them of the location of the radio-equipped vehicle and will request each agency to notify its members to report any gas-related problems to the employee at that location. The employee at this vehicle then will relay all information to the On-Duty Person and/or supervisor.

3. A survey shall be conducted as soon as possible to assess damage to our facilities.
   a. During this survey, inspect district regulator stations for damages, paying particular attention to regulator control lines in an effort to prevent over-pressuring.
   b. In certain instances, it will be advisable to station someone at primary regulator stations to prevent the gas supply from being turned off by unauthorized personnel.
   c. Leak survey crews with portable instruments shall be utilized to check the areas involved. After an estimate of the severity of the situation is ascertained, a decision must be made as to isolating pipelines, shutting them off completely, or leaving gas on the system. Refer to Procedure for Emergency Shutdown, if necessary.
   c. Consideration shall be given as to whether additional personnel and/or equipment will be needed. If in doubt, it is preferable to have extra crews standing by on the scene even though they may not be needed. This will allow more flexibility for unexpected requirements and also will be an aid in reassuring the public.

CENTRAL VALLEY GAS STORAGE
Natural Gas Transmission Pipeline
DOT General Emergency Response Procedures

Ref: 192.615	Date Revised: April 2012

Types of Emergencies: [192.615(a)(3)]

Four types of natural gas emergencies are defined and a plan for each type of emergency is established. The responsibility for declaring an emergency is defined. The liaison between the Company and public officials is outlined and guidelines for educating public officials and the general public are provided.

The company will provide prompt response to each of the following types of emergencies:

- escaping gas and/or gas detected inside a building
- fire or explosion
- natural disaster (including earthquakes, etc.)
- **civil disturbance.**

This section of the emergency response plan describes "Emergency Response for Civil Disturbance."

Emergency Response for Civil Disturbance [192.615(a)(3)]

Civil Disturbance is an unlawful act of a group of people whereby life and property are endangered or may be endangered and company pipeline facilities may be sabotaged.

1. The company pipeline facilities and work crews will require physical protection in areas of civil disorder. Persons may attempt to disrupt company operations and sabotage company equipment. The Gas Operations Person shall:
   a. Establish communications with appropriate civil authorities.
   b. Determine the extent of the area and prepare to isolate the section.
   c. Monitor the operation of the gas system at a safe location. Watch for signs of major changes in flow rates that would indicate volumes of gas escaping or loss of pressure.
   d. Report all incidents of sabotage to civil authorities.
2. The Gas Operations Person shall request police protection for any personnel dispatched into the affected area. Company personnel shall not physically resist potential saboteurs or unruly persons. Company personnel threatened by such persons shall secure the gas facilities and withdraw from the area. Under no circumstances shall company personnel carry firearms. The Gas Operations Person shall make all arrangements for security guards. The Gas Operations Person shall consider the following actions to prevent disruption of service:

a. Verify all public reports and requests for service by obtaining the telephone number from the person calling in and recalling the number. Telephone numbers can also be checked against city directories.
b. Install locking devices on all above ground valves inside fenced enclosures and buildings.

APPENDICES

17. Forms
18. Emergency Equipment
19. Glossary of Terms

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

FORMS INDEX

Ref: 192.615 **Date Revised: April 2012**

Form Number	Form Title/Description:	Em. Plan Tab #:	Form To Be Used By:
EM-1	Initial Notification Document	3	First person to receive emergency notification.
EM-2	First Responder On Scene Checklist	4	First company pipeline person capable of performing First Responder function.
EM-3	Agency Notification Log	6	Company On-duty supervisor or designated company employee
EM-4	Company Notification Log	3	Company On-duty supervisor or designated company employee
EM-5	Emergency Log of Miscellaneous Activities	3	Any person performing em. response activities
EM-6	Incident Command System Checklist by ICS Job Title	5	Any person performing Incident Command response activities
EM-7	Post Incident Response Critique Checklist	2	Company supervisor performing em. response critique review
EM-8	Emergency Drill Documentation	2	Company supervisor performing em. response drill review
EM-9	Emergency Plan Notification Record	2	DOT Compliance Supervisor for record of face to face liaison with public officials.
	Telephone Report of Incidents	Section #6 in O&M	Pipeline Supervisor or DOT Compliance Supervisor reporting incidents to the DOT.
	Safety Related Condition Report	Section #3 in O&M	Pipeline Supervisor or DOT Compliance Supervisor reporting safety related condition to the DOT.
RSPA F 7100.2	Follow Up Written Incident Report	Section #6 in O&M	Pipeline Supervisor or DOT Compliance Supervisor reporting incidents to the DOT.
	Annual Report	Section #7 in O&M	Pipeline Supervisor or DOT Compliance Supervisor completing DOT annual report.
	Training Documentation	10	Pipeline Supervisor or DOT Compliance Supervisor performing emergency response training.

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

Initial Notification Document

Form # EM-1

Ref: 192.615	**Date Revised: April 2012**

Caller Information:	1) Date:	
	2) Time:	
	3) Name of Caller:	
	4) Telephone # of Caller:	
Emergency Information:	5) Emergency Location (include directions if needed)	
	6) Status of the Event: Check all that apply explain in comments section ❑ Fire? ❑ Escaping Gas? ❑ Explosion? ❑ Gas odor? ❑ Natural disaster? ❑ Civil disorder? ❑ Visible cloud?	❑ Traffic involved? ❑ Structures involved? (schools, business, homes,etc) ❑ Special considerations? (RR, sewer, waterway, electrical power lines, other)
	7) Emergency action already taken by civilians or public officials (fire, police, Hwy patrol, etc.)?	
Comments And Other Pertinent Information:		

Ref: 192.615	Date Revised: April 2012

Call Receiver Information:	Print Name of Person Receiving Call:
	Signature:

CENTRAL VALLEY GAS STORAGE
Emergency Response Procedures
First on Scene Checklist
Form # EM-2

Ref: 192.615	Date Revised: April 2012

1st Priority:

- Protect the public, responders, company personnel.

Responsibilities: **Scope, Assessment, and Mitigation:**

- Identify the type, form, nature, quantity and hazards involved in the incident.
- Develop a proper course of action (evacuating, traffic control, prevention of accidental ignition, etc.)

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

First on Scene Checklist

Form # EM-2

Ref: 192.615	Date Revised: April 2012

Checklist: **Assessment:**

- ☐ Is the fluid being released as a liquid, an aerosol, or a gas?
- ☐ Is there a visible vapor cloud?
- ☐ Has a liquid pool started to form?
- ☐ How large is the visible cloud or pool?
- ☐ Is the liquid pool likely to spread and enter a body or water?
- ☐ Is the vapor likely to enter nearby buildings?
- ☐ If already ignited, how large is the fire?
- ☐ Is the situation immediately dangerous to persons or property?
- ☐ Is the situation likely to get worse?
- ☐ What can be done to reduce the risk to persons and property?
- ☐ Are there ignition sources that need to be removed?

Mitigation:

- ☐ Evacuate or shelter in place.
- ☐ Ignition source control.
- ☐ Emergency shutdown or isolation.

Other Activities To Consider:

- ☐ Interact with other response agencies.
- ☐ Start documentation with emergency log of misc. activities (form #EM-5)
- ☐ Notify local emergency response agencies (911).
- ☐ Notify other agencies (federal, state, other local agencies)
- ☐ Notify appropriate personnel within the pipeline Company:
    - Manager, and/or Duty supervisor
    - SCADA system operator
    - Pipeline Advisor
    - Environmental and Safety Coordinator
    - Other personnel needed to respond to the scene (repair crew, operators, supervisors, etc.)

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

Agency Notifications and Reporting

Form # EM-3

Ref: 192.615	**Date Revised: June 2011**

Name of company person making calls: ______________________________
Title of company person making calls: ______________________________

Local Emergency Service:	**911, 24 hours/day**
Person Contacted:	
Person Title:	
Date and Time:	
Report #:	
Reporting Criteria: • Any emergency	Comments:

National Response Center:	**(800) 424-8802, 24 hours/day**
Agency Person Contacted:	
Agency Person Title:	
Date and Time:	
NRC report #:	
Reporting Criteria: • Pipeline incident per 49 cfr section 191.3 (death, hospitalization, $50,000 in damage, significant event) • Condensate spill to navigable waterway per 33 CFR 153.203 & 40 CFR 110.10	Comments: ☐ (Report name of person reporting, location and time of incident, number of fatalities and personal injuries, and other significant facts re: cause or ex tent of damages) ☐ (Report if spill is causing a film or sheen upon or discoloration of the surface of the water or causing a sludge or emulsion to be deposited beneath the surface of the water.)

USDOT - Office of Pipeline Safety (PHMSA):	**Western Region (720) 963-3160, Fax: (720) 963-3161**
Agency Person Contacted:	
Agency Person Title:	
Date and Time:	
Report #:	
Reporting Criteria: • Pipeline safety related condition per 49 cfr section 191.23 (imminent hazard, material defects, unintended movement, etc.)	Comments:

Ref: 192.615	**Date Revised: June 2011**

Name of company person making calls: ______________________
Title of company person making calls: ______________________

Agency Notifications:

Cal/OSHA: (Sacramento Office)	(916) 263-2800, Fax (916) 263-2798
Person Contacted:	
Person Title:	
Date and Time:	
Report #:	
Reporting Criteria: • Within eight (8) hours after the death of any employee from a work-related incident or the in-patient hospitalization of three or more employees as a result of a work-related incident, orally report the fatality/multiple hospitalization by telephone or in person to the Area Office of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, that is nearest to the site of the incident. [29 cfr 1904.39]	Comments:

Agency Contacted:	
Agency Person Contacted:	
Agency Person Title:	
Date and Time:	
Report #:	
	Comments:

Agency Contacted:	
Agency Person Contacted:	
Agency Person Title:	
Date and Time:	
Report #:	
	Comments:

CENTRAL VALLEY GAS STORAGE
Emergency Response Procedures
Agency Notifications and Reporting
Form # EM-3

Ref: 192.615	**Date Revised: June 2011**

Name of company person making calls: ______________________
Title of company person making calls: ______________________

Agency Notifications:

California Office of Emergency Services:	(800) 852-7550, 24 hours/day (or (916) 262-1621 if outside CA)
Person Contacted:	
Person Title:	
Date and Time:	
Report #:	
Reporting Criteria: • Actual or threatened release of any hazardous material that poses threat to public or the environment. [HSC 25507(a)] • Release of hazardous substance to state waters [Water Code 13271(a)] • Spills or leakage of oil or liquid pollutant on state lands or waters [2 CCR 2142] • Release of hazardous material or waste upon any highway. [Vehicle Code 23112.5(a)]	Comments: (Report name/number of person reporting, location and time of incident, cause and type of incident, type and estimated quantity of released material, actions taken, current facility condition, injuries, potential health or environmental hazards outside of facility.)

CPUC	800-235-1076
Person Contacted:	
Person Title:	
Date and Time:	
Report #:	
Reporting Criteria: Discharge or threatened discharge of oil/condensate greater than one barrel into marine waters.	Comments: (make sure that CA Department of Fish and Game is notified.)

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

COMPANY NOTIFICATIONS

Form # EM-4

Ref: 192.615	**Date Revised: April 2012**

Company Person Contacted:	Company Person Who Placed Call:	Date:	Time:	Time Arrived at Scene or Command Post:

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

LOG OF MISCELLANEOUS ACTIVITIES

Form #EM-5

Ref: 192.615	Date Revised: April 2012

Date: ____________
Title: ____________
Signature: ____________

Time:	Action:

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

LOG OF MISCELLANEOUS ACTIVITIES

Form #EM-5

Ref: 192.615 **Date Revised: April 2012**

Date: ____________
Title: ____________
Signature: ____________

Time:	Action:

DOT PIPELINE

Emergency Response Procedures

ICS Checklists

Form #EM-6

Ref: 192.615	**Date Revised: June 2012**

Incident Commander

IC Role: The Incident Commander is responsible for overall incident response and control of all activities. The IC establishes the "Command Post" at the incident location or other appropriate location. Authorization of action plans and resources are key activities of the IC.

IC Position Candidate Examples:

- Initial Responder
- Operations Manager
- Plant Operator
- Director, Storage & Peaking Ops – West Region

IC Checklist:

- ❑ Identify and isolate incident area; establish perimeters and control points.
- ❑ Establish a command post and staging areas.
- ❑ Notify and request assistance from dispatch, immediate supervisor, or appropriate higher ranking officials.
- ❑ Initiate incident command system and coordinate scene activities.
- ❑ Appoint command staff – safety liaison and information officers- and begin operations.
- ❑ Implement standard operating procedures or emergency response plan; develop and release incident action plan; revise and disseminate operational plans.
- ❑ Provide policy, direction, and control for emergency operations; set priorities and establish response strategies.
- ❑ Implement site safety plan; revise and disseminate plan.
- ❑ Establish site perimeter and control points.
- ❑ Reroute traffic and control access to site
- ❑ Establish work zones
  - Exclusion zone (hot zone)
  - Contamination reduction zone (decon zone)
  - Support zone
- ❑ Conduct operations; eliminate potential for airborne dispersion, terminate release of hazardous materials, reduce exposure of personnel and equipment.
- ❑ Monitor and sample site
- ❑ Determine type of evacuation: immediate, precautionary, and scheduled.

Public Information Officer

Information Officer Role:	The Public Information Officer is responsible for providing on-site contact with news media and furnishing the media with Company approved news release information.
Information Officer Position Candidate Examples:	• Company Public Affairs Manager • Public Affairs Consultant • Operations Manager • EHS Specialist
Information Officer Checklist:	❑ Obtain briefing from incident commander. ❑ Contact the jurisdictional agency to coordinate public information activities. ❑ Establish single-incident information center whenever possible. ❑ Arrange for necessary work space, material, telephones, and staffing. ❑ Prepare initial information summary as soon as possible after arrival. ❑ Obtain approval for release from incident commander. ❑ Release information to news media. ❑ Post information in command post and other appropriate locations. ❑ Attend meetings to update information releases. ❑ Arrange for meetings between media and incident personnel. ❑ Provide escort service to the media and VIP's ❑ Respond to special request for information. ❑ Maintain log.
Information Officer Hints:	**Specifically, the Information Officer should address the following:** ❑ Name, title, and what the Info Officer function is. ❑ What has happened in simple terms. ❑ Injuries (no names unless family has been notified). ❑ Major concerns (Safety of people and protection of environment) **Watch for Red Flag questions:** ❑ What is the cause? Who is at fault? ❑ How much will it cost? ❑ How much was released? **Do not speculate. Stick to the known facts.**

Safety Officer

Safety Officer Role:	The Safety Officer is responsible for providing a "Site Safety Plan" and assessing activities for hazardous and/or unsafe situations and developing means for assuring the safety of response personnel.
Safety Officer Position Candidate Examples:	• Initial Responder • Operations Manager • Plant Operator • EHS Specialist • EHS Consultant
Safety Officer Checklist:	☐ Obtain briefing from incident commander. ☐ Identify hazardous situations associated with the incident ☐ Identify control measures: (engineering administrative/PPE). ☐ Initiate evacuation procedures. ☐ Develop decontamination procedures. ☐ Conduct safety meetings. ☐ Participate in planning meetings. ☐ Review incident action plan. ☐ Review and approve medical plan ☐ Investigate accidents that have occurred within incident areas. ☐ Maintain a log. **Note:** Exercise emergency authority to stop and prevent unsafe acts.

Liaison Officer

Liaison Officer Role:	The Liaison Officer is responsible for conducting initial regulatory contacts and coordinating required government reports and inquires. Ensure that the Company is tracking regulatory agency response and potential for incidents of non-compliance.
Liaison Officer Position Candidate Examples:	• Initial Responder • Operations Manager • Director, Storage & Peaking Ops – West Region • EHS Specialist
Liaison Officer Checklist:	☐ Obtain briefing from incident commander. ☐ Provide a point of contact for agency representatives. ☐ Identify agency representative from each agency. ☐ Establish communications link and location. ☐ Provide inter-organizational contacts for incident personnel. ☐ Monitor incident operations for inter-organizational problems. ☐ Maintain log.

Operations Section Chief

Operations Section Chief Role:	The Operations Section Chief is responsible for directing tactical emergency response, incident control actions, and recovery/clean-up operations. Also, request needed resources and prepares operational plans if needed.
Operations Section Chief Position Candidate Examples:	• Initial Responder • Operations Manager • Director, Storage & Peaking Ops – West Region • EHS Specialist
Operations Section Chief Checklist:	❑ Obtain briefing from incident commander. ❑ Develop operations portion of Incident Action Plan. ❑ Brief and assign operations personnel in accordance with Incident Action Plan. ❑ Supervise Operations. ❑ Determine need and request additional resources. ❑ Review suggested list of resources to be released and initiate recommendation for release of resources. ❑ Assemble and disassemble strike teams assigned to operations section. ❑ Report information about special activities, events, and occurrences to incident commander.

Planning Section Chief

Planning Section Chief Role:	The Planning Section Chief is responsible for development of "Incident Action Plans" and management of incident status reports. Role includes assessing the situation, predicting outcomes and resource status, and initiating planning meetings.
Planning Section Chief Position Candidate Examples:	• Initial Responder • Operations Manager • Plant Operator • Director, Storage & Peaking Ops – West Region • EHS Specialist
Planning Section Chief Checklist:	❑ Obtain briefing from incident commander. ❑ Activate planning section units. ❑ Reassign initial attack personnel to incident positions as appropriate. ❑ Establish information requirements and reporting schedules for all ICS organizational elements for use in preparing the incident action plan. ❑ Establish a weather data collection system when necessary. ❑ Supervise preparation of incident action plan. ❑ Assemble information on alternative strategies. ❑ Assemble and disassemble strike teams not assigned to operations. ❑ Identify need for use of specialized resources. ❑ Provide periodic predictions on incident potential. ❑ Compile and display incident status summary information. ❑ Advise general staff of any significant changes in incident status. ❑ Provide incident traffic plan. ❑ Supervise planning section units. ❑ Prepare and distribute incident commander's orders. ❑ Insure that normal agency information collection and reporting requirements are being met. ❑ Prepare recommendations for release of resources for submission to the incident commander.

Logistics Section Chief

Logistics Section Chief Role:	The Logistics Section Chief is responsible for identifying needed resources and supplies and on-scene delivery and management of supply facilities, services, and materials.
Logistics Section Chief Position Candidate Examples:	• Initial Responder • Operations Manager • Plant Operator • Director, Storage & Peaking Ops – West Region • Mechanic • Maintenance Specialist
Logistics Section Chief Checklist:	❑ Obtain briefing from incident commander. ❑ Plan organization of logistics section. ❑ Assign work locations and preliminary work tasks to section personnel. ❑ Participate in preparation of Incident Action Plan. ❑ Identify service and support requirements for planned and expected operations. ❑ Provide input to and review communications plan, medical plan, and traffic plan. ❑ Coordinate and process request for additional resources. ❑ Review incident action plan and estimate section needs for next operational period. ❑ Insure incident communications plan is prepared. ❑ Advise on current service and support capabilities. ❑ Prepare service and support elements of the incident action plan. ❑ Estimate future service and support requirements. ❑ Receive demobilization plan from planning section. ❑ Recommend release of unit resources in conformity with demobilization plan. **Insure general welfare and safety of logistics section personnel.**

Finance Section Chief

Finance Section Chief Role:	The Finance Section Chief is responsible for management of cost control and critical manpower planning.
Finance Section Chief Position Candidate Examples:	• Operations Manager • Administrative Assistant • Supply Chain Specialist • Plant Operator • Director, Storage & Peaking Ops – West Region
Finance Section Chief Checklist:	❑ Obtain briefing from incident commander. ❑ Attend briefing with responsible agency to gather information. ❑ Attend planning meeting to gather information. ❑ Identify needs, order supplies, and support needs for finance section. ❑ Develop an operating plan for finance function on incident. ❑ Prepare work objectives for staff. ❑ Determine need for commissary operation. ❑ Inform command staff and general staff when section is fully operational. ❑ Meet with agency representatives as required. ❑ Provide input in all planning sessions on financial and cost analysis matters. ❑ Maintain daily contact with agency(s) administrative headquarters on finance matters. ❑ Insure that all personnel time records are transmitted to appropriate locations. ❑ Participate in all demobilization planning. ❑ Insure that all obligation documents initiated at the incident are properly prepared and completed. ❑ Brief agencies on all incident related business management issues needing attention and follow-up prior to leaving incident.

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

POST-INCIDENT RESPONSE CRITIQUE

Form #EM-7

Ref: 192.615	Date Revised: April 2012

Date of Critique: __________
Title: ________________
Signature: ________________

Issue:	Response Actions:	Recommendations For Improvement: (Consider procedures, forms, training)
Initial Action And Deployment:	☐ Was initial information handled accurately, quickly, and completely? ☐ Did the On-Duty Person receive notification in a timely manner? ☐ Did the first person on-scene arrive in a timely manner? ☐ Did the First Responder take the correct action? (scope, assessment, evacuation, etc.)	
Initial On-Scene Activities:	☐ Were isolation zones setup if appropriate? ☐ Was ICS setup properly and in a timely manner? ☐ Did ICS function properly? ☐ Was mitigation handled properly? ☐ Was containment handled properly? ☐ Were emergency events and actions documented? ☐	
Reporting And Notifications:	☐ Were all agency notifications made in a timely manner? ☐ Were Company personnel notified? ☐ Were emergency contractors notified? ☐ Were gas supply companies notified?	

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

POST-INCIDENT RESPONSE CRITIQUE

Form #EM-7

Ref: 192.615	**Date Revised: April 2012**

Issue:	**Response Actions:**	**Recommendations For Improvement:** (Consider procedures, forms, training)
Comm:	☐ ICS roles clearly communicated? ☐ Proper communication between all appropriate response personnel (radios, cell phones, etc.) ☐ Messages clear and concise.	
Media And Public Affairs:	☐ Public information released? ☐ Did IC approve released info? ☐ Was interface with public satisfactory?	
Site Safety:	☐ Was a site safety plan developed? ☐ PPE used? ☐ Was hazard info available?	
Logistics And Planning:	☐ Was emergency equipment readily available? ☐ Was emergency equipment appropriate?	
Finance:	☐ Were monetary funds available when needed?	
Other:	☐ Were there any problem areas not previously discussed?	

____

CVGS OPERATIONS MANAGER:

____

Date:

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

Emergency Drill Documentation

Form # EM-8

Ref: 192.615	Date Revised: April, 2012

Date: ____________________
Em. Drill Start Time: ____________________
Em. Drill Finish Time: ____________________
Location of Drill: ____________________

Description of Emergency Drill:

Evaluator Checklist:

Immediate Actions: (Actions, Knowledge, Documentation, Available Tools/Info)

- ❑ Em call handling
- ❑ Agency Notification
- ❑ Company Notification
- ❑ Em. Contractor Notification
- ❑ Gas company notifications
- ❑ First on scene actions

Ongoing Actions: (Actions, Knowledge, Documentation, Available Tools/Info)

- ❑ On scene command or ICS
- ❑ On scene air monitoring
- ❑ On scene leak isolation
- ❑ Company staff mobilization
- ❑ Em. Contractor mobilization
- ❑ Containment & isolation of area
- ❑ Agency notifications and reports

Overall Evaluation of Emergency Systems and Knowledge:

- ❑ Efficient, accurate, and updated info (phone list, checklist, forms, etc.)
- ❑ Accurate procedures
- ❑ Em Resources readily available (equipment, contractors, Co. employees, etc.)
- ❑ Communication Systems
- ❑ Public protection
- ❑ Employee protection and PPE
- ❑ Roles and Responsibilities understood
- ❑ Training (Hazwoper, Em. Manual, PPE, ICS, etc.)
- ❑ Knowledge of pipeline systems & equipment
- ❑ Documentation
- ❑ ICS (Incident command, planning, operations, logistics, finance)

CENTRAL VALLEY GAS STORAGE

Emergency Response Procedures

Emergency Drill Documentation

Form # EM-8

Ref: 192.615	Date Revised: April, 2012

Date: ____________________
Em. Drill Start Time: ____________________
Em. Drill Finish Time: ____________________
Location of Drill: ____________________

Description of Emergency Drill:

Evaluator Checklist:

Immediate Actions: (Actions, Knowledge, Documentation, Available Tools/Info)

- ☐ Em call handling
- ☐ Agency Notification
- ☐ Company Notification
- ☐ Em. Contractor Notification
- ☐ Gas company notifications
- ☐ First on scene actions

Ongoing Actions: (Actions, Knowledge, Documentation, Available Tools/Info)

- ☐ On scene command or ICS
- ☐ On scene air monitoring
- ☐ On scene leak isolation
- ☐ Company staff mobilization
- ☐ Em. Contractor mobilization
- ☐ Containment & isolation of area
- ☐ Agency notifications and reports

Overall Evaluation of Emergency Systems and Knowledge:

- ☐ Efficient, accurate, and updated Info (phone list, checklist, forms, etc.)
- ☐ Accurate procedures
- ☐ Em Resources readily available (equipment, contractors, Co. employees, etc.)
- ☐ Communication Systems
- ☐ Public protection
- ☐ Employee protection and PPE
- ☐ Roles and Responsibilities understood
- ☐ Training (Hazwoper, Em. Manual, PPE, ICS, etc.)
- ☐ Knowledge of pipeline systems & equipment
- ☐ Documentation
- ☐ ICS (Incident command, planning, operations, logistics, finance)

CVGS DOT Gas Transmission Pipeline

Emergency Response Procedures

Emergency Planning & Resources Notification Record

Form #EM-9

Ref: 192.615, Advisory ADB 10-08 Nov 2010	Date Revised: March 2012

Information communicated to emergency responders will be detailed, provide an opportunity for two-way feedback, and include additional details on the products transported, facilities located within the jurisdiction and the local emergency planning liaison.

The purpose of the emergency official's liaison meetings is to build the relationship between the pipeline company and the responders and help to understand the expectations of the responders. The preferred method for conducting liaison meetings is <u>face to face</u> with specific emergency officials or group meeting conducted by Paradigm. During these meetings CVGS will provide and verify the following:

- Summary copy of the CVGS pipeline emergency response plan including maps, product transported, and emergency contact info
- Verify the response agency has the proper equipment and resources to respond to a CVGS pipeline emergency

For emergency officials that were invited and don't attend group meetings, a summary copy of the CVGS pipeline emergency response plan including maps, product transported, and emergency contact info will be mailed.

This record is to document that the company has established and maintained liaison with the appropriate fire, police, and other public officials for the purposes listed above and below:

- Learning the responsibility and resources of each government organization that may respond to a pipeline emergency;
- Acquaint the officials with the company's ability in responding to a pipeline emergency;
- ID the types of pipeline emergencies of which the company notifies the officials; and
- Plan how the company and officials can engage in mutual assistance to minimize hazards to life or property.

CVGS will use the Incident Command System as a method for organization and interaction with the agencies during an actual emergency. The preferred method of review with public officials is <u>face to face.</u> [OPS interpretation letter, Feb. 4, 1993, 192.615(c), & PHMSA Advisory ADB 10-08, Nov 3, 2010]

CVGS DOT Gas Transmission Pipeline

Emergency Response Procedures

Emergency Planning & Resources Notification Record

Form #EM-9

Ref: 192.615, Advisory ADB 10-08 Nov 2010	Date Revised: March 2012

Agency:

____
(agency name)

____
(street address)

____
(city, state, zip)

____
(phone #)

Method of Delivery:

- ☐ Face to Face (preferred method)
- ☐ Left copy of Company DOT Emergency Plan and/or summary version covering objectives above
- ☐ Copy mailed.
- ☐ Other (explain)

Agency Contact:

____
(print name)

____
(title)

____
(signature) (date)

Company Representative:

____
(print name)

____
(title)

____
(signature) (date)

CENTRAL VALLEY GAS STORAGE
Training Registration

Date:	Location:	Instructor Name:	Instructor Signature:
Description of Training:		Regulatory Reference for Training:	

#	Name:	Signature:	Employee Number:	Comments:
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				

CENTRAL VALLEY GAS STORAGE
Training Registration

#	Name:	Signature:	Employee Number:	Comments:
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 1678. Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING SYSTEMS

Report Date ______________

No. ______________ (DOT Use Only)

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at* http://ops.dot.gov.

PART A – GENERAL REPORT INFORMATION

Check one: ☐ **Original Report** ☐ **Supplemental Report** ☐ **Final Report**

Operator Name and Address

a. Operator's 5-digit Identification Number (when known) /__/__/__/__/__/

b. If Operator does not own the pipeline, enter Owner's 5-digit Identification Number (when known) /__/__/__/__/__/

c. Name of Operator ______________

d. Operator street address ______________

e. Operator address ______________
City, County or Parish, State and Zip Code

2. Time and date of the incident

/__/__/__/__/ hr. /__/__/ month /__/__/ day /__/__/ year

3. Location of incident

a. ______________
Nearest street or road

b. ______________
City and County or Parrish

c. ______________
State and Zip Code

d. Mile Post/Valve Station ______________

e. Survey Station No. ______________

f. Latitude: __________ Longitude: __________
(if not available, see instructions for how to provide specific location)

g. Class location description
Onshore: O Class 1 O Class 2 O Class 3 O Class 4
Offshore: O Class 1 *(complete rest of this item)*
Area ______________ Block # __________
State /__/__/ or Outer Continental Shelf ☐

h. Incident on Federal Land other than Outer Continental Shelf
O Yes O No

i. Is pipeline Interstate O Yes O No

4. Type of leak or rupture

O Leak: O Pinhole O Connection Failure *(complete sec. F5)*
O Puncture, diameter *(inches)* ______________

O Rupture: O Circumferential – Separation
O Longitudinal
– Tear/Crack, length *(inches)* _
– Propagation Length, total, both sides *(feet)* ______

O N/A

O Other: __________

5. Consequences *(check and complete all that apply)*

a. ☐ Fatality Total number of people: /__/__/__/
Employees: /__/__/__/ *General Public:* /__/__/__/
Non-employee Contractors: /__/__/__/

b. ☐ Injury requiring inpatient hospitalization Total number of people: /__/__/__/
Employees: /__/__/__/ *General Public:* /__/__/__/
Non-employee Contractors: /__/__/__/

c. ☐ Property damage/loss *(estimated)* Total $__________
Gas loss $__________ Operator damage $__________
Public/private property damage $__________

d. ☐ Release Occurred in a 'High Consequence Area'

e. ☐ Gas ignited – No explosion f. ☐ Explosion

g. ☐ Evacuation *(general public only)* /__/__/__/__/ people

Reason for Evacuation:
O Emergency worker or public official ordered, precautionary
O Threat to the public O Company policy

6. Elapsed time until area was made safe:

/__/__/ hr. /__/__/ min.

7. Telephone Report

/__/__/__/__/__/__/ NRC Report Number /__/__/ month /__/__/ day /__/__/ year

8. a. Estimated pressure at point and time of incident:
______________ *PSIG*

b. Max. allowable operating pressure *(MAOP)*: __________ *PSIG*

c. MAOP established by 49 CFR section:
☐ 192.619 (a)(1) ☐ 192. 619 (a)(2) ☐ 192. 619 (a)(3)
☐ 192.619 (a)(4) ☐ 192. 619 (c)

d. Did an overpressurization occur relating to the incident? O Yes O No

PART B – PREPARER AND AUTHORIZED SIGNATURE

______________ (type or print) Preparer's Name and Title

______________ Area Code and Telephone Number

______________ Preparer's E-mail Address

______________ Area Code and Facsimile Number

______________ Authorized Signature

______________ (type or print) Name and Title

______________ Date

______________ Area Code and Telephone Number

 Reproduction of this form is permitted

PART C - ORIGIN OF THE INCIDENT

1. Incident occurred on
   - O Transmission System
   - O Gathering System
   - O Transmission Line of Distribution System
2. Failure occurred on
   - O Body of pipe   O Pipe Seam
   - O Joint
   - O Component
   - O Other: ______________________
3. Material involved *(pipe, fitting, or other component)*
   - O Steel
   - O Plastic (If plastic, complete all items that apply in a-c)
     Plastic failure was: ☐ a.ductile ☐ b.brittle ☐ c.joint failure
   - O Material other than plastic or steel: ______________
4. Part of system involved in incident
   - O Pipeline   O Regulator/Metering System
   - O Compressor Station   O Other: ____________
5. Year the pipe or component which failed was installed: /__/__/__/__/

PART D – MATERIAL SPECIFICATION (If applicable)

1. Nominal pipe size *(NPS)* /__/__/__/__/__/ in.
2. Wall thickness /__/__/__/__/__/ in.
3. Specification ____________ SMYS /__/__/__/__/__/__/
4. Seam type ______________________
5. Valve type ______________________
6. Pipe or valve manufactured by ______________________ in year /__/__/__/__/

PART E – ENVIRONMENT

1. Area of incident
   - O Under pavement
   - O Under ground
   - O Inside/under building
   - O In open ditch
   - O Above ground
   - O Under water
   - O Other: ____________
2. Depth of cover: ____________ inches

PART F – APPARENT CAUSE

Important: There are 25 numbered causes in this section. Check the box to the left of the primary cause of the incident. Check one circle in each of the supplemental items to the right of or below the cause you indicate. See the instructions for this form for guidance.

F1 – CORROSION

1. ☐ External Corrosion
2. ☐ Internal Corrosion

If either F1 (1) External Corrosion, or F1 (2) Internal Corrosion is checked, complete all subparts a – e.

a. Pipe Coating
- O Bare
- O Coated

b. Visual Examination
- O Localized Pitting
- O General Corrosion
- O Other: ______________

c. Cause of Corrosion
- O Galvanic   O Stray Current
- O Improper Cathodic Protection
- O Microbiological
- O Stress Corrosion Cracking
- O Other: ______________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
O No   O Yes, Year Protection Started: /__/__/__/__/

e. Was pipe previously damaged in the area of corrosion?
O No   O Yes, How long prior to incident: /__/__/__/ *years* /__/__/ *months*

F2 – NATURAL FORCES

3. ☐ Earth Movement ⇒ O Earthquake O Subsidence O Landslide O Other: ______________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ O Washouts O Flotation O Mudslide O Scouring O Other: ____________
6. ☐ Temperature ⇒ O Thermal stress O Frost heave O Frozen components O Other: ____________
7. ☐ High Winds

F3 - EXCAVATION

8. ☐ Operator Excavation Damage *(including their contractors)* / Not Third Party
9. ☐ Third Party Excavation Damage *(complete a-d)*
   a. Excavator group
   O General Public O Government O Excavator other than Operator/subcontractor
   b. Type: O Road Work O Pipeline O Water O Electric O Sewer O Phone/Cable O Landowner O Railroad
   O Other: ______________
   c. Did operator get prior notification of excavation activity?
   O No O Yes: Date received: /__/__/ mo. /__/__/ day /__/__/ yr.
   Notification received from: O One Call System O Excavator O Contractor O Landowner
   d. Was pipeline marked?
   O No O Yes *(If Yes, check applicable items i – iv)*
   i. Temporary markings: O Flags O Stakes O Paint
   ii. Permanent markings: O Yes O No
   iii. Marks were *(check one)* O Accurate O Not Accurate
   iv. Were marks made within required time? O Yes O No

F4 – OTHER OUTSIDE FORCE DAMAGE

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: O Man made O Natural
11. ☐ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ☐ Rupture of Previously Damaged Pipe
13. ☐ Vandalism

F5 – MATERIAL AND WELDS

Material

14. ☐ Body of Pipe ⇒ O Dent O Gouge O Wrinkle Bend O Arc Burn O Other: ____________
15. ☐ Component ⇒ O Valve O Fitting O Vessel O Extruded Outlet O Other: ____________
16. ☐ Joint ⇒ O Gasket O O-Ring O Threads O Other: ____________

Weld

17. ☐ Butt ⇒ O Pipe O Fabrication O Other: ____________
18. ☐ Fillet ⇒ O Branch O Hot Tap O Fitting O Repair Sleeve O Other: ____________
19. ☐ Pipe Seam ⇒ O LF ERW O DSAW O Seamless O Flash Weld
O HF ERW O SAW O Spiral O Other: ____________

*Complete a-g if you indicate **any** cause in part F5.*

a. Type of failure:
☐ Construction Defect ⇒ O Poor Workmanship O Procedure not followed O Poor Construction Procedures
☐ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes O No

c. Was part which leaked pressure tested before incident occurred? O Yes, *complete d-g* O No

d. Date of test: /__/__/ mo. /__/__/ day /__/__/ yr.

e. Test medium: O Water O Natural Gas O Inert Gas O Other: ____________________

f. Time held at test pressure: /__/__/ hr.

g. Estimated test pressure at point of incident: ____________________ *PSIG*

F6 – EQUIPMENT AND OPERATIONS

20. ☐ Malfunction of Control/Relief Equipment ⇒ O Valve O Instrumentation O Pressure Regulator O Other: __________
21. ☐ Threads Stripped, Broken Pipe Coupling ⇒ O Nipples O Valve Threads O Mechanical Couplings O Other: __________
22. ☐ Ruptured or Leaking Seal/Pump Packing

23. ☐ Incorrect Operation

a. Type: O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures O Other: __________

b. Number of employees involved who failed post-incident drug test: /__/__/__/ Alcohol test: /__/__/__/

c. Were most senior employee(s) involved qualified? O Yes O No d. Hours on duty: /__/__/

F7 – OTHER

24. ☐ Miscellaneous, *describe:* ______________________________

25. ☐ Unknown
O Investigation Complete O Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART G – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

INCIDENT AND SERVICE INTERRUPTION REPORT

SAFETY RELATED CONDITION

REPORTED BY:	REPORTED TO:	TIME:	DATE: ______ M0-DAY-YR
PHONE No.:	PHONE No.:		
COMPANY:	DISTRICT/LOCATION:	MEDIA ATTENTION	YES NO

Time/Location

PLANT:	PIPELINE NAME:			☐ Rural ☐ Non Rural ☐ Offshore				
STATE:	COUNTY/ PARISH:			SEC.-TWN-RANGE: ☐ Gas ☐ Haz Liq				
PIPELINE DATA	☐ Transmission ☐ Gathering	GATHERING: ☐ D.O.T. Juris ☐ Non Juris	Size	Wall	Grade	MAOP	OP Pressure	

Incident

		Yes	No		Yes	No
Release and Fatality	Employee ☐ Public ☐			Fire or Explosion		
Release and Injury	Employee ☐ Public ☐			Other significant Event		
Gas Release and Property Damage > $50,000 Haz Liquid Release > 50 bbls				Total Estimated Property Damage to Company and others $		

System Interruption

System Interruption ☐ Yes ☐ No	Estimated Length of System interruption		Hours		Minutes
System or Customer affected:					
	DATE & TIME COMPLETED	EST. ACT.			

Description & Apparent Cause

☐ Outside Force ☐ Corrosion ☐ Material Failure ☐ Construction Defect ☐ Other

DESCRIPTION AND APPARENT CAUSE: ______

Action Taken

Temporary measures to protect the public or maintain the system:	
	DATE & TIME SYSTEM COMPLETED — EST. ACT.
Repair: ______	DATE & TIME REPAIR COMPLETED — EST. ACT.

Report Activity

Telephone Report	To ☐ DOT ☐ STATE ☐ OTHERS:		
	Reported By:	Date Reported:	Time Reported:
☐ Form RSPA F 7100.2 ☐ Form DOT 7000-1	Reported By:		Date:

Distribution:

______

______

______

Signatures:

Completed By: ______

Supervisor: ______

SAFETY RELATED CONDITION REPORT

Company:	Operating Location:	Date: MO / DAY / YR

Person Submitting Report:	Person Who Determined Condition Exists:
Name:	Name:
Title:	Title:
Telephone:	Telephone:
Date Condition Discovered:	Date Condition Determined:

Location of Condition:

- ☐ Rural
- ☐ Non-Rural
- ☐ Offshore

Pipeline Name and Number: ______ Class Location:(Gas) ______

Date(s) of Installation of all Affected Pipeline Segments: ______

O.D. ______ Station or Mile Post: ______

Wall Thickness: ______ Grade: ______

Plant Field / Area: ______

State: ______ County/Parish: ______ Sec/Twnship/Rnge: ______

Name of nearest street or road (where applicable) ______

Condition Description:

Corrective Action Taken:

Signatures:

Person Completing This Form: ______

Supervisor: ______

CENTRAL VALLEY GAS STORAGE
Emergency Response Procedures
Gas Transmission Pipeline
Emergency Equipment List and Contractors

Ref: 192.615	Date Revised: April 2012

Emergency Equipment

Item:	Location:
Portable Combustible gas detector	Auxiliary Building/Control Room, Em. Contractor vehicle
Pipeline locator	Auxiliary Building, Em. Contractor vehicle
Cell phones, pagers, radios	Each CVGS Employee, Control Room
Fire extinguishing equipment	Each Company or EM. Contractor vehicle, Well Pad, Compressor Building, Utility Building, Auxiliary Building
Em. Breathing units and/or respirator	Em. Contractor vehicle
Valve wrenches	Each Company or Em Contractor vehicle
Safety harness and lines	Em Contractor vehicle
Barricades, rope, signs	Auxiliary Building Warehouse, Emergency Contractor
Potable water	Auxiliary Building, Emergency Contractor
Shovels and rakes	Auxiliary Building Warehouse Area, Emergency Contractor
Hand tools	Auxiliary Building, Emergency Contractor
Pipeline clamps	Emergency Contractor
Portable welding equipment	Emergency Contractor
Portable pumps	Emergency Contractor
Sorbent materials	Auxiliary Building, Compressor Building, Emergency Contractor
Earth moving equipment	Emergency Contractor
Vacuum truck	Emergency Contractor
Lighting	Emergency Contractor
Back-hoe	Emergency Contractor
Shoring	Emergency Contractor
Air Compressor	Emergency Contractor
Generator	Emergency Contractor
Blower	Emergency Contractor
Pre-tested pipe	CVGS pipe yard (at compressor station site)

Emergency Contractors

Company:	**TBD**
Address:	**TBD**
Phone:	**TBD**
FAX:	**TBD**

Glossary of Terms and Acronyms

ACGIH	American Conference of Governmental Industrial Hygienists. This group is best known for developing TLV's for occupational chemical exposures.
AGA	American Gas Association
AHM	Acutely hazardous material (CH & SC Sec. 25532 et seq.)
ANSI	American National Standards Institute
API	American Petroleum
APWA	American Public Works Association
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BLEVE	Boiling-liquid expanding-vapor explosion. The possible result of a Complex sequence of event involving the impingement of flame on the exterior of a container of liquefied gas.
Cal EPA	California Environmental Protection Agency. Formerly the Environmental Affairs Agency; was expanded in 1991 to include the Department of Toxic Substances Control (formerly DHS-TSCP), the Air Resources Board, the State Water Resources Control Board, the Regional Water Quality Control Boards, the Integrated Waste Management Board, the Department of Pesticide Regulation, and the Office of Health Risk Assessment.
Cal OSHA	California Division of Occupational Safety and Health. In the Department of Industrial Relations.
CAS	Chemical Abstract Service
CCR	California Code of Regulations (formerly California Administrative Code)
CEPRC	Chemical Emergency Planning and Response Commission (California).
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CFR	Code of Federal Regulations
CHEMTREC	Chemical Transportation Emergency Center
CHRIS	Chemical Hazards Response Information System
CMA	Chemical Manufacturers Association
CUPA	Certified Unified Program Agency
CWA	Clean Water Act
DOHS	Department of Health Services (California; a.k.a. CDHS;DHS;SDOHS).
DOT	Department of Transportation (federal agency)

Glossary of Terms and Acronyms (cont.)

EHS	Extremely hazardous substance (SARA Title III). Any of 406 chemicals identified by EPA as toxic and listed under SARA Title III, 40 CFR 355, Appendix A. The list is subject to periodic revision.
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right to Know Act of 1986. A.k.a. SARA Title III (42 U.S.C. Sec. 9601 et seq.)
ERPG	Emergency Response Planning Guide
ESD	Emergency Shutdown
FEMA	Federal Emergency Management Agency
HAZMAT	Hazardous Materials
HAZWOPER	Hazardous Waste Operations and Emergency Response 29 CFR 1910.120.
HCS	Hazard Communication Standard (HAZCOM)
ICS	Incident Command System. The organizational arrangement by which One person, normally the Fire Chief of the impacted district, is in charge of both an integrated, comprehensive emergency response organization and the emergency incident site and is backed by an Emergency Operations Center staff with resources, informational, and advice.
IDLH	Immediately Dangerous to Life or Health
LEPC	Local Emergency Planning Committee
LEL	Lower explosive limit or lower flammable limit (LFL). By percentage, The lowest concentration of a substance in air, which will ignite.
LFL	See LEL.
MSDS	Material Safety Data Sheet
NACE	National Association of Corrosion Engineers
NCRIC	National Chemical Response and Information Center
NFPA	National Fire Protection Association
NGPSA	Natural Gas Pipeline Safety Act of 1968
NIOSH	National Institute of Occupational Safety and Health
NRC	National Response Center.
NRT	National Response Team
OES	Governor's Office of Emergency Services
OPS	Office of Pipeline Safety
OSHA	Occupational Safety & Health Administration (federal).

Glossary of Terms and Acronyms (cont.)

PPb	Parts per billion
Ppm	Parts per million
SARA	Superfund Amendments and Reauthorization Act of 1986
SERC	State Emergency Response Commission
SMYS	Specified Minimum Yield Strength
SPCC	Spill prevention, control, and countermeasures plan (from CWA).
STEL	Short Term Exposure Limit
TLV	Threshold Limit Value
TPQ	Threshold planning quality (from EPCRA). A quantity designated for Each chemical on the list of extremely hazardous substances that triggers Notification by facilities to the State Emergency Response Commission that such facilities are subject to emergency planning requirements under SARA Title III.
TSI	Transportation Safety Institute
TWA	Time-Weighted Average
UEL	Upper explosive limit or upper flammable limit (UFL). The maximum Percentage of substance in air which will ignite. (See also LEL).
UFC	Uniform Fire Code.
UFL	Upper Flammable Limit
ULCC	Utility Location and Coordination Council
USCG	U.S. Coast Guard
U.S. EPA	United States Environmental Protection Agency.

Attachment 6

Central Valley Gas Storage Integrity Management Plan

Central Valley Gas Storage

*An **AGL Resources** Company*

Integrity Management Plan

June 2013 version

CVGS Integrity Management Plan
Natural Gas Pipelines

Ref: 49 CFR 192.901-951 (subpart O)	Updated: July 2011

Summary Contents

CVGS
Gas Integrity Management Plan
Record of Revisions

Ref: 49 CFR 192.901- 951	Updated: June 2013

Gas IMP Record of Revisions: July 2012
Updated Element #1 , Section 1.2, Element #2, Section 2.2, Element #3, Section 3.2, Element #5 , Section 5.2, Element #6, Section 6.3, Element #8, Section 8.2, Element #9, Section 9.2, Element #10, Section 10.2, Element #11, Section 11.2, Element #12, Section 12.2, Element #13, Section 13.2, and Element #14, Section 14.2 to identify the Scope for CVGS to read: The following pipeline systems and segments are covered by the CVGS gas IM program: • None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence areas.
Gas IMP Record of Revisions: December 2012
Updated Element #1, Section 1.4 to add the following language to the "Requirement if there are no HCAs": ...As part of this evaluation, CVGS will determine if installation of additional sectionalizing block valves would be prudent to enhance the safety of the public in light of any such changes along the pipeline route.
Gas IMP Record of Revisions: June 2013
Updated Element #1, Section 1.5 to remove the language 'not to exceed 18 months' from once per calendar year requirements with regard to newly identified HCAs.

Integrity Management Plan
Natural Gas Pipelines
Scope and Summary of IMP Regulations

Ref: 49 CFR 192.901-951	Updated: Sept 2007

Objective

The objective of the gas integrity management rule is to improve pipeline safety through:

- accelerating the integrity assessment of pipelines in High Consequence Areas,
- improving integrity management systems within companies,
- improving the government's role in reviewing the adequacy of integrity programs and plans, and
- providing increased public assurance in pipeline safety.

Applicability

The rule applies to gas transmission operators jurisdictional to 49 CFR Part 192. This rule becomes effective February 14, 2004.

In determining if an intrastate pipeline meets the definition of a transmission line set out in Part 192.3, an operator must consider the factors listed in 192.3(a)-(c) of the pipeline safety regulations. For a pipeline to be designated as distribution, the operator must document the reason(s) the pipeline does not meet one of the factors listed in 192.3(a)-(c). The terms "storage facility" and "distribution center" are not defined in the pipeline safety regulations. Therefore, for states participating in the Natural Gas Pipeline Safety Program, the OPS will recognize the individual state determination of these terms when designating a pipeline as a distribution or transmission pipeline. It is incumbent upon the operator to appropriately designate each of the pipelines in their system and document the basis for the determination.

Key Features

- Provides enhanced protection for defined High Consequence Areas. Operators may identify High Consequence Areas using either of two methods:

    - Method 1: A pipeline segment is located in a high consequence area if any of the following apply:
        - A Class 3 location under 192.5, or
        - A Class 4 location under 192.5, or
        - 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; or
        - Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

- Method 2: A pipeline segment is located in a high consequence area if any of the following apply:
  - The area within a potential impact circle contains 20 or more buildings intended for human occupancy, or
  - The area within a potential impact circle contains an identified site.
  - The terms "potential impact radius," "potential impact circle," and "identified site" are defined in the rule.
  - When using potential impact circles, the length of the high consequence area extends axially along both directions of the pipe to the edge of the potential impact circles that define the boundaries of the high consequence area (i.e., the boundary of the high consequence area is defined by the circumference of the potential impact circle, not its center point).
- When identifying high consequence areas based on building counts within a potential impact circle that is greater than 660 feet (200 meters) in radius, the operator may elect to prorate the building count criteria and use building counts within a circle of 660 ft radius. An exact formula for this exception is provided in the rule. An operator may elect to use this exception only until December 17, 2006, after which time building counts must be completed for the entire potential impact circle area.

- Identified Site means each of the following areas:
  - An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
  - A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
  - A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.
- Operators must determine which sites are identified sites as follows:
  - An operator must identify an identified site from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials. Fire Marshall's and local emergency response officials, such as Fire Chiefs, are also considered

to be local officials from which an operator may obtain information that identifies an identified site.
- o However, if a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites. (i) Visible marking (e.g., a sign); or (ii) The site is licensed or registered by a Federal, State, or local government agency; or (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

- Gas transmission pipeline operators must develop a written Integrity Management Plan that includes:
  - Identification of all covered segments
  - A Baseline Assessment Plan to assure the integrity of all covered segments
  - A Framework that contains all required elements of the Integrity Management Program
  - A process to assure continual improvement to the program
  - Provisions to implement industry standards invoked by reference
  - A process to document (and notify OPS as required) any changes to its program.

- A gas transmission pipeline operator's Integrity Management Program must include all of the following program elements:
  - Identification of all high consequence areas
  - Baseline Assessment Plan
  - Identification of threats to each covered segment, including by the use of data integration and risk assessment
  - A direct assessment plan, if applicable
  - Provisions for remediating conditions found during integrity assessments
  - A process for continual evaluation and assessment
  - A confirmatory direct assessment plan, if applicable
  - A process to identify and implement additional preventive and mitigative measures
  - A performance plan including the use of specific performance measures
  - Recordkeeping provisions
  - Management of Change process
  - Quality Assurance process
  - Communication Plan
  - Procedures for providing to regulatory agencies copies of the risk analysis or integrity management program
  - Procedures to ensure that integrity assessments are conducted to minimize environmental and safety risks
  - A process to identify and assess newly identified high consequence areas

- Operators may deviate from certain time frame requirements related to reassessment intervals and certain time frame requirements related to remediation, if it demonstrates exceptional performance of its integrity management program, by meeting or exceeding the performance-based requirements of ASME B31.8S.
- An operator's integrity management program must document minimum qualification requirements for the following:
  - Supervisory personnel
  - Persons that carry out integrity assessments and evaluate assessment results
  - Persons responsible for additional preventive and mitigative actions
- An operator must identify and evaluate all potential threats to the covered segment. The operator must collect and integrate data from the entire pipeline that could be relevant to the covered segment and conduct a risk assessment in accordance with ASME/ANSI B31.8S.
- If an operator identified any of the following threats, it must take specific actions to address the threats:
  - Third Party Damage – Operators must use data integration from the assessment of other threats to identify potential third party damage and take additional preventive and mitigative action
  - Cyclic Fatigue – Operators must use cyclic fatigue analysis to prioritize baseline assessments and reassessments
  - Manufacturing and Construction Defects – Operators must prioritize a segment containing manufacturing or construction defects as a high risk segments unless it shows by analysis that the defect is stable and that the risk of failure is low
  - ERW Pipe – Covered segments containing low frequency electric resistance welded pipe or lap welded pipe must be prioritized as a high risk segment for the baseline assessment or reassessment, and assessed using technologies proven to be capable of assessing seam integrity and of detecting seam corrosion anomalies.
  - Corrosion – If corrosion is identified, all similar pipeline segments (both covered and non-covered) with similar coating and environmental characteristics must be evaluated and remediated, as necessary.
- The Baseline Assessment Plan must:
  - Identify potential threats to each covered segment
  - Identify methods to assess integrity based on the threats identified for each covered segment (acceptable methods include internal inspection, pressure testing, direct assessment, or other technology that the operator demonstrates provides an equivalent level of understanding of line integrity)
  - Identify a schedule for completing the assessments including the risk factors used in determining schedule priorities
  - If applicable, include a direct assessment plan, appropriate for the threats identified for the covered segments
  - Include a procedure for ensuring that the baseline assessments are conducted in a manner that minimizes environmental and safety risks

- Operators must complete the baseline assessment of 50% of its covered segments, beginning with the highest risk segments, by December 17, 2007 and 100% of its covered segments by December 17, 2012.
- An operator may use assessments completed before December 17, 2002 as a baseline assessment if the prior assessment meets the requirements of Subpart O and anomalies have been remediated in accordance with Subpart O. In this case, however, a reassessment must be completed by December 17, 2009.
- Direct assessment may be used for the following threats:
  - External Corrosion (Must comply with NACE RP0502-2002)
  - Internal Corrosion (Must comply with ASME/ANSI B31.8S)
  - Stress Corrosion Cracking (Must comply with ASME/ANSI B31.8S)
- The rule requires that certain defects be remediated within prescribed time limits. For Immediate Conditions, a pressure reduction must be implemented until the condition is repaired.
  - Immediate Conditions:
    - Remaining strength is less than or equal to 1.1 x MAOP
    - A dent with any indication of metal loss, cracking, or a stress riser
    - An anomaly judged to require immediate action
  - One Year Conditions:
    - Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 8:00 and 4:00 (upper 2/3 of pipe)
    - Dent > 2% (>0.25" for pipe diameter less than NPS 12) that affects curvature at a girth weld or a longitudinal seam weld
  - Monitored Conditions (Remediation not required):
    - Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 4:00 and 8:00 (lower third of pipe)
    - Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 8:00 and 4:00 (upper 2/3 of pipe) and engineering analysis demonstrates that critical strain levels are not exceeded
    - Dent > 2% (>0.25" for pipe diameter less than NPS 12) that affects curvature at a girth weld or a longitudinal seam weld and engineering analysis demonstrates that critical strain levels are not exceeded
- Operators must conduct risk assessments to identify additional preventive and mitigative measures to protect high consequence areas and enhance public safety. Such additional measure include, but are not limited to:
  - Installing Automatic Shut-Off Valves or Remote Control Valves
  - Installing computerized monitoring and leak detection systems
  - Replacing segments with heavier wall pipe
  - Additional training
  - Conducting drills with local emergency responders
  - Implementing additional inspection and maintenance programs
  - Enhancements to damage prevention programs
- An operator must perform a periodic evaluation based on data integration and risk assessment and implement a program to continually assess the integrity of its pipelines. Mandatory reassessment intervals are summarized in the following table:

Maximum Reassessment Interval			
Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low stress reassessment	not applicable	not applicable	7 years + ongoing actions specified in §192.941

(*) A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

- Waivers to the maximum reassessment intervals can be requested in two cases:
  - Unavailability of internal inspection tools
  - Inability to maintain product supply if the assessment is performed within the required interval
- An operator's integrity management program must include methods to measure the effectiveness of its program. As a minimum, it must include the performance measures specified in ASME/ANSI B31.8S, and submit its performance measures to OPS semi-annually.
- A written integrity management program and records that demonstrate compliance with Subpart O must be maintained for the life of the pipeline and will be reviewed by OPS and/or State regulators during inspections.

Integrity Management Plan
Natural Gas Pipelines
Glossary of Terms

Ref: 49 CFR 192.901-951	Updated: Sept 2007

B31 G (published by ASME): a semi-empirical analytic method used to estimate acceptability of corroded line pipe for continued service.

Bell hole: an excavation that minimizes surface disturbance yet provides sufficient room for examination or repair of buried facilities.

Cathodic Protection (CP): a technique by which underground metallic pipe is protected against deterioration (rusting and pitting).

Close Interval Survey (CIS): an inspection techniques that includes a series of above ground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e., 2,100 ft) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

Composite repair sleeve: a permanent repair method using composite sleeve material, which is applied with an adhesive.

Consequence: the impact that a pipeline failure could have on the public, employees, property and the environment.

Defect: an imperfection of a type and magnitude exceeding acceptable criteria.

Direct Current Voltage Gradient (DCVG): an inspection techniques that includes above ground electrical measurements taken at predetermined increments along the pipeline and used to provide information on the effectiveness of the coating system.

Double Submerged-Arc Welded pipe (DSAW pipe): pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc welded process.

Electric Resistance Welded pipe (ERW Pipe): pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of pressure and heat obtained from electrical resistance. ERW pipe forming is distinct from flash welded pipe and furnace butt-welded pipe as a result of being produced in a continuous forming process from coils of flat plate.

Evaluation: the analysis and determination of the facilities fitness for service under the current operating conditions.

Examination: the direct physical inspection of the pipelines by a person and may also include the use of nondestructive examination techniques (NDE).

Failure: a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.

Fracture toughness: the resistance of a material to failure from the extension of a crack.

Gas: as used in this Code, any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air.

Geographical Information System (GIS): a system of computer software, hardware, data, and personnel to help manipulate, analyze, and present information that is tied to a geographic location.

Global Positioning System (GPS): a system used to identify the latitude and longitude of locations using GPS satellites.

Hydrogen Induced Cracking (HIC): a form of hydrogen induced damage consisting of cracking of the metal.

Hydrogen-induced damage: a form of degradation of metals caused by exposure to environments (liquid or gas) that cause absorption of hydrogen into the material. Examples of hydrogen induced damage are: formation of internal cracks, blisters, or voids in steels; embrittlement (i.e., loss of ductility); and high temperature hydrogen attack (i.e., surface decarbonization and chemical reaction with hydrogen).

In-line Inspection (ILI): a pipeline inspection technique that uses devices known in the industry as "smart pigs." These devices run inside the pipe and provide indications of metal loss, deformation and other defects. Incident is an unintentional release of gas due to the failure of a pipeline.

Incident: an unintentional release of gas due to the failure of a pipeline.

Indication: a finding of a nondestructive testing technique. It may or may not be a defect.

Inspection: the use of a nondestructive testing technique.

Integrity assessment: a process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, and characterizing the evaluation by defect type and severity and determining the resulting integrity of the pipeline through analysis.

Leak: an unintentional Escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and non-propagating, longitudinal, and circumferential), separation or pull-out, and loose connections.

Location class: an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Class location units are categorized as Class 1 through 4. Class 1 locations are more rural, and Class 4 locations are more urban.

Magnetic Flux Leakage (MFL): a type of in-line inspection technique that induces a magnetic field in a pipe wall between two poles of a magnet. Sensors record changes in the magnetic flux (flow) that can be used to evaluate metal loss.

Management of change (MOC): a process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural or organizational nature that can impact system integrity.

Maximum Allowable Operating Pressure (MAOP): the maximum pressure at which a gas system may be operated in accordance with the provisions of ASME B31.8 Code.

Mechanical damage: a type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, and residual stresses, any one of which can be detrimental.

Microbiologically Influenced Corrosion (MIC): corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

Mitigation: the limitation or reduction of the probability of occurrence or expected consequence for a particular event.

Nondestructive Examination (NDE): an inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic, and dye penetrant methods.

Operator: the entity that operates and maintains the pipeline facilities and has fiduciary responsibility for such pipeline facilities.

Performance-based integrity management program: an integrity management process that utilizes risk management principles and risk assessments to determine prevention, detection, and mitigation actions and their timing.

Pig: a device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.

Piggability: the ability of a pipeline or segment to be inspected by an ILI device.

Pipe grade: a portion of the material specification for pipe, which includes specified minimum yield strength.

Pipeline: all parts of physical facilities through which gas moves in transportation, including: pipe, valves, fittings, flanges (including bolting and gaskets), regulators, pressure vessels, pulsation dampeners, relief valves, and other appurtenances attached to pipe; compressor units; metering stations; regulator stations; and fabricated assemblies. Included within this definition are gas transmission and gathering lines, transporting gas from production facilities to onshore locations and gas storage equipment of the closed pipe type, which is fabricated or forged from pipe or fabricated from pipe and fittings.

Prescriptive integrity management program: an integrity management process that follows preset conditions that result in fixed inspection and mitigation activities and timelines.

Pressure test: a measure of the strength of a piece of equipment (pipe) in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.

Probability: the likelihood of an incident occurring. Rich gas a gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane.

Rich gas: a gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane.

Right of Way (ROW): a strip of land on which pipelines, railroads, power lines, and other similar facilities are constructed. It secures the right to pass over property owned by others and ROW agreements only allow the right of ingress and egress for the operation and maintenance of the facility. The width of the ROW can vary and is usually determined based on negotiation with the affected landowner or by legal action.

Risk: a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

Risk assessment: A systematic process, in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and be performed at varying level of detail depending on the operator's objectives (see section 5).

Risk management: an overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

Root cause analysis: a family of processes implemented to determine the primary cause of an event. These processes all seek to examine cause-and effect relationship through the organization and analysis of data. Such processes are often used in failure analyses. Rupture a complete failure of any portion of the pipeline.

Rupture: a complete failure of any portion of the pipeline.

SCADA system: a supervisory control and data acquisition system.

Stress corrosion cracking (SCC): a form of environmental attack of the metal involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks.

Smart pig: the industry term for a type of ILI device.

Specified Minimum Yield Strength (SMYS): expressed in pounds per square inch, the minimum yield strength of the steel in pipe as required by the pipe product specifications.

Segment: a length of pipeline or part of the system that has unique characteristics in a specific geographic location.

Stress concentrator: a discontinuity in a structure or change in contour that causes a local increase in stress.

Subject matter experts (SME): individuals that have expertise in a specific area of operation or engineering.

System: refers to either the operator's entire pipeline infrastructure or large portions of that infrastructure that has definable starting and stopping points.

Third-party damage: damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this document it also includes damage caused by the operator's personnel or the operator's contractors.

Transmission system: one or more segments of pipeline usually interconnected to form a network, which transports gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high-or low-pressure distribution system, a large-volume customer, or another storage field.

Transportation of gas: gathering, transmission, or distribution of gas by pipeline or the storage of gas.

Ultrasonic: high frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

Wrinkle bend: a pipe bend produced by field machine or controlled process that may result in abrupt contour discontinuities on the inner radius.

CVGS
Gas Integrity Management Plan
Element #1: ID of Pipeline Segments Impacting HCAs

Ref: 49 CFR 192.901- 915	**Updated: July 2012**

In This Element:

1.1 Objectives and Purpose of ID of HCA [192.901-915]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these ID of HCA procedures to assist in this effort.

1.2 Scope, Applicability, and Use of PHMSA FAQs [192.901]

<u>Scope for CVGS</u>

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence areas.

Applicability

The rule applies to gas transmission operators jurisdictional to 49 CFR Part 192. This rule became effective February 14, 2004. For gas transmission pipeline constructed of plastic, only the requirements of 192.917, 192.921, 192.935, and 192.937 apply.

The terms "storage facility" and "distribution center" are not defined in the pipeline safety regulations. Therefore, for states participating in the Natural Gas Pipeline Safety Program, OPS will recognize the individual state determination of these terms when designating a pipeline as a distribution or transmission pipeline. CVGS will appropriately designate each of the pipelines in their system and document the basis for the determination. Use gas O&M procedure #4.02 and form or equivalent to document this jurisdictional determination. [Element #1: Record #1]

Note, gas gathering lines are exempt from this gas IMP regulation. [Federal Register Notice, Volume #69, No. 66, 18228, April 6, 2004, FAQ #9 & #188]

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for HCA identification of HCAs are shown in appendix 1A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

1.3 Definitions Applicable to ID of HCAs [192.903]

"Covered Segment" as defined in the rule means a continuous segment of pipeline located in an HCA. If the potential impact circle methodology is used to identify HCAs, then, at a minimum, the covered segment begins at the outermost edge of the first potential impact circle that meets the HCA criteria and extends axially to the outermost edge of the last contiguous potential impact circle that meets the HCA criteria. This length of pipe may be subdivided to facilitate integrity assessments. Examples include such divisions as pressure limiting stations, pipe size changes or other practical divisions.

High Consequence Area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as-
  (i) A Class 3 location under 192.5; or
  (ii) A Class 4 location under 192.5; or
  (iii) 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; or
  (iv) The area within a potential impact circle containing an identified site.

(2) The area within a potential impact circle containing
  (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (d) applies; or
  (ii) An identified site.

Where potential impact is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See PHMSA Figure E.IA. at the end of this element.)

If in identifying a high consequence area under paragraph (1) (iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to [20x (660 feet [or meters]/potential impact radius in feet [or meters]) ^{2}].

Identified Site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (T he days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or

(b) A building that is occupied by twenty or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) - month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

<u>Potential Impact Circle</u> is a circle of radius equal to the potential impact radius (PIR).

<u>Potential Impact Radius (PIR)</u> means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

PIR is determined by the formula
r= 0.69 (square root of ($p*d^2$),
where "r" is the radius of a circular area in feet surrounding the point of failure,
"p" is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch,
and "d" is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S-2004 (supplement to ASME B31.8; ibr, see 192.7) to calculate the impact radius formula.

1.4 Process for ID of HCAs [192.905]

CVGS will identify high consequence areas (HCAs) using method #1 or method #2 by December 17, 2004. Methods # 1 and #2 are described in detail above in section 1.2, definitions.

The following sections and steps for section #1.4 are discussed in more detail below:

General Requirements
Step #1: Use Laser Range Finder and/or Maps for Determination of HCAs
Step #2: Identified Site Surveys from Public and Emergency Officials
Step #3: Identified Site Surveys from Routine O&M Activities
PHMSA FAQS Used as Procedures for Clarifying Process of ID of HCAs

General Requirements:

To determine which segments of CVGS's transmission pipeline system are covered by this subpart, CVGS will identify the high consequence areas and document this review. CVGS will use method (1) or (2) from the definition in 192.903 to identify high consequence areas. CVGS may apply one method to its entire pipeline system or CVGS may apply one method to individual portions of the pipeline system. CVGS may also choose to include sections of class 1 or class 2 pipelines into the IM program.

CVGS has described in its integrity management program documentation ***which method it is applying to each portion of the CVGS's pipeline system.*** The description will include the potential impact radius when utilized to establish a high consequence area. In cases where potential impact circles are used to identify high consequence areas, the review will include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain either an identified site or 20 or more buildings intended for human occupancy. For example, see PHMSA figure E1A at the end of this IMP element. CVGS gas IMP List of HCAs with PIR calculation Excel worksheet will be used to document the list of HCAs and appropriate information.
[Element #1: Record #2]

Also, CVGS's integrity management program will include system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas. Specifically, the two methods that will be used are a laser range finder and/or aerial photography maps as described below.

Step #1: Use Laser Range Finder and/or Maps for Determination of HCAs

- A laser range finder will be used by standing directly over the pipeline and pointing the laser range finder at the closest portion of the potential identified site. T he findings shall be recorded on one of the more of the following forms:

  - ☐ #1-1A (HCA Identification Survey Method #1) [Element #1: Record #3] , or
  - ☐ #1-1B (HCA Identification Survey Method #2) [Element #1: Record #4], or
  - ☐ #1-1C (HCA Identified Site Survey) [Element #1: Record #5], or
  - ☐ #1-1D (Change in Operation Affecting HCA) [Element #1: Record #6],

  Also, the error factor shall be documented on these forms and supported by manufacturer's technical documentation. When manufacturer's technical documentation can not be obtained, a minimum of ten feet will be used for laser range finder error factor. [Element #1: Record #7]

- Aerial photography [Element #1: Record #8] with over lay of the pipeline may also be used to support or further define HCAs. Location of the pipeline shall be within ten feet of actual location as defined by as-built drawing alignment sheets [Element #1: Record #9] and/or with GPS points using sub-meter Trimble GPS instrument or equivalent. A ten foot buffer will be added to aerial photography overlay to account for potential minimum errors in alignment sheets and/or collection of GPS data points.

  Include the manufacturer's technical documentation on accuracy for the GPS unit as part of the IMP records. [Element #1: Record #10]

Step #2: Identified Site Surveys from Public and Emergency Officials

CVGS will make a reasonable effort to review and evaluate sites meeting the criteria for "identified sites." CVGS will attempt to contact officials with safety, emergency response or planning responsibilities to assist in locating identified sites using one or more of the following methods:

1) Use of Pipeline Association for Public Awareness (PAPA) [Element #1: Record #11] , or

2) By CVGS sending a letter to the public and emergency officials requesting information on identified sites[Element #1: Record #12] , or
3) Conduct face to face meetings when appropriate. For example, these public officials could include officials on a local emergency planning commission or relevant Native American tribal officials. Use form #1-1C (HCA Identified Site Survey) or equivalent to document this review. [Element #1: Record #13]

Also, if a public official with safety or emergency response or planning responsibilities informs CVGS that it does not have the information to identify an identified site, CVGS will use one or more of the following sources, as appropriate, to identify these sites. Use form #1-1C (HCA Identified Site Survey) or equivalent to document this review.

- Visible marking (e.g., a sign); or
- The site is licensed or registered by a Federal, State, or local government agency; or

The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

Step #3: Identified Site Surveys from Routine O&M Activities

As another option to the identified site survey, CVGS will use information from routine operation and maintenance activities as listed in section #1.5 (annual review for new HCA segments). Use form #1-1C (HCA Identified Site Survey) or equivalent to document this review. [Element #1: Record #14]

PHMSA FAQS Used as Procedures for Clarifying Process of ID of HCAs

How CVGS Operating Employees Will be Considered in HCA Analysis

CVGS will count operating employees when identifying HCAs. The rule is intended to provide enhanced protection for gatherings of people, and gatherings of operator employees are expected to gain the same enhanced protection. Areas, including buildings and facilities, where operator employees gather in sufficient numbers and on a sufficient number of days to meet criteria in the definition of HCAs will be so classified. [FAQ #121]

How Standing Traffic Will be Considered in HCA Analysis:

Identified sites are defined as areas that are "occupied" by more than 20 persons for specified periods. While roads and expressways near pipelines could well carry enough traffic that more than 20 persons are in proximity to the pipeline at one time, these travelers can not be said to "occupy" that location. The definition of identified sites is intended to provide additional protection for areas where people stay for more than a few seconds or minutes. Most roads and expressways need not be considered as potential "outside areas" that could qualify as identified sites. Additionally, the preamble recognized that added protection was provided to pipelines near highways with design characteristics commensurate with the pipeline safety regulations. [FAQ #143]

However, for CVGS pipelines that are not designed commensurate with the pipeline safety regulations and are located in areas that are regularly congested, such that traffic stands for many minutes within a potential impact circle, CVGS will make a determination to include or exclude these pipelines as "identified sites" on their own merits based on the integrated information they have about their pipelines at these locations. OPS expects that such areas will usually occur within developed areas where the pipeline would already be defined as a high consequence area, and that HCAs identified solely due to the proximity of traffic choke points will be rare.

How Parking Lots Will be Considered in HCA Analysis:

Where parking lots are used for other purposes (e.g., an antique car club that meets on weekends, regular social gatherings), these uses will be considered on their own merits. Identified sites are defined as areas that are occupied by more than 20 persons for specified periods. While it is possible that sufficient people might be in a parking lot near a pipeline resulting in more than 20 persons in proximity to the pipeline at one time, these persons are considered to be in transit and cannot truly be said to "occupy" the parking lot and therefore are not subject to the regulation. [FAQ #145]

How Commercial and Industrial Buildings Will be Considered in HCA Analysis:

Each commercial and industrial building that is occupied will be considered when determining HCAs. If 20 or more persons occupy a building, it may qualify as an identified site. In buildings with multiple offices/businesses, CVGS may assume that 20 or more people "occupy" the building 5 days/week and at least 10 weeks/year or they may count the occupants. Commercial buildings that CVGS concludes are not occupied by 20 or more people will be considered in counting the number of "buildings" intended for human occupancy. Each structure/office/unit that is occupied in such a building shall be counted in the analysis of 20 or more buildings within the impact circle. [FAQ #146]

How Portions of a Building Within PIR Will be Considered in HCA Analysis:

The potential impact radius is an approximation of the extent of immediate damage from a pipeline incident. Damage may extend slightly beyond that radius in some instances. Additionally, structures extending into the radius would very likely burn, and those fires will not be limited to the portion of the structure within the radius. The rule requires that a building containing 20 people for the time periods specified in the rule must be treated as an identified site if any portion of it is within the potential impact radius. [FAQ #162]

How Homes With Disabled Individuals Will be Considered in HCA Analysis:

A single home housing a disabled person will not be considered an identified site. The rule defines identified sites as including "a facility" occupied by persons who are confined, of impaired mobility or would be difficult to evacuate. The rule also provides that CVGS seek information about these facilities from public safety officials in order to provide a reasonable bound on the efforts that operators must expend to identify such sites. Generally, the focus should be on facilities that are licensed or registered as a care provider, and where multiple disabled individuals would be expected. [FAQ #176]

How Buildings With 20 or More People, but Not All at Once Will be Considered in HCA Analysis:

If a facility or site has 20 or more people visit throughout the day but never 20 or more at one time, this does not meet the identified site criteria. The definition of an identified site provides for buildings/locations that are "occupied by twenty (20) or more persons". A location that 20 or more people passed through in a day would not be "occupied" by 20 or more persons. Twenty or more persons must be present at one time for the building/outside area/open structure to be defined as an identified site. [FAQ #182]

Requirements If There are No HCAs:

CVGS is not required to develop an integrity management program if there are no high consequence areas on its system. But, CVGS must complete an evaluation to determine that no high consequence areas exist, and this evaluation must be maintained and available for inspection. Even if no HCAs exist, however, there are some requirements in Subpart O with which CVGS must comply. These requirements include the following:

1) Once per calendar year not to exceed 18 months, CVGS will evaluate its pipeline to determine if new HCAs have been created. Changes along the pipeline route, including housing construction and creation of new facilities meeting criteria in the definition of identified sites could cause HCAs to come into existence. CVGS will demonstrate that it has periodically evaluated its pipeline to assure that there continue to be no HCAs. As part of this evaluation, CVGS will determine if installation of additional sectionalizing block valves would be prudent to enhance the safety of the public in light of any such changes along the pipeline route.

2) For transmission pipelines operating below 30 percent of SMYS in class 3 or 4 locations but not in an HCA, enhanced protection against third-party damage will be implemented in accordance with 192.935(d).

3) CVGS will submit semi-annual "performance measure" reports in accordance with 192.945(a) indicating that there are no HCAs on its system.

If the periodic evaluation identifies that a new HCA exists, then CVGS will prepare an integrity management plan and meet all the requirements of subpart O. [FAQ #150]

How CVGS Will Address Idle and Out of Service Lines (Not Fully Abandoned):

In-service idle pipe (i.e., that contains gas, but is not presently being used to transport gas) represents a potential hazard to public health and the environment, even though idle. If such pipe leaks or ruptures, an explosion could result. Leaks may go undetected for some time, since idle pipe may not be covered by operator's SCADA systems. For these reasons, CVGS will meet all requirements and deadlines for pipe that contains gas.

Such pipe must be included when determining if the requirement to assess 50% of covered pipeline mileage by December 17, 2007, has been met.

Out-of-service pipe (i.e., pipe laid up with nitrogen) represents much less hazard. Degradation of such pipe can occur, but is not likely to result in safety impacts. OPS will accept deferral of activities required by the rule for out-of-service pipe. All deferred activities must be completed as part of any later return of that line to service. A baseline assessment needs not be run immediately if the deadline for completing baseline assessments (i.e., December 17, 2012) has not yet expired, unless the risk posed by the line would require an earlier assessment. The baseline assessment plan shall be modified to assure that a baseline assessment is completed by the appropriate deadline. If the deadline has expired, then a baseline assessment will be completed as part of returning the line to service. Adding an idle line into the IMP program would be considered a substantive program change and would require notification under 192.909(b). [FAQ #7]

<u>How CVGS Will Address Facilities:</u>

CVGS will consider pipeline facilities when establishing potential impact circles (the diameter of the pipe into/out of the equipment will be used), and if applicable, the facility will be included in the integrity management program processes for addressing these facilities. [FAQ #84]

1.5 Annual Review of Pipeline Segments for New HCAs or Change in HCAs

CVGS will conduct a review <u>once per calendar year not to exceed 18 months</u> for change in conditions along their pipelines. Pipeline throughput, changes in population and/or environment will be periodically reviewed. When CVGS becomes aware of changes that create or change an HCA (e.g., population expands to encompass more of the area near the pipeline right-of-way), this information will be factored into their integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls. Agenda format will be used to conduct this review. See section #1.7 below.

As a minimum, the factors listed below will be considered and analyzed for changes and impacts on pipeline segments potentially affecting HCAs.

- Changes in pipeline maximum allowable operating pressure (MAOP)

- Pipeline modifications affecting pipeline diameter
- Changes in the commodity transported
- Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites
- Change in the use of existing buildings (e.g., hotel or house converted to nursing home)
- Installation of a new pipeline
- Change in pipeline class location (e.g., class 2 to 3), change in class location boundary, or pipeline reroutes
- Corrections to erroneous pipeline center line data

Pipeline O&M procedures and completed reports and surveys that will be gathered and reviewed to collection the information for potential changes to HCAs, include the following:

1) Annual Reports, O&M 1.04 [Element #1: Record #15]
2) Onshore Gas Gathering Determination, O&M #4.02 [Element #1: Record #1]
3) Continuing Surveillance, O&M #5.01[Element #1: Record #16]
4) Pipeline Patrols, O&M #5.03 [Element #1: Record #17]
5) Maximum Allowable Operating Pressure (MAOP), O&M #8.01 [Element #1: Record #18]
6) Pipeline Uprating, O&M #12.01 [Element #1: Record #19]
7) Conversion of Service, O&M #12.02 [Element #1: Record #20]

Form 1-1D (Change in Operation Affecting HCA) or equivalent will be used to document this review.

A newly-identified HCA will be incorporated into the integrity management program <u>within one calendar year</u> of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within <u>ten years</u> of its identification.

How CVGS Will Handle Inherited Gas IMP Segments, Plans, and Deadlines:

The regulatory deadlines for assessments (e.g., that re-assessments be conducted within specified intervals, based on operating stress levels) continue to apply, as well as the schedule requirements for any remediation required by 192.933 that may be pending at the time ownership of the pipeline is transferred. Compliance deadlines established in 192 Subpart O for identifying segments in HCAs and for completing 50% or 100% of Baseline Assessments continues to apply. For purposes of integrity management, if CVGS inherits or purchases a new pipeline segment with HCAs, it will be integrated into the NPCA IM program within one calendar year. Integration of new assets into existing Baseline Assessment Plans may result in realigning schedules
for future assessments based on the relative risk of the acquired pipeline and the operator's existing pipeline(s). [FAQ #10]

Newly Identified Areas:

When CVGS has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in 192.903, CVGS will complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it will be incorporated into CVGS's baseline assessment plan as a high consequence area within one calendar year from the date the area is identified.

1.6 Notification to OPS for Changing HCA ID Method

If CVGS initially selects method 1 to identify HCAs and later changes to method 2 for the same portion of its system, this may constitute a change in IMP that needs to be communicated to OPS/state, if there is a substantial change. A change in the method for determining HCAs would not, by itself, be considered a substantial change requiring notification under 192.909(b). If the change results in a significant change in the amount of system mileage that is determined to be HCA (e.g., 25% change), a notification will be submitted. [FAQ #183] [Element #1: Record #21]

Also, integration of acquired pipe into CVGS's IM Program could constitute the kind of substantial change in the IMP for which notification is required under 192.909(b), if the integration caused significant changes to existing schedules and programs. [FAQ #10]

1.7 Review and Updates of IMP

CVGS will review and update the integrity management program and procedures once per calendar year not to exceed 18 months as described in element #6 (Continual Evaluation and Assessments) of this plan. When changes to the plan occur, CVGS will document any modifications to the plan and the reasons for the modification as shown in the gas IMP record of revisions or equivalent. [Element #1: Record #22]

1.8 Review and Implementation of Element #1

CVGS will use the agenda, "Gas IMP Element #1, ID of HCA Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #1 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #1: Record #23]

- ID of HCA Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the HCA review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #1 requirements are met
- Action item list as a result of the element #1 review [Element #1: Record #24]

1.9 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.901 – What do the regulations in this subpart cover?

4. 49 CFR 192.903 – What definitions apply to this subpart?

5. 49 CFR 192.905 – How does an operator identify a high consequence area?

6. OPS Gas Integrity Management, Protocols Area A, ID of HCAs, January 2008

7. OPS Advisor Bulletin, ADB-03-07, Guidance on When Baseline Integrity Assessment Begins, November 17, 2003

8. OPS Advisor Bulletin, ADB-03-03, Guidance on Reasonable Effort to Locate Identified Sites, July 17, 2003

10. OPS Frequently Asked Questions (FAQs), HCA Identification January 2007

11. OPS Frequently Asked Questions (FAQs), General & Rule Applicability January 2007

12. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #1 Introduction, section #2 Overview

13. Baker C-FER Technologies Report: PIR for Flammable Gases Other Than Natural Gas, June 2005

Ref: 49 CFR 192.901- 915	Updated: July 2011

1.10 List of Required Ongoing Documentation for Element #1

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	1.2	Jurisdictional determination	IMP Leader	AR	5 yrs	Co. intranet
2.	1.4	Gas IMP List of HCAs with PIR calculation	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	1.4	Form #1-1A (HCA Identification Survey Method #1)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	1.4	Form #1-1B (HCA Identification Survey Method #2)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	1.4	Form #1-1C (HCA Identified Site Survey)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	1.4	Form #1-1D (Change in Operation Affecting HCA)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	1.4	Laser range finder instrument manufacturer's technical info on accuracy	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
8.	1.4	Aerial photography or survey maps	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
9.	1.4	As-built drawing alignment sheets	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
10.	1.4	GPS instrument manufacturer's technical info on accuracy	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
11.	1.4	Public Officials/Em. Officials Identified Site Survey - PAPA	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
12.	1.4	Public Officials/Em. Officials Identified Site Survey - CVGS letter to public officials	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
13.	1.4	Public Officials/Em. Officials Identified Site Survey - face to face meeting	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
14.	1.4	Identified Site Survey from routine O&M activities	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
15.	1.5	Annual Reports, O&M #1.04	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
16.	1.5	Continuing Surveillance, O&M #5.01	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
17.	1.5	Pipeline Patrols, O&M #5.03	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Ref: 49 CFR 192.901- 915 **Updated: July 2011**

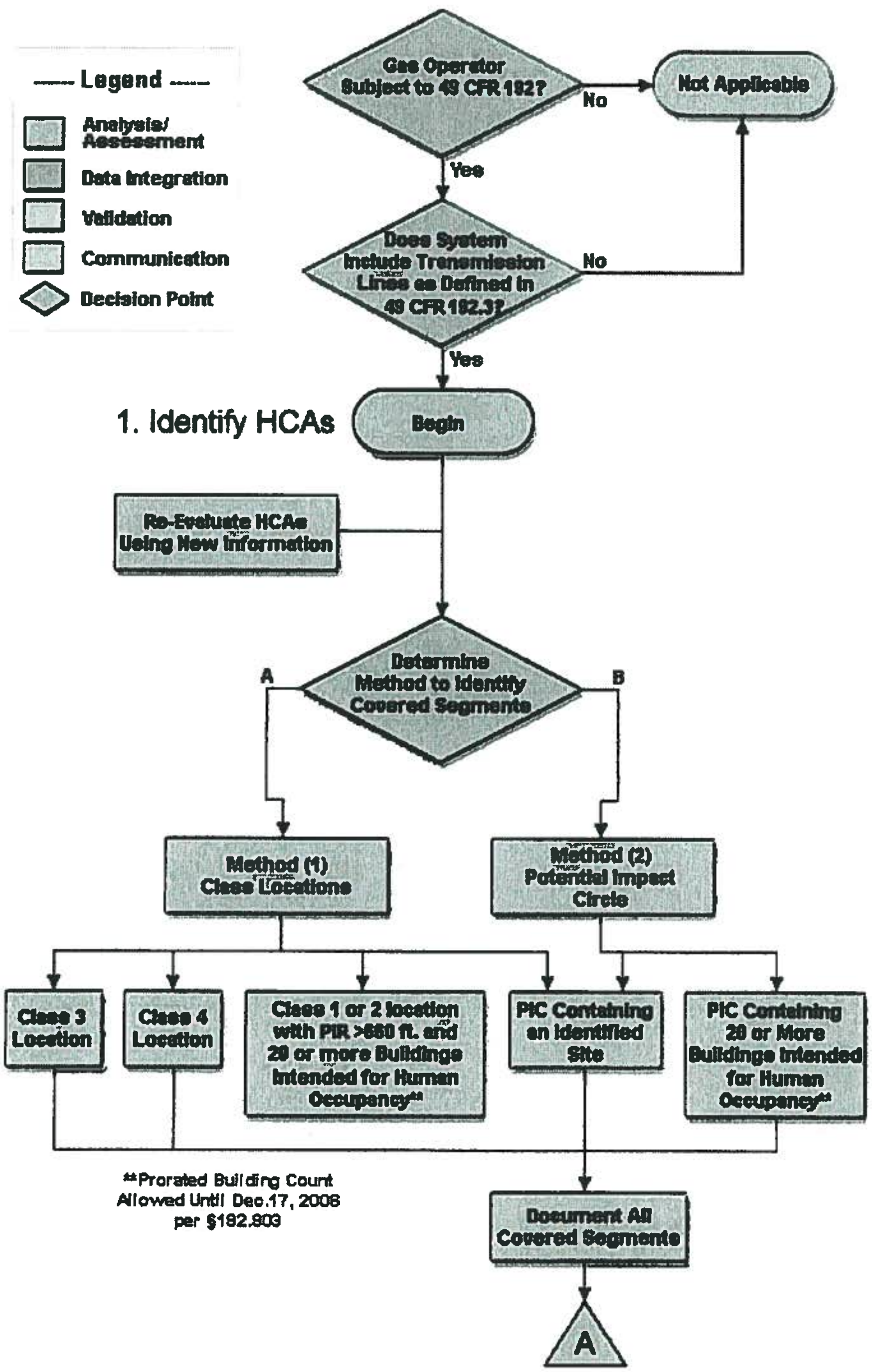
18.	1.5	Maximum Allowable Operating Pressure, O&M #8,01	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
19.	1.5	Pipeline Uprating, O&M #12.01	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
20.	1.5	Conversion of Service, O&M #12.02	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
21.	1.6	Notification to OPS for change in HCA method	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
22.	1.7	Gas IMP record of revisions	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
23.	1.8	Element #1 agenda	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
24.	1.8	Element #1 action items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

Integrity Management Plan
Natural Gas Pipelines
Gas IMP Flowchart

Ref: 49 CFR 192.919, 921-931, 945, 949	Updated: July 2007

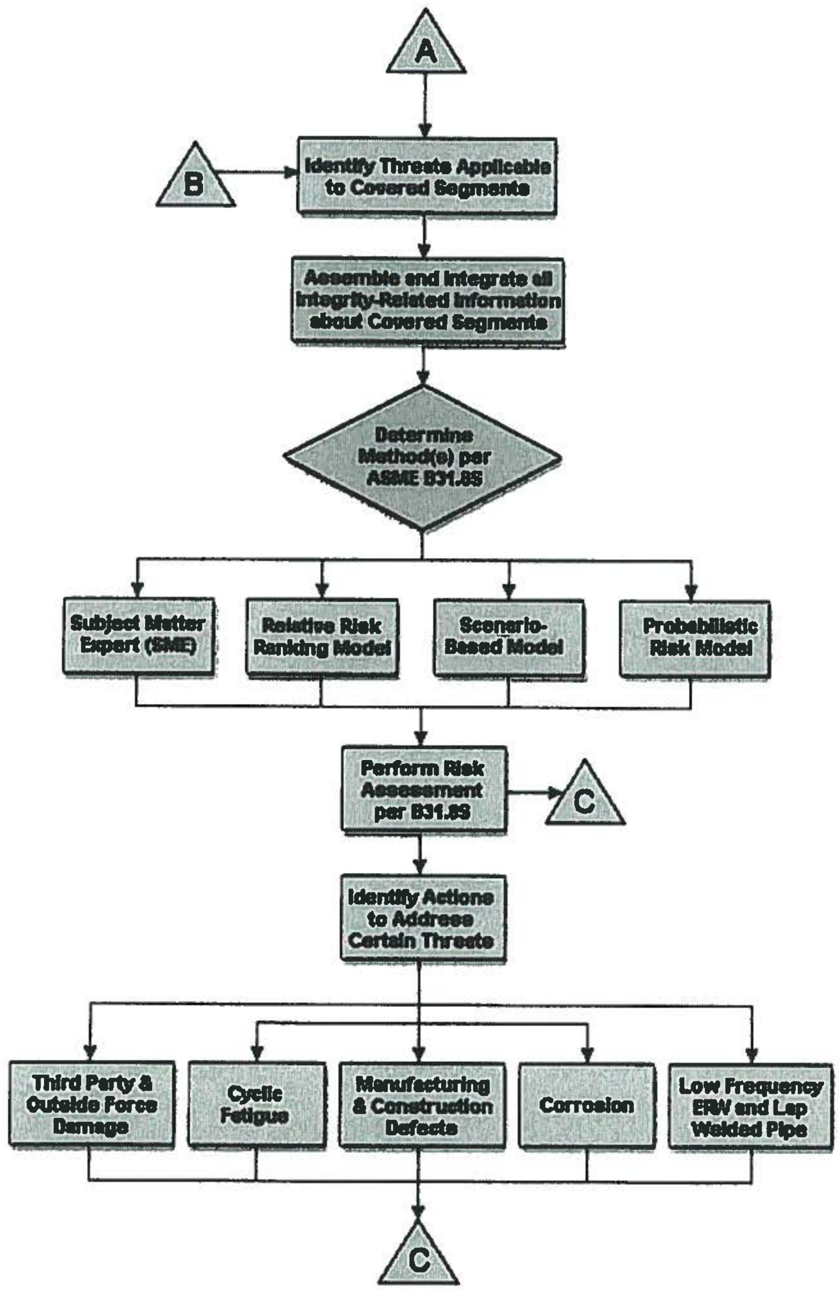
Determine Rule Applicability



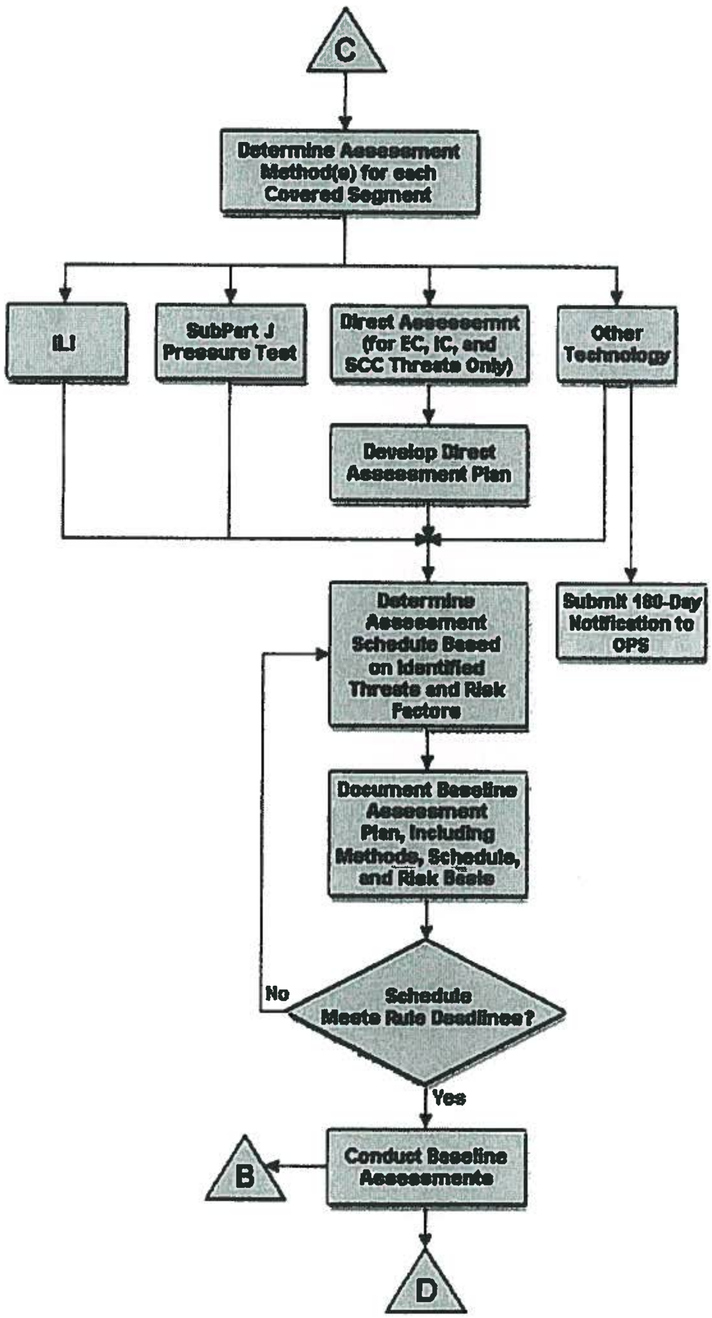
Integrity Management Plan
Natural Gas Pipelines
Gas IMP Flowchart

Ref: 49 CFR 192.919, 921-931, 945, 949	Updated: July 2007

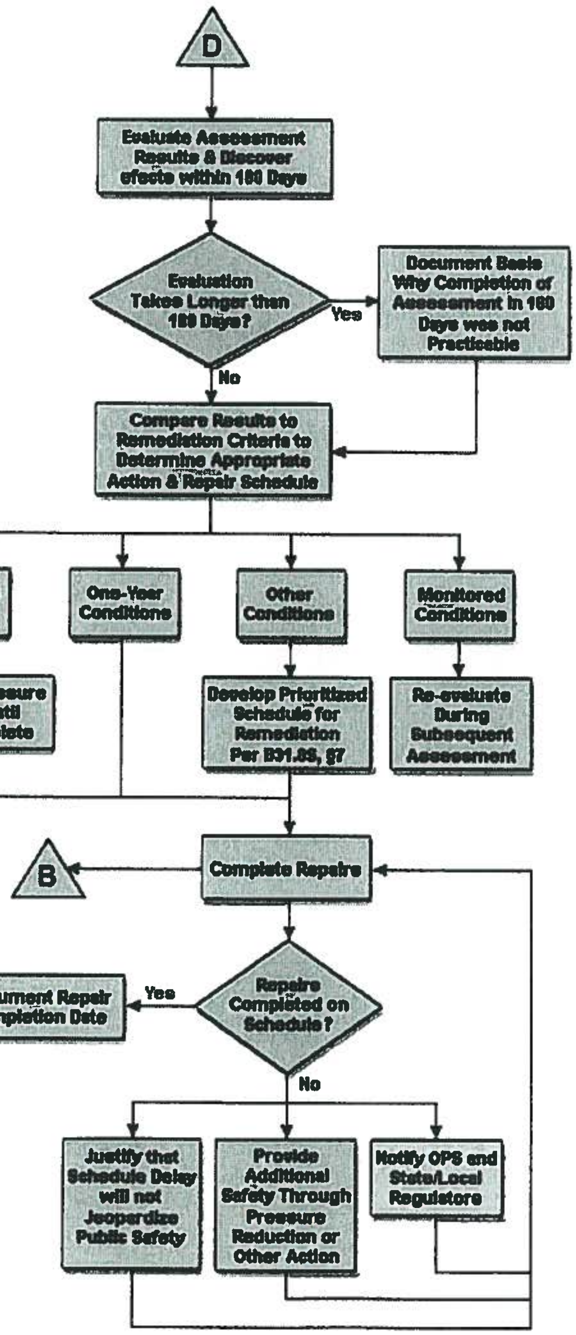
2. Threat Identification & Risk Assessment



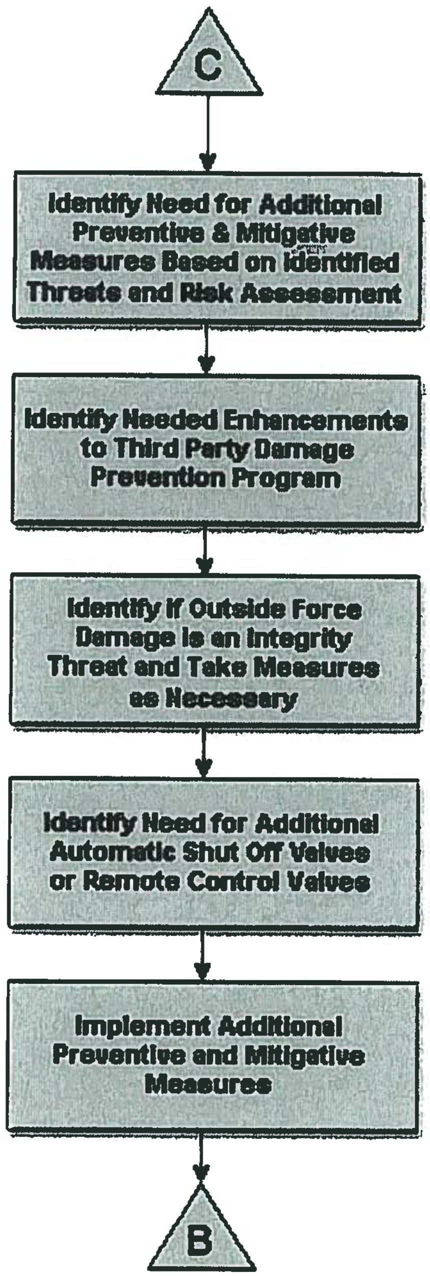
3. Baseline Assessment Plan



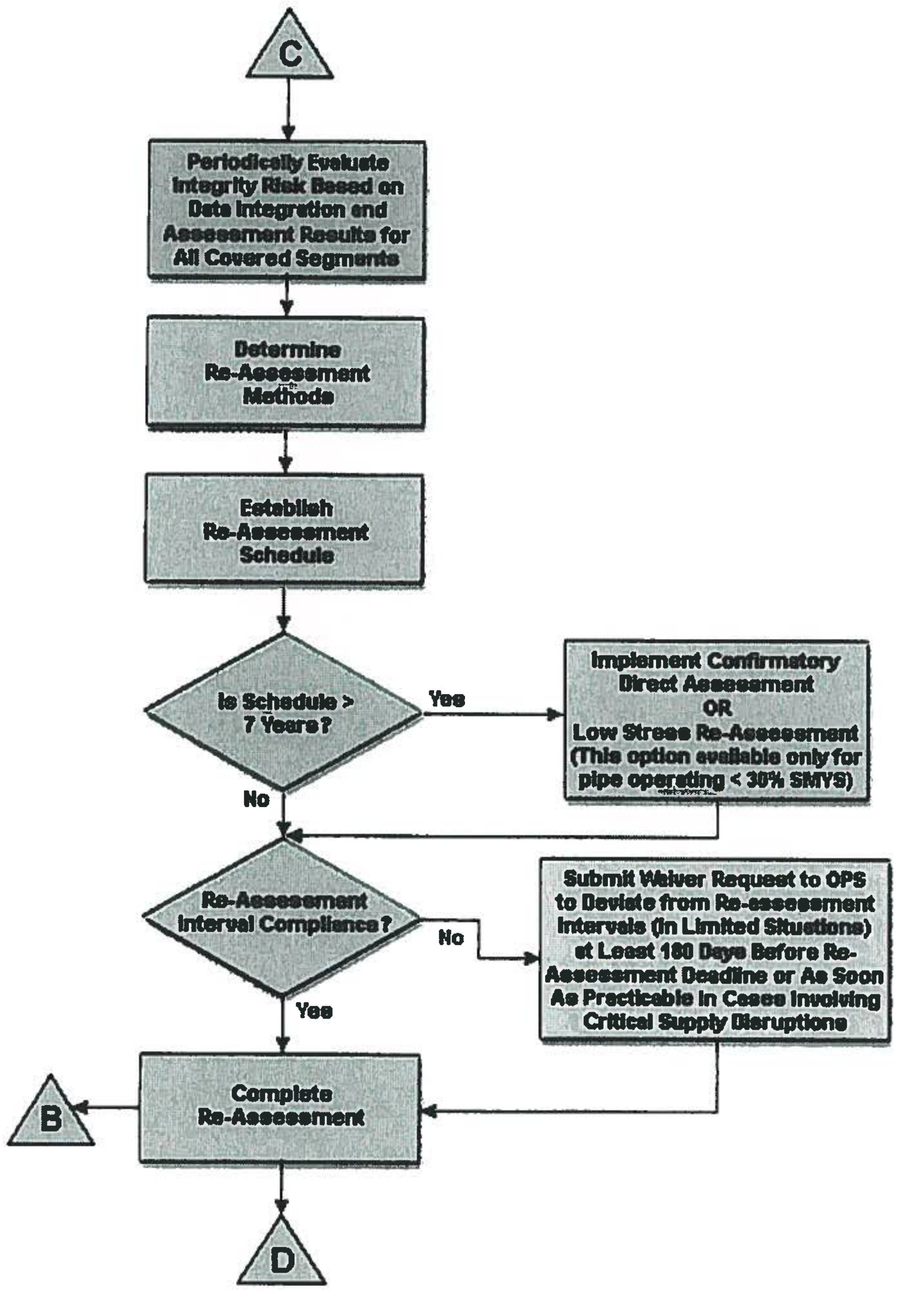
4. Remediation



5. Additional Preventive & Mitigative Measures



6. Continual Evaluation and Re-Assessment



CVGS
Gas Integrity Management Plan
Element #2: Threats, Data Integration, and Risk Analysis

Ref: 49 CFR 192.917	Updated: July 2012

Contents of this Element:

21 Objectives and Purpose of Threats, Data Integration, and Risk Analysis

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these threats, data integration, and risk analysis procedures to assist in this effort.

2.2 Scope, Applicability, and Use of PHMSA FAQs [192.917]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.

CVGS
Gas Integrity Management Plan
Element #2: Threats, Data Integration, and Risk Analysis

Ref: 49 CFR 192.917	Updated: July 2011

Applicability and Summary of Requirements

The rule applies to gas transmission operators jurisdictional to 49 CFR Part 192 that have high consequence areas (HCAs).

CVGS must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S-2004 (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories: [192.971(a)]

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

To identify and evaluate the potential threats to a covered pipeline segment, CVGS must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, CVGS must follow the requirements in ASME/ANSI B31.8S-2004, section 4. At a minimum, CVGS must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S-2004, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline. [192.971(b)]

CVGS must conduct a risk assessment that follows ASME/ANSI B31.8S-2004, section 5, and considers the identified threats for each covered segment. CVGS must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment. [192.971(c)]

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for threats, data integration, and risk analysis are shown in appendix 2A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

2.3 Definitions Applicable to Element #3

Failure is a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.

Hydrogen Induced Cracking (HIC) is a form of hydrogen induced damage consisting of cracking of the metal.

Hydrogen-Induced Damage is a form of degradation of metals caused by exposure to environments (liquid or gas) that cause absorption of hydrogen into the material. Examples of hydrogen induced damage are: formation of internal cracks, blisters, or voids in steels; embrittlement (i.e., loss of ductility); and high temperature hydrogen attack (i.e., surface decarbonization and chemical reaction with hydrogen).

Indication is a finding of a nondestructive testing technique. It may or may not be a defect.

Mechanical Damage is a type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, and residual stresses, any one of which can be detrimental.

Microbiologically Influenced Corrosion (MIC) is corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

Probability is the likelihood of an incident occurring.

Rich gas is a gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane. Rich gas will have a different PIR factor than natural gas.

Risk is a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

Risk Assessment is a systematic process, in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and be performed at varying level of detail depending on CVGS's objectives (see section 5).

Risk Management is an overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

Root Cause Analysis is a family of processes implemented to determine the primary cause of an event. These processes all seek to examine cause-and effect relationship through the organization and analysis of data. Such processes are often used in failure analyses.

Rupture is a complete failure of any portion of the pipeline.

Stress Concentrator is a discontinuity in a structure or change in contour that causes a local increase in stress.

Third-Party Damage is damage to a gas pipeline facility by an outside party other than those performing work for CVGS. For the purposes of this document it also includes damage caused by CVGS's personnel or CVGS's contractors.

Ultrasonic is high frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

Wrinkle Bend is a pipe bend produced by field machine or controlled process that may result in abrupt contour discontinuities on the inner radius.

2.4 Threat Identification [192.917(a)]

CVGS will identify and evaluate all potential threats to each covered pipeline segment. CVGS will use the prescriptive approach in identifying and evaluating all potential threats.

Specific Steps for Threat Identification

1) Using the threat worksheet, complete the data fields in the worksheet [Element #1: record #1]
2) Determine if potential threat is threat or no threat based on data collected and reviewed
3) Using ESRI ArcGIS Desktop 10 or equivalent, conduct data integration to determine if there are any interactive threats (see section #2.7 below)
4) For particular threats listed below, take specific actions to address those threats

- Third Party Damage – CVGS must use data integration from the assessment of other threats to identify potential third party damage and take additional preventive and mitigative action
- Cyclic Fatigue – CVGS must use cyclic fatigue analysis to prioritize baseline assessments and reassessments
- Manufacturing and Construction Defects – CVGS must prioritize a segment containing manufacturing or construction defects as a high risk segment unless it shows by analysis that the defect is stable and that the risk of failure is low
- ERW Pipe – Covered segments containing low frequency electric resistance welded pipe or lap welded pipe must be prioritized as a high risk segment for the baseline assessment or reassessment, and assessed using technologies proven to be capable of assessing seam integrity and of detecting seam corrosion anomalies.
- Corrosion – If corrosion is identified, all similar pipeline segments (both covered and non-covered) with similar coating and environmental characteristics must be evaluated and remediated, as necessary.

Threats are identified in order to determine what mechanisms can cause failure of each segment so that appropriate assessment methods are applied to the segments and effective preventive and mitigative measures can be defined for the segments. Also, threats are evaluated in order to provide input to segment risk assessment, which is used to set segment integrity assessment priorities and evaluate the benefits of preventive and mitigative activities.

Using Appendix A of ASME/ANSI B31.8S-2004, CVGS will identify and evaluate the eleven categories of threats shown below.

Threat Categories to be Evaluated Under Prescriptive Program:

Time Dependent Threats:

1. External corrosion
2. Internal corrosion
3. Stress corrosion cracking

Static (stable) or Resident Threats

4. Construction and manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe, lap welded pipe, flash welded pipe, or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3]
5. Welding or fabrication related defects
   - Defective pipe girth weld
   - Defective fabrication weld
   - Wrinkle bend or buckle
   - Stripped threads, broken pipe, coupling failure
6. Equipment failures
   - Gasket O-ring failure
   - Control/Relief equipment malfunction
   - Seal/pump packing failure
   - Miscellaneous

Time-Independent Threats (Random)

7. Third party/mechanical damage [192.917(e)(1)]
8. Incorrect operations (including human error)
9. Weather related and outside force damage
   - Cold weather
   - Lightening
   - Heavy rains or floods
   - Earth movement

Additional Threats

10. Cyclic fatigue or other loading condition. [192.917(e)(2)]
11. All other potential threats. [192.917(a)]
12. Interactive threats (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage. [ASME/ANSI B31.8S-2004, Section 2.2]. [192.917(a)]

CVGS has determined that all the threats listed above apply except for stress corrosion cracking (SCC). SCC is not a threat on the NPCA pipeline because it does not meet any of the criteria for SCC as listed in ASME/ANSI B31.8S-2004, appendix A3, section A3.3 and PHMSA advisory ADB-03-05, dated October 8, 2003.

In general, a threat shall be included for a segment if CVGS's failure history includes failures due to the threat on the segment or similar segments (both covered segments and other segments in the CVGS systems). Interactive threats will be given higher risk scores and higher priority of investigation and remediation unless justification is provided.

In addition to consideration of the failure categories listed above, CVGS will address all other threats that stem from unique segment characteristics. For example, loading from heavy railroad use could be added as a threat due to mechanical stress.

Threat Elimination

CVGS will not eliminate a threat from consideration for a specific segment unless there is documented justification based on sound engineering practices. Criteria for eliminating a specific threat for a particular pipeline segment shall consider pipeline failure history, design, manufacturing, construction, operation, and maintenance. Specifically, a threat will not be eliminated unless it meets all of the following criteria.

Threat Elimination Criteria:

1) No previous history of failure due to specific threat, and
2) Smart pig capable of discriminating for type of threat being eliminated with results showing no indications of specific threat, or pressure test without failures
3) No root cause analysis conclusion for any failure of the pipeline, including non HCA segments
4) Threat specific monitoring data that does not indicate any findings for that specific threat. For example, if trying to eliminate internal corrosion as a threat then CVGS must review the conclusions from coupon monitoring, internal exposed pipe reports, gas quality analysis, analysis of fluids if any, and verification that drips and low points are clean and dry of fluids.

The ***unavailability of identified data elements is not a justification for exclusion of a threat*** from the integrity management program. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required. If a threat is eliminated from the risk analysis and IM program, it will be reviewed each year with agenda #2 to verify that the threat elimination is still justified.

2.5 Actions to Address Particular Threats

When CVGS identifies any of the following threats, CVGS will take the following actions to address the threat.

2.5.1 Third Party Damage (TPD)

Data Integration

CVGS will utilize the data integration required in 192.917(b) and ASME/ANSI B31.8S-2004, appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. When TPD is identified through data integration, CVGS will implement comprehensive additional preventative measures in accordance with 192.935(b) listed below and monitor the effectiveness of the preventive measures.

CVGS must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum— (Also, shown in Element #8.4)

1) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
2) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.
3) Participating in one-call systems in locations where covered segments are present.
4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving

> excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502–2008 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S-2004 and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

If, in conducting a baseline assessment under 192.921, or a reassessment under 192.937, CVGS uses an internal inspection tool or external corrosion direct assessment, CVGS will integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. CVGS will also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration. See element # 8, Preventive and Mitigative Measures.

Specifically, in order to carry out the data integration needed for the threat evaluation required for residual third party damage, CVGS will use stationing and GPS for dig locations to accurately locate potential residual third party damage identified by ILI or ECDA in comparison to locations of encroachments and foreign line crossings.

When the data integration activities provide a potential indication of residual third party damage in a covered segment and where data integration suggests potential damage to the pipeline exists, the procedures shall include a local excavation and direct examination of the pipeline, including (as necessary) NDE of the pipeline to identify or characterize damage. Since the threat of residual third party damage is the result of a localized, time independent event, CVGS procedures will require responses where the data integration suggests evidence of a residual third party defect, and would not necessarily require a response for the entire covered segment. However, data gathered from the evaluation of previous residual third party defects shall be considered when evaluating data for the entire covered segment and the need for additional surveys and actions taken to assure the integrity of the covered segment. [FAQ #218]

<u>DA Requirements for TPD</u>

Question: If DA is not currently accepted as a primary assessment method for third party damage, and the threat of third party damage is present, does the rule require that DA always be accompanied by either a pressure test, or ILI, or another assessment method that is capable of assessing third party damage?

Answer: No. The rule addresses the threat of third party damage in two ways. First, the threat of a future third party damage event is expected to be present in covered segments. Therefore, **prevention** of future events is addressed under the requirements for preventive and mitigative actions.

Second, if, as part of a baseline assessment or reassessment, CVGS has gathered data from an ECDA or internal inspection tool survey, then he must take further action to look for third party damage events that did not result in immediate failure, but may have resulted in residual damage that could fail in the future. The rule requires that the data gathered as a result of the ECDA or internal inspection tool surveys be integrated with data relevant to third party activity, such as encroachments or foreign line crossings. Areas in which anomalies from an internal inspection or ECDA survey align with such possible indicators of third party activity provide potential indications of residual third party damage in the covered segment.

2.5.2 Cyclic Fatigue

CVGS will evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. CVGS will use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

2.5.3 Manufacturing and Construction Defects

All CVGS pipeline HCA segments will be considered to contain manufacturing and construction defects since there is no practical way to guarantee a defect-free pipe. If CVGS identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, CVGS will analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. CVGS may consider manufacturing and construction related defects to be stable defects if an operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, CVGS will prioritize the covered segment as a high risk segment for baseline assessment or a subsequent reassessment.

1) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
2) MAOP increases; or
3) The stresses leading to cyclic fatigue increase.

Pipe older than 50 years, mechanically coupled pipelines, or where pipelines joined by means of acetylene girth welds, where low temperatures are experienced, or where the pipe is exposed to movement such as land movement or removal of supporting backfill, examination of the terrain will be conducted. If land movement is observed, or can reasonably be anticipated, a pipeline movement monitoring program shall be established and appropriate intervention activities undertaken. [ASME B31.8S-2004, A4.3]
For girth welds, a review of the welding procedures and NDT information is required to ascertain that the welds are adequate.

For fabrication welds, a review of the welding procedures and NDT information, as well as a review of forces to ground settlement or other outside loads, is required to ascertain that the welds are adequate.

For wrinkle bends and buckles as well as couplings, reports of visual inspection shall be reviewed to ascertain their continued integrity. Potential movement of the pipeline may cause additional lateral and/or axial stresses. Information relative to pipe movement shall be reviewed, such as temperature range, bend radius, degree of bend, depth of cover, and soil properties. These are important factors in determining whether or not bends are being subjected to injurious stresses or strains.

The existence of these construction related threats alone does not pose an integrity issue. The presence of these threats in conjunction with the potential for outside forces significantly increases the likelihood of the event. The data must be integrated and evaluated to determine where these construction characteristics coexist with external or outside force potential. [ASME B31.8S-2004, A5.3]

<u>How Manufacturing and Construction Defects Will Be Addressed If Subpart J Tested:</u>

OPS considers a successful Subpart J pressure test to be sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at operating pressures less than or equal to MAOP, as of the date of the pressure test. Any manufacturing and construction defects that survive the Subpart J pressure test are considered to be stable and not subject to failure, unless other threats adversely affect the stability of the residual manufacturing and construction defects. CVGS is expected to conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects, as required by ASME B31.8S-2004, Section 2.2, and establish its assessment plans accordingly.

<u>How Manufacturing and Construction Defects Will Be Addressed If The Segment Has Not Been Subpart J Tested:</u>

Assessments may be required, if operating conditions on the line change. Initially, manufacturing and construction defects may be considered to be stable based on operating history, if no pipeline failures have been caused by manufacturing and construction defects. However, the rule requires that pipeline segments be prioritized as high risk, and appropriately scheduled for an assessment, if the operating conditions change significantly. The specific operating conditions that require an assessment for manufacturing and construction defects are any one or more of the following:

- Operating pressure, including abnormal operating conditions, which exceed the maximum operating pressure experienced during the five years preceding identification of the HCA; or
- MAOP increases; or
- The stresses leading to cyclic fatigue increase.

In addition, other interacting threats could adversely affect the stability of residual manufacturing and construction defects. CVGS is expected to conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects, as required by ASME B31.8S-2004, Section 2.2, and establish its assessment plans accordingly.

The rule requirement in 192.917(e)(3)(i) specifies that any pressure increase, regardless of amount, will require that the segment be prioritized as high risk for integrity assessment. [FAQ #221]

<u>Pressure Test to Establish M&C Threats are Stable</u>

Section 192.917(e)(3) requires that CVGS consider the five years preceding identification of a high consequence area to determine a maximum operating pressure that will assure

the stability of manufacturing and construction (M&C) threats. As long as operation does not involve pressures higher than the highest operating pressure experienced during those five years, any M&C threats can be considered stable. (The "preceding five years" referred to in sub-paragraph 192.917(e)(3)(i) is the same five years preceding HCA identification.) [FAQ #231]

Note that section 192.917(e)(3) specifies that "the analysis must consider the results of prior assessments on the covered segment." This includes any prior hydrostatic tests, including tests conducted after the pipe was installed. OPS considers that a hydrostatic test, meeting subpart J requirements, is sufficient to demonstrate that any manufacturing and construction defects will remain stable at the operating pressures related to that test. CVGS need not consider the operating pressure in the five years preceding HCA identification for segments that have passed a Subpart J hydrostatic test. [FAQ #231]

Use of a spike test, alone, as an assessment method would constitute "other technology". Operators planning to use "other technology" to perform assessments must notify OPS (or a state regulator) at least 180 days in advance. A spike test may be performed along with a pressure test meeting subpart J requirements. In that case, the subpart J test is considered the primary assessment, and no notification would be required. [FAQ #141]

2.5.4 ERW Pipe

If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S-2004, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system when such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, CVGS will select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. CVGS will prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

If there are any low-frequency ERW (LFERW) or lap-welded (LW) pipe segments susceptible to longitudinal seam failure included in CVGS's BAP, these segments will be uniquely identified.

2.5.5 Corrosion

If CVGS identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in 192.933, meaning immediate, one year, and monitored), CVGS will evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. CVGS will establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with CVGS's established operating and maintenance procedures under part 192 for testing and repair.

During excavations, NPCA will check soil resistivity for purpose of data gathering and information as it relates to corrosion rates listed below.

<u>Corrosion Rates Related to Soil Resistivity [ASME B31.8-2004, table B1]</u>

Corrosion Rate mils/year	Soil Resistivity (ohm-cm)
3	> 15,000 + no active corrosion
6	1,000 - 15,000 and/or active corrosion
12	< 1000 (worst case)

2.5.6 Stress Corrosion Cracking

Both industry standards ASME B31.8S-2004, Appendix A3.2, and NACE RP 0402-2004, list the following as screening criteria for SCC assessments. ASME B31.8S-2004 standard states that SCC would not be identified as a threat unless the following three conditions are present:

- Operating stress > 60% SMYS
- Age of pipeline > 10 years
- Any coating type other than FBE

High-pH SCC also will be eliminated as a threat unless:

- The operating temperature was above 100° F (38° C),and
- The distance from an upstream compressor station is less than 20 miles (32 km).

These screening factors will identify the majority of susceptible locations, but not necessarily all of them. Therefore, it will be necessary to evaluate any segment in which one or more service incidents or hydrostatic test breaks or leaks have been caused by one of the two types of SCC. Similar criteria have not been defined for liquid pipelines, but presumably the same criteria should apply. Lack of failures that have been attributed to SCC is insufficient reason to discount the SCC threat. Prior to the mid-1990s, many companies did not routinely perform metallurgical examination of failed pipe. It is postulated that some historical failures might have been caused by, but not attributed to, SCC.

2.5.7 Equipment Threats

Certain relief and regulator valves are known to have their set points drift. These equipment types may require extra scrutiny.

Certain gasket types are prone to premature degradation. These equipment types may require more frequent leak checks.

2.5.8 Incorrect Operations Threat

If the data shows the operations and maintenance are performed in accordance with operations and maintenance procedures, the procedures are correct, and that operating personnel are adequately qualified to fulfill the requirements of the procedures, no additional assessment is required. Deficiencies in these areas require mitigation as outlined below.

CVGS shall ensure the following:

- Procedures are current
- Personnel are adequately qualified
- Following of procedures is enforced
- A program to qualify operation and maintenance personnel for each activity that they perform
- Strong internal review or audit program by in-house experts or third party experts

2.5.9 Weather related and outside force

Pipe may be susceptible to extreme loading at the following locations:

1) Where the pipeline crosses a fault line
2) Where the pipeline traverses steep slopes
3) Where the pipeline crosses water or is adjacent to water, or where the river bottom is moving
4) Where the pipeline is subject to extreme surface loads that cause settlement to underlying soils
5) Where blasting near the pipeline is occurring
6) Where the pipe is at or above the frost line
7) Where the soil is subject to liquefaction
8) Where ground acceleration exceeds 0.2 g

2.6 Data Gathering [192.917(b)]

The focus of the data gathering is the assembly of data for input to CVGS's risk assessment, the results of which support decisions in all other integrity management program elements.

CVGS will gather and integrate existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data has been assembled and integrated. This means that data for both covered segments and similar non-covered segments will be gathered. [§192.917(b)] The data gathering described below follows the prescriptive approach outlined in ASME/ANSI B31S-2004, section #4.

Using the element #2 agenda, once per calendar year not to exceed 18 months, data will be reviewed for changes or updates that could affect an HCA. Any new data affecting HCAs will be incorporated within one year. Sources of new data may include additional inspections to satisfy gaps in the data, and/or from the MOC process. See section #2.10, implementation of IMP element #2 agenda & action items.

The typical data sources for pipeline integrity program are shown in the table below. These data sources are taken from Table 2 of ASME B31.8S-2004. [Element #2: record #2]

Data Sources for Prescriptive Pipeline IM Program [ASME B31.8-2004, Table #2]

#	Data Sources Description:
1	Process and instrument drawings (P&ID)
2	Pipeline alignment drawings
3	Original construction notes and records
4	Pipeline aerial photography
5	Facility drawings and maps
6	As built drawings
7	Material certifications
8	Survey reports and drawings
9	Safety related condition reports
10	Inspection records
11	Test reports, records
12	Incident reports
13	Compliance reports and audit reports
14	Design and engineering reports
15	Technical evaluations
16	Manufacturer equipment data

Specific steps for data gathering are listed below.

1) CVGS will use the prescriptive approach as described in ASME B31.8-2004, non-mandatory appendix A to data gathering, reviewing, and integration
2) CVGS IMP leader will first collect the data required to perform a threat review and risk assessment. The individual data elements are shown in the table below.

   These data sets are listed below for each threat shown in ASME, non-mandatory appendix A. Other data requirements may be added as the program progresses and improves.

   If one or more sources from ASME B31.8S-2004, Table 2 are not available, the IMP Leader or designee will take reasonable action to obtain the data. Data that cannot be obtained from records will be supplemented by expert opinion (SME-subject matter expert). In no case is the unavailability of data a justification for dismissing a threat from consideration or treating a threat as a low risk.

Data Elements for Prescriptive Pipeline IM Program
[ASME B31.8-2004, Non-Mandatory Appendix A]

Threat Category:	#	Data Description:
External Corrosion [ASME B31.8-2004, A1.2]	1.1	Year of installation
	1.2	Coating type
	1.3	Coating condition
	1.4	Years with adequate CP
	1.5	Years with questionable CP
	1.6	Years without CP
	1.7	Soil characteristics
	1.8	Pipe inspection reports (bell hole)
	1.9	MIC detected
	1.10	Leak and failure history including root cause
	1.11	Wall thickness
	1.12	Diameter
	1.13	Operating stress level (% SMYS)
	1.14	Past hydro test information
	1.15	External forces
Internal Corrosion [ASME B31.8-2004, A2.2]	2.1	Year of installation
	2.2	Pipe inspection reports (bell hole)
	2.3	Leak history
	2.4	Wall thickness
	2.5	Diameter
	2.6	Past hydro test information
	2.7	Gas, liquid, or solid analysis (particularly hydrogen sulfide, carbon dioxide, oxygen, free water, and chlorides)
	2.8	Bacteria culture results
	2.9	Corrosion detection devices (coupons, probes, etc)
	2.10	Operating parameters (particularly pressure and flow velocity, and periods where there is no flow)
	2.11	Operating stress level (% SMYS)

Threat Category:	#	Data Description:
Stress Corrosion Cracking (SCC) [ASME B31.8-2004, A3.2]	3.1	Age of pipe
	3.2	Operating stress level (% SMYS)
	3.3	Operating temperature
	3.4	Distance of the segment from a compressor station
	3.5	Coating type
	3.6	Past hydro test information for reasons other than SCC investigation
Manufacturing (pipe seam & pipe) [ASME B31.8-2004, A4.2]	4.1	Pipe material
	4.2	Year of installation
	4.3	Manufacturing process (age of manufacturer as alternative)
	4.4	Seam type
	4.5	Joint factor
	4.6	Operating pressure history
Construction (pipe girth weld, fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, broken coupling) [ASME B31.8-2004, A5.2]	5.1	Pipe material
	5.2	Wrinkle bend identification
	5.3	Coupling identification
	5.4	Post construction coupling reinforcement
	5.5	Welding procedures
	5.6	Post construction girth weld reinforcement
	5.7	NDT information of welds
	5.8	Hydro test information
	5.9	Pipe inspection reports (bell hole)
	5.10	Potential for outside forces
	5.11	Soil properties
	5.12	Depth of cover for wrinkle bends
	5.13	Maximum temperature ranges for wrinkle bends
	5.14	Bend radii and degrees of angle change for wrinkle bends
	5.15	Operating pressure history and expected operations, including significant pressure cycling and fatigue mechanism

Threat Category:	#	Data Description:
Equipment (gaskets, O-rings, control, relief, seal & pump packing) [ASME B31.8-2004, A6.2]	6.1	Year of installation of failed equipment
	6.2	Regulator valve failure info
	6.3	Relief valve failure info
	6.4	Flange gasket failure info
	6.5	Regulator set point drift (outside of manufacturer's tolerances)
	6.6	Relief set point drift (outside of manufacturer's tolerances)
	6.7	O-ring failure info
	6.8	Seal packing failure info
3rd Party Damage (TPD) [ASME B31.8-2004, A7.2]	7.1	Vandalism incidents
	7.2	Pipe inspection reports (bell hole)
	7.3	Leak reports resulting from immediate damage
	7.4	Incidents involving previous damage
	7.5	ILI results for dents and gouges at top half of pipe
	7.6	One call records
	7.7	Encroachment records
Incorrect Operations [ASME B31.8-2004, A8.2]	8.1	Procedure review information
	8.2	Audit information
	8.3	Failures caused by incorrect operations
Weather Related and Outside Force (earth movement, heavy rains or floods, cold weather, lighting) [ASME B31.8-2004, A9.2]	9.1	Joint method (mechanical coupling, acetylene weld, arc weld)
	9.2	Topography and soil conditions (unstable slopes, water crossings, water proximity, soil liquefactions susceptibility)
	9.3	Earthquake fault
	9.4	Profile of ground acceleration near fault zones (greater than 0.2g acceleration)
	9.5	Depth of frost line
	9.6	Year of installation
	9.7	Pipe grade, diameter, and wall thickness (internal stress calculation added to external loading, total stress not to exceed 100% SMYS

3) When analyzing the results of the threat review and risk assessments, the IMP leader may find that additional data may be required. When this occurs, this procedure and the "Threat and Data Collection" worksheet will be revised by the IMP leader.
4) Initially, data collected in step #1 and step #2 above will be placed on the company intranet. The IMP leader will work toward process improvement by placing key data into the ESRI ArcGIS Desktop 10 geo database.

Key data for inputting into the ArcGIS Desktop 10 database is shown below and follows industry standard ADPM 4.0 data model.

Pipeline Facilities and Equipment Data:

1) Stationing and/or GPS points
2) Pipe segment data (date manufactured, girth weld, pipe grade, wall thickness, seam type, O.D, pressure rating, segment length)
3) Valve info
4) Casings
5) Taps
6) DOT class per 192.5
7) HCA locations
8) CP test stations
9) Instrument device and type
10) Rectifier
11) CP anodes
12) Critical bonds
13) Line crossings

Pipeline Inspection and Repair Data:

14) Smart pig results
15) Pressure tests
16) ECDA report and/or CIS, DCVG
17) Guided wave
18) CP surveys

19) Soil resistivity
20) Exposed pipe reports
21) Outside force areas
22) Repairs and records of direct inspections
23) Leaks

Gathering Information From the Entire Pipeline:

CVGS will consider information from portions of pipelines not in HCAs when developing my integrity management program. Section 192.917(b) requires that CVGS gather and integrate existing data "on the entire pipeline" that could be relevant to covered segments as part of performing their risk assessment. Data from non-covered segments must be considered in this process.

CVGS generally need not conduct excavations, perform new analyses, etc. to generate information, but must consider data that already exists. The initial data gathering process is likely to highlight weaknesses in the existing data, however. OPS expects that the CVGS will identify these weaknesses and will modify O&M procedures, as appropriate, to improve the process for gathering new data during future opportunities (e.g., when pipe is exposed). [FAQ #222]

2.7 Data Integration and Analysis [192.917(b)]

The most important aspect of data gathering and integration is the ANALYSIS of aggregated data in order to discern integrity threats and risks that would not otherwise be observed from independently reviewing the various individual data elements.

For integrity management program applications, the first data integration steps will include development of a common reference system that will allow data elements from various sources to be combined and accurately associated with common pipeline locations. CVGS will use a GIS system stationing and/or GPS coordinates as the common spatial reference system. Where possible during routine inspections and integrity assessments, GPS coordinates will be taken using sub-meter accuracy instruments. To satisfy this requirement, NPCA will ESRI ArcGIS Desktop 10.

As a minimum, integration of ILI or ECDA results with data on encroachments or foreign line crossings in the same segment to define locations of potential third party damage will be performed. Other data integration layers will be developed as the program progresses. [192.917(e)(1)].

Example of Data Integration As Provided in ASME/ANSI B31.8S-2004:

An operator suspects that a possible corrosion problem exists on a large diameter pipeline located in a populated area. However, a CIS indicates good cathodic protection coverage in the area. A Direct Current Voltage Gradient (DCVG) coating condition inspection is performed and reveals that the welds were tape-coated and are in poor condition. The CIS results did not indicate a potential integrity issue but data integration prevented incorrect conclusions.

The analytical process considering the synergistic effect of multiple and/or independent facts or data constitutes data integration. Operators must also evaluate the aggregated data to look for problems that might not have been identified absent such an evaluation. [FAQ #240]

Example of Data Integration As Provided in the American Gas Association (AGA) Gas Piping Technology Committee (GPTC)

The advantages of data integration can be illustrated using the following hypothetical example. During the installation of a housing development, a piece of excavating equipment hits and gouges a transmission pipeline. The damage is not reported to the pipeline operator, CVGS. The pipeline does not fail but now contains a stress concentrator that could lead to future failure. Sometime after the damage, CVGS conducts a close-interval survey (CIS). In the vicinity of the housing development, a slight decrease in the pipe-to-soil potential is noted, although cathodic protection criteria are still being met. A year later, CVGS runs a magnetic flux leakage (MFL) inspection tool. The inspection tool identifies a minor anomaly on the top of the pipeline in the area of the housing development. CVGS may now have several pieces of data concerning the pipeline through the housing development. This data could include:

- Record of line location in response to a one-call
- Record of a facility patrol indicating activity along the rights-of-way
- Close-interval survey showing a minor anomaly
- An internal inspection tool survey indicating a minor anomaly.

Each of these items individually may not indicate a serious threat to the pipeline. However, when the data is integrated, by linking to the same point in the pipeline, there is an indication that the pipeline may have been damaged and the integrity of the pipeline may have been compromised.

Specific steps for data integration and analysis are listed below. [Element #2: record #3]

1) CVGS will use the prescriptive approach as described in ASME B31.8-2004, non-mandatory appendix A to data gathering, reviewing, and integration
2) After the data is gathered as described in section #2.5 above, the IMP leader or designee will create map layers in the ESRI ArcGIS Desktop 10 software files.
3) Once map layers are created for the key data elements, these layers will be used during annual agenda reviews by the IMP team to determine if there are additional or higher risk threats once the data is integrated and layered on the maps
4) Data will also be validated as describe below [Element #2: record #4]
5) Any findings from the data integration annual review will be documented on the master IMP action item list.

Quality of Information

CVGS will use the best information that they have available in performing the data integration and analysis associated with integrity management and must assure the quality of information used. Information of this nature would be subject to review during integrity management inspections. [FAQ #205]

Missing or Unsubstantiated Data

If significant data elements are missing or unsubstantiated, modifications of the proposed risk model may be required after carefully reviewing the impact of missing data and taking into account the potential effect of uncertainties created by using required estimated values.

All of the specified data elements shall be available for each threat in order to perform the risk assessment. If such data is *not available*, it shall be *assumed that the particular threat applies* to the pipeline segment being evaluated or, alternatively, the segment shall be prioritized higher.

During agenda reviews, CVGS will determine if significant data deficiencies exist. If deficiencies are found, action to obtain the data can be planned and initiated relative to its importance. This may require additional inspections and field data collection efforts and will be noted on the agenda action item list and/or the summary of action item list.

Validity of Data

The validity of the data will be documented in the "Threats" worksheet. Where unsubstantiated data is used in the risk assessment process, its potential impact on the variability and accuracy of assessment results will be considered. This is often referred to as metadata or information about the data.

Another data collection consideration is whether the age of the data invalidates its applicability to the threat. The age of the data will be documented in the "Data Sources" worksheet. Data pertaining to time-dependent threats such as corrosion or Stress Corrosion Cracking (SCC) may not be relevant if it was collected many years before the integrity management program was developed. Stable and time-independent threats do not have implied time dependence so earlier data is applicable.

CVGS will ***validate the data for accuracy***. If CVGS lacks sufficient data or where data quality is suspect, CVGS will follow the requirements in ASME/ANS B31.8S-2004, section 4.2.1, section 4.4, and Appendix A and summarized below.
[ASME B31.8S-2004, 4.1, 4.2.1, 4.4, 5.7(e), and Appendix A]

1) Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat.
2) Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.
3) Records are maintained that identify how unsubstantiated data is used, so that the impact on the variability and accuracy of assessment results can be considered. See data validation column in "Threats" worksheet.
4) Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

Methods for validation of accuracy will include excavations with direct examination to verify ILI results and using different vendors to conduct the same tasks. For example, CVGS may use two different vendors to conduct cathodic protection surveys. Another example would be excavating a corrosion anomaly as indicated by an ILI tool to determine the accuracy of the tool.

Data Aspects and Units

The data units will be defined in the "Threats" Excel worksheet, when applicable. Examples of units and aspects include the following:

- Resolution
- Units of measure
- Accuracy of data
- Location
- Quality of data
- Metadata (data about the data including where and how the data was obtained and used and the other data attributes specified above.)

Types of Information That Must be Integrated in Performing a Continual Evaluation of Pipeline Integrity [05/17/2004]

CVGS must consider all information relevant to determining risk associated with pipeline operation in HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. At a minimum, CVGS must gather and evaluate the set of data specified in appendix A to ASME/ANSI B31-2004.8S. A list of some of the more important information that shall be considered in an integrated manner is provided below.

- Results of previous integrity assessments
- Information related to determining the potential for, and preventing, damage due to excavation, including damage prevention activities, and development or planned development along the pipeline
- Corrosion control information (e.g., Years with adequate Cathodic protection, years with questionable Cathodic protection, close interval survey results)
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness)

- Operating parameters (e.g., maximum allowable operating pressure, pressure cycle history)
- Leak and incident history
- Information about the potential consequences of a failure in a high consequence area

CVGS will consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations.[FAQ #81]

2.8 Risk Assessment [192.917(c)]

The purpose of the risk assessment is to support integrity decisions required by the IM rule, including

- Scheduling baseline integrity assessments and re-assessments
- Implementing additional preventive and mitigative measures

CVGS's risk assessment will support the following objectives: [ASME B31.8S-2004, 5.3-4]:

1) Prioritization of pipelines/segments for scheduling integrity assessments and mitigating action
2) Assessment of the benefits derived from mitigating action (i.e., reduced risk)
3) Determination of the most effective mitigation measures for the identified threats
4) Assessment of the integrity impact from modified inspection intervals
5) Assessment of the use of or need for alternative inspection methodologies
6) More effective resource allocation
7) Facilitation of decisions to address risks along a pipeline or within a facility (i.e. action items)

When CVGS is performing any of the tasks described by objectives (1) through (7), it must apply its risk assessment as a tool in doing so.

This section of the procedures will address the following in regards to the CVGS risk assessment:

- Process for how the risk assessment is conducted
- How RA results are used to meet rule requirements (risk ranking of segments for scheduling and consideration of mitigative measures)

- The input information needed to produce the risk results (data gathering described above)
- The method or methods used to produce the results (RA process/steps)

<u>How the RA is Conducted</u>

CVGS will conduct a risk assessment that follows the ASME/ANSI B31.8S-2004, section #5 and consider the identified threats for each covered segment. CVGS will initially use the ***Subject Matter Expert (SME) risk approach*** as described in ASME/ANSI B31.8S-2004 section #5.5.

<u>Specific steps to RA process using the "BAP and Mitigation" Excel worksheet:</u> [Element #2: record #5]

1) Take one HCA segment at a time and evaluate the segment for each risk factor required by the IMP program.
2) Then determine what the SEVERITY would be for the risk factor and assign a SEVERITY number of 1-5 in the worksheet column labeled "F".

   Also, complete the mitigative measures column "J" with mitigative activities that are actually being conducted of the time of the risk assessment (and affect severity) for the appropriate HCA segment. Only mitigative activities that are above and beyond the regulatory requirements should be listed in column "E" of the risk analysis worksheet.

   Any HCA segment threat element with a <u>SEVERITY of 1</u> shall recommend one or more mitigative options listed in Element #8 of the IMP program.

   Any HCA segment threat element with a SEVERITY of 2 should consider and recommend one or more mitigative options listed in Element #8 of the IMP program.

3) Next, determine what the LIKELIHOOD would be for the risk factor and assign a LIKELIHOOD number of 1-5 in the worksheet column labeled "G".

Note, use the default severity and likelihood definitions listed below unless specific definitions are contained in the segment worksheet.

Also, complete the mitigative measures column "J" with mitigative activities that are actually being conducted at the time of the risk assessment (and affect likelihood) for the appropriate HCA segment. Only mitigative activities that are above and beyond the regulatory requirements should be listed in column "E" of the risk analysis worksheet.

Any HCA segment threat element with a likelihood of 1 shall recommend one or more mitigative options listed in Element #8 of the IMP program.

Any HCA segment threat element with a likelihood of 2 should consider and recommend one or more mitigative options listed in Element #8 of the IMP program.

4) The worksheet will automatically multiple the SEVERITY and LIKELIHOOD risk factors and put a total number in the column labeled "H" with heading title of "T."
5) The worksheet will automatically compare the total number in the column labeled "T" and input the final risk number. See the risk mapping matrix/conversion below for details.
6) The worksheet will calculate a "Total Risk Score" and automatically insert the "Total Risk Score" number into the "Risk Rank & Schedule" worksheet.
7) The worksheet will also determine the average score by dividing the total score by the number of risk factors.
8) Using the average score that is automatically inserted into the "Risk Rank & Schedule" worksheet, compare and rank all HCA segments against each other in the "Risk Rank & Schedule" worksheet.
9) Next, input additional recommended mitigative measures in column "J" for each threat based on the following total risk score in column "I":

Relative Risk Priority Ranking:

1-2	Red = unacceptable risk (requires one or more mitigative options)
3-4	Orange = risk is not desirable (should recommend one or more mitigative options)
5-7	Blue = risk is acceptable with controls in place
8-10	Green = risk is acceptable

10) Then complete the "Risk Matrix if Additional Measures Implemented" column "F" and column "G" to determine the new potential relative risk.
11) RA results will also be used to prioritize the covered segments for the baseline and continual assessments. Unless there are exceptions that are documented, pipeline segments with higher risk (lower numbers in the RA) will be scheduled as higher priority segments.

CVGS RA described above includes the following characteristics:

- A defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, section 5.7(a)]
- Considers the frequency and consequences of past events, using CVGS and industry data [ASME B31.8S-2004, section 5.7(c)]
- Integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S-,2004 section 5.7(d)]
- Includes a structured set of weighting factors to indicate the relative level of influence of each risk assessment component [ASME B31.8S-,2004 section 5.7(i)]
- Incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S-2004, section 5.7(k)];

Subject Matter Expert (SME) Qualifications

ASME/ANSI B31.8S-2004 defines "subject matter experts" as "individuals that have expertise in a specific area of operation or engineering." Section 192.915 requires that CVGS's IM program provide criteria for qualifications. CVGS is responsible for assuring that the individuals it may rely on as SMEs have an appropriate level of expertise and experience to fulfill their function. CVGS shall document the qualification of their SMEs. OPS inspections may include examination of the qualification of SMEs. [FAQ #166]

New Information and Updating Risk Assessment

The purpose of this requirement is to ensure that risk assessments results continue to represent pipeline risk as conditions change over time and new information on the pipeline is obtained.

CVGS will use the MOC process (major changes) and/or the annual agenda review (minor changes) as described in section #2.10 to initiate revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments. Provisions for change to the risk assessment will include the following:

1) The risk assessment plan calls for recalculating the risk for each segment to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions. [ASME B31.8S-2004, 5.11, 5.7(c)]
2) CVGS will integrate the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. [ASME B31.8S-2004, 5.4]
3) The integrity management plan calls for revision to the risk assessment process if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments. [192.917(c); ASME B31.8S-2004, 5.12]
4) CVGS will use annul agenda reviews as the feedback mechanism to ensure that the risk model is subject to continuous validation and improvement. [192.917(c); ASME B31.8S-2004, 5.7(f)]

Examples of major changes requiring the MOC process is listed below:

- Addition of new risk factors (representing threats or consequence categories) to the risk model
- Deletion of risk factors from the risk model
- Changes to the relative numerical weighting of risk factors within the risk model
- Changes to the algorithm defining how risk factor data is combined in the risk model

If pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments, then the corrected data shall be used when the risk results are updated during annual reviews.

Validation of Risk Assessment

CVGS will conduct the following processes to validate the results of the risk assessments as required by §192.917(c) and ASME B31.8S-2004, §5.12.

- IMP team review of results (annual agenda reviews)
- SME reviews
- Review of lessons learned from industry

How CVGS Will Re-Prioritize Each Time a New Segment is Added:

The rule specifies a ten (10) year assessment schedule for newly identified segments. CVGS will list the newly identified segments in its baseline assessment plan, and document its assessment method selection and threat identification, within one year of identification. However, the assessment may be scheduled for completion at any time within that 10 year period following identification of the new HCA, without the need to re-prioritize the pre-existing assessment schedules. [FAQ #110]

2.9 Plastic Transmission Pipeline

CVGS does not have plastic transmission pipelines at this time. If CVGS constructs or obtains any plastic transmission pipelines, CVGS will develop procedures for addressing specific threats as required by 192.917(d).

2.10 Review and Implementation of Element #2

CVGS will use the agenda, "Gas IMP Element #2, Threats, Data Integration Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #2 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #2: Record #6]

- Threats, Data Integration, and Risk Analysis Agenda Objectives

- List of personnel that shall attend including name and job title
- Frequency of the review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #2 requirements are met
- Action item list as a result of the element #2 review [Element #2: Record #7]

2.11 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.917, How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

4. OPS Gas Integrity Management, Protocol Section #C, Identify Threats, Data Integration, and Risk Assessment, July 2008

5. OPS Frequently Asked Questions (FAQs), ID of Threats, Risk Analysis and Prioritization, Specific Threats, January 2008

6. OPS Frequently Asked Questions (FAQs), Data Integration, January 2008
7. ASME B31.8S-2004, Managing System Integrity for Gas Pipeline, Section #5, Risk Assessment

8. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008

Ref: 49 CFR 192.917 Updated: July 2011

2.12 List of Required Ongoing Documentation for Element #2

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	2.4	Threat Identification Worksheet	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
2.	2.6	All data required by ASME B31.8S-2004 data gathering guidelines	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	2.7	Data integration using ESRI ArcGIS Desktop 10 software	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	2.7	Validation of data accuracy	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	2.8	Risk Analysis & Mitigative Measures Worksheet	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	2.10	Review and Implementation Agenda for Element #2	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	2.10	Action item list	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Gas Integrity Management Plan
Element #3: Baseline Assessments

Ref: 49 CFR 192.919 & 921	Updated: July 2012

Contents of this Element:

3.1 Objectives and Purpose of Baseline Assessment [192.919 & 921]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these baseline assessment procedures to assist in this effort.

3.2 Scope, Applicability, and Use of PHMSA FAQs [192.919 &921]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.

CVGS
Gas Integrity Management Plan
Element #3: Baseline Assessments

Ref: 49 CFR 192.919 & 921	**Updated: July 2011**

Applicability and Summary of the Regulations

This element covers 192.919, "What must be in a baseline assessment", and 192.921, "How is the baseline assessment to be conducted." A summary of the requirements from these two regulations is shown below.

"What must be in a baseline assessment?" [192.919]

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats

(b) The methods selected to assess the integrity of the pipeline

(c) A schedule for completing the integrity assessment of all covered segments

(d) If applicable, a direct assessment plan

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

"How is the baseline assessment to be conducted?" [192.921]

Assessment methods. An operator must assess the integrity of the pipeline in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible.

(2) Pressure test conducted in accordance with subpart J of this part.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking.

(4) Other technology

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment.

(e) *Prior assessment.* An operator may use a prior integrity assessment.

(f) *Newly identified areas.* An operator must complete the baseline assessment of the pipeline in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years

(h) *Plastic transmission pipeline.* An operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917.

<u>Use of PHMSA FAQs</u>

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for baseline assessment are shown in appendix 3A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

3.3 Definitions Applicable to Element #2

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory Direct Assessment (CDA) is an integrity assessment method using a more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Direct Assessment (DA) is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

External Corrosion Direct Assessment (ECDA) is a four-step process that combines pre-assessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

3.4 Assessment Methods [192.921]

<u>Step #1: Select assessment method based on threats and document in BAP worksheet during annual agenda review</u>

Based on the priorities and threats determined by risk assessment, CVGS shall conduct integrity assessments using the appropriate integrity assessment methods. The integrity assessment methods that can be used are:

- ***In-line Inspection***
- ***Pressure testing***
- ***Direct assessment (ICDA, ECDA, SCCDA, CDA)***
- ***Other technology***

<u>Step #1: Select the assessment method based on the threats to the segment and document on the BAP, RA, and Mitigation worksheet [Element #3: record #1]</u>

The following pipeline systems and segments are covered by the CVGS gas IM program:

- The CVGS whole gas pipeline system (.71 miles) located in Alameda, California.
- CVGS will use pressure test as the primary assessment method.
- ECDA, which includes CIS, DCVG, ACM, will be used as a supplemental survey

Direct assessment may only be used for the following threats:

- External Corrosion (Must comply with NACE RP0502-2002)
- Internal Corrosion (Must comply with ASME/ANSI B31.8S-2004)
- Stress Corrosion Cracking (Must comply with ASME/ANSI B31.8S-2004)

The integrity assessment method will be <u>based on the threats</u> to which the segment is susceptible. More than one method and/ or tool may be required to address all the threats in a pipeline segment. Conversely, inspection using any of the integrity assessment methods may not be the appropriate action for CVGS to take for certain threats. Other actions, such as prevention, may provide better integrity management results, for example third party damage.

When pigging and hydrostatic testing is impractical CVGS will demonstrate by historical records such as gas quality, internal inspections, etc. that an internal corrosion problem does not exist. When CVGS demonstrates that a covered segment is not susceptible to the threat of internal corrosion, then no assessment method need be applied to assess this threat.

Assessment methods must be identified, and demonstrated to be capable of addressing applicable threats, before an assessment is conducted. At the same time, OPS recognizes that last-minute problems arise and that plans must often change as a result. It is acceptable for operators to change their assessment plans due to unexpected situations, but the reasons for the change and the acceptability of a changed assessment method should be documented when the change is made, prior to implementing the assessment.
[FAQ #217]

Below is a more detailed discussion of each of the assessment methods.

3.4.1 In-line Inspection (ILI)

If internal inspection tools are selected, CVGS will follow ASME B31.8S-2004, Section 6.2 in selecting the appropriate internal inspection tool for the covered segment.
[192.921(a)(1)]

In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize indications in a pipeline. The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives. Element #2, "Identification of Threats, Data Integration, and Risk Analysis" discusses the topic of ILI tools for certain threats.

CVGS will evaluate the general reliability of any in-line assessment method selected by looking at factors including but not limited to:

- Detection sensitivity;
- Anomaly classification;
- Sizing accuracy;
- Location accuracy;
- Requirements for direct examination;
- History of tool;
- Ability to inspect full length and full circumference of the section; and
- Ability to indicate the presence of multiple cause anomalies.

Step #2: Document tool selection based on criteria above [Element #3: record #2]

Assessments conducted using only MFL metal loss tools require that all indications of mechanical damage in the pipeline segment be investigated/excavated unless they are known to have been repaired. Or CVGS may choose to run a second tool capable of determing the extent of mechanical damage (normally a deformation tool). Also, if seam failure or cracks are a potential threat, then a transverse SMFL tool shall be used.

Using the remediation worksheet or other appropriate documentation, CVGS will record the "as found" depth of the anomaly discovered during the direct inspection. [Element #3: record #3] The "as found" depth will be compared to the depth reported on the ILI report. CVGS will feed verification results back to the ILI vendor to assist in tool evaluation and potentially recalibrating the tool and smart pig report. [Element #3: record #4]

CVGS shall specify the threshold for vendor reporting of anomalies. At this time, CVGS will specify that the vendor shall report all metal loss anomalies greater than 10% WT. This threshold is appropriate to screen out insignificant or trivial anomalies, while still ensuring that significant anomalies that represent integrity threats are reported. The threshold values shall include an allowance for tool tolerance. [Element #3: record #5]

Tool tolerances will also be applied to deformation depth and to orientation. For example, ILI vendors specify the accuracy of their tool in predicting the circumferential location of a defect. A 6% dent of the top of the pipe (between 8 and 4 o'clock) is a one year condition; whereas, a 6% dent on the bottom of the pipe (between 4 and 8 o'clock) is a monitored condition. Defects located near the 4 and 8 o'clock positions should be evaluated to see if they should be included in the more conservative repair condition to account for tool inaccuracies.

Defect characterization shall consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 192.933(d) [immediate, one year, and monitored conditions], are promptly identified. Important aspects of tool tolerance affect the following critical integrity management considerations:

- Defect sizing data for determination of correct repair criteria categorization should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length shall be increased by the amount of the tool tolerance). This is especially important for "borderline" anomalies.

- Defect sizing data used as input into calculations to determine remaining strength of the pipe should be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length should be increased by the amount of the tool tolerance).

Operators are required to integrate relevant information on the condition of the pipeline in making decisions on excavation timing and other mitigative actions. Tool accuracy should be considered as part of the data integration process.

Accounting for tool accuracy is most important for immediate repair anomalies. Immediate repair conditions may not be discovered (because the ILI tool "undercalled" the defect), even if the tool functioned within its published accuracy specifications, if tool accuracy is not considered. Information on tool accuracy should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized. This does not necessarily mean simply adding the vendor-supplied accuracy specification to reported depth of metal loss indications. Several sources of data may be used, in conjunction with vendor-supplied tool specifications, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data should also be considered.

In addition, information on tool accuracy may be incorporated in engineering analysis such as "probability of exceedance" to help operators prepare a comprehensive defect remediation plan and schedule future assessments. Pipeline operators have the flexibility to apply processes specific to their unique risks by utilizing these techniques when evaluating specific pipeline defects.

Tool accuracy specifications are not the only uncertainty associated with assessment results, and are therefore not the only factor to be considered in evaluating the quality of internal inspection data and in making excavation timing and mitigation decisions. Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 192.933, are promptly identified. The operator must document its approach for dealing with ILI accuracy and uncertainty per 192.947(d). For example, ILI tools are typically less accurate when the anomalies are small and this should be considered when evaluating the anomaly for scheduling repairs. **[FAQ #68]**

3.4.2 Pressure Testing

CVGS will follow ASME B31.8S-2004, Section 6.3 in selecting the pressure test as the appropriate assessment method. CVGS will consider the results of the risk assessment and the types of anomalies expected to determine when to conduct inspections utilizing pressure testing.

Pressure test is appropriate for the following threats:

1) External corrosion
2) Internal corrosion
3) Manufacture ring
4) Construction
5) Third party damage (TPD)
6) Interactive threats involving TPD and/or manufacturing

If a pressure test is specified by CVGS assessment plan, the pressure test will be conducted in accordance with Part 192, Subpart J requirements. [192.921(a)(2)] [Element #3: record #6]

Pressure testing will be used as the primary assessment method when internal inspections are not practical. The IMP Leader shall review all pressure test results and determine the cause of failures, analysis of pressure reversals, and validate test acceptance and validity.

CVGS may use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939. [Element #3: record #7]

CVGS will require metallurgical examination of the failed material if test failures occur. This examination can provide more information about the material condition of the pipe. [Element #3: record #8]

Pressure testing has long been an industry-accepted method for validating the integrity of pipelines. This integrity assessment method can be both a strength test and a leak test. Selection of this method shall be appropriate for the threats being assessed. ASME B31.8-2004 contains details on conducting pressure tests for both post construction testing and for subsequent testing after a pipeline has been in-service for a period of time. The Code specifies the test pressure to be attained and the test duration in order to address certain threats. It also specifies allowable test mediums and specifies under what conditions the various test mediums can be used.

Use of a spike test, alone, as an assessment method would constitute "other technology". Use of "other technology" to perform assessments would require NPCA to notify OPS (or a state regulator) at least 180 days in advance. A spike test may be performed along with a pressure test meeting subpart J requirements. In that case, the subpart J test is considered the primary assessment, and no notification would be required. [FAQ #141]

3.4.3 Direct Assessment *(ICDA, ECDA, SCCDA, CDA)*

How is Direct Assessment Will Be Used and For What Threats [192.923]

Direct Assessment is an integrity assessment method utilizing a structured process through which CVGS is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination and evaluation in order to determine the integrity. The three types of direct assessment include the following: [Element #3: record #9]

- Internal Corrosion Direct Assessment (ICDA)
- External Corrosion Direct Assessment (ECDA)
- Stress Corrosion Cracking Direct Assessment (SCCDA)

General:

CVGS may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. CVGS may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

DA as Primary Method:

If CVGS uses direct assessment as a primary assessment method, CVGS will develop a plan that complies with the requirements in:

1) ASME/ANSI B31.8S-2004 (ibr, see 192.7), section 6.4; NACE RP0502-2002(ibr, see 192.7); and 192.925 if addressing external corrosion (ECDA).

2) ASME/ANSI B31.8S-2004, section 6.4 and appendix B2, and 192.927 if addressing internal corrosion (ICDA).
3) ASME/ANSI B31.8S-2004, appendix A3, and 192.9298 if addressing stress corrosion cracking (SCCDA).

DA as Supplemental Method:

If CVGS uses direct assessment as a supplemental assessment method for any applicable threat, CVGS will have a plan that follows the requirements of confirmatory direct assessment in 192.931. [192.923(c)] The information learned from the DA as a supplemental assessment will be integrated into the CVGS IM program.

3.4.4 Other Technology

Other proven integrity assessment methods may exist for use in managing the integrity of pipelines. For the purpose of this Standard, it is acceptable for CVGS to use these inspections as an alternative to those listed above.

For prescriptive-based integrity management programs, the alternative integrity assessment shall be an industry-recognized methodology and be approved and published by an industry consensus standards organization.

If CVGS decides to perform assessments using other technology, CVGS will develop IMP procedures for selection of technology, review of industry standards, validation of other technology results, and procedures that address reporting and analysis of anomalies and defects.

When "other technology" assessment is selected, CVGS will notify OPS within 180 days before conducting the assessment. Also, CVGS will notify the State or local pipeline safety authority if required when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. See element #14 and 192.949. [192.921(a)(4)] [Element #3: record #10]

If guided wave UT is used as one of the complementary tools for indirect inspections as part of ECDA, it would not be considered other technology. NACE RP0502-2002 lists some indirect inspection tools, but notes that they are not the only tools that can be used. Rather, they are representative examples. "Other indirect inspection methods can and should be used as required by the unique situations along a pipeline or as new technologies are developed. [The operator must] assess the capabilities of any method independently before using it in an ECDA program" (3.4.3.1). Use of guided wave technology, alone, as an examination method or as an alternative to excavating pipeline to conduct a direct examination would be considered "other technology" and would require notification prior to use. [FAQ #198]

Close interval survey/over line survey does not qualify for "other technology." These are indirect measurement techniques that can be used in ECDA. If used in that context, and in conformance with NACE RP0502-2002, these techniques would not represent "other technology". OPS would not find them acceptable as assessment methods if used alone, outside the context of ECDA. [FAQ #204]

3.5 Validation of Assessment Results

Step #2: Validate assessment tools and document during annual agenda review

After ILI tools are run, CVGS will perform excavations or use other techniques to verify the accuracy and reliability of the inspection tools in order to have confidence in the assessment results. Verification of tool tolerance shall be one piece of information that shall be verified. Tool tolerance is specific to each tool type and manufacturer.

The primary method CVGS will use to validate and calibrate ILI tool data will be through excavations. The IMP Leader and/or IMP Team will make the determination on the appropriate number and location of validation digs. CVGS will use a minimum of two excavation digs unless the IMP Leader and IMP Engineer can justify a lesser number. If data comparison from the two excavations conflicts with the ILI tool anomaly data, at least one other excavation dig shall be performed. CVGS will select the two most severe locations for the two validation digs, unless the engineer can justify otherwise. The engineer shall document their excavation decision based on statistics or other sound engineering practices. [Element #3: record #11]

The actual anomaly characteristics (type and dimensions) will be compared to the anomaly characteristics inferred from the ILI tool data to calibrate the ILI tool data to match known examples of detected anomalies. CVGS will work with the ILI vendor to assure the assessment data is valid.

These verifications will be selected to verify tool accuracy for various types of anomalies, including but not limited to, internal corrosion, external corrosion, dents, ovality, gouges, and other types of anomalies. In the case of metal loss anomalies, an onsite UT tool will be used to determine the actual remaining wall thickness in order to verify or eliminate the possibility of internal corrosion.

The required information to be gathered during an excavation to ensure proper validation of the assessment inspection tools and for validation data for the IM program is listed below: [Element #3: record #12]

1) Soil type, pH, and resistivity
2) Test for MIC, if indications of this type of corrosion during the inspection
3) Coating type and condition
4) Pipe type, wall thickness of pipe, and depth of anomaly

Documentation and Distribution of Assessment Results

All reviews of inline inspection reports shall include any conclusions, identification of any integrity issues and any potential trends. Assessment results conclusions will be retained for the life of the pipeline. Assessment results will only be distributed to the appropriate IMP Team members and management as described in the CVGS team charter.

The engineer reviewing the inline inspection report shall request feedback from the vendor in regards to the tool performance, results, and updating the ILI report. This report shall be maintained as part of the IMP records. [Element #3: record #13]

Resolution of Conflict between the Rule and Standards

When the requirements of the rule appear to conflict, the more restrictive requirements will be applied. For example, ASME/ANSI B31.8S-2004, Appendix B, section B1.3, Indirect Examinations, states that the secondary indirect examination method must evaluate at least 25% of each ECDA region. NACE Standard RP0502-2002, section 4.1.2 states that the indirect inspection step requires the use of at least two inspections over the entire length of each ECDA region. To comply with both standards, CVGS will fulfill the more restrictive requirements. Indirect examinations with both complimentary tools must thus be made over the entire length of an ECDA region.

When the language of the rule conflicts with the ASME standard, the rule requirements shall take precedence. For example, section 192.921(a)(2) requires that pressure required to satisfy rule assessment requirements must be conducted in accordance with subpart J. ASME/ASNI B31.8S-2004, section 6.3 states that the details for conducting pressure tests are in ASME B31.8-2007. These two documents contain different requirements for conducting pressure tests. In this case, the pressure tests must satisfy the requirements of subpart J.

Assessment Review Timing

CVGS will obtain sufficient information to identify conditions that present a potential threat to the integrity of the pipeline no more than 180 days after an integrity assessment, unless CVGS can demonstrate that it is impracticable to obtain the information within this limit.

3.6 Prioritized Schedule [192.919(c), 921(b) & (d)]

Step #3: Complete BAP with prioritized schedule during annual agenda review including documentation of new HCAs as described in section 3.8

All baseline integrity assessments must be completed by ***December 17, 2012***. Assessments for 50% of the pipeline mileage in HCAs must be completed by ***December 17, 2007***. CVGS may use assessments completed before December 17, 2002 as a baseline assessment if the prior assessment meets the requirements of Subpart O and anomalies have been remediated in accordance with Subpart O. In this case, however, a reassessment must be completed by December 17, 2009.

The highest risk segments will be prioritized for early assessment, meaning assessments will be performed in the relative sequence identified by risk assessment.

Covered Segments Meeting the Following Conditions Will be Prioritized as High Risk Segments: [Element #3: record #1]

1) Segments that contain ***low frequency resistance welded (ERW) pipe*** or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004, Appendix A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. [§192.917(e)(4)]

2) Covered segments that have ***manufacturing or construction defects*** (including seam defects) where any of the following changes occurred in the covered segment: operating pressure increases above the maximum operating pressure experienced during the preceding five years; MAOP increases; or the stresses leading to cyclic fatigue increase. [§192.917(e)(3)]
3) ***Any pressure increase***, regardless of amount

Idle Line Applicability

The regulations do not define "idle" pipe. Pipe is considered either active or abandoned. OPS understands "idle" pipe, as used in the context of this question, as pipe not currently being used to move gas but that could be put back in service at a future date. All pipe is subject to the requirements of the integrity management rule. However, idle pipe presents different risks and different treatment is appropriate.

In-service pipe (i.e., that contains gas, but is not presently being used to transport gas) represents a potential hazard to public health and the environment, even though idle. If such pipe leaks or ruptures, an explosion could result. Leaks may go undetected for some time, since idle pipe may not be covered by operator's SCADA systems. For these reasons, operators must meet all requirements and deadlines for pipe that contains gas. Such pipe must be included when determining if the requirement to assess 50% of covered pipeline mileage by December 17, 2007, has been met.

Out-of-service pipe (i.e., pipe laid up with nitrogen) represents much less hazard. Degradation of such pipe can occur, but is not likely to result in safety impacts. OPS will accept deferral of activities required by the rule for out-of-service pipe. All deferred activities must be completed as part of any later return of that line to service. Baseline assessments need not be run immediately if the deadline for completing baseline assessments (i.e., December 17, 2012) has not yet expired, unless the risk posed by the line would require an earlier assessment. The baseline assessment plan should be modified to assure that a baseline assessment is completed by the appropriate deadline. If the deadline has expired, then a baseline assessment must be completed as part of returning the line to service.

Adding an idle line into the IM program would be considered a substantive program change and would require notification under 192.909(b). [FAQ #7]

Amount of Pressure Increase to Trigger Assessment of M&C Defects

The rule specifies that any pressure increase, regardless of amount, will require that the segment be prioritized as high risk for integrity assessment. [FAQ #221]

Scope beyond Simple Line Pipe

The continual evaluation, preventive and mitigative actions, and information analysis requirements of the rule apply to pipelines as defined in 49 CFR 192.3. This includes, but is not limited to, line pipe, valves and other appurtenances attached to line pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. The baseline integrity assessment and periodic re-assessment requirements apply only to line pipe including crossovers, bypass piping, etc. [FAQ #6]

Dates an Assessment Will be Considered Complete:

The date on which an assessment will be considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities for in-line inspection tool runs and direct assessments. This would be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with direct assessment is made or the date on which field activities associated with "other technology" for which an operator has provided timely notification are conducted. Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. These activities are considered to occur after the completion of the "assessment".

In those rare instances in which only a partial assessment is performed (e.g., in-line inspection system loss of power results in loss of data near the end of a pig run) CVGS will evaluate the results that were obtained within 180 days of the early termination, in accordance with 192.933(b) [discovery of the condition not to exceed 180 days]. If however, the quality of the partial data is suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun.

3.7 Use of Prior Assessment

CVGS will not use prior assessments in the BAP. Prior assessments are those that were completed prior to December 17, 2002.

3.8 Newly Identified HCAs & Newly Installed Pipe

CVGS will monitor conditions along their pipelines. Pipeline throughput, changes in population and/or environment will be periodically reviewed. When CVGS becomes aware of changes that create or change an HCA (e.g., population expands to encompass more of the area near the pipeline right-of-way), this information will be factored into their integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls.
In addition, CVGS will monitor the National Pipeline Mapping System (NPMS) for changes to the HCAs in the event that changes are introduced. OPS will periodically update the HCA maps and make them available on the internet for operator use. Over time, new HCAs may be identified by the OPS as population distributions change, or new identified sites are listed.

Any gas transmission pipeline placed into service after the effective date of the integrity management rule, February 14, 2004, is considered "newly installed" for purposes of the rule. Newly installed pipe includes replacement pipe. Pipe replaced in a covered segment may be credited as a completed assessment plus be credited as newly installed pipe that does not require re-assessment for another 10 years.

A newly identified HCA, including newly installed pipe, must be incorporated into the integrity management program within one calendar year, not to exceed 18 months of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within ten years of its identification. Newly identified HCAs will be documented in the BAP & Risk Analysis worksheet. [Element #3: record #1]

CVGS will document pipeline and HCA changes during annual agenda reviews. Any modifications or changes to the BAP, and the reasons for the modifications, will be documented before they are implemented.

Inheritance of Plans and Deadlines

For purposes of integrity management, an operator acquiring a pipeline would be expected to integrate that pipeline into its integrity management program. OPS would expect this integration to occur within one year. Integration of new assets into existing Baseline Assessment Plans may result in realigning schedules for future assessments based on the relative risk of the acquired pipeline and the operator's existing pipeline(s).

Integration of acquired pipe into an operator's IM plan could constitute the kind of substantial change in the IM program for which notification is required under 192.909(b), if the integration caused significant changes to existing schedules and programs. [FAQ #10]

Growth of Existing HCAs

Growth of a pipeline segment already in the IM program, as a result of growth of the related HCA, does not constitute a newly-identified HCA, and no requirements of the rule applicable to newly-identified HCAs are triggered by such growth. Operators must assure, however, that the pipe newly covered under the IM program is appropriately assessed at the next scheduled assessment for the covered segment. Operators must also consider any unique issues, e.g., relative to preventive and mitigative measures decisions, that may be introduced by including the new pipe as part of the HCA. [FAQ #233]

3.9 Consideration of Environmental and Safety Risks

CVGS will address requirements for conducting the baseline assessment and reassessments in a manner that minimizes environmental and safety risks. CVGS will utilize existing DOT pipeline O&M procedures and CVGS EHS procedures to ensure precautions will be implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of product) during reassessments. Additional procedures will be developed as needed and identified by the Management of Change (MOC) procedures.

Considerations to be addressed in the CVGS procedures will include:

- Minimizing byproducts from the assessment
- Special monitoring
- Keeping personnel at safe distances when pressurizing pipelines
- Controlling ignition sources
- Line de-pressurization
- Use of protective clothing

Specific pipeline O&M procedures to address these issues are listed below:

1. #3.01 Damage Prevention Program
2. #3.05 Crossing Company Pipelines
3. #4.01 Class Location Survey
4. #5.01 Continuing Surveillance
5. #6.02 Internal Corrosion
6. #6.04 Internal and External Examination of Buried Pipe
7. #6.05 Cathodic Protection & External Corrosion Control
8. #8.01 Maximum Allowable Operating Pressure (MAOP)
9. #9.01 Pipeline Repair Procedures
10. #9.03 Purging Safety Including Blowdown
11. #9.04 Air Movers
12. #14.03 Prevention of Accidental Ignition
13. #15.01 Pressure Testing
14. #15.02 Visual Inspection and Nondestructive Testing

Specific EHS procedures to address these issues are listed below: [Element #3: Record #14]

1. #4.09 Excavation, Trenching, Shoring
2. #4.03 Confined Space
3. #5.98 Respiratory Protection
4. #3.12 Personnel Protective Equipment (PPE)
    - Eye wear
    - Safety clothing
    - Hard hats
    - General foot wear

3.10 Changes and Updates to the BAP

The baseline assessment plan will be modified whenever there are changes to the pipeline in HCAs. Examples of when the BAP will be updated:

1) CVGS identifies a new HCA through monitoring of ROW or when conducting annual IMP agenda reviews
2) Revisions to existing HCA boundaries
3) New or modified pipeline installations
4) Purchase or acquisition of pipeline systems
5) Divestiture of pipeline systems
6) Revisions to the impact analysis
7) Revisions to the risk analysis or integrated information analysis
8) Results of completed assessments
9) Any other change that could affect the assessment method or schedule

Pipeline segments in newly identified HCAs will be included in the Baseline Assessment Plan within one calendar year, not to exceed 18 months after their identification. These pipeline segments will be assessed within ten years of their identification.

The Baseline Assessment Plan will also be modified when CVGS gains knowledge from the initial (baseline) assessments or from its risk assessments that leads to a change in inspection priorities, assessment methods, or other improvements to its program. CVGS will document all plan modifications and the reason(s) for the changes. This documentation must be available for OPS review during an inspection. Any significant changes will be documented as outlined in the MOC process, element #11.

CVGS will review and update the integrity management program and procedures once per calendar year, not to exceed 18 months as described in element #6 of this plan (program evaluation). When changes to the plan occur, CVGS will document the following for each change:

- Reasons for the modification
- Authority for approving change

- Analysis of implications
- Communication of change to affected parties

Notification of Changes to Assessment Schedules

The rule requires that operators notify OPS of any changes "that may **substantially** affect the program's implementation or may **significantly** modify the program or schedule for carrying out the program elements" (emphasis added). Changes to the schedule for assessing individual pipeline segments that do not significantly affect program implementation or plans for carrying out program elements would not require a notification. Operators need not notify OPS of insignificant changes to their assessment schedules. Operators must document the basis for such changes (as required by 192.909(a)), and this documentation must be available for OPS review during integrity management inspections. [FAQ #31]

Notification Types [FAQ #97]

The notifications required by the rule are:

- Substantial change to program implementation or significant change to schedule for carrying out elements. (Within 30 days of adoption). The notification should include a description of the changes and the basis on which they were made
- Inability to meet remediation deadlines in the rule and unable to reduce pressure (When operator determines schedules cannot be met). A description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned should be included.
- Use of technology other than in-line inspection, Direct Assessment, or pressure testing for conducting assessments. (180 days prior to assessment). The operator should provide a description of the "other technology", its basis for concluding that the method will result in equivalent understanding of pipe condition, and its schedule for assessment.

In addition, all notifications must include information about the pipe segments and HCAs involved.

- Pressure reduction imposed as a result of IM anomalies extends for more than 365 days. The notification must explain the reasons for the delay and justify that *the continued pressure reduction will not jeopardize the integrity of the pipeline.*

Thresholds for Notification of Plan Changes

The type of changes considered here would include significant revisions to the baseline assessment plan schedule such as significant delays in segment assessments, or changes that affect the overall manner in which an operator is conducting its IM program. These qualifiers are intended to preclude notifications for minor, even editorial, changes, or changes anticipated to occur to baseline assessment schedules due to foreseeable circumstances such as weather, permitting delays, or re-ranking schedule priorities due to updated risk assessment information. [FAQ #111]

Achieving Versions of BAP

Section 192.947(d) requires that operators maintain, for the useful life of the pipeline, documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Copies of the evolving revisions of the baseline assessment plan, and of plans for periodic reassessments, should be included with the records maintained under this section. [FAQ #32]

3.11 Review and Implementation of Element #3

CVGS will use the agenda, "Gas IMP Element #3 and #6, Baseline Assessment and Continual Assessment Review Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #3 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #3: record #15]

Baseline Assessment and Continual Assessment Agenda Objectives

- List of personnel that shall attend including name and job title
- Frequency of the review
- Description of how the review will be conducted

- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #3 requirements are met
- Action item list as a result of the element #3 review[Element #3: Record #16]

3.10 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915)
Federal Register, Volume #69, No. 102,
May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915)
Federal Register, Volume #69, No. 66,
December 17, 2003.

3. 49 CFR 192.919 – What must be in a baseline assessment plan?

4. 49 CFR 192.921 – How is the baseline assessment to be conducted?

5. OPS Gas Integrity Management, Protocols Area B, Baseline Assessment Plan, January 2008

6. OPS Frequently Asked Questions (FAQs), Assessment, Baseline Assessment Plan, and Assessment Methods, January 2008

7. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #6, Integrity Assessment

Ref: 49 CFR 192.919 & 921	Updated: July 2011

3.11 List of Required Ongoing Documentation for Element #3

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	3.4	BAP, RA, and Mitigation worksheet for documenting assessment method based on threats	IMP Leader	AR	Life of pipeline	Co. intranet
2.	3.4.1	ILI Tool selection, when applicable	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	3.4.1	Remediation worksheet to document "as found" anomaly	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
4.	3.4.1	Report to ILI vendor for potential re-calibration of ILI tool, "as reported" versus "as found" anomaly	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	3.4.1	ILI vendor tool criteria and specifications	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	3.4.2	Pressure test records	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
7.	3.4.2	Documentation for extended assessment intervals	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
8.	3.4.2	Metallurgical examination of failed pipe during pres. test	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
9.	3.4.3	Direct assessment records	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
10.	3.4.4	Other technology records and notification to PHMSA	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet

3.11 List of Required Ongoing Documentation for Element #3 (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
11.	3.5	Excavation decision to validate assessment tool	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
12.	3.5	Excavation info to validate assessment tool(s)	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
13.	3.5	Vendor report of ILI tool performance & updated ILI report	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
14.	3.9	Safe work permits, safety procedures	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
15.	3.11	Annual agenda review	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
16.	3.11	Action items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Integrity Management Plan
Element #4: Direct Assessments

Ref: 49 CFR 192.923, 925, 927, 929	Updated: July 2011

Contents of this Element:

4.1 Summary of Requirements for Direct Assessment [192.923, 925, 927, 929]

Direct assessment may be used as one of the forms of assessment but only if the following threats are involved:

- External Corrosion (Must comply with NACE RP0502-2002)
- Internal Corrosion (Must comply with ASME/ANSI B31.8S)
- Stress Corrosion Cracking (Must comply with ASME/ANSI B31.8S)
  - affects curvature at a girth weld or a longitudinal seam weld and engineering analysis demonstrates that critical strain levels are not exceeded

4.2 Objective and Purpose for Direct Assessment

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS will use these direct assessment procedures to assist CVGS in meeting these objectives.

4.3 Definitions Applicable to Element #4

ECDA is a four step process that combines (1) Pre-Assessment, (2) Inspections, (3) Examinations and Evaluations, and (4) Post-Assessment to assist in determining the integrity of the pipeline. ECDA addresses the issue of external corrosion only.
ICDA is a process used to determine the integrity of the pipeline for internal corrosion only.

SCCDA is a process used to determine if the integrity of the pipeline is affected by stress corrosion cracking.

4.4 Direct Assessment - General [192.923]

CVGS **will not use** direct assessment as the primary assessment method. CVGS may use direct assessment process and selected procedures to supplement other assessment methods allowed under the IMP regulations. If CVGS later decides to use direct assessment as the primary method, procedures will be developed meeting the requirements of the IM regulations before the assessment begins.

Direct assessment is an acceptable assessment method. Like all assessment methods, however, it can only be used in situations for which it is applicable. DA is not applicable for all threats. In addition, there are circumstances (described in NACE-RP0502-2002) under which DA cannot be used. CVGS will be expected to be able to demonstrate that DA, and any other assessment method, is applicable for the threats and circumstances associated with IM assessments for which it is used. [FAQ #187]

CVGS
Integrity Management Plan
Element #5: Remediation and Repair

Ref: 49 CFR 192.933, 935	Updated: July 2012

Contents of this Element:

5.1 Objective and Purpose for Remediation and Repair [192.933, 935]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. CVGS will use these remediation and repair procedures to assist CVGS in meeting these objectives.

5.2 Scope, Applicability, and Use of PHMSA FAQs [192.919 &921]

<u>Scope for CVGS</u>

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the remediation worksheet to schedule and document repairs
- CVGS will use the BAP and risk analysis to document mitigative measures

CVGS
Integrity Management Plan
Element #5: Remediation and Repair

Ref: 49 CFR 192.933, 935	Updated: July 2011

Applicability and Summary of the Regulations

This element covers 192.933, "What actions must be taken to address integrity issues", and 192.935, "What additional preventive and mitigative measures must an operator take?" A summary of the requirements from these two regulations is shown below.

"What actions must be taken to address integrity issues?" [192.933]

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

If CVGS is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay.

(b) *Discovery of condition.* An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation.

(d) *Special requirements for scheduling remediation.* There are three categories of repairs under the regulation:

(1) *Immediate repair conditions.*
(2) *One year*
(3) *Monitored*

"What additional preventive and mitigative measures must an operator take?" [192.935]

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. Such additional measures include, but are not limited to:

- Installing automatic shut-off valves or remote control valves,
- Installing computerized monitoring and leak detection systems,
- Replacing pipe segments with pipe of heavier wall thickness,
- Providing additional training to personnel on response procedures,
- Conducting drills with local emergency responders, and
- Implementing additional inspection and maintenance programs.

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for baseline assessment are shown in appendix 5A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

5.3 Definitions Applicable to Element #5

Defect: is an imperfection of a type and magnitude exceeding acceptable criteria.

Failure is a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.

Indication is a finding of a nondestructive testing technique. It may or may not be a defect.

Inspection is the use of a nondestructive testing technique.

Leak is an unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and non-propagating, longitudinal, and circumferential), separation or pull-out, and loose connections.

Mechanical damage is a type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, and residual stresses, any one of which can be detrimental.

Mitigation is the limitation or reduction of the probability of occurrence or expected consequence for a particular event.

Rupture is a complete failure of any portion of the pipeline.

Stress concentrator is a discontinuity in a structure or change in contour that causes a local increase in stress.

Third-party damage is damage to a gas pipeline facility by an outside party other than those performing work for CVGS. For the purposes of this document it also includes damage caused by CVGS's personnel or CVGS's contractors.

Discovery of a condition occurs when CVGS has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, CVGS may have adequate information when CVGS receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when CVGS receives the final internal inspection report. CVGS is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless CVGS can demonstrate that the 180-day period is impractical.

Immediate Conditions: Criteria are listed below.

- Remaining strength is less than or equal to 1.1 x MAOP
- A dent with any indication of metal loss, cracking, or a stress riser
- An anomaly judged to require immediate action

One-Year Conditions are conditions requiring remediation within one year of discovery. Criteria are listed below.

- Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 8:00 and 4:00 (upper 2/3 of pipe)
- Dent > 2% (>0.25" for pipe diameter less than NPS 12) that affects curvature at a girth weld or a longitudinal seam weld

Monitored conditions are conditions which must be monitored until the next assessment. (Remediation not required): Criteria are listed below.

- Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 4:00 and 8:00 (lower third of pipe)
- Dent > 6% (>0.50" for pipe diameter less than NPS 12) between 8:00 and 4:00 (upper 2/3 of pipe) and engineering analysis demonstrates that critical strain levels are not exceeded

5.4 Program Requirements for Discovery [192.933]

Discovery of a condition occurs when CVGS has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. This point in time can vary, depending on the specific circumstances; however, anomalies representing immediate threats to pipeline integrity will be discovered as soon as practical, usually within 5 days. For example CVGS may have adequate information when CVGS gathers and integrates information from other inspections or when CVGS receives the final internal inspection report.

CVGS is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless CVGS can demonstrate that the 180-day period is impractical.

If there is a situation where the ILI was seriously under calling defects, and CVGS request the smart pig vendor to redo the report, CVGS shall still obtain sufficient information to satisfy the discover requirement within 180-days.

The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities for in-line inspection tool runs and direct assessments. For example, the dates when an assessment would be considered complete is listed below:

- When a hydrostatic test is completed
- When the last in-line inspection tool run of a scheduled series of tool runs is performed
- When the last direct examination associated with direct assessment is made, meaning the date the anomaly is excavated and evaluated
- When the date on which field activities associated with "other technology" for which CVGS has provided timely notification are conducted.

In those rare instances in which only a partial assessment is performed (e.g., in-line inspection system loss of power results in loss of data near the end of a pig run) CVGS will be expected to evaluate the results that were obtained within 180 days of the early termination, in accordance with 192.933(b). If however, the quality of the partial data is suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun. [FAQ #34]

Step #1: Document Actual Date of Discovery

CVGS will document the actual date of discovery on the remediation schedule. [Element #5: Record #1] Once the discovery is made a schedule that prioritizes evaluation and remediation of anomalous conditions will be maintained. CVGS remediation schedule will be used to track completion of remediation activities and demonstrate compliance with required timeframes.

5.5 Evaluation and Remediation Scheduling [192.933]

CVGS will complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in 192.933(d) [immediate, one year, and monitored), CVGS will follow the schedule in ASME/ANSI B31.8S-2004 (incorporated by reference, see § 192.7), section 7, Figure 4. If CVGS cannot meet the schedule for any condition, CVGS will explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

One of the most important aspects of integrity management is discovering defects in the pipe before they grow to a critical size and fail, leak, or rupture. CVGS will address this issue during annual reviews by data integration and using the ASME remediation criteria discussed in the paragraph above.

Two key aspects of discovering anomalies are:

1. Integrated information analysis
2. ILI vendor contract specifications

Step #2: Integrated Information Analysis

Information from ILI or DA assessments shall be integrated with other information in order to identify defects that represent integrity threats. [Element #5: Record #2] While most defects can be discovered from a review of assessment data alone, some defects may not be obvious from the assessment data. Integration of other data with ILI data is a very important step for CVGS to take to assure that defects are discovered.

Examples of data with which ILI results shall be integrated include:

- Data indicative of TPD risk (foreign line crossings, one-call and encroachments, ROW surveys, and aerial surveys, construction activity on or near the ROW).
- Surveillance, testing, and other monitoring data (previous ILI results, CIS, coating surveys such as ACVG or DCVG, coupon data, etc.)
- Operational data (cyclic loading, etc.)
- Maintenance, repair, as-built, and other available data (repair records, maintenance records, etc.)

CVGS will use ESRI ArcGIS Desktop 10 or equivalent to conduct integrated information analysis.

Step #3: ILI Vendor Contract Specifications

ILI vendors have a tremendous affect on the effectiveness and quality of ILI assessments. CVGS has formal, contractual controls in place to properly manage ILI assessments and assure that integrity threats are discovered in a timely manner.

CVGS shall have ILI contracts that address the following: [Element #5: Record #3]

1) Tool specifications (including detection/sizing specifications, reliability, and tolerances) (Note: FAQ-68 indicates that tool tolerance must be considered - tool tolerance is based on a percentage of wall thickness.)
2) CVGS shall specify the threshold for vendor reporting of anomalies. CVGS will specify that the vendor shall report all metal loss anomalies greater than 10%

WT. CVGS considers this threshold appropriate to screen out insignificant or trivial anomalies, while still ensuring that significant anomalies that represent integrity threats are reported. The threshold values shall include an allowance for tool tolerance.

3) Tool velocity
4) How ERF is to be calculated. CVGS will use <u>ASME B31G interaction criterion</u>.
5) Anomaly reporting classification (including the prompt reporting <u>within five days</u> of anomalies that could be immediate conditions or that could represent an imminent pipeline integrity threat) [ASME B31.8S-2004, section #7.2.1]
6) Criteria for data validation and confirming a good tool run. Items to be addressed include:
    - Lost or missing data. What percentage of coverage is acceptable?
    - Failed sensors. How many sensors can fail and the run is still considered acceptable?
7) Deliverable specifications (including preliminary and final report content, format, use of terminology, etc.)
8) Time limits for all actions required to meet or support discovery and remediation deadlines
9) Procedures for addressing and resolving issues or concerns encountered during the entire ILI process (including preparation, tool run, validation of data, analyzing data, resolving discrepancies, etc.)

<u>Step #4: Criteria for Scheduling Remediation of Anomalies</u>

CVGS will review integrity assessments (ILI, pressure test, ECDA, other) and integrate as appropriate to classify anomalies by priority and schedule accordingly. Information to consider during the scheduling includes; depth of anomaly, type of anomaly, risk analysis, data integration, accessibility.

In general, the following criteria will be used to schedule remediation of anomalies. Criteria is listed in order of threat importance (i.e., #1 criteria has more importance than #3 criteria)

1) <u>Remediation Scheduling Priority #1:</u>
   Any anomaly meeting the criteria of an immediate condition under the IMP rule will be first priority.

2) Remediation Scheduling Priority #2:
Any anomaly meeting the criteria of a one year condition under the IMP rule will be second priority.

3) Remediation Scheduling Priority #3:
Using the ILI report, anomalies with 20% or more wall loss combined with one or more of the following using data integration (interactive threats) will be scheduled as priority #3.

- Data indicative of TPD risk (foreign line crossings, one-calls, encroachments, ROW surveys, aerial surveys, and construction activity on or near the ROW).
- Surveillance, testing, and other monitoring data (previous ILI results, CIS, coating surveys such as ACVG or DCVG, coupon data, etc.)
- Operational data (cyclic loading, etc.)
- Maintenance, repair, as-built, and other available data (repair records, maintenance records, etc.)

4) Remediation Scheduling Priority #4:
Using the ILI report, anomalies with 40% or more wall loss will be scheduling priority #4.

5) Remediation Scheduling Priority #5:
Using ASME B31.8S-2004, figure #4, anomalies needing a timed response according to the figure #4 timeline will be scheduled as required.

CVGS has a prioritized schedule for evaluation and remediation of anomalies identified during assessment or reassessment activities. The prioritized schedule documents which of the criteria specified in §192.933(d) and/or ASME B31.8S-2004 were used as the basis for the schedule. See CVGS remediation schedule for documentation of criteria used. [Element #5: Record #1]

Immediate repair conditions will be scheduled immediately upon discovery. Note that ASME B31.8S-2004, Section 7.2.1, requires that immediate ILI indications be examined within 5 days of discovery. "Examined" is understood to mean excavation and direct examination. [Element #5: Record #4]

CVGS can delay examination of an immediate defect beyond 5 days, but must document the basis for their conclusion that any delay will not impact pipeline safety. [Element #5: Record #5] CVGS must notify PHMSA of their inability to examine an immediate repair condition in five days if they cannot provide safety by reducing pressure or taking other action (see §192.933(a)).

5.6 Classification and Remediation of Anomalies [192.933(d)]

Step #5: Conduct Remediation and Repairs According to Schedule
[Element #5: Record #6]

5.6.1 General

This section describes CVGS's program for the classification and remediation of anomalies that meet the criteria for:

(1) Immediate repair conditions;
(2) One-year conditions;
(3) Monitored conditions; or
(4) Other conditions as specified in ASME/ANSI B31 8S, Section 7.

5.6.2 Immediate Repair Conditions [192.933(d)(1)]

CVGS requires a temporary pressure reduction or the pipeline to be shut down as soon as practicable [FAQ #134] upon discovery of all immediate repair conditions. Immediate repair conditions are classified as follows:

1) Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP;

2) A dent having any indication of metal loss, cracking, or a stress riser;

3) An indication or anomaly that is judged by the person designated by CVGS to evaluate assessment results as requiring immediate action.

4) Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding; [ASME B31.8S, 2004,

Section 7.2.1]

5) All indications of stress corrosion cracks; [ASME B31.8S, 2004, Section 7.2.2]; or

6) Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. [ASME B31.8S, 2004, Section 7.2.3]

Hydrostatic test failures will be remediated before returning the pipeline to operation.

Temporary Pressure Reduction for Immediate Repair Indications

Pressure reductions shall be taken promptly. "Promptly" means as promptly as the pressure reduction can be safely implemented, and without undue delay.

The amount of the pressure reduction will be determined using ASME B31.G, or pressure may be reduced to 80% of the operating pressure (not MAOP) at the time of discovery. The remaining strength calculations are limited to use in cases were remaining wall thickness is > 20% of nominal wall thickness, i.e., maximum depth of metal loss is less than 80% WT (d/t<0.8). Any metal loss > 80% WT shall be considered an immediate condition as required by the regulations. [FAQ #67]

B31G and RSTRENG are not valid for situations with metal loss exceeding 80% of wall thickness (see figure 1-2 in B31G, which requires "repair or replace" for conditions involving wall loss greater than 80%). These methods cannot be used to determine failure pressure for these situations. [FAQ #241]

Since temporary pressure reductions may remain in place for up to 365 days, this provides a reasonable amount of safety margin to compensate for defect growth for one year until the defect can be repaired.

There are three options for calculating reduced operating pressures: The IMP Engineer shall make the final determination of which method to use. [Element #5: Record #7]

1) CVGS can use B31.G or RSTRENG to calculate Psafe. This calculation, in either case, includes a safety factor of 0.72.

2) CVGS can reduce pressure to 80% of its level at the time the defect was discovered. OPS consider that a reduction of this magnitude includes sufficient safety margin.
3) CVGS can use B31.G or RSTRENG to calculate Pfailure and can then apply safety margins to determine a new safe operating pressure. CVGS can demonstrate and justify reliable defect growth rates using empirical data and may be able to justify higher temporary operating pressures, if they can show that the defect will not grow to a size that results in the predicted failure pressure being less than 1.1 times the temporary operating pressure within 365 days of initiating the pressure reduction. (If reliable defect growth rates cannot be determined, Table B1 of B31.8S provides conservative estimates of growth rates that can be used for this purpose). Defect growth calculations must be performed based on defect growth during the entire time between when the assessment data was obtained and the end of the 365 day period. [FAQ #229]

Tool tolerance shall be considered in such a way as to assure pipeline integrity, especially when using pressure reduction calculation. For example, defect sizing data for determination of correct repair criteria categorization shall be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length shall be increased by the amount of the tool tolerance). This is especially important for "borderline" anomalies. Defect sizing data used as input into calculations to determine remaining strength of the pipe shall be adjusted to account for the tool tolerance associated with the measurement, in the conservative direction (e.g., metal loss depth and length shall be increased by the amount of the tool tolerance).

Several sources of data may be used, in conjunction with vendor-supplied tool tolerances, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data shall also be considered.

Since the temporary pressure can remain in force for 365 days, growth rate determinations will be performed by CVGS based on the time from the assessment to the end of the 365-day term of reduced pressure.

Note that in some cases, an immediate repair condition may also require submittal of a safety related condition report. The IMP leader will review each immediate repair condition to determine if SRC report is required.

5.6.3 One-Year Conditions [192.933(d)(2)]

One-Year Conditions are conditions requiring remediation within one year of discovery. One year repair conditions are classified as follows:

1) A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; or,

2) A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld.

5.6.4 Monitored Conditions [192.933(d)(3)]

Monitored conditions are conditions which must be monitored until the next assessment. Monitored conditions are classified as follows:

1) A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe;

2) A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; or,

3) A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded.

The rule does not require that monitored conditions be repaired. These conditions must be recorded so that they can be monitored during future integrity management assessments. They must be repaired if future assessments show changes which cause these anomalies to meet criteria for immediate repair or one-year conditions or in the judgment of the person evaluating the assessment are sufficient to require repair. [FAQ #62] Monitored conditions will be listed on CVGS remediation schedule.

Examples of conditions that might be identified that could result in the need to remediate the monitored condition include, but are not limited to:

1) Corrosion growth rates at nearby locations are determined to be greater than originally assumed.
2) New threats to the pipeline segment are identified that could interact with the monitored condition and cause failure before the next assessment.
3) Identification of previously unknown encroachment could cause a small dent that was previously thought to be construction damage to be re-interpreted as third party damage.

5.6.5 Other Conditions [192.933(d)(3)]

CVGS will evaluate anomalies and meet the provisions of ASME/ANSI B31.8S, Section 7, figure 4 for scheduling and remediating any other threat conditions that do not meet the classification criteria of any other threat listed above.

ASME B31.8S-2004, Section 7, Figure 4, provides a graph that instructs CVGS how to determine required repair time frames for any anomalous conditions that do not meet the special criteria found in §192.933(d)(1)-(d)(3) for immediate, one year, or monitored conditions.

By using current operating pressure as a % of SMYS, CVGS can determine which plot on the graph applies to its pipeline. Then by determining predicted failure pressure (Pf) for the anomaly in question and using the ratio of Pf to the MAOP for the pipeline, the time by which the anomaly must be repaired can be determined.

The formulas in the following table model the curves depicted in ASME B31.8S-2004, Section 7, figure 4. Either these formulas or Figure 4 may be used for determination of the required response time for anomalies. [Element #5: Record #8]

Timing for Scheduled Responses [ASME B31.8S-2004, Section 7, figure 4]

Pipeline Operating Stress Level	Formula to Find Response Time (Years)	Not to Exceed Response (Timeframes)
At or Above 50% SMYS	Years = (Pf / MAOP - 1.1) / 0.029	10 years
At or Above 30% up to 50% SMYS	Years = (Pf / MAOP - 1.1) / 0.06	15 years
Less than 30% SMYS	Years = (Pf / MAOP - 1.1) / 0.11	20 years

Actions Required on Non-covered Segments if CVGS Finds Corrosion or Other Anomalies During an Assessment of Segments in HCA [Element #5: Record #9]

Section 192.917(e)(5) requires that if CVGS finds corrosion on a covered pipeline segment "must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics." The conditions for which this provision applies are specified in 192.933(d). There is one specific criterion in Section 192.933(d)(i) related to corrosion – an immediate repair condition in which a calculation of remaining strength shows a predicted failure pressure less than or equal to 1.1 times MAOP.

In determining actions for non-covered segments, CVGS shall consider any data obtained for non-covered segments during the same assessment (i.e., that were part of the same ILI run) that identified the immediate corrosion condition as specified by 192.933(d)(i). Additionally, CVGS shall consider non-covered segments where coating and environmental conditions are similar to those resulting in the immediate corrosion condition in the covered segment. CVGS shall conduct a root cause evaluation to identify the factors (e.g., coating and environmental conditions, equipment or CVGS error) that were important to the significant corrosion that was found, and shall use the results of that evaluation to guide their review of data regarding non-covered pipeline segments to identify areas that need to be addressed.

The special scheduling requirements and requirements to reduce pressure or take other action of Section 192.933(d) do not apply to non-covered segments. PHMSA expects CVGS to take action to address these segments in a timely manner, consistent with the importance to safety of the potentially degraded condition of the pipeline. [FAQ #224]

CVGS may find other anomaly problems in non-covered segments while performing assessment of covered segments (e.g., because non-covered segments are also inspected during an ILI assessment) and must take appropriate actions to meet the requirements in 192.485, 192.703(b), 192.711, 192.713, 192.715, 192.717, and 192.719 as applicable. The provisions and requirements in Section 192.933(d) apply only to covered segments. In non-covered segments, CVGS is responsible for determining the appropriate criteria and schedule for remediating anomalies, consistent with the significance of the identified problem. [FAQ#225]

192.309 Construction Repair Criteria vs. IMP Repair Criteria

49 CFR 192.309 discusses repair criteria for new construction of transmission lines. Subsection 192.309(b) in particular discusses repair criteria for dents in pipeline operating above 20% SMYS and 40% SMYS. Subsection 192.309(b)(3) only applies to pipe operating > 40% SMYS. While the deformation (dent) size criteria are similar, 933(d) applies to all transmission pipe in HCAs and 309(b)(3) only applies to pipeline operating >40% SMYS.

Overlaying 192.933(d) repair criteria onto the 192.309(b) criteria, it can be seen that the dent repair criteria in 192.933(d) are stricter in their application than the 192.309(b)(3) dent criteria for pipelines operating between 20% and 40% of SMYS. The basis for this is that the 192.933(d) criteria are intended to afford extra protection to pipelines in HCAs, whereas the 192.309(b) criteria apply to all new construction pipelines. CVGS must repair (or otherwise remediate) such construction defects found during assessments, even though the defects did not meet the repair criteria in 192.309(b) at the time of construction.

The repair schedules in 192.933 apply only to the covered segment. However, CVGS is responsible for promptly addressing anomalies identified in the other portions of the pigged section in accordance with 192.703(b). [FAQ #66]

Repairs will be completed using CVGS O&M procedures #9.01 Repairs.

5.7 Requirements When Timelines Can Not Be Met [192.933(a)]

General

CVGS is not using exceptional performance criteria. Therefore, CVGS will not attempt to deviate from the timelines for remediation as provided in §192.933 by demonstrating exceptional performance.

CVGS will notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. CVGS must also notify the State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [Element #5: Record #10, #11]

Any time a remediation schedule cannot be met, CVGS must document:
[Element #5: Record #12]

1) Why the specified remediation schedule cannot be met, and
2) Why the changed schedule will not jeopardize public safety using a technically sound basis

CVGS will use ASME B31G to determine the appropriate pressure reduction required by the rule, or CVGS will reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered.

Long-Term Pressure Reduction [192.933(a)(2)] [Element #5: Record #13, 14]

When a pressure reduction exceeds 365 days, CVGS will notify PHMSA under § 192.949 and explain the reasons for the remediation delay. This notice must include a documented technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. CVGS will also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

Ref: 49 CFR 192.933, 935	Updated: July 2011

5.8 Implementation of Element #5

CVGS will use the attached agenda, "Gas IMP Element #5, Remediation Agenda and Action Items", for implementation of this element. CVGS will conduct this element #5 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #5: Record #15]

- Remediation and repair agenda objectives
- List of personnel that shall attend including name and job title
- Frequency of the remediation and repair review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #5 requirements are met
- Action item list as a result of the element #5 review [Element #5: Record #16]

5.9 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915)
   Federal Register, Volume #69, No. 102,
   May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915)
   Federal Register, Volume #69, No. 66,
   December 17, 2003.

3. 49 CFR 192.933 – What actions must be taken to address integrity issues?

4. 49 CFR 192.935 – What additional preventative and mitigative measures must an operator take?

5. OPS Gas Integrity Management, Protocols Area E, Remediation, January 2008

6. OPS Frequently Asked Questions (FAQs): Remediation and Repair

7. ASME B31.8S, 2004, Managing System Integrity for Gas Pipeline, Section #7, Mitigation (Repair and Prevention)

Ref: 49 CFR 192.933, 935 Updated: July 2011

5.10 List of Required Ongoing Documentation for Element #5

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	5.4	Remediation Schedule Including: • Date of discovery [5.5] • Scheduling priority [5.6] • Type of anomaly • Size of anomaly • How anomaly repaired • Date of remediation completion	IMP Leader	AR	5 yrs	Co. intranet
2.	5.5	Integrated Information Analysis	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
	5.5	Integrity Assessment Reports • ILI (preliminary and final) • Pressure test • DA • Other	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	5.5	ILI Vendor Contract Specs	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	5.5	Immediate Repair Examination Report	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	5.5	Reason and Safety Provided for Delayed Examination of an Immediate Defect Beyond 5 Days	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	5.6	Record of Remediation and Repairs According to Schedule (Immediate, One Year, Monitored, Other)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	5.6	ASME B31G calculation For Pressure Reduction Justification	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

5.10 List of Required Ongoing Documentation for Element #5 (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
8.	5.6	ASME B31.8S, Section #7, Figure 4: Calculation to Determine Scheduling of Other Conditions	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
9.	5.6	Record of Actions on Non-Covered Segments	IMP Leader	1x/yr1	Life of pipeline	Co. intranet
10.	5.7	OPS Notification When Remediation Schedule Can Not Be Met	IMP Leader	1x/yr1	5 yrs	Co. intranet
11.	5.7	State Agency Notification When Remediation Schedule Can Not Be Met	IMP Leader	1x/yr1	5 yrs	Co. intranet
12.	5.7	Company Documentation When Remediation Schedule Can Not be Met	IMP Leader	1x/yr1	5 yrs	Co. intranet
13.	5.7	Technical Justification to Exceed 365 Day Pressure Reduction	IMP Leader	1x/yr1	5 yrs	Co. intranet
14.	5.7	Operating logs or other documentation demonstrating that pressure reductions were promptly taken in response to the discovery of immediate conditions or in response to remediation schedules extending beyond those specified in the rule	IMP Leader	1x/yr1	5 yrs	Co. intranet
15.	5.8	Element #5 Agenda	IMP Leader	1x/yr1	5 yrs	Co. intranet
16.	5.8	Gas IMP Element #5 Action Items	IMP Leader	1x/yr1	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Gas Integrity Management Plan
Element #6: Continual Evaluation & Assessments

Ref: 49 CFR 192.937, 939, 941, 943	Updated: July 2011

Contents of this Element:

6.1 Objectives and Purpose of Continual Evaluation & Assessments

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these continual evaluations and assessment procedures to assist in this effort.

6.2 Definitions Applicable to Element #6

ECDA is a four step process that combines (1) Pre-Assessment, (2) Inspections, (3) Examinations and Evaluations, and (4) Post-Assessment to assist in determining the integrity of the pipeline. ECDA addresses the issue of external corrosion only.

ICDA is a process used to determine the integrity of the pipeline for internal corrosion only.

SCCDA is a process used to determine if the integrity of the pipeline is affected by stress corrosion cracking.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

6.3 Scope, Applicability, and Use of PHMSA FAQs [192.937, 939, 941, 943]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.

Applicability

192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

After completing the baseline assessment, CVGS must perform a periodic evaluations based on data integration and risk assessment and implement a program to continually assess the integrity of its pipelines. Mandatory reassessment intervals are summarized in the regulation and shown in this procedure.

In conducting the integrity reassessment, CVGS must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

<u>Use of PHMSA FAQs</u>

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for continual evaluations are shown in appendix 6A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

6.4 Periodic Evaluations [192.937(b)]

CVGS will conduct a periodic evaluation of pipeline integrity based on data integration and risk assessment to identify the threats specific to each covered segment and the risk represented by these threats.

The evaluation will consider the following:

1) Past and present assessment results
2) Data integration and risk assessment information
3) Decisions about remediation
4) Additional preventive and mitigative actions

These periodic evaluations will be conducted once per calendar year, not to exceed 18 months as described in section #6.11 below. The periodic evaluations of data will be thorough, complete, and adequate for establishing reassessment methods and schedules. These periodic "evaluations" will be analytical reviews of a wide range of data and information regarding the pipeline integrity. Data from the entire pipeline will be considered and not just data from covered segments. CVGS is only required to gather and integrate existing data about its pipeline system, i.e., the data does not have to be created if it does not exist.

In addition to a regularly scheduled periodic evaluation interval, CVGS shall conduct periodic evaluations of its pipeline as needed in response to certain events, in order to assure that pipeline integrity threats are promptly identified. The factors/events that shall initiate an immediate evaluation of pipeline integrity include the following:

- External corrosion failure
- Internal corrosion failure
- Stress corrosion cracking failure
- Any event that requires reporting under "incident reporting" 191.3
- The occurrence of a time-dependent failure requires immediate evaluation of the re-assessment interval per ASME B31.8S-2004, Table 3, Note 1

Step #1: Conduct periodic evaluation as discussed in this section and section #6.10. [Element #6: record #1]

Quality of Information

CVGS shall use the best information that they have available in performing the data integration and analysis associated with integrity management and must assure the quality of information used. Information of this nature would be subject to review during integrity management inspections. [FAQ #205]

Information Requirements for Continual Evaluation

CVGS must consider all information relevant to determining risk associated with pipeline operation in HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. At a minimum, an operator must gather and evaluate the set of data specified in appendix A to ASME/ANSI B31.8S-2004. A list of some of the more important information that should be considered in an integrated manner is provided below.

- Results of previous integrity assessments
- Information related to determining the potential for, and preventing, damage due to excavation, including damage prevention activities, and development or planned development along the pipeline
- Corrosion control information (e.g., Years with adequate Cathodic protection, years with questionable Cathodic protection, close interval survey results)
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness)
- Operating parameters (e.g., maximum allowable operating pressure, pressure cycle history)
- Leak and incident history
- Information about the potential consequences of a failure in a high consequence area

CVGS shall consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations. [FAQ #81]

6.5 Re-assessment Methods [192.937(c)]

CVGS will use one or more of the following re-assessment methods depending on the applicable threats: See element #3.

1) An internal inspection tool(s) capable of detecting corrosion and any other threats that CVGS intends to address using this tool(s). The process must follow ASME/ANSI B31.8S-2004, Section 6.2 in selecting the appropriate inspection tool.
2) A pressure test conducted in accordance with subpart J. CVGS will use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S-2004, to justify an extended reassessment interval in accordance with 192.939. Pressure test is appropriate for threats as defined in ASME/ANSI B31.8S-2004, section 6.3.
3) Direct assessment, refer to element #4 and FAQ#187.
4) Other technology that CVGS can demonstrate will provide an equivalent understanding of the condition of the pipe. If other technology is the method selected, the process will require that the CVGS notify OPS at least 180 days before conducting the assessment, in accordance with 192.949. Also, verify that notification to a State or local pipeline safety authority is required when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.
5) Confirmatory direct assessment when used on a covered segment that is scheduled for a reassessment period longer than seven years. Refer to element #7.
6) Low stress assessment method. See section #6.6 below.

The appropriate interval used must be technically justifiable. CVGS will periodically review the evaluation results to determine if the new information warrants changes to reassessment intervals and/or methods, and makes changes to the intervals as appropriate.

6.6 Low Stress Re-assessment (< 30% SMYS) [192.941]

CVGS will not use low stress HCAs at this time. These procedures will be followed if low stress HCA is incorporated into the CVGS IM program.

For pipelines operating at < 30% SMYS, CVGS may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, CVGS will addresses the requirements described below. CVGS will complete a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method.

If used to address external corrosion, CVGS will incorporate the following:

1) If the pipe is cathodically protected, electrical surveys (i.e., indirect examination tool/method) must be performed at least every 7 years. CVGS will use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for covered segments. This evaluation must consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment.
2) If the pipe is unprotected or cathodically protected where electrical surveys are impractical, CVGS will require (1) the conduct of leakage surveys as required by 192.706, at 4-month intervals; and (2) the identification and remediation of areas of active corrosion every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment.

If used to address internal corrosion, CVGS will incorporate all of the following:

1) Gas analysis for corrosive agents must be performed at least once each calendar year.
2) Periodic testing of fluids removed from the segment must be conducted. At least once each calendar year CVGS will test the fluids removed from each storage field that may affect a covered segment.
3) At least every seven (7) years, CVGS will integrate data from the analysis and

testing required by internal corrosion item #1 and item #2 above with applicable internal corrosion leak records, incident reports, and test records, and define and implement appropriate remediation actions.

6.7 Re-assessment Intervals [192.939]

CVGS will reassess covered segments on which a baseline assessment was conducted no later than seven years after the baseline assessment of that covered segment unless the reassessment evaluation indicates an earlier reassessment.

For pipelines operating at or above 30% SMYS, CVGS will follow the requirements described below:

1) When CVGS establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment must be performed at intervals not to exceed seven (7) years followed by a reassessment at the interval established by CVGS.
2) Unless a deviation is permitted under exception performance [192.913(c)], the maximum reassessment interval shall not exceed the values listed in the table below.
3) If the reassessment method is a pressure test, ILI, or other equivalent technology, the interval must be based on either:

   (a) the identified threat(s) for the covered segment (see §192.917) and on the analyses of the results from the last integrity assessment, and a review of data integration and risk assessment; or

   (b) using the intervals specified for different stress levels of pipeline listed in ASME/ANSI B31.8S-2004, section 5, Table 3. CVGS will use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S-2004, to justify an extended reassessment interval in accordance with §192.939.
4) If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to element #4 for CVGS's interval determination.

For pipelines operating below 30% SMYS, CVGS will select one of the following reassessment approaches:

1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph 192.939(a)(1) except that the stress level referenced in 192.939(a)(1)(ii) would be adjusted to reflect the lower operating stress level. However, if an established interval is more than seven (7) years, the CVGS will conduct at seven (7) year intervals either a confirmatory direct assessment in accordance with 192.931, or a low stress reassessment in accordance with 192.941. The CVGS will use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S-2004, to justify an extended reassessment interval in accordance with §192.939.
2) Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to element #4 for evaluating CVGS's interval determination.
3) Reassessment by confirmatory direct assessment at seven year intervals in accordance with subpart 192.931, with reassessment by one of the methods listed in 192.939(b)(1) – (b)(3) by year 20 of the interval.
4) Reassessment by the "low stress method" at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in 192.939(b)(1) through (b)(3) by year 20 of the interval.

For a covered segment on which a prior assessment was credited as a baseline assessment under subpart 192.921(e) that segment will be reassessed by no later than December 17, 2009.

The following table sets forth the maximum reassessment intervals. [192.939(b)(6)]

Maximum Reassessment Interval

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941.

(*)A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**)A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

Requirements That Need to be Adopted Before the Line Stress is Raised to >30% SMYS

Provisions applicable to pipelines operating below 30% SMYS apply to pipelines for which the MAOP is less than 30% SMYS. Increasing operating pressure to greater than 30% SMYS would require uprating pursuant to Subpart K. For integrity management purposes, the requirements applicable to each covered pipeline segment must be met at all times. Some requirements vary depending on pipe stress level. There is no grace period allowed to come back into compliance if stress levels are changed. If CVGS plans to increase stress levels to >30% SMYS must determine, as part of planning for that increase, whether additional actions need to be taken to be in compliance with integrity management requirements. If an assessment has not been performed in over 15 years, the maximum interval allowed for pipelines between 30 and 50% SMYS under 192.939, then an assessment would need to be conducted before the pressure increase is implemented. (Note that similar considerations are required for pressure changes that would increase stress levels to above 50% SMYS). [FAQ #178]

Extended Reassessment Interval for Hydrostatically Tested Pipeline, Tested to a Pressure Different Than Those Listed in Table 3 of ASME/ANSI B31.8S-2004

CVGS may use straight-line interpolation to determine acceptable intervals between the 5, 10, 15, and 20 year intervals listed in Table 3. In no case must operators reassess more frequently than once every seven years unless such frequent reassessments are determined necessary by risk assessment. [FAQ #236]

Reassessment Schedule When Defects Found During Confirmatory DA

The rule specifies that sections 6.2 and 6.3 of NACE RP-0502-2002 must be used to schedule the next reassessment if CDA identifies any defects requiring remediation prior to the next scheduled assessment (192.931(d)). Even though the NACE standard, as a whole, is not applicable to ICDA, these sections still must be used in scheduling new assessments when internal corrosion defects are revealed during CDA. [FAQ #132]

Scope of Seven Year Assessments

Intervals for full assessments must be established per the requirements in 192.939. Maximum reassessment intervals vary with pipeline stress level as presented in the table in that section, but shorter intervals may be required if indicated by the operator's risk analysis. If an interval of longer than seven years is established, then some assessment must be performed no less frequently than every seven years. Confirmatory direct assessment, alone, is sufficient to fulfill this requirement. [FAQ #133]

7 Years as Minimum Reassessment Requirement

Section 192.939(a)(1) specifies requirements for establishing reassessment intervals. Two options are allowed: basing the interval on identified threats, assessment results, data integration, and risk analysis or using the intervals specified in Table 3 of ASME/ANSI B31.8S-2004. An operator using the former option (192.939(a)(1)(i)) could establish intervals longer than those in Table 3. The intervals that can be established by either method are limited to the maximum intervals in the Table in 192.939.

Pressure tests used as IM assessments must meet the requirements of Subpart J, including required test pressures. Higher test pressures must be used to justify extended reassessment intervals (192.937(c)(2)). As used here "extended reassessment intervals" refers to any interval longer than seven years as required by 192.937(a) and 192.939(a) and (b).

When CVGS conducts assessment by pressure testing and who use test pressures meeting Subpart J requirements may establish a reassessment interval of seven years, unless their analysis under 192.939(a)(i) indicates a need for a shorter interval. This is true even if Table 3 would lead to a shorter interval.

When CVGS uses Table 3 test pressures, CVGS may establish reassessment intervals in accordance with Table 3 up to the maximums listed in the table in 192.939, again unless their analysis under 192.939(a)(i) indicates a need for a shorter interval. If NPCA establishes intervals longer than seven years, NPCA must conduct a confirmatory direct assessment within the seven-year period. (For segments operating at less than 30% SMYS, a low-stress reassessment per 192.941 may be conducted in lieu of CDA – see 192.939(b)(1)). [FAQ #207]

Coverage for 7-Year CDA

All covered segments must be assessed at least every 7 years. For pipelines operating below 30% SMYS, confirmatory direct assessment (CDA) or low-pressure reassessment (per 192.941) are available options for performing these assessments. It is up to each operator to select the assessment method appropriate for each covered segment. [FAQ #216]

Can CDA be Used to Extend Assessment Intervals?

No. CDA is an interim measure, intended to provide for assessments at the minimum frequency specified in the Pipeline Safety Improvement Act of 2002. It provides assurance that significant unknown degradation is not occurring, but does not provide a knowledge of pipe condition equal to that which would be obtained from one of the other specified methods. A successful CDA allows operation for the remainder of the assessment interval (or until the next CDA in the case of low-pressure pipeline on 20-year interval and for which the interval has more than 7 years to run) but it does not allow that interval to be extended. [FAQ #228]

6.8 Deviation from Re-Assessment Requirements

When CVGS elects to deviate from certain requirements listed in §192.913(c), CVGS will use a performance based approach that satisfies the requirements for exceptional performance as follows:

1) A comprehensive process for risk analysis;
2) All risk factor data used to support the program;
3) A comprehensive data integration process;
4) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
5) A procedure for evaluating every incident, including its cause, within CVGS's sector of the pipeline industry for implications both to CVGS's pipeline system and to the operator's integrity management program;
6) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
7) Semi-annual performance measures beyond those required in §192.943 that are part of CVGS's performance plan.
8) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

CVGS will remediate anomalies identified in the more recent assessment per the requirements of §192.933 (actions that must be taken to address integrity issues). CVGS will also incorporate the results and lessons learned from the more recent assessment into CVGS's data integration and risk assessment.

6.9 Waiver from Re-assessment Intervals [192.943]

CVGS will apply for a waiver, should it become necessary, from the required reassessment interval. The waiver request will demonstrate that the waiver is justified as specified in the rule. Such a waiver request will only be made in the following limited situations: [Element #6: record #2]

1) Lack of internal inspection tools.
2) Cannot maintain local product supply.
3) Application must be made at least 180 days before the end of the required reassessment interval. (Exception: If local product supply issues make the 180 day submittal impractical, CVGS must apply for the waiver as soon as the need for waiver becomes known).

PHMSA Waivers for Re-assessment Interval Extended Beyond the Maximum Interval Specified in 192.939

OPS can grant waivers from the reassessment intervals specified in 192.939 in instances in which appropriate inspection tools are not available or where conducting an assessment would imperil gas supply. Operators must apply for such waivers at least 180 days before the end of the reassessment interval, unless local gas supply issues make this impractical. Operators whose integrity management programs meet criteria for exceptional performance in 192.913 can implement performance-based programs in which they can establish longer reassessment intervals based on their own risk analyses, except that reassessment by some method must be carried out at an interval no greater than seven years (see 192.913(c)). [FAQ #43]

6.10 Consideration of Environmental and Safety Risks [192.911(o)]

CVGS will addresses requirements for conducting the reassessments in a manner that minimizes environmental and safety risks. CVGS will utilize existing DOT pipeline O&M procedures and CVGS EHS procedures to ensure precautions will implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of product) during reassessments. Additional procedures will be developed as needed and identified by the Management of Change (MOC) procedures.

6.11 Review and Implementation of Element #6

CVGS will use the agenda, "Gas IMP Element #6, Continual Evaluation and Assessment Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #6 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #6: Record #1]

- Baseline and Continual Assessment Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #6 requirements are met
- Action item list as a result of the element #6 review [Element #6: Record #3]

6.12 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.937 – What is a continual process of evaluation and assessment to maintain pipeline integrity?

4. 49 CFR 192.939 – What are the required reassessment intervals?

5. 49 CFR 192.941 - What is a low stress reassessment?

6. 49 CFR 192.943 – When can an operator deviate from these reassessment intervals?

7. 49 CFR 192.911(o) – What are the elements of an integrity management program?
8. OPS Gas Integrity Management, Protocols Area F, Continual Evaluation and Assessment, January 2008

9. OPS Frequently Asked Questions (FAQs), Continual Evaluation and Assessment, January 2008

6.12 List of Required Ongoing Documentation for Element #6

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	6.4 6.10	Periodic evaluation using agenda and data integration	IMP Leader	AR	5 yrs	Co. intranet
2.	6.9	Waiver from reassessment interval	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	6.11	Action item list	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Gas Integrity Management Plan
Element #7: Confirmatory Direct Assessment

Ref: 49 CFR 192.937(c)(5), 931	Updated: July 2011

Contents of this Element:

7.1 Summary of Requirements for CDA [192.937(c)(5), 931]

Confirmatory Direct Assessment (CDA) is a gas IMP assessment process that can be used on a covered segment that is scheduled for reassessment at a period longer than seven years

7.2 CDA - General

CVGS **<u>will not use</u>** confirmatory direct assessment as a process on a covered segment. If the company later decides to use direct assessment, detailed procedures will be developed meeting the requirements of the IM regulations before the assessment begins.

When CVGS uses CDA as allowed in §192.937, the Company will follow the requirements of §192.931, §192.925 (ECDA) and §192.927 (ICDA). CDA will be used to identify damage resulting from external corrosion or internal corrosion only.

CVGS's CDA plan for external corrosion will comply with all of the requirements contained in §192.925 with the following exceptions;

i. The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.
ii. The procedures for direct examination and remediation must provide that all immediate action indications and at least one scheduled action indication are excavated for each ECDA region.

CVGS's CDA plan for internal corrosion will comply with all of the requirements contained in §192.927, except that procedures for identifying locations for excavation will require excavation of only one high risk location in each ICDA region.

When CVGS discovers any defect requiring remediation prior to the next scheduled assessment, CVGS will evaluate the need to accelerate the schedule for the next assessment. If the schedule is accelerated, the new assessment scheduled will be determined using the methodology documented in NACE RP0502-2002, Section 6.2 and 6.3. [§192.931(d)]

i. If the defect requires immediate remediation, CVGS will reduce pressure consistent with §192.933 until CVGS has completed reassessment using one of the assessment techniques allowed in §192.937.

7.3 Related References and Documents

1. 49 CFR 192.937(c)(5), 931
2. ASME B31.8S-2004, Managing System Integrity for Gas Pipeline, Section #6, Integrity Assessment
3. OPS Frequently Asked Questions (FAQs), #s:
4. OPS Gas Integrity Management Protocols, Protocol Area #G, Confirmatory Direct Assessment, Dec 2007

CVGS
Gas Integrity Management Plan
Element #8: Preventive and Mitigative Measures

Ref: 49 CFR 192.935	Updated: July 2012

Contents of this Element:

8.1 Objectives and Purpose of Preventive and Mitigative Measures [192.935]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these preventative and mitigative measure procedures to assist in this effort.

8.2 Scope, Applicability, and Use of PHMSA FAQs [192.935]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the BAP and risk analysis to document mitigative measures.

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for preventive and mitigative measures are shown in appendix 8A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

8.3 Definitions Applicable to Element #8

Risk: a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

Risk assessment: A systematic process, in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives (see section 5).

Risk management: an overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

8.4 General Requirements and ID of Additional Measures [192.935(a)]

CVGS will take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. The process for identifying additional measures will be based on identified threats to each pipeline segment and the risk analysis required by §192.917 and described in CVGS IMP element #2. Mitigative measures are shown on the CVGS risk analysis and mitigative review worksheet.

The additional measures evaluated by CVGS will cover a spectrum of alternatives such as, but not limited to the following:

1) Enhancements to damage prevention program (third party damage, TPD)

2) Installing automatic shut-off valves or remote control valves
3) Installing computerized monitoring and leak detection systems
4) Replacing pipe segments with pipe of heavier wall thickness
5) Providing additional training to personnel on response procedures
6) Conducting drills with local emergency responders
7) Implementing additional inspection and maintenance programs

Other preventive or mitigative measures not specifically referenced by the regulation that CVGS will consider include:

- Implementing damage prevention best practices,
- Establishing better monitoring of cathodic protection where corrosion is a concern,
- Establishing shorter inspection intervals,
- Increasing the frequency of ROW inspections,
- Adopting other management controls
- Replacing pipe segments with pipe of heavier wall thickness

CVGS will use annual reviews with agenda and risk analysis for documenting the decision-making process that is used to decide which measures are to be implemented. These annual agenda reviews involve input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control as appropriate. The decision-making process considers both the likelihood and consequences of pipeline failures. These additional measures will be identified and documented in the action item list. Documentation will include identification of the additional items, completed implementation items, and schedules for completion. See CVGS IMP element #2, risk analysis, and IM program action item list.

8.5 Enhancements to Damage Prevention (TPD) [192.935(b)(1) & 192.935(e)(1)]

CVGS will implement the following preventive and mitigative requirements regarding threats due to third party damage. These minimum enhancements to the 192.614 required damage prevention program will include the following with respect to covered segments to prevent and minimize the consequences of a release:

1) Using <u>qualified personnel</u> for work CVGS is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [192.935(b)(1)(i)] [Element #8: Record #1]

2) Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191. [192.935(b)(1)(ii)] [Element #8: Record #2]
3) Participating in one-call systems in locations where covered segments are present. [192.935(b)(1)(iii)] [Element #8: Record #3]
4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. [192.935(b)(1)(iv)] [Element #8: Record #4]

If CVGS finds physical evidence of encroachment involving excavation that CVGS did not monitor near a covered segment, CVGS must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502–2008 (incorporated by reference, *see* §192.7). CVGS must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination. [Element #8: Record #5 & 6]

If the threat of third party damage is identified by results of the data gathering, data integration process, and threat review (see 192.917, gas IMP element #3), CVGS will implement these enhancements to the damage prevention program.
Step #1: Conduct and Complete Enhancements to Damage Prevention Program as Listed in section #8.5 above

Note, when CVGS has a covered segment operating below 30% SMYS and for plastic transmission pipelines, CVGS will implement a subset of these enhancements. See element #8.11 below.

8.6 Automatic Shut-Off Valves or Remote Control Valves [192.935(c)]

CVGS will review covered segments to determine if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. CVGS will use a SME risk analysis-based process to determine if an automatic shut-off valve or remote control valve shall be added. As a minimum, the following factors will be considered: [Element #8: Record #7]

1. Swiftness of leak detection and pipe shutdown capabilities
2. Type of gas being transported
3. Operating pressure
4. Rate of potential release
5. Pipeline profile
6. Potential for ignition
7. Location of nearest response personnel
8. Computerized monitoring
9. Leak Detection

Step #2: Conduct Automatic Shutoff Review Using Risk Analysis Format

8.7 Pipeline Operating Below 30% SMYS [192.935(d)]

CVGS will implement the following preventive and mitigative requirements for pipelines operating below 30% SMYS:

1) CVGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if CVGS is conducting a task that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [Element #8: Record #8]
2) CVGS's processes for damage prevention program enhancements will include participating in one-call systems in locations where covered segments are present. [Element #8: Record #9]
3) Excavations near the pipeline will be monitored, or patrols will be conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2)] [Element #8: Record #10, #11]
4) If indications of unreported construction activity are found, follow up investigations will be conducted to determine if mechanical damage has occurred. [§192.935(d)(2)] [Element #8: Record #12]

For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area, CVGS will implement the following minimum requirements:

1) CVGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if CVGS is conducting a task that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
2) CVGS's processes for damage prevention program enhancements will include participating in one-call systems in locations where covered segments are present.
3) Excavations near the pipeline will be monitored, or patrols will be conducted of the pipeline at bi-monthly intervals as required by 192.705. [192.935(d), 192.935(d)(2)]
4) If indications of unreported construction activity are found, follow up investigations will be conducted to determine if mechanical damage has occurred. [192.935(d)(2)]
5) CVGS will perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [192.935(d)(3), Table E.II.1] [Element #8: Record #13]

Step #3: Implement Preventive & Mitigative Measures for Pipeline Operating Below 30% SYMS, if Applicable

The following tables summarize these more restrictive requirements:

Class 3	Cathodically Protected, electrical surveys practical	Cathodically Protected, electrical surveys impractical	Cathodically unprotected
Odorized	Semi-annual (935(d))	Quarterly (935(d))	Quarterly (935(d)
Un-odorized	Semi-annual (935(d) and 706(a))	Quarterly (935(d))	Quarterly (935(d))

Class 4	Cathodically Protected, electrical surveys practical	Cathodically Protected, electrical surveys impractical	Cathodically unprotected
Odorized	Semi-annual (935(d))	Quarterly (935(d))	Quarterly (935(d)
Un-odorized	Quarterly (706(b))	Quarterly (935(d))	Quarterly (935(d))

8.8 Plastic Transmission Pipeline [192.935(e)]

CVGS does not have plastic transmission pipeline in an HCA segment at this time. If CVGS has plastic transmission pipelines in the future, CVGS will implement the following applicable third party damage requirements to covered segments:
[Element #8: Record #14]

1) CVGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if CVGS is conducting a task that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
2) CVGS's processes for damage prevention program enhancements will include participating in one-call systems in locations where covered segments are present.
3) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. [192.935(b)(1)(iv)]
4) If CVGS finds physical evidence of encroachment involving excavation that CVGS did not monitor near a covered segment, CVGS must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502–2008 (incorporated by reference, *see* §192.7). CVGS must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

<u>Step #4: Implement Preventive & Mitigative Measures for Plastic Transmission, if Applicable</u>

8.9 Outside Force Damage Preventive & Mitigative Measures [192.935(b)(2)]

CVGS will address threats due to outside force (e.g., earth movement, floods, and unstable suspension bridge). If CVGS makes a determination that outside force (e.g., earth movement, floods, and unstable suspension bridge) is a threat to the integrity of a covered segment, CVGS will take measures to minimize the consequences to the covered segment. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

Consideration for outside force damage will be part of the risk analysis that includes mitigative measures. See IMP element #2 and CVGS risk analysis.

Information on geographic areas with the potential for certain external threats can be found on the National Pipeline Mapping System (NPMS) found at the following location:

- http://www.npms.phmsa.dot.gov/

Using NPMS, CVGS will determine areas with a high or medium risk of floods, landslides, earthquakes, or hurricanes. PHMSA issued user name and log in will be required to view the pipeline with outside force map overlays. [Element #8: Record #15]

Step #5: Conduct Review for Outside Force Areas Using NPMS

8.10 Corrosion Preventive and Mitigative Measures [192.917(e)(5)]

CVGS will take required actions to address corrosion threats. If CVGS makes a determination that corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line, CVGS will implement the following minimum requirements:

- The corrosion will be evaluated and remediated, as necessary, for all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. [Element #8: Record #16]
- A schedule will be established for evaluating and remediating, as necessary, the similar segments consistent with CVGS's established operating and maintenance [Element #8: Record #17]

"Could adversely affect the integrity of the line" means an immediate repair condition in accordance with 192.933. In other words, this requirement applies if CVGS finds corrosion metal loss resulting in a Pf <1.1 times MAOP. [FAQ #135]

Implicit in this requirement is that CVGS's evaluation determines the root cause of the condition.[Element #8: Record #18] Clearly in most cases, it would not be practical to excavate all pipelines with similar coating and environmental characteristics. This suggests that the evaluation further refine the criteria by which other portions of the line will be investigated or excavated. For example;

- If the root cause was poor dis-bonded coating, an ACVG or DCVG Survey might be planned to determine the extent of coating damage and investigate areas of poor coating [Element #8: Record #19]
- If the defect was discovered based on ECDA, the indirect assessment logs may need to be re-graded and further excavations performed.

Consideration for corrosion will be part of the risk analysis that includes mitigative measures. See IMP element #2 and CVGS risk analysis.

Step #6: Implement Additional Corrosion Preventive and Mitigative Measures, if Appropriate

8.11 Review and Implementation of Element #8

CVGS will use the agenda, "Gas IMP Element #8, Preventive and Mitigative Measures Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #8 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #8: Record #20]

- Preventive and Mitigative Measures Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review

- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #8 requirements are met
- Action item list as a result of the element #8 review[Element #8: Record #21]

8.12 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.935 – What additional preventative and mitigative measures must an operator take?

4. OPS Gas Integrity Management, Protocols Area H, Preventive and Mitigative Measures, January 2008

5. OPS Frequently Asked Questions (FAQs), Preventive and Mitigative Measures January 2008

6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #5 Risk Assessment and section #7, Responses to Integrity Assessments and Mitigation

7. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008

8.13 List of Required Ongoing Documentation for Element #8

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	8.5	OQ Records for Personnel Marking and Locating	IMP Leader	AR	5 yrs	Co. intranet
2.	8.5	Central Database for TPD	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	8.5	One Call System Records	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	8.5	Monitoring Excavation (Exposed Pipe Reports)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	8.5	Excavation When Encroachment Without Monitoring	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	8.5	Above Ground Surveys (CIS, DCVG, etc.)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	8.6	Auto Shutoff Review Using Risk Analysis Approach	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
8.	8.7	OQ Records for Personnel Marking and Locating (< 30% SMYS)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
9.	8.7	One Call Records (<30% SMYS)	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
10.	8.7	Monitoring Excavation - Exposed Pipe Reports (<30% SMYS)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
11.	8.7	Bi-Monthly Patrols for Excavations Near the Pipeline (<30% SMYS)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
12.	8.7	Follow Up Investigation When Indications of Unreported Construction Activity (<30% SMYS)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
13.	8.7	Semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). (<30% SMYS)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
14.	8.8	Plastic Pipe Additional Surveys, if Applicable	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
15.	8.9	NPMS Maps with Outside Force Overlays	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

8.16 List of Required Ongoing Documentation for Element #8 (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
16.	8.10	Corrosion Evaluation	IMP Leader	AR	5 yrs	Co. intranet
17.	8.10	Schedule for Remediating Corrosion on Similar Segments	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
18.	8.10	Corrosion Root Cause Analysis	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
19.	8.10	Corrosion Surveys to Determine Extent of Damage (CIS, DCVG, etc.)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
20.	8.11	Element #8 agenda	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
21.	8.11	Element #8 action items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

CVGS
Integrity Management Plan
Element #9: Performance Measures

Ref: 49 CFR 192.945	Updated: July 2012

Contents of this Element:

9.1 Objective and Purpose for Performance Measures [192.945]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS will develop performance measures to determine IMP effectiveness. Effective performance measures will guide CVGS by focusing resources to provide for effective preventative maintenance.

9.2 Scope, Applicability, and Use of PHMSA FAQs [192.919 &921]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the performance measures worksheet to document performance measures requirements

CVGS
Integrity Management Plan
Element #9: Performance Measures

Ref: 49 CFR 192.945	Updated: July 2011

Applicability and Summary of the Regulations

This element covers 192.945, "What methods must an operator use to measure program effectiveness"?" A summary of the requirements from this regulation is shown below.

"What methods must an operator use to measure program effectiveness?" [192.945]

(a) General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S-2004 (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S-2004, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter.

(b) External Corrosion Direct assessment. In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of full ECDA process as defined in §192.925.

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for performance measures are shown in appendix 9A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

9.3 Performance Measures Submittal to OPS
[§192.945(a) and ASME B31.8S-2004, §12(b)(5)]

Step #1: Semi-Annual Submittal to OPS on Four Performance Measures

CVGS will conduct performance measurement semi-annually (completed through June 30th and December 31st of each year) for each of the following: [ASME B31.8S-2004, §9.4]

- Number of miles of pipeline inspected versus program requirements
- Number of immediate repairs completed as a result of the integrity management inspection program
- Number of scheduled repairs completed as a result of the integrity management program
- Number of leaks, failures and incidents (classified by cause).

The four overall performance measures of ASME B31.8S-2004, § 9.4 will be submitted to OPS on a semi-annual basis. Semi-annual reports will be submitted by February 28th (or 29th) and August 31st of each year thereafter. [Element #9: Record #1]

CVGS will have a senior executive officer review and sign the report. By signing, the senior executive officer is certifying the report has been reviewed and to the best of the senior executive officer's knowledge and belief, the report is true and complete. CVGS will enter the name and title of the senior executive officer certifying the report in the appropriate box on the form and in the signature block on the form. Entering the senior executive officer's name onto the electronic form has the same legal authenticity and requirements as a paper document.

In lieu of filing electronically, CVGS can mail or fax the reports to PHMSA.

PHMSA Fax number: (202) 366–7128

PHMSA mailing address:

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

CVGS will submit the semi-annual report for each state in which CVGS has jurisdictional gas transmission pipelines. If CVGS pipeline operations change so that there are no longer any HCAs, CVGS will continue to submit performance metrics semi-annually. This is so CVGS can continue looking for new HCAs. CVGS will review information such as population growth or land use changes that could result in new HCAs. See CVGS IM procedure #1, ID of HCAs.

9.4 General Requirements & ID of Additional Performance Measures
[§192.945(a) and ASME B31.8S-2004, §12(b)(5) and appendix A]

Step #2: Determine Which of the ASME B31.8S-2004, Appendix A Threats Apply to the CVGS Pipelines

In addition to the four performance measures already discussed in section #9.2 above, CVGS will also determine which of the ASME B31.8S-2004 Appendix A threats apply. CVGS will use these identified threats for measuring integrity management program effectiveness. [Element #9: Record #2]

Step #3: Review Additional Threats Semi-Annually: CVGS will review threat specific measures semi-annually. A list of these threat specific measures is listed below and documented on the "performance measures" worksheet. [Element #9: Record #3]

Threat-Specific Measures as Identified in ASME B31.8S-2004, Appendix A:

External Corrosion Threats ASME B31.8S-2004, Appendix A, Section A1.8	(a) Number of hydrostatic test failures caused by external corrosion (b) Number of repair actions taken due to in-line inspection results, immediate and scheduled (c) Number of repair actions taken due to direct assessment results, immediate and scheduled (d) Number of external corrosion leaks (for low stress pipelines it may be beneficial to compile leaks by leak classification)
Internal Corrosion Threats ASME B31.8S-2004, Appendix A, Section A2.8	(a) Number of hydrostatic test failures caused by internal corrosion (b) Number of repair actions taken due to in-line inspection results, immediate and scheduled (c) Number of repair actions taken due to direct

	assessment results, immediate and scheduled (d) Number of internal corrosion leaks (for low stress pipelines it may be beneficial to compile leaks by leak grade)
Stress Corrosion Cracking ASME B31.8S-2004, Appendix A, Section A3.6	(a) Number of in-service leaks/failures due to SCC (b) Number of repair or replacements die to SCC (c) Number of hydrostatic test failures due to SCC
Manufacturing ASME B31.8S-2004, Appendix A, Section A4.8	(a) Number of hydrostatic test failures caused by manufacturing defects (b) Number of leaks due to manufacturing defects
Construction ASME B31.8S-2004, Appendix A, Section A5.8	(a) Number of leaks or failures due to construction defects (b) Number of girth welds/couplings reinforced/removed (c) Number of wrinkle bends removed (d) Number of wrinkle bend inspections (e) Number of fabrication welds repaired/removed
Equipment ASME B31.8S-2004, Appendix A, Section A6.8	(a) Number of regulator valve failures (b) Number of relief valve failures (c) Number of gasket or O-ring failures
Third Party Damage ASME B31.8S-2004, Appendix A, Section A7.8	(a) Number of leaks or failures caused by third party damage (b) Number of leaks or failures caused by previously damaged pipe (c) Number of leaks or failures caused by vandalism (d) Number of repairs implemented as a result of third party damage prior to a leak or failure
Incorrect Operations ASME B31.8S-2004, Appendix A, Section A8.8	(a) Number of leaks or failures caused by incorrect operations (b) Number of audits/reviews conducted (c) Number of findings per audit/review classified by severity (d) Number of changes to procedures due to audit/reviews
Weather / Outside Force ASME B31.8S-2004, Appendix A, Section A9.8	(a) Number of leaks that are weather related or due to outside force (b) Number of repair, replacement, or relocation actions due to weather related or outside force threats

CVGS
Integrity Management Plan
Element #9: Performance Measures

Ref: 49 CFR 192.945	Updated: July 2011

The following pipeline O&M procedures, completed reports, and surveys will be gathered and reviewed for performance measures, including the following:

1) Reporting and Control of Incidents, O&M #1.01 [Element #9: Record #4]
2) Reporting of Safety Related Conditions, O&M #1.02 [Element #9: Record #5]
3) Investigation of Failures and Accidents, O&M #1.03 [Element #9: Record #6]
4) Annual Reports, O&M #1.04 [Element #9: Record #7]
5) Class Location Survey Report, O&M #4.01 [Element #9: Record #8]
6) Continuing Surveillance Report, O&M #5.01[Element #9: Record #9]
7) Gas Leak Survey Reports, O&M #5.02 [Element #9: Record #10]
8) Pipeline Patrol Reports, O&M #5.03 [Element #9: Record #11]
9) Internal and External Examination of Buried Pipe (exposed pipe reports) O&M #6.04 [Element #9: Record #12]
10) Pipeline Repair Procedures and Reports, O&M #9.01 [Element #9: Record #13]
11) Conversion of Service, O&M #12.02 [Element #9: Record #14]
12) Abandonment or Inactivation of Facilities, O&M #13.01 [Element #9: Record #15]
13) Pressure Testing and Reports, O&M #15.01 [Element #9: Record #16]
14) Visual Inspection and NDT Testing and Reports, O&M #15.02 [Element #9: Record #17]
15) Control Room Management Incident Review, PSOM #17.11 [Element #9: Record #18]

Additional integrity documents to be gathered and reviewed for performance measures worksheet.

16) Smart pig reports (ILI) [Element #9: Record #19]
17) Direct assessment reports [Element #9: Record #20]
18) Construction repair reports [Element #9: Record #21]
19) Equipment failure reports [Element #9: Record #22]

Step #4: Review IM Program for Potential Additional Threats

CVGS will review the integrity program for additional threats that may not be listed as described above. These potential additional performance measures shall only be selected reasonable indicators of the plan's effectiveness and will remain good indicators as the IM program evolves.

A list of questions that will be asked before selecting and adding these potential measures is listed below. [Element #9: Record #23]

- Is it an actual report card measuring results (e.g., reduction in anomalies) rather than just activities (e.g., leaks repaired per year)?
- Is it readily measurable (i.e., stated in terms of quality, quantity, time, or cost)?
- Does the data exist or can it be gathered in a practical manner?
- Is the data in a form such that it can be readily used as a measure of performance?
- Do any of the plan performance measures overlap any other?
- Is the measure a key indicator of the integrity management plan's effectiveness?
- Is the number of plan performance measures manageable?
- Will the measure be useful over time?

Threshold for Reporting Leaks, Failures, and Incidents

One of the four overall performance measures required by 192.945(a) is the number of leaks, failures, and incidents (classified by cause). These terms are defined in Section 13 of ASME/ANSI B31.8S-2004 and listed below. This is the same standard in which this performance measure is specified. CVGS will apply the definitions in the ASME standard when reporting their performance measures. [FAQ #136]

- **Leak**: an unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and non-propagating, longitudinal, and circumferential), separation or pull-out, and loose connections.
- **Failure:** a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.
- **Incident**: an unintentional release of gas due to the failure of a pipeline.

Timing for Determination of Performance Measures

CVGS will report the number of events (e.g., miles of pipe inspected, scheduled repairs completed) occurring within each six month reporting period. The rule requires that the measures cover a six-month period, ending June 30 and December 31, and be reported within two months after those dates. [FAQ #137]

Crediting Prior Assessments for New HCA Performance Measures

CVGS can use assessments conducted prior to identification of an HCA as baseline inspections. The provisions of 192.921(e) would apply, and the date of the assessment would mark the beginning of the required reassessment interval. If CVGS, in the postulated situation, uses the prior assessment as the baseline for the new HCA segment, then the associated mileage can be included in the next semi-annual performance measure submittal. If CVGS elects not to treat the prior assessment as its baseline, then the mileage shall not be reported. [FAQ #186]

9.5 Performance Measures if Performing ECDA as Primary Assessment
[§192.945(b), 192.945(b), and NACE RP 0502-2002]

In addition to the general requirements for performance measures described above in this element, when CVGS uses direct assessment to assess the external corrosion threat, CVGS shall define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

9.6 Performance Measures Characteristics
[§192.945(a) and ASME B31.8S-2004, section #9.2]

Performance measures focus attention on the integrity management program results that demonstrate improved safety has been attained. The measures provide an indication of effectiveness but are not absolute. Performance measure evaluation and trending can also lead to recognition of unexpected results that may include the recognition of threats not previously identified. All performance measures shall be simple, measurable, attainable, relevant, and permit timely evaluations. Proper selection and evaluation of performance measures are an essential activity in determining integrity management program effectiveness.

Integrity management program performance measures can generally be categorized into groups. These categories will be noted on the CVGS performance measures worksheet.

Process or Activity Measures: Process or activity measures can be used to evaluate prevention or mitigation activities. These measures determine how well CVGS is implementing various elements of the integrity management program. Measures relating to process or activity shall be selected carefully to permit performance evaluation within a realistic time frame.

Operational Measures: Operational measures include operational and maintenance trends that measure how well the system is responding to the integrity management program. An example of such a measure might be the changes in corrosion rates due to the implementation of a more effective CP program. The number of third party hits after the implementation of prevention activities such as improving the excavation notification process within the system is another example.

Direct Integrity Measures: Direct integrity measures include leaks, ruptures, injuries and fatalities. In addition to the above categories, performance measures can also be categorized as "leading" measures or "lagging" measures. Lagging measures are reactive in that they provide an indication of past integrity management program performance. Leading measures are proactive; they provide an indication of how the plan may be expected to perform. Several examples of performance measures classified as described above are illustrated in ASME B31.8S-2004, Table 8.

9.7 Exceptional Performance Measures

When CVGS chooses to demonstrate exceptional performance in order to deviate from certain requirements of the rule, CVGS will conduct the following additional performance measure requirements: [Element #9: Record #24]

1) Additional performance measures beyond those required in §192.945 will be part of CVGS's performance plan. [§192.913(b)(vii)]

2) All performance measures (all measures required by §192.945 and the additional performance measures) will be submitted to OPS on a semi-annual frequency in accordance with §192.951. [§192.913(b)(vii)]

9.8 Review and Implementation of Element #9

CVGS will use the agenda, "Gas IMP Element #9, Performance Measures Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #9 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #9: Record #25]

- Performance Measures Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the performance measures review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as an agenda checklist to ensure all element #9 requirements are met
- Action item list as a result of the element #9 review [Element #9: Record #26]

9.9 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915)
   Federal Register, Volume #69, No. 102,
   May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915)
   Federal Register, Volume #69, No. 66,
   December 17, 2003.

3. 49 CFR 192.945 – What Methods Must an Operator Use to Measure Program Effectiveness?

4. OPS Gas Integrity Management, Protocols Area I, Performance Measures, January 2008

5. OPS Frequently Asked Questions (FAQs), Performance Measures
   January 2007

6. ASME B31.8S-2004, Managing System Integrity for Gas Pipeline, Section #9, Performance Plan

7. GPTC Review of Integrity Management for Natural Gas Pipelines, Section VIII, Assess Plan Effectiveness and Improvement

9.10 List of Required Ongoing Documentation for Element #9 – Performance Measures

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	9.3	Semi-Annual Report to OPS	IMP Leader	2x/yr[2]	5 yrs	Co. intranet
2.	9.4	Threat Review Worksheet	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	9.4	Semi-Annual Review of Additional Performance Measures Worksheet	IMP Leader	2x/yr[2]	5 yrs	Co. intranet
4.	9.4	Reporting and Control of Incidents, O&M #1.01	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
5.	9.4	Reporting of Safety Related Conditions, O&M #1.02	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
6.	9.4	Investigation of Failures and Accidents, O&M #1.03	O&M Sprvr	1x/yr[1]	Life of Pipe	Co. intranet
7.	9.4	Annual Reports, O&M #1.04	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
8.	9.4	Class Location Survey Report, O&M #4.01	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
9.	9.4	Continuing Surveillance Report, O&M #5.01	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
10.	9.4	Gas Leak Survey Reports, O&M #5.02	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
11.	9.4	Pipeline Patrol Reports, O&M #5.03	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
12.	9.4	Internal and External Examination of Buried Pipe (exposed pipe reports) O&M #6.04	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
13.	9.4	Pipeline Repair Procedures and Reports, O&M #9.01	O&M Sprvr	1x/yr[1]	Life of Pipe	Co. intranet
14.	9.4	Conversion of Service, O&M #12.02	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
15.	9.4	Abandonment or Inactivation of Facilities, O&M #13.01	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet
16.	9.4	Pressure Testing and Reports, O&M #15.01	O&M Sprvr	1x/yr[1]	Life of Pipe	Co. intranet
17.	9.4	Visual Inspection and NDT Testing and Reports, O&M #15.02	O&M Sprvr	1x/yr[1]	Life of Pipe	Co. intranet
18.	9.4	Control Room Management Incident Review, PSOM #17.11	O&M Sprvr	1x/yr[1]	5 yrs	Co. intranet

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
19.	9.4	Smart Pig Reports (ILI)	IMP Leader	1x/yr[1]	Life of Pipe	Co. intranet
20.	9.4	Direct Assessment Reports	IMP Leader	1x/yr[1]	Life of Pipe	Co. intranet
21.	9.4	Construction Repair Reports	IMP Leader	1x/yr[1]	Life of Pipe	Co. intranet
22.	9.4	Equipment Failure Reports	IMP Leader	1x/yr[1]	Life of Pipe	Co. intranet
23.	9.4	Review for Potential Additional Measures	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
24.	9.7	Exceptional Performance Measures	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
25.	9.8	Element #9 Agenda, Performance Measures	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
26.	9.8	Element #9 Agenda Action Items				

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

Note #2: Frequency is semi-annually completed through June 30th and December 31st of each year.

CVGS
Integrity Management Plan
Element #10: Record Keeping

Ref: 49 CFR 192.947	Updated: July 2012

Contents of this Element:

10.1 Objectives and Purpose of Record Keeping [192.947]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these record keeping procedures to assist in this effort.

10.2 Scope, Applicability, and Use of PHMSA FAQs [192.47]

<u>Scope for CVGS</u>

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the list of required ongoing documentation at the end of each procedure to verify recordkeeping requirements.
- All CVGS records will be maintained on the copy intranet unless noted otherwise.

10.3 Minimum Records to be maintained by CVGS [192.947]

CVGS will maintain the following minimum records for the IM program:

1) A written integrity management program in accordance with 192.907

2) Threat identification and risk assessment documentation in accordance with 192.917

3) A written baseline assessment plan in accordance with 192.919

4) Documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements

5) Training program documentation and training records per §192.915

6) Remediation schedule and technical basis documentation per §192.933

7) Direct assessment plan documentation per §192.923 through §192.929

8) Confirmatory assessment documentation per §192.931

9) Documentation of Notifications to OPS or State/Local Regulatory Agencies

Numerous records are generated as a result of Integrity Management Program Implementation. To the extent that these records demonstrate compliance with IMP requirements, they will be maintained by CVGS such that they are in good condition, legible, readily retrievable, protected from damage, and secured sufficiently to prevent unauthorized use. Also, IM program documents shall be properly completed (i.e., no missing signatures or dates when necessary to demonstrate compliance with the rule.

For records such as memoranda or notes, these documents shall be retrievable from a central location to the extent practicable, as opposed to being retained exclusively by individuals without record storage responsibilities. Since many records must be retained for the life of the pipeline, this suggests that records be kept is some sort of formalized or structured record-keeping system, as opposed to individual working files.

The quality assurance plan in element #12 defines who is responsible for development and maintenance of these records. Also, list of required ongoing documentation in each procedure and agenda defines who is responsible for the each record.

Step #1: Using the Record Keeping Agenda to Verify IM Programs Records:

Use the agenda, "Gas IMP Element #10 & #11, Records and MOC Agenda and Action Items", as described in section #10.4 of this procedure to verify that all appropriate records are completed and available for PHMSA review. [Element #10: Record #1] Specific records will be listed in each procedure and procedure agenda and repeated at the end of the procedure.

Archiving Versions of Baseline Assessment Plan

Section 192.947(d) requires that CVGS maintain, for the useful life of the pipeline, documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Copies of the evolving revisions of the baseline assessment plan, and of plans for periodic reassessments, shall be included with the records maintained under this section. [FAQ #32]

Electronic Databases as Records

CVGS shall be prepared to discuss with inspectors evidence demonstrating that the database was used as a contemporary record, rather than having been created after the fact. Procedures, historical printouts, and archived copies of the database are examples of means that can be used to demonstrate that the database is relevant documentation. [FAQ #165]

10.4 Review and Implementation of Element #10

CVGS will use the agenda, "Gas IMP Element #10 & #11, Records and MOC Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #10 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #10: Record #1]

- Record Keeping and MOC Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the record keeping and MOC review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #10 requirements are met
- Action item list as a result of the element #10 review [Element #10: Record #2]

10.5 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.947 – What records must an operator keep?

4. OPS Gas Integrity Management, Protocols Area J, Record Keeping, January 2008

5. OPS Frequently Asked Questions (FAQs), Record Keeping and MOC January 2007

6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #4 Gathering, Reviewing, and Integrating Data

10.6 List of Required Ongoing Documentation for Element #10 – Record Keeping

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	10.3	Element #10 agenda, Record Keeping and MOC [Element #10: Record #1]	IMP Leader	1x/yr[1]	5 yrs.	Co. intranet
2.	10.3	Action item list as a result of the element #10 review [Element #10: Record #2]	IMP Leader	1x/yr[1]	5 yrs.	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

Contents of this Element:

11.1 Objective and Purpose for Management of Change [192.909]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS will use MOC process to track significant changes made to the IM program.

11.2 Scope, Applicability, and Use of PHMSA FAQs [192.919 &921]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the pipeline management of change procedures to document when significant changes are made.

Ref: 49 CFR 192.909	**Updated: July 2011**

Applicability and Summary of the Regulations

"How can an operator change its integrity management program?" [192.909]

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for management of change are shown in appendix 11A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

11.3 Definitions Applicable to Element #11

Management of change (MOC) a process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural or organizational nature that can impact system integrity. Other MOC definitions are defined in the Company MOC procedures.

11.4 Documentation and Notification of Changes to the Integrity Management Program

CVGS will use existing MOC procedures to document changes to the integrity management program. Notification will also be performed in accordance with existing MOC procedures. CVGS will ensure the reasons for program changes have been documented prior to implementation of the change(s).

It is not the intent of CVGS that every program change be communicated in accordance with this requirement. Some judgment will be used in considering whether the change is "significant". Significant is further defined in the company MOC procedures.

Step #1: Determine if Change Requires MOC Documentation

Using the examples below and the CVGS MOC procedures determine if a change would require documentation under the MOC process. It should be noted that changes in the integrity management program can drive physical changes to the pipeline, and changes to the pipeline can affect the integrity management program in areas like risk analysis and assessment methods. [Element #11: Record #1]

Step #2: MOC Documentation

If answer to step #1 is yes, then document MOC process using CVGS MOC procedures. [Element #11: Record #2] Include appropriate supporting documentation as determined by the specific MOC. [Element #11: Record #3]

Examples of significant changes for integrity management are:

- Merger of companies or major acquisition of pipeline
- Determination of susceptibility to SCC when previously considered unsusceptible
- Introduction of an assessment methodology not previously used
- Abandoning an assessment methodology previously planned for use
- Significant delays in segment assessments
- New gas streams coming online (for example, new wells) that increase the BTU heat value of the transported gas (change from lean to rich gas)
- Pipeline reroutes that place the pipeline closer to identified sites
- An increase in pipeline MAOP that results in a larger potential impact circle
- Pipeline modifications affecting piping diameter that results in a larger potential impact circle
- Corrections to erroneous pipeline center line data

- Addition of new HCA segments

Examples of changes that would not be considered significant and would not require notification are:

- Reprioritization of remediation actions that do not result in noncompliance with the Rule
- Reprioritization of preventive or mitigative measures
- Reprioritization of assessments due to updated risk analysis
- Use of a different model for ICDA than the one referenced in the rule.
- Minor editorial procedure changes
- Minor schedule changes to assessments
- Minor schedule changes to remediation

11.5 Agency Notification Requirements for Significant Changes

When there is significant changes to the program, program implementation, or schedules, OPS or the State or local pipeline safety authority, if applicable, will be notified within 30 days after CVGS has adopted the change.

The notifications required by the rule are:

- Substantial change to program implementation or significant change to schedule for carrying out elements. (Within 30 days of adoption). The notification shall include a description of the changes and the basis on which they were made
- Inability to meet remediation deadlines in the rule and unable to reduce pressure (When CVGS determines schedules cannot be met). A description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned shall be included.
- Use of technology other than in-line inspection, Direct Assessment, or pressure testing for conducting assessments. (180 days prior to assessment). CVGS shall provide a description of the "other technology", its basis for concluding that the method will result in equivalent understanding of pipe condition, and its schedule for assessment.
- Pressure reduction imposed as a result of IM anomalies extends for more than 365 days. The notification must explain the reasons for the delay and justify that the continued pressure reduction will not jeopardize the integrity of the pipeline.

In addition, all notifications must include information about the pipe segments and HCAs involved. [FAQ #97] See CVGS IMP element #14, Agency Notification, Inspections, and Documentation for more details on timing of submittals and required information that must be submitted.

11.6 Attributes of the Change Process

CVGS MOC process will meet the requirements of ASME/ANSI B31.8S-2004, Section 11, including:

- Consideration of impacts of changes to pipeline systems and their integrity.
- Addressing technical, physical, procedural, and organizational changes.
- Reason for change
- Authority for approving changes
- Analysis of implications
- Acquisition of required work permits
- Documentation
- Communication of the change to affected parties
- Time limitations
- Qualification of staff

CVGS will ensure the integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. Equipment or system changes will be identified and reviewed before implementation. CVGS will update the risk assessment process and outputs to include changes to applicable data.

<u>Deadline for Implementing MOC</u>

CVGS's management of change process shall be implemented as soon as there is a program whose change needs to be managed. If CVGS approves its IM program, or portions thereof, for use before December 17, 2004, then management of change procedures shall apply (to those approved programs/portions) at the same time. The rule requires that CVGS have a written IM program that addresses each program element by December 17, 2004, meaning that a management of change process must be implemented by no later than this date. [FAQ #201]

11.7 Review Implementation of Element #11

CVGS will use the agenda, "Gas IMP Element #10 & #11, Records and MOC Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #1 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #10 & #11: Record #4]

- Record Keeping & MOC Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the record keeping and MOC review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #10 and #11 requirements are met
- Action item list as a result of the element #10 and #11 review [Element #10 & #11: Record #5]

11.8 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915)
Federal Register, Volume #69, No. 102,
May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915)
Federal Register, Volume #69, No. 66,
December 17, 2003.

3. 49 CFR 192.909 – How can an operator change its integrity management program?

4. OPS Gas IMP Protocols for Small Operators, Protocol Section #K, Management of Change, January 2008

5. OPS Frequently Asked Questions (FAQs): Record Keeping and MOC

6. ASME B31.8S-2004, Managing System Integrity for Gas Pipeline, Section #11, Management of Change

7. Company MOC Procedures

Ref: 49 CFR 192.909 **Updated: July 2011**

11.9 List of Required Ongoing Documentation for Element #11 – Management of Change

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	11.4	Determination if Change Requires MOC	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
2.	11.4	MOC Documentation of Significant Change	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	11.4	MOC Supporting Documentation as Determined by the Specific MOC	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	11.7	Element #10 & #11 agenda, Record Keeping and MOC	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	11.7	Action item list as a result of the element #10 & ##11 agenda review	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Integrity Management Plan
Element #12: Quality Assurance

Ref: 49 CFR 192.911(l)	Updated: July 2012

Contents of this Element:

12.1 Objectives and Purpose of Quality Assurance [192.911(l)]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these quality assurance procedures to assist in this effort.

12.2 Scope, Applicability, and Use of PHMSA FAQs [192.919 &921]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use documents described in this procedure to satisfy the requirements

CVGS
Integrity Management Plan
Element #12: Quality Assurance

Ref: 49 CFR 192.911(l)	Updated: July 2011

<u>Applicability and Summary of the Regulations</u>

CVGS will have a quality assurance process that meets the requirements of ASME/ANSI B31.8S-2004, section 12. The quality assurance process will include responsibilities, authorities, review of the integrity management program, corrective action plans, qualification and training, and invoking non-mandatory statements in the standards.

<u>Use of PHMSA FAQs</u>

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

12.3 Definitions Applicable to Element #12

Quality assurance is a process that describes how CVGS will ensure implementation of proper standards in meeting the integrity management rule. Quality control is defined in the ASME B31.S standard as ***"documented proof that the operator meets all the requirements of their integrity management program."***

Authority means the personnel assigned to the integrity management program will have the power to act on their appropriate level of responsibility that is assigned to them.

Review is the process of looking over or inspection of the integrity management program with the intent of ensuring compliance.

Non-Mandatory statement means a statement that is written in "should" statements from industry standards or other documents invoked by Subpart O.

12.4 General Quality Assurance Program Requirements [§192.911(l)]

CVGS has a quality assurance process exists that meets the requirements of ASME/ANSI B31.8S-2004, section 12. These processes are outlined below:

- Determine the documentation required for the IM program (see section #12.5)
- Responsibilities and authorities under the IM program will be clearly and formally defined (see section #12.6)
- Results of the IM program will be reviewed at predetermined intervals and include recommendations for improvements (see section #12.7)
- Personnel qualification requirements must be identified for anyone who is involved in the IM program (see section #12.8)
- Monitoring of the IM program to ensure that it is being implemented according to the written procedures (see section #12.7)
- Periodic internal audits of the IM program (see section #12.10)
- Corrective actions to improve the IM program (see section #12.7)

When CVGS chooses to use outside resources to conduct any process that affects the quality of the integrity management program, CVGS will ensure the quality of such processes and document them within the quality program.

12.5 Integrity Management Program Documentation

Integrity management program documentation requirements are listed at the end of each IM procedure.

12.6 IM Program Roles, Responsibilities, and Authorities

The CVGS Team Charter and roles and responsibilities listed below define general team member roles and responsibilities. The required documentation section at the end of each procedure defines who is responsible for completing specific tasks including documentation. The CVGS Team Charter will reviewed by the appropriate level of management and agreed that when a person is assigned an IM program task, the person also has the authority to complete that tasks. [Element #12: Record #1]

Roles and Responsibilities

The following shows roles and responsibilities for the CVGS IMP team members.

Company Management:

- Accountable for management oversight all IM program elements
- Provide guidance, approval and funding to implement all IM program elements

IMP Coordinator:

- Accountable for implementation and oversight of all IM program elements
- Conduct annual review of program procedures and update as appropriate
- Lead annual reviews of all IM program elements using agendas
- Provide recommendations for program improvements in their area of responsibility in the IM program
- Develop and track action items and recommendations for improvements
- Conduct internal audits minimum once per three years using company personnel, consultants, or PHMSA agency audit
- Communicate key IM program documents to company management as shown in the team charter

Pipeline/Facility Supervisor:

- Accountable for implementation and oversight for specific documents listed at the end of each IM procedure
- Provide recommendations for program improvements in their area of responsibility in the IM program
- Assist IMP Coordinator with annual agenda reviews when required
- Communicate IM program R&Rs to pipeline operators

Pipeline Operators:

- Provide recommendations for program improvements in their area of responsibility in the IM program
- Assist IMP Coordinator with annual agenda reviews when required

Subject Matter Experts (SMEs):

- Provide recommendations for program improvements in their area of responsibility and expertise in the IM program
- Assist IMP Coordinator with annual agenda reviews when required

Step #1: Review Team Charter and Key Documents with Mgmt and Get Signature

The quality assurance process will use the following definitions:
Authority means the personnel assigned to the integrity management program will have the power to act on their appropriate level of responsibility that is assigned to them.

Review is the process of looking over or inspection of the integrity management program with the intent of ensuring compliance.

12.7 IM Program Review, Corrective Action, and Monitoring

The IMP program will be reviewed on an annual basis not to exceed 18 months. These reviews will be conducted by use of agendas as described in each IMP procedure. This review will include a review of the IM program procedures and effectiveness of the QA process by the IMP leader. Also, a review of all the key documents and data will be reviewed annually not to exceed 18 months for each covered segment with the appropriate covered segment IMP team. These reviews will include recommendations for improvement where necessary.

Corrective actions items will be documented during each agenda review in the master IMP action item list. These corrective actions will be monitored by the IMP Leader on a periodic basis, normally quarterly, for effectiveness in correcting the deficiency or area in need of improvement. [Element #12: Record #2]

The CVGS corrective action process includes the following:

- Prompt identification, including date identified
- Target date for completion
- Correction of deficiencies, including date completed
- Require the investigation of the root cause of any significant condition
- Specify the appropriate actions to prevent recurrence to address the root cause
- Engage in periodic tracking to ensure completion those activities

Step #2: Document Corrective Actions during Agenda Reviews

12.8 Personnel Qualification and Training Requirements

CVGS will verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. These qualification requirements are described below. CVGS integrity management program supervisory personnel will have the appropriate training or experience for their assigned responsibilities. Records shall be maintained by CVGS for any training or qualification used for the integrity management program. Typically, these qualification records will be resumes, work histories, training certificates, class attendance rosters and conference sessions, etc.

Specific requirements for qualification of personnel who participate in implementing preventive and mitigative measures include: [§192.915(c)]

i. Personnel who mark and locate buried structures.
ii. Personnel who directly supervise excavation work.
iii. Other personnel who participate in implementing preventive and mitigative measures as appropriate. [ASME B31.8S-2004, §12(b)(4)]

As part of the review process, CVGS will verify that personnel who execute the activities within the integrity management program are competent and properly trained in accordance with this quality control procedure. Verification of qualification and training will include contractors when they perform IM program tasks. When appropriate, specific requirements of qualification and training will be documented in vendor contracts. An example would be the qualifications for a smart pig vendor.

IM program qualification requirements, training requirements, and records are documented on the company intranet. IM program tasks that are also operator qualification (OQ) covered tasks are defined in the CVGS OQ program. Examples include the three mitigative measures listed above (marking and locating, excavation, and other mitigative measures). Specifically, IM programs records that will be maintained that relate to qualification and training are listed below:

- Personnel qualification requirements must be identified for anyone who is involved in the integrity management program. This applies to both CVGS, consultants, and vendor personnel
- Minimum set of qualification requirements for the various functions to be performed in an integrity management program

- Detailed records including resumes, training certificates, or class attendance demonstrating that qualification requirements are met
- Re-qualification requirements and timeframes if appropriate for the IM program tasks

See training requirements below and the training plan worksheet in the IMP files. [Element #12: Record #3]

Personnel who are not qualified may participate in the assessment activities, but only under the direct control and supervision of a qualified person as part of on-the-job-training (OJT).

When CVGS chooses to use outside resources to conduct any process that affects the quality of the integrity management program, CVGS will ensure the quality of such processes and document them within the quality program.

Step #3: Document CVGS, Consultant, and Contractor Qualifications
[Element #12: Record #4, #5]

Gas IMP Team Qualification Requirements

TEAM:	Gas Integrity Management Team (GIMT)
OBJECTIVE:	The GIMT's mission is to provide an effective and consistent development, implementation, and continuous improvement of the Gas Integrity Management Program (IMP) for Central Valley Gas Storage (CVGS) gas transmission pipeline This supports the company goals to eliminate pipeline incidents which pose significant risk to the public, employees and the environment. The GIMT will use subject matter experts (SME) risk-based decision-making to ensure compliance with DOT's integrity management rule. The GIMT will also provide guidance for anybody conducting operational activities that could affect the integrity of the pipeline.
IMP TEAM MANAGEMENT SUPPORT/SPONSOR:	Tim J. Hermann CVGS Vice President, Midstream Operations
IMP TEAM LEADER:	Andy Bradfield Pipeline Consultant Compliance Services Inc
OTHER IMP TEAM MEMBERS:	Wayne Mardian CVGS – Operations Manager Richard Tucker DBTS, VP – Pipeline Maintenance & Repair Contractor Brien Vierra FJ Technologies, Inc. – Engineering Consultant

GIMT Qualification Requirements (cont.)

IMP TEAM MANAGEMENT SUPPORT/SPONSOR:	Tim J. Hermann CVGS Combustion Turbine Manager
Qualification Requirements:	1. Basic understanding of DOT integrity management regulations, risk analysis process, and need for mitigative measures to reduce pipeline integrity risks
IMP Team Supervisor in Charge of Daily Operations	Wayne Mardian CVGS – Operations Manager
Qualification Requirements:	1. General understanding of DOT integrity management regulations, risk analysis process, and need for mitigative measures to reduce pipeline integrity risks 2. General understanding of risk assessment methodologies
IMP TEAM LEADER:	Andy Bradfield Pipeline Consultant Compliance Services Inc
Qualification Requirements:	1. Associate of Science or Bachelors College degree with at least 5 years of pipeline/facility operation, maintenance, or constructions experience; and 2A. Minimum 5 years of pipeline/facility operation, maintenance experience in a supervisory or manager capacity with strong technical background; or 2B. Minimum 5 years of DOT pipeline compliance experience; and 3. Experience or certification in Process Hazard Analysis methodologies or other risk assessment techniques experience.

GIMT Qualification Requirements (cont.)

IMP TEAM MEMBER #1:	Richard Tucker DBTS, VP – Pipeline Maintenance & Repair Contractor
Qualification Requirements:	1. Completion of all job applicable OQ training modules; and 2. Minimum 5 years of experience with pipeline/facility operations and maintenance; and 3. Knowledge of DOT O&M, OQ, and IMP regulations applicable to the pipeline facility.
IMP TEAM MEMBER #2:	Brien Vierra FJ Technologies, Inc. – Engineering Consultant
Qualification Requirements:	1. Understanding of DOT IMP regulations and OPS IMP protocols, and 2. Minimum 5 years of experience with pipeline operations, maintenance, and engineering 3. Bachelors degree in engineering or science with at least 5 years of pipeline/facility operation, maintenance, or construction experience; or

Qualification of Personnel Reviewing Integrity Data

Purpose and Background

The purpose of this procedure is to establish the process for ensuring that data gathered through periodic evaluation of pipelines in accordance with the Integrity Management Program is analyzed by personnel qualified to determine the integrity of the pipe from the data.

Inspections conducted under the company's Integrity Management Plan will result in data that must be analyzed by personnel qualified to do so. For example, in-line inspection data requires highly-specialized expertise and the benefit of experience to interpret the often cryptic analog indications provided by the tool. Hydrostatic pressure testing requires compliance with 49 CFR, Part 192, Subpart J, to be valid and requires expertise in compensating for varying factors such as temperature and elevation.

In-Line Inspection

Due to the extensive training and experience required to adequately interpret analog in-line inspection data, the company will rely on its ILI vendors to provide the expertise required for data analysis. The company will only contract with reputable in-line inspection vendors with at <u>least three years of proven experience</u> in inspecting and evaluating pipe using the tools for which they are being contracted. Specifically, the ILI vendor responsible for interpreting smart pig data will have the following qualifications:

- Three years of experience with tools used for the inspection
- The personnel operating the ILI systems and the personnel taking, reducing, analyzing and reporting the resultant data shall be qualified in accordance with ASNT ILI-PQ, level II.

CVGS may conduct its own review of the data and the interpretations provided by the vendor as a quality control check. The person conducting such QC reviews should have had at least one year of experience in reviewing ILI raw data, but in no case shall the reviewer over-ride the interpretations of the vendor unless it results in a more conservative response to the data. In all cases, questions regarding a vendor's interpretation shall be referred back to the vendor for review and clarification.

Hydrostatic Testing

Hydrostatic testing shall be performed in compliance with 49 CFR, Part 192, Subpart J. The hydrotest will be conducted under the direction of a company employee who has been qualified to the company's Operator Qualification Program. A company engineer, consulting engineer, or California State Fire Marshall (CSFM) certified testing company shall certify the hydrostatic test.

Direct Assessment

Direct Assessment methodologies that may be employed in the determination of the company pipeline integrity shall be conducted by reputable vendors with proven experience in applying the methodology. CVGS will only contract with reputable direct assessment vendors with at least three years of proven experience in inspecting and evaluating pipe using the methodologies from NACE RP 0502.

CVGS may conduct its own review of the data and the interpretations provided by the vendor as a quality control check. The person conducting such QC reviews shall have had at least one year of experience in reviewing ILI raw data. In no case shall the reviewer over-ride the interpretations of the vendor unless it results in a more conservative response to the data. In all cases, questions regarding a vendor's interpretation shall be referred back to the vendor for review and clarification.

Hydrostatic Testing

Hydrostatic testing shall be performed in compliance with 49 CFR, Part 192, Subpart J. The hydrotest will be conducted under the direction of a CVGS employee who has been qualified to CVGS's Operator Qualification Program. A CVGS engineer, consulting engineer, or California State Fire Marshall (CSFM) certified testing CVGS shall certify the hydrostatic test.

12.10 IM Program Internal Audits

Audits of integrity management programs are an important element of evaluating program effectiveness and identifying areas for improvement. Audits will be performed by personnel within the organization (self assessments), or by auditors from outside organizations. The IMP records binder/files contains CVGS integrity management program audit results. [Element #12: Record #6]

The scope of the audits will be threefold as described below.

1) First, process activities required by 49 CFR 192 will be reviewed using the OPS protocol checklist found on the OPS website.
2) The second audit type will be a complete review of the integrity management program to ensure all activities are performed accurately and in a timely manner.
3) Lastly, the audit review shall include a review of the performance measures to determine if they shall be updated to more accurately measure the program.

Step #4: Document Audits

CVGS goals for the audit program are described below.

- Continuous improvement of the integrity management program.
- Verify agenda process for reviewing IM program elements is functioning properly
- Verify all IM program documentation is in place as listed at the end of each procedure and agenda
- Verify action items and mitigative measures are implemented in a timely manner
- Monitoring all IMP program elements to ensure that it is being implemented according to the written procedures

The IMP Leader will ensure audits are conducted at least once every three years. Audits can be conducted by IMP Leader, other CVGS personnel, IMP consultant, PHMSA, or state agency with authority. If all IMP element agendas reviews are completed in a calendar year, this can also be considered an internal audit. The IMP Leader will also ensure audit findings are tracked and remedied in a timely manner. All audits will include a corrective actions and recommendations for improvement to the IM program.

Additional audits/program evaluations may be initiated due to management of changes issues like change in management or key IMP personnel, or when key operating parameters change. See CVGS management of change procedures.

12.11 Invoking Non-Mandatory Statements in Standards ASME [B31.8S,§11(a)(8) & §12.2(b)(4)]

CVGS will use non-mandatory requirements (e.g., "should" statements) from industry standards or other documents invoked by Subpart O (e.g., ASME B31.8S-2004 and NACE RP0502-2002) by one of the following approaches: [§192.7(a)]

1) CVGS will incorporate the non-mandatory standard into the CVGS's plan and implement as recommended in the standard; or
2) CVGS will use an equivalent alternative method for accomplishing the same objective and will justify and implement the equivalent alternative method; or
3 CVGS will document the justification including the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O.

CVGS will use <u>approach number one</u> above at this time. Approach number two and three are still available under the rule and may be used in the future if appropriate.

Where sections of consensus standards are incorporated by reference into a rule, those sections become binding requirements the same as if the language were repeated in the rule. [FAQ #155]

12.13 Review and Implementation of Element #12

CVGS will use the agenda, "Gas IMP Element #12, Quality Assurance Agenda and Action Items", for review and implementation of this element. CVGS will conduct this element #12 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #12: Record #7]

- Quality Assurance Agenda Objectives
- List of personnel that shall attend including name and job title
- Frequency of the quality assurance review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature
- PHMSA gas IMP protocols used as a checklist to ensure all element #12 requirements are met
- Action item list as a result of the element #12 review [Element #12: Record #8]

12.14 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.
2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.
3. 49 CFR 192.911 – What are the elements of an integrity management program?
4. OPS Gas Integrity Management, Protocols Area L, Quality Assurance, January 2008
5. OPS Frequently Asked Questions (FAQs), #76, #244, #155, #167, #114, January 2008
6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #12 Quality Control Plan

Ref: 49 CFR 192.911(l)	Updated: July 2011

12.15 List of Required Ongoing Documentation for Element #12

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	12.6	Team Charter (signed by mgmt)	IMP Leader	AR	5 yrs	Co. intranet
2.	12.7	Master Action Item Worksheet	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	12.8	CVGS IMP Team Training Plan				
4.	12.8	CVGS IMP Team Qualification Records (resumes, work histories, training records and certifications)	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	12.8	Contractor Qualification Records	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	12.10	IM Program Audits	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	12.13	Element #12 agenda	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
8.	12.13	Element #12 action items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Gas Integrity Management Plan
Element #13: Communication Plan

Ref: 49 CFR 192.911(m)	Updated: July 2012

Contents of this Element:

13.1 Objectives and Purpose of Communications Plan [192.911(m)]

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these communications plan procedures to assist in this effort.

13.2 Scope, Applicability, and Use of PHMSA FAQs [192.911(m)]

Scope for CVGS

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.
- CVGS will use the team charter as the main communications tool.

Summary of Requirements for Communication Plan [192.911(m)]

CVGS will have a communication plan that includes the elements of ASME/ANSI B31.8S, section 10. The communication plan will include the following procedures and communicated periodically:

- Addressing safety concerns raised by the PHMSA or state authority with jurisdictional authority
- Keeping CVGS employees informed of appropriate integrity issues
- Making the public aware of its integrity management efforts and results

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

13.3 Internal Communication Requirements

CVGS internal communications is aimed at building program support and to inform all appropriate CVGS personnel in the progress and problems of the program.

Communication to IM Program Management Sponsor

To build support from CVGS management and communication key IM program information, a "Team Charter will be used. The Team Charter will include the following minimum information:

1) IM program objectives
2) Identification of Management Sponsor and Support
3) Identification of IMP program leader
4) Identification of other IMP team members
5) Team start up activities
6) Description of key activities (annual reviews) and milestones
7) Team deliverables
8) Deliverables to IMP management sponsor
9) Benefits and measures
10) IMP management sponsor signature and commitment

Ref: 49 CFR 192.911(m)	Updated: July 2011

Step #1: Review Team Charter with IMP Management Sponsor

The team charter and charter deliverables key documents will be reviewed with the IMP management sponsor once per calendar year, not to exceed 18 months after all the element agenda reviews are completed. Deliverables as identified in the team charter include the following:

1. Risk assessment with recommended mitigation activities, and risk benefits if mitigation activities implemented [Element #13: Record #1]
2. IMP performance measures [Element #13: Record #2]
3. Changes and improvements to the IM program as shown on the ongoing action item list [Element #13: Record #3]
4. Remediation and repair worksheet and schedule [Element #13: Record #4]
5. Team charter [Element #13: Record #5]
6. Integrity program roles and responsibilities [Element #13: Record #6]
7. Additional documentation requested by IMP management sponsor or other CVGS mgmt [Element #13: Record #7]

Communication to IM Program Team Members and CVGS Personnel

CVGS will communicate the progress and problems to IM program team members and other CVGS personnel as appropriate.

Step #2: Communication with Company Employees on IMP Issues

The following methods will be used for communication:

- Safety meetings [Element #13: Record #8]
- IMP annual reviews using agendas [Element #13: Record #9]
- IMP specialty meeting when needed [Element #13: Record #10]
- Emails [Element #13: Record #11]
- Documents on CVGS intranet [Element #13: Record #12]
- As required by the MOC process (see element #11) [Element #13: Record #13]

Communications shall be conducted as often as necessary to ensure that appropriate individuals and IMP team members have current information about CVGS's system and their integrity management efforts. These communications will take place periodically, usually at an annual interval during CVGS safety meetings.

13.4 External Communication Requirements

This procedure establishes the minimum communication requirements in order to keep appropriate CVGS the public informed about their integrity management efforts. External communication information will be communicated as part of the CVGS existing "Public Awareness Procedures (O&M #3.03).

CVGS integrity management communication plan will meet the requirements of ASME/ANSI B31.8S, Section 10. These requirements include provisions for external communications meeting the following four target audiences:

1) Landowners and tenants along the rights-of-way
[Element #13: Record #14]
2) Public officials other than emergency responders
[Element #13: Record #15]
3) Local and regional emergency responders
[Element #13: Record #16]
4) Excavators
[Element #13: Record #17]

ASME/ANSI B31.8S, Section 10 describes basic information that shall be provided periodically to different stakeholders. In summary, it includes information about the pipeline and relevant emergency response procedures. It shall also include high-level information about the fact that CVGS has a program to monitor pipeline integrity that provides for periodic assessment of pipeline in high consequence areas. API RP-1162 and CVGS O&M procedure #3.03 (Public Awareness) provides a further description of a public communications program. [FAQ #184]

Step #3: Conduct External Communications to Target Audiences

Frequency for external communication is described in CVGS O&M procedure #3.03, Public Awareness procedures.

13.5 Addressing PHMSA and State Safety Concerns

CVGS's communication plan will include provisions to address safety concerns raised by PHMSA and State or local pipeline safety authorities, as applicable. Specifically, this means when PHMSA or the jurisdictional state agency issues corrective actions, CVGS will respond with a formal letter signed by the IMP Management Sponsor or designee and include one or more of the following:

- Remedial corrective measures completed or scheduled
- Root cause determination (for failure investigations)
- Actions to prevent recurrence

Agency corrective action issues will be reviewed at a minimum frequency as described in section #13.6, Review and Implementation of Element #13. More frequent reviews of agency corrective issues will be conducted as appropriate as determined by the IMP team leader or IMP Management Sponsor [Element #13: Record #18]

When requested, CVGS will submit the company's risk analysis or integrity management program to PHMSA and State or local pipeline safety authorities, as applicable. The IMP team leader will develop corrective action responses and review with IMP Management Sponsor or designee before submittal. See IMP element #14, "Agency Notification" for submittal information.

13.6 Review and Implementation of Element #13

CVGS will use the agenda, "Gas IMP Element #13 and #14, Communication Plan and Agency Notification, for review and implementation of this element. CVGS will conduct this element #13 and #14 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #13: Record #19]

Communication Plan, Agency Notification, and Environmental Safety Agenda Objectives

- List of personnel that shall attend including name and job title
- Frequency of the Communication Plan and Agency Notification Agenda review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature

- PHMSA gas IMP protocols used as a checklist to ensure all element #13, #14, and #15 requirements are met
- Action item list as a result of the element #13 and #14 review [Element #13: Record #20]

13.7 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.911 – What are the elements of an integrity management program?

4. PHMSA Gas IMP Protocols for Small Operators, Protocol Section #M, Communications Plan, July 2008

5. PHMSA Frequently Asked Questions (FAQs): #184

6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #8 Communications Plan

13.8 List of Required Ongoing Documentation for Element #13

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	13.3	Risk assessment with recommended mitigation activities	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
2.	13.3	IMP performance measures	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	13.3	Changes and improvements to the IM program as shown on the ongoing action item list	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	13.3	Remediation and repair worksheet and schedule	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	13.3	Team Charter	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	13.3	Integrity program roles and responsibilities	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	13.3	Additional documentation requested by IMP management sponsor or other CVGS mgmt	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
8.	13.3	Safety meetings	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
9.	13.3	IMP annual reviews using agendas	IMP Leader	1x/yr[1]	Life of pipeline	Co. intranet
10.	13.3	IMP specialty meeting when needed	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
11.	13.3	Emails	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
12.	13.3	Documents on CVGS intranet	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
13.	13.3	As required by MOC process	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
14.	13.4	Public awareness external communication to landowners	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
15.	13.4	Public awareness external communication to public officials	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
16.	13.4	Public awareness external communication to emergency responders	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

13.8 List of Required Ongoing Documentation for Element #13 (cont.)

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
17.	13.4	Public awareness external communication to excavators	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
18.	13.5	Corrective action response to agency issues	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
19.	13.6	Element #13, #15, and #15 agenda, Communications Plan, Agency Notification, and Environmental and Safety Risk Agenda and Action Items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
20.	13.6	Action item list as a result of the element #13, #14, & ##15 agenda review	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

CVGS
Gas Integrity Management Plan
Element #14: Agency Notification, Inspections, & Documentation

Ref: 49 CFR 192.911(n)	Updated: July 2012

Contents of this Element:

14.1 Objectives and Purpose

The objective and purpose of an IMP is to maintain the integrity of the pipeline system at levels necessary to provide safe and reliable pipeline systems. To ensure that the IMP achieves these objectives, CVGS has developed these agency notification and agency inspection procedures to assist in this effort.

11.2 Scope, Applicability, and Use of PHMSA FAQs [192.911(n)]

<u>Scope for CVGS</u>

The following pipeline systems and segments are covered by the CVGS gas IM program:

- None - HCA identification method #1 was used and all CVGS pipeline segments are entirely within Class I locations and there are no identified sites. Therefore, the integrity management regulations do not apply at this time. CVGS will continue to conduct annual surveys for the presence of High Consequence Areas.

Ref: 49 CFR 192.911(n)	**Updated: July 2011**

Applicability and Summary of the Regulations

"What are the elements of an integrity management program?" [192.911(n)]

Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) PHMSA; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where PHMSA has an interstate agent agreement.

Use of PHMSA FAQs

PHMSA Frequently Asked Questions (FAQs) are intended to clarify, explain, and promote better understanding of the pipeline integrity management rules. These FAQs are not substantive rules and do not create rights, assign duties, or impose new obligations not outlined in the existing integrity management regulations and standards.

PHMSA FAQs for agency notification are shown in appendix 14A of this element. When FAQs are used within the procedures, they will be followed by CVGS as a requirement.

14.3 Agency Notification Requirements

Step #1: Determine if Agency Notification is required Using the Info Below

Step #2: Submit Required Info to Agency in Timely Manner as Described Below

CVGS must file any report required by this subpart O (Gas Transmission Pipeline Integrity Management) electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with §191.7 of this subchapter. [192.951]

Except for safety related conditions as provided in 191.7(b), CVGS must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at:

- *http://PHMSAweb.phmsa.dot.gov* unless an alternative reporting method is authorized in accordance with paragraph 191.7(d) of this section which is shown below. [Element #14: Record #1]

Alternative Reporting Method [191.7(d)

If electronic reporting imposes an undue burden and hardship, CVGS may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP–20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. [Element #14: Record #2]

CVGS must contact PHMSA at 202–366–8075, or electronically to *informationresourcesmanager@dot.gov* or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. [Element #14: Record #3]

If alternate reporting is used, submit the information using one of the methods listed below: [Element #14: Record #4]

- By mail to;
  Office of Pipeline Safety
  Pipeline and Hazardous Materials Safety Administration
  U.S. Department of Transportation
  Information Resources Manager, PHP–10,
  1200 New Jersey Avenue, SE.,
  Washington, DC 20590-0001
- Via facsimile to (202) 366–7128
- By email to *informationresourcesmanager@dot.gov*

Notification Types

The notifications required by the rule are:

- Substantial change to program implementation or significant change to schedule for carrying out elements. (Within 30 days of adoption). The notification shall include a description of the changes and the basis on which they were made
- Inability to meet remediation deadlines in the rule and unable to reduce pressure (When CVGS determines schedules cannot be met). A description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis

for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned shall be included.

- Use of technology other than in-line inspection, Direct Assessment, or pressure testing for conducting assessments. (180 days prior to assessment). CVGS shall provide a description of the "other technology", its basis for concluding that the method will result in equivalent understanding of pipe condition, and its schedule for assessment.
- Pressure reduction imposed as a result of IM anomalies extends for more than 365 days. The notification must explain the reasons for the delay and justify that the continued pressure reduction will not jeopardize the integrity of the pipeline.

In addition, all notifications must include information about the pipe segments and HCAs involved. [FAQ #97]

Notification and Temporary Pressure Reduction [192.933(a)(1)]

If the company is unable to respond within the time limits for certain conditions specified in this section, the company must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. The company must determine any temporary reduction in operating pressure required by this
section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, *see* § 192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered.

The company will notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. The company must also notify the State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

Notification and Long-Term Pressure Reduction [192.933(a)(2)]

When a pressure reduction exceeds 365 days, the company will notify PHMSA under § 192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The company will also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

When Notifications Must be Submitted

Notifications of different types must be submitted on different schedules:

- Notifications that CVGS has made substantial changes to its program implementation or significantly altered the schedule for carrying out program elements must be submitted no less than 30 days after the changes are adopted.
- Notification of intent to use other technology to perform an assessment must be submitted no less than 180 days prior to the scheduled assessment.
- Notification that CVGS will be unable to meet required remediation schedules must be submitted as soon as it is determined that the schedule cannot be met.

PHMSA encourage operators to submit notifications as far in advance as practical to assure time for appropriate review and for making alternative plans in the event that PHMSA objects to the proposed alternative approach. [FAQ #98]

Information Requirements for a Notification

Notifications must provide enough information for PHMSA to understand the reason for the deviation/change from the actions specified in the rule. They must also include information about the affected pipe segments. PHMSA will consider this information in reviewing the notification. Notifications must also include the name, title, telephone number, and e-mail address of the person responsible for their integrity management program, who may be contacted if additional information is needed. CVGS can submit notifications via this web site (will require a password). The data fields on the form provide additional guidance regarding the information that shall be included. Operators using the web site will receive e-mails confirming their submittal of notifications via the web site as well as concerning the progress of the PHMSA review.
[FAQ #99]

Thresholds for Notification of Plan Changes

The type of changes considered here would include significant revisions to the baseline assessment plan schedule such as significant delays in segment assessments, or changes that affect the overall manner in which CVGS is conducting its IM program. These qualifiers are intended to preclude notifications for minor, even editorial, changes, or changes anticipated to occur to baseline assessment schedules due to foreseeable circumstances such as weather, permitting delays, or re-ranking schedule priorities due to updated risk assessment information. [FAQ #111]

Notification of Different Model for ICDA

As stated in §192.927(c)(2) the operator must demonstrate that a different model for ICDA region identification is technically equivalent to the one shown in GRI 02-0057. Documentation of this equivalency analysis shall be retained by the operator for inspection during an audit. The notification requirement for the "other technology" assessment method does not apply and there is no notification requirement specified in the rule for an L's selection of an alternate ICDA region identification model. [FAQ #153]

Safety Related Condition Reports and Notifications

The requirements for safety-related condition reports are distinct from those for integrity management. Where the provisions of 191.23 require a report, such report must be made independent of any requirements in Subpart O. [FAQ #181]

"Other Technology" Notifications and 180 Days

If PHMSA completes a review of the company notification for use of "other technology" the company can implement the other technology before the remainder of the 180 days. The 180-day period is intended to allow for PHMSA review. Once that review is completed, if no objections are noted, the operator may proceed. [FAQ #245]

Seeking Waivers When Changing Assessment Schedules

PHMSA understand that there are a number of factors that could result in the need to modify Baseline Assessment Plans after their initial preparation. For example, as information is obtained from the initial integrity assessments, risk analysis, and operating experience, an operator's understanding about the specific integrity threats and relative importance of those threats may change. An operator may elect to apply a different integrity assessment method (e.g., select a different in-line inspection tool that may improve the capability to detect a particular type of defect), or perhaps accelerate assessments in some areas because the risks are higher than previously understood.

Because assessment plans are likely to change, PHMSA expects operators to document the basis for changes in the plan (required by 192.909(a)) so these can be reviewed during inspections. It is not necessary to apply for a waiver to change the Baseline Assessment Plan. Even though an operator's plan may change, the operator must still complete baseline assessments for 50% of the mileage in HCAs by December 17, 2007, and complete baseline assessments for all of the mileage in HCAs by December 17, 2012. [FAQ #30] [Element #14: Record #5]

Notification of Changes to Assessment Schedule

The rule requires that operators notify PHMSA of any changes "that may **substantially** affect the program's implementation or may **significantly** modify the program or schedule for carrying out the program elements" (emphasis added). Changes to the schedule for assessing individual pipeline segments that do not significantly affect program implementation or plans for carrying out program elements would not require a notification. Operators need not notify PHMSA of insignificant changes to their assessment schedules. Operators must document the basis for such changes (as required by 192.909(a)), and this documentation must be available for PHMSA review during integrity management inspections. [FAQ #31]

14.4 Agency Inspections

Advance Scheduling of PHMSA Inspections

PHMSA will schedule all integrity management inspections as far in advance as possible. PHMSA will coordinate the inspections with the companies to identify mutually agreed upon dates whenever possible. [FAQ #93]

Availability of PHMSA Protocols

Inspections of integrity management requirements will be conducted using written inspection protocols. Those protocols are available on this website (http://primis.rspa.dot.gov/gasimp/) and comments submitted via this website will be considered during their development. [FAQ #94]

Public Access to Inspection Results

PHMSA does not intend to make the detailed results of individual company inspections available to the public. However, consistent with the provisions of the Freedom of Information Act, members of the public may request and be granted access to information from PHMSA files. PHMSA is considering making summary level information on the industry's performance available to the general public on its web site, and will make available there a summary of the performance measurement information operators must report under the rule. PHMSA will take care to protect information that is sensitive to national security and homeland defense, including responses to FOIA requests. [FAQ #95]

14.5 Enforcement and Consistency In Application

Consistency of PHMSA Inspections

The integrity management rule contains a number of management-based and performance-based requirements. Inspection for compliance with these requirements is fundamentally different than for prescriptive requirements. PHMSA recognizes that inspecting against these requirements will require subjective judgments on the part of inspectors, and that it is important to assure consistency in this process. Consistency is being achieved through several means.

- The inspections will be conducted using written protocols. A core team of experienced state and federal inspectors is involved in developing inspection protocols and guidance.
- Integrity management inspections are performed by experienced inspectors.
- All inspectors conducting integrity management inspections, including state inspectors, will receive training specific to the rule.

- The core team intends to meet periodically during the early stages of implementing this rule to review inspection experience to be sure the appropriate level of consistency is being achieved. [FAQ #96]

Enforceability of Beyond Regulation Program Provisions

Section 192.907 requires that "...an operator of a covered pipeline segment must develop and follow a written integrity management program...". Requirements that an operator chooses to incorporate in its program, even though they may go beyond requirements specified in regulations, become a part of the program that the operator must "follow". PHMSA expects that an operator will implement all activities included in the operator's program. PHMSA encourages operators to undertake additional activities beyond those required by regulation. However, PHMSA discourage operators from including those additional activities in their programs if they do not intend to implement those additional activities. [FAQ #160]

14.6 State Requirements

PHMSA or State Request for Information

If PHMSA or state agent requests documents from CVGS, use one of the acceptable methods listed below: [Element #14: Record #4]

- By mail to;
  Office of Pipeline Safety
  Pipeline and Hazardous Materials Safety Administration
  U.S. Department of Transportation
  Information Resources Manager, PHP–10,
  1200 New Jersey Avenue, SE.,
  Washington, DC 20590-0001
- Via facsimile to (202) 366–7128
- By email to *informationresourcesmanager@dot.gov*
- For state agencies, send documents to appropriate address as required by the state agency

Submitting Performance Measures to States

The rule requires that an operator "notify" PHMSA (192.909(b), 192.921(a)(4), 192.933(c)), and 192.937(c)(4)), and these sections also require that operators notify state authorities where the pipeline is under their jurisdiction. Notifications under these provisions shall be sent both to PHMSA and to states. Section 192.945 requires that performance measures be submitted to PHMSA. PHMSA intends to make these measures available to states. This rule does not require that operators separately submit performance measures to states, although some states may establish their own requirements to do so. Waivers from this regulation will be treated in the same manner as any other waiver, and the application process shall be the same. [FAQ #210]

More Restrictive State Requirements

States may apply standards more restrictive than federal rules. CVGS shall consult with state pipeline safety authorities regarding the application of state laws. [FAQ #206]

14.7 Review and Implementation of Element #14

CVGS will use the attached agenda, "Gas IMP Element #13, and #14, Communications Plan and Agency Notification, for implementation of this element. CVGS will conduct this element #14 agenda review a minimum of once per calendar year not to exceed 18 months.

As a minimum the following agenda items will be defined or included: [Element #14: Record #6]

- Communication and agency notification agenda objectives
- List of personnel that shall attend including name and job title
- Frequency of the HCA review
- Description of how the review will be conducted
- List of procedures, regulations, and reference documents that will be available during the review
- List of forms and documents needed to complete the review
- List of required records needed to complete the review
- Attendance sheet including signature

- PHMSA gas IMP protocols used as a checklist to ensure all element #1 requirements are met
- Action item list as a result of the element #14 review [Element #14: Record #7]

14.8 Source References

1. Amended Final Rule and Pre-amble Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 102, May 26, 2004.

2. Correction to Final Rule and Discussion, (49 CFR 192.901-915) Federal Register, Volume #69, No. 66, December 17, 2003.

3. 49 CFR 192.911 – What are the elements of an integrity management program?

4. PHMSA Gas Integrity Management Protocols, Protocol Area #N, Submittal of Program Documents, January 2008

5. PHMSA Frequently Asked Questions (FAQs): Notification & Regulatory Inspections

6. PHMSA Frequently Asked Questions (FAQs): Inspection, Enforcement, and State Agencies

7. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #1 Introduction, section #2 Overview

Ref: 49 CFR 192.911(n)	Updated: July 2011

14.9 List of Required Ongoing Documentation for Element #14 – Agency Notification

Rec. #:	Sect. #:	Description of Required Documentation:	Respon. Person	Freq. & Deadline	Record Retention Period	Record Location
1.	14.3	Electronic report submission to PHMSA, when required	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
2.	14.3	Written request for alternate reporting, when applicable	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
3.	14.3	Call or email documentation for alternate reporting	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
4.	14.3	Alternate reporting documentation, when applicable	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
5.	14.3	Waiver	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
6.	11.7	Element #13 and #14 agenda, Communications Plan and Agency Notification Agenda and Action Items	IMP Leader	1x/yr[1]	5 yrs	Co. intranet
7.	11.7	Action item list as a result of the element #13 and #14 agenda review	IMP Leader	1x/yr[1]	5 yrs	Co. intranet

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

Attachment 7

Central Valley Gas Storage
Hazardous Substances Control Plan

Hazardous Substance Control

Prepared for

Central Valley Gas Storage
Princeton, CA

February 2012

Project No. 66350

Prepared by

Burns & McDonnell Engineering Company, Inc.

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1.0 HAZARDOUS SUBSTANCE CONTROL

The release of hazardous substances and subsequent emergency response procedures are discussed in the Hazardous Substance Control element of this plan. For the purposes of this plan, hazardous substances are defined as any substance or materials, including wastes, which exhibit hazardous characteristics and could adversely affect the health or safety of people or the environment. This plan includes measures that will be implemented if an accidental release occurs or if any subsurface hazardous substances are encountered during operation of the facility. This section does not address releases of natural gas from a pipeline. The provisions outlined in this element include telephone numbers of county and state agencies and primary, secondary, and final clean-up procedures.

The criteria listed below are requirements for hazardous substance use during the operation of the CVGS facility. Facility personnel are required to comply with these procedures during facility operations and maintenance activities.

1.1 PREVENTION MEASURES

The environmental and economic effects of a hazardous substance release can be best avoided by utilizing release prevention and containment procedures. The potential for a release to occur can be reduced by implementing the following requirements:

- Use, storage, and transport of hazardous substances must be performed in accordance with applicable local, state, and federal regulations and the requirements within this document.
- Equipment containing petroleum or other hazardous substances will be inspected periodically for leaks or signs of deterioration that could cause a leak or release. Leaks or deteriorated conditions should be repaired prior to use.
- Equipment shall be properly maintained and maintenance activities will be documented and available for inspection at any time.
- Personnel must take care not to cause an uncontrolled release of hazardous substances to the environment (i.e. use spill-safe fuel cans, absorbent pads, drip pans etc.).
- Personnel must not overfill vehicles and equipment. Leave room for fuel expansion, especially during times of extreme temperature change.
- Personnel must properly store and dispose of hazardous substances, wastes, and unused materials and follow good housekeeping practices. This includes full and partially full containers of waste material such as, but not limited to rags, gloves, trash, scrap metal, and empty containers.

- Petroleum products and other hazardous substances must not be stored or transferred near wells or spill pathways, such as storm drains. This includes fueling of vehicles and equipment.
- Hazardous substances must be stored in Department of Transportation (DOT) or UN-approved containers or other approved tanks and they must be stored in designated hazardous material storage areas.
- Containers must be kept closed unless material is being transferred.
- Project personnel will take care so that transferring operations are monitored and not left unattended.
- Storage and handling of flammable and combustible liquids including gasoline and diesel fuel will be in accordance with rules developed under California and Federal Code of Regulations (Title 8 Section 5451 and 29CFR1910.106, respectively). These regulations include, but are not limited to, bonding and grounding during transfer operations, fire protection requirements, storage quantity limitations, and spacing and location requirements.
- Gasoline and fuel storage tanks greater than 55 gallons in capacity must have a secondary containment constructed of an impervious material and capable of holding 110% of that tank's capacity or must be designed to have sufficient freeboard for precipitation events.
- Handling and disposal of hazardous wastes will be in accordance with California waste management regulations and the U.S. Environmental Protection Agency regulations (40 CFR 260- 40 CFR 272).

1.1.1 Storage in Designated Areas

Hazardous substances, including petroleum-based fuel and lubricants, will be stored only at designated storage areas.

1.2 INCIDENT RESPONSE MEASURES (SURFACE AND SUBSURFACE)

If a release incident occurs during the course of operation, personnel will first assess the situation for unsafe conditions. Employee safety is a priority. If needed, safety concerns should be prioritized and the appropriate safety and emergency personnel notified. After the safety of personnel has been addressed, the release discovering personnel should address "First on Scene Response Activities" in tab #5 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual and take the following actions as appropriate:

- Report the release to the CVGS management identified in Section 1.3.2.2 and they will contact the Environmental Health & Safety Department (EHS). The EHS staff member shall assess the release and make the necessary regulatory notifications.

- Reference the Material Safety Data Sheets (MSDS), which will be available in designated storage areas discussed in 1.1.1 above and in the Facility office.
- Immediately stop the source of the release. Stopping the source of the release will minimize the amount of material needed to be cleaned up and its potential to impact an environmental resource.
- Start containment actions, using on-site equipment and spill supplies to safely respond, and contain the release. If needed, call for additional supplies, equipment and manpower to assist with the containment effort.
- Assist to the fullest extent possible.
- Complete the “First On Scene Checklist” in tab #17 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual.

Environmental personnel will confirm with management that contaminated material is removed and properly disposed.

Depending on the type and severity of the release, the release will be documented in the facility’s Spill Prevention Control and Countermeasure (SPCC) Plan and appropriate written documentation will be submitted to necessary agencies. If a written report is required, EHS personnel will coordinate the completion of this documentation with CVGS management. Copies of written reports will also be filed onsite and with EHS staff. See Section 1.3 for reporting procedures.

Facility personnel accessing remote facility locations will maintain a supply of emergency clean-up materials for conducting initial containment and clean-up activities. In addition, spill kits will be placed at various locations throughout the facility and will be readily available in the instance of a release. Spill kits will typically contain 10-15 oil absorbent pads, 3-mil trash bags or spill bags, gloves, spill response information. Additional materials such as oil absorbent socks, overpack drums and containment booms may also be stored on-site.

1.2.1 Clean-up Procedures

After securing personnel safety, if personnel are trained to do so, they must immediately clean-up incidental releases involving hazardous substances. Release debris and waste will be properly labeled and stored in the Hazardous Waste Storage Area (HWSA). CVGS personnel can clean up incidental releases, if they are trained to do so. Incidental releases are those where the substance can be absorbed, neutralized, or otherwise controlled at the time of release by employees in the immediate release area, or by maintenance personnel. Incidental releases are not considered to be emergency responses.

If the release cannot be safely and adequately handled by on-site personnel, a licensed emergency response contractor will be contacted to contain, clean up and perform required sampling and disposal of released materials and debris. If required, samples of the waste may be collected and analyzed at a certified laboratory for waste characterization and determination. Additional clean-up will be performed as necessary. Temporary storage and disposal of release materials will be performed in accordance with federal, state, and local rules and regulations. EHS will conduct regulatory reporting, as necessary.

1.2.1.1 Primary Spill Clean-up Procedures

Incidental releases may be cleaned up by site-personnel if they are properly trained to do so. Contact EHS for guidance. Employees must wear proper personal protective equipment (PPE) when cleaning up releases. Proper PPE includes hard hat, protective gloves (e.g. latex or Nitrile), steel-toe boots, and safety goggles. If there is a likelihood of contamination of footwear while cleaning up the release, disposable foot coverings (booties) shall be worn.

The goal of primary release-clean up procedures for large releases is to contain the release and prevent the material from leaving the site. CVGS personnel shall not attempt to clean up large releases. Contact CVGS management and EHS for assistance. For large releases or if there is personal injury or a strong threat of personal injury, shut off any ignition sources and follow appropriate notification procedures described in Section 1.3.2. Do not allow anyone to enter the release area.

Absorb or wipe up the excess released material with paper towels, absorbent pads, sand, or vermiculite. Place contaminated materials into a suitable labeled container for disposal. Do not place absorbent materials in the trash. Refer to the product Material Safety Data Sheet (MSDS) for proper release clean-up procedures.

1.2.1.2 Secondary Spill Clean-up Procedures

For releases that cannot be cleaned-up by facility personnel, a clean-up contractor will be contacted and will remove any conspicuous released material from the site. The site will also be assessed to determine if any of the released material has penetrated surface soils. In addition, secondary spill clean-up should involve necessary repairs to equipment on-site that caused the release or was impacted by the release.

1.2.1.3 Final Spill Clean-up Procedures

If it is suspected that the release has penetrated surface materials, sampling may be required to determine if additional clean-up is required. Such sampling shall be conducted in accordance with appropriate procedures for the type of released material and in accordance with federal, state, and local regulations. If any post clean-up samples contain concentrations of hazardous substances above pre-release levels, additional excavation may be required, followed by another round of confirmation sampling. Impacted material shall be removed, as necessary, and properly disposed of.

1.3 REPORTING PROCEDURES

Determining whether a spill needs to be reported can be uncertain; therefore, all notifications will be made through the On-site Manager and EHS. Contact information, spill response procedures and notification requirements will be posted in the HWSA and available in the facility office or through EHS

1.3.1 Spill Reporting

The Environmental Protection Agency (EPA) has established requirements to report spills to navigable waters or adjoining shorelines. Specifically, the EPA requires the reporting of discharges of hazardous substances in quantities that may be harmful to public health or welfare, or to the environment. The EPA has determined that quantities that may be harmful include those that:

- Violate applicable water quality standards;
- Cause a film or “sheen” upon, or discoloration of the surface of the water or adjoining shorelines; or
- Cause a sludge or emulsion to be deposited beneath the surface of the water or up adjoining shorelines.

The requirement for reporting oil spills stems from EPA’s Discharge of Oil regulation, which has come to be known as the “sheen rule”. Under this regulation, reporting of oil spills to the federal government does not depend on the specific amount of oil spilled, but instead relies on the presence of visible sheen created by the spilled oil. When determining whether to report a spill, ask the following questions:

- Is the spill to navigable waters or adjoining shorelines?
- Could water quality standards be violated?
- Could the spill cause a film, “sheen”, or discolorations?
- Could the spill cause a sludge or emulsion?

More information can be found regarding the EPA's oil program by calling the National Response Center at 1-800-424-9346 or at http://www.epa.gov/oilspill/oilreqs.htm

The need to report a hazardous substance release to the National Response Center, other than oil, can be determined by consulting the CERCLA list of hazardous substances and reportable quantities (40 CFR Table 302.4). Any releases that involve a reportable quantity of any hazardous substance must be reported to the National Response Center at 1-800-424-8802.

Reportable Quantities of hazardous substances stored at CVGS are as follows:

Ethylene Glycol (pure) ____________________ 5,000 pounds
Methyl Alcohol ____________________ 5,000 pounds
Urea ____________________ Not Applicable
Lubricating Oil ____________________ Not Applicable
Triethylene Glycol ____________________ Not Applicable

When calling EHS to report a release, employees should have as much information available as possible. If possible, employees should be ready to report the following:

- Their name, location, organization, and telephone number;
- Name and address of the party responsible for the incident;
- Date and time of the incident;
- Location of the incident;
- Source and cause of the release or release;
- Types of material(s) released or released;
- Quantity of materials released or released;
- Danger or threat posed by the release or release;
- Number and types of injuries (if any);
- Weather conditions at the incident location; and
- Any other information that may help emergency personnel to respond to the incident.

1.3.2 Notification Procedures

Hazardous substance releases or threatened releases, including petroleum products such as gasoline, diesel, and hydraulic fluid must be reported immediately, regardless of the quantity released, if the release has entered or threatens to enter a water of the state, has caused injury to a person, or threatens injury to public health. Notifications should be documented using the "Agency Notification and Reporting" form in tab #17 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual.

1.3.2.1 State Notification Requirements

In accordance with California State Law, any significant releases or threatened releases of hazardous substances shall be reported to the Governor's Office of Emergency Services immediately at 1-800-852-7550 or (916) 845-8911 (Health and Safety Code 25507).

The State of California requires notification for the following occurrences:

- Any spill or other release of 42 gallons or more of petroleum products;
- Discharges or threatened discharges of oil in marine waters;
- Discharges of any hazardous substances or sewage, into or on any waters of the state;
- Discharges that may threaten or impact water quality;
- Any found or lost radioactive material;
- Discharges of oil or petroleum products, into or on any waters of the state; and
- Hazardous Liquid Pipeline releases and every rupture, explosion or fire involving a pipeline transporting natural gas or hazardous liquid.

Reportable releases for the State of California are further identified by Propositions 65 (Safe Drinking Water and Toxic Enforcement Act of 1986 and 9030 of the California Labor Code). A Section 304 Follow-Up Report form is required for reportable releases, which is to be submitted to the Governor's Office of Emergency Services as soon as possible, but no later than 30 days following the release. This form can also be used to submit to other agencies that may be involved due to the nature of the release.

1.3.2.2 Emergency Contacts

The following Facility personnel shall be notified in the event of a release at the facility:

CVGS Primary Contact:

D.G. Woodward, Operations Manager

CVGS Secondary Contact:

Brian Jones, Director, Storage & Peaking Ops, West Region

Ph: 337-526-9160

CVGS Release Response Contractor:

TBD

EHS:

Keith Bodger, Environmental Consultant

Ph: 630-388-2381

M: 630-514-7589

F: 630-983-4345

kbodger@aglresources.com

If needed, local emergency response agencies shall be notified immediately, by CVGS personnel, following the release or threatened release of hazardous substance.

- Fire/Police/Ambulance 911
- Colusa Police Department (530) 458-7777
- Colusa Fire Department (530) 458 -7721
- Colusa Medical Center (530) 458-5821

The State of California also requires the notification of a local Certified Unified Program Agency (CUPA). The identified CUPA for Colusa County area is Colusa County Health and Human Services at (530) 458-0395

1.3.2.3 Additional Notification Requirements

If the nature of the release dictates the need for additional notifications, these notifications may include, but are not limited to the following list of agencies:

- California Emergency Management Agency (CEMA) (800) 852-7550
- Department of Toxic Substance Control (DTSC) (800) 698-6942
- National Forest Service, Mendocino National Forest (530) 934-3316
- Department of Transportation (DOT) District 3 (530) 741-4226
- Regional Water Quality Control Board (RWQCB) (916) 227-4363
- Department of Fish and Game (916) 358-2900
- Office of Spill Prevention and Response (CDFG-OSPR) (800) 852-7550
- Local Hazardous materials Program (530) 458-0320
- California Department of Toxic Substances Control (DTSC) (800)728-6942
- Cal/OSHA Division of Occupational Health and Safety (800) 963-9424
- Air Quality Management District (530) 458-5821
- State Lands Commission (SLC) (562) 590-5201
- California Department of Oil & Gas (916) 322-1110

* * *

Attachment 8

Central Valley Gas Storage Worker Health and Safety Plan

WORKER HEALTH & SAFETY

Prepared for

Central Valley Gas Storage
Princeton, CA

February 2012

Project No. 66350

Prepared by

Burns & McDonnell Engineering Company, Inc.

TABLE OF CONTENTS

Page No.

* * * *

1.0 WORKER HEALTH AND SAFETY

This element of the plan will include provisions that establish procedures for worker health and safety including training. This portion of the plan will also establish security measures to prevent unauthorized entry to cleanup sites and to reduce hazards outside the investigation/cleanup area. It will also address gas leaks, methods of evacuation, and general protection measures.

1.1 OPERATIONS WORKER HEALTH AND SAFETY TRAINING

To comply with applicable worker health and safety standards, and to assist with employees recognition and understanding of how to protect themselves from potential hazards during the operation of CVGS Facility, training programs will be implemented. Training will be required for each of the safety procedures, outlined below, to control and mitigate potential site hazards.

Required Training Plans may include but are not limited to the following:

- Internal alarm/notification
- Evacuation and re-entry
- Hazard Communications (Hazcom)
- Selection and proper use of protective equipment
- Job-specific hazards of waste management
- Incidental release response procedures
- Emergency response procedures (expressly including Escaping Gas/Natural Gas Leaks and other specific emergency situations documented in tabs #13-16 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual .)
    - First Responder, Awareness Level
    - First Responder, Operations Level

For emergency response, CVGS management will assess the training needs for its employees and provide that which is necessary based on the response level desired during such an event.

1.2 INCIDENT SECURITY MEASURES

In the event of an on-site incident such as an equipment malfunction, fire, or gas leak, staff should follow safety procedures covered in applicable training sessions. After the incident is under control, CVGS personnel will implement measures to restrict unauthorized access to the incident area site until the incident has been contained, cleaned-up, and investigated. The following actions may be taken to maintain security during an on-site incident:

- Information regarding the incident and the access restrictions will be communicated to staff members in the most efficient way possible. Communication options include, but are not limited to alarms, two-way radios, cell phones, and e-mail notifications.
- The main gates for the compressor station are controlled by an electronic access system and may be monitored to restrict access to the gas storage facility.
- Access to individual buildings may be controlled by the electronic access system and/or caution tape and signs may be used to cordon off entrances and clearly mark buildings as restricted access locations.
- Portions of the site affected by the release may be restricted in a similar way to individual buildings.
- Through coordination with local emergency responders, traffic control personnel or signage can be placed along access roads to the Facility (such as McAusland Road and Southam Road) to warn the public, or other personnel about restricted areas or clean-up efforts.

1.3 NATURAL GAS LEAKS

In the event of a natural gas leak requiring emergency response activities by CVGS, facility personnel will follow the procedure documented in tab #13 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual.

As part of ongoing training and coordination with local emergency agencies and PG&E, CVGS will conduct and document regular communications and training to:

- Learn the responsibility and resources of each organization that may respond to a gas pipeline emergency.
- Acquaint the agencies with CVGS's capabilities in responding to a gas pipeline emergency.
- Identify the types of gas pipeline emergencies of which CVGS notifies the agencies.
- Coordinate how CVGS, agencies and PG&E can engage in mutual assistance during a natural gas pipeline emergency to minimize hazards to life or property.

1.4 METHODS OF EVACUATION

Facility personnel will be instructed regarding evacuation procedures, staging areas and routes. In the event of an alarm or other signal, facility personnel are to follow instructions of the CVGS Incident

Commander and proceed to the appropriate evacuation staging area or exit the facility. (Please refer to the attached Compressor Station Site Plan.)

In the event of a site evacuation, the primary staging area will be just inside the primary CVGS compressor station property exit security gate (north of the two gates) on McAusland Road. If use of the primary staging area is not appropriate due to the nature of the emergency, a secondary staging point will be designated by the CVGS Incident Commander and communicated to facility personnel. If the station property is to be entirely evacuated, facility personnel will proceed through the 'man-gate' adjacent to the staging area onto McAusland Road. Personnel will then proceed south on McAusland Road to Southam Road, turn left and proceed to State Highway 45 which is approximately ¼ mile to the east. Evacuated personnel are to report to the off-site evacuation location designated by the CVGS Incident Commander for an employee headcount.

Depending on the nature of the emergency, assistance may be requested of the Fire Department and/or Emergency Rescue, the Police/Sheriff Department, State Police, an Ambulance Unit, or PG&E; most of which can be reached by dialing 911 or with additional contact numbers documented in tab #8 of the DOT General Emergency Response Procedures provided in Part 4 of the Plant Operations Manual.

In the event of a complete property evacuation, if possible, indicated roads should be converted to one-way access allowing vehicles and pedestrians to exit the site in a calm and efficient fashion. The CVGS Incident Commander should coordinate site access control with local police and/or fire authorities to prevent access by the general public from the north via McAusland Road, from the east via Southam Road and from the south via the path of Dodge Road to McAusland Road.

* * * * *

STORAGE TANKS

MARK	DESCRIPTION	CAPACITY	LOCATION
TK-1	TRI-ETHYLENE GLYCOL STORAGE TANK	6,300 GAL.	EXHIBIT AX.2
TK-2	USED TRI-ETHYLENE GLYCOL STORAGE TANK	6,300 GAL.	EXHIBIT AX.2
TK-3	USED ENGINE COOLING WATER/GLYCOL TANK	6,300 GAL.	EXHIBIT AX.2
TK-4	ENGINE COOLANT	6,300 GAL.	EXHIBIT AX.2
TK-5	USED LUBE STORAGE TANK	1,200 GAL.	EXHIBIT AX.2
TK-6	COMPRESSOR OIL TANK UCON	2,500 GAL.	EXHIBIT AX.2
TK-7	ENGINE LUBRICATING OIL TANK	2,500 GAL.	EXHIBIT AX.2
TK-8	CONDENSATE TANK	6,300 GAL.	EXHIBIT AX.2
TK-9	UREA TANK	6,500 GAL.	EXHIBIT AX.2
TK-10	WELL PAD PRODUCED WATER TANK	130,000 GAL.	EXHIBIT AX.3
TK-11	METHANOL STORAGE TANK	1,000 GAL.	EXHIBIT AX.3
TK-12	UTILITY WATER STORAGE TANK	18,000 GAL. EA.	EXHIBIT AX.3

LEGEND:

- CAMERA (C)
- KEYCARD ACCESS (KA)
- EGRESS

0 40 80 120

Scale In Feet

DESIGNED IN ACCORDANCE WITH TITLE 49-PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

PREPARED BY:

ENEngineering
7135 JANES AVENUE
WOODRIDGE, IL. 60517
TEL. 630-353-4000
FAX 630-353-7777
WWW.ENENGINEERING.COM

REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
B	02/28/12	CCL	ISSUED FOR PERMIT		
A	03/16/11	RSR	ISSUED FOR PERMIT		

REVISIONS

central Valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

COMPRESSOR STATION SITE PLAN

COLUSA COUNTY CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
03/16/11	1"=40'	RSR	-	EXHIBIT AX.2	00	B

Attachment 9

Central Valley Gas Storage
Fire Prevention and Management Plan

PURPOSE

These practices clarify company requirements for locating, inspecting and maintaining fire protection systems. They contain minimum requirements for providing adequate fire prevention, protection and maintenance procedures.

CORE INFORMATION

Employees should only attempt to extinguish fires in the earliest (incipient) stages that can be controlled by portable and/or wheeled fire extinguishers, without the need for protective clothing or breathing apparatus.

Work Areas

Keep work areas clean. Store flammable and combustible materials in proper containers.

Extinguisher Selection

Select fire extinguishers according to the following criteria:

TABLE 1

CLASS	DEFINITION	RECOMMENDED EXTINGUISHING AGENT	MAXIMUM DISTANCE TO FIRE EXTINGUISHER
A	Ordinary combustibles, wood, paper, cloth	Pressurized water, Foray (ABC)	75 feet
B	Combustible and flammable liquids	Purple K	50 feet
C	Electrical equipment.	Purple K, CO_2	50 feet
D	Combustible metals	Dry powder	50 feet

Types of Portable Extinguishers

Stored Pressure These units contain the expellant gas and extinguishing agent in a single chamber. Discharge is directly controlled by the unit's valve. These units are always pressurized and are equipped with a pressure indicator gauge to indicate readiness for use. Following use, return these units to a distributor for recharge.

Cartridge Operated These units store expellant gas in a separate cartridge (e.g. CO_2) within or adjacent to the shell containing the extinguishing agent. These units are activated (pressurized) only on demand and can be recharged with dry chemical and a new expellant cartridge on site. Once pressurized, discharge is controlled by a valve that is generally located at the end of the discharge hose.

Sealed Pressure These units are similar to stored pressure units, but are non-refillable. They differ from stored pressure units in that they are sealed by a fragile metal disc as opposed to a valve, and after use, the unit is discarded. These units are commonly found in vehicles, trailers and in homes.

Fire Extinguisher Placement

Keep all fire extinguishers and fixed extinguishing systems fully charged and operational. Keep fire extinguishers in their designated locations when not being used.

Keep enough spare extinguishers to maintain adequate protection during maintenance or recharge of extinguishers. Keep spare dry chemical and cartridges on hand to recharge cartridge operated extinguishers. Mount and label portable fire extinguishers installed in plants, transmission stations, and compressor stations as follows:

- Mount extinguishers in a conspicuous location free from obstructions.
- Mount extinguishers with a maximum distance of five feet from the floor to the top of extinguisher
- Place signs or decals reading "Fire Extinguisher" to identify the location of the extinguisher.

Contact Environmental, Health and Safety and Crisis Management (EHSCM) for help in determining the type, size or number of extinguishers needed.

Inspections

Inspect all extinguishers monthly and annually. Refer to the manufacturer's inspection and maintenance manual for detailed inspection procedures. Enter the inspection date on the extinguisher's inspection tag.

Monthly

Inspect all wheeled and portable fire extinguishers monthly to determine that:

- The extinguisher is in its designated location
- Access to the extinguisher is free of obstructions
- The extinguisher is mounted in a conspicuous location
- Signs or decals are posted
- The seals and tamper indicators are not broken
- The extinguisher is free from damage and excessive corrosion
- The hose is in good condition
- Hydrostatic test date is current, and
- An inspection tag is attached to the extinguisher.

Cartridge Operated Extinguishers

Inspect the extinguisher to ensure:

- The cartridge is free from punctures and
- There is adequate dry chemical in the extinguisher.

Stored Pressure Extinguishers

Ensure the gauge indicates adequate pressure.

If the inspection shows the extinguisher is damaged or does not operate properly, immediately remove it from service and repair or replace it. Place a spare extinguisher in its place until the extinguisher is repaired or replaced.

Annual Inspection

All wheeled and portable fire extinguishers shall be inspected annually by a qualified inspector. Keep a copy of inspector certificates and state licenses (if required) on file.

Hydrostatic Testing

If an extinguisher has severe corrosion, the shell is damaged, or other conditions exist that make the integrity of the extinguisher questionable, remove the extinguisher from service, discard or hydrostatically test it to ensure that the shell is in good condition. Testing must performed only by personnel with the proper testing equipment and knowledge.

Regardless of condition, hydrostatically test fire extinguishers at the following intervals:

EXTINGUISHER TYPE	TEST INTERVAL (YEARS)
Cartridge operated water and/or antifreeze	5
Stored pressure water and/or antifreeze	
Foam	
Dry chemical, with stainless steel shells or soldered brass shells	
Carbon Dioxide	
Dry chemical, stored pressure and mild steel shells, brazed Brass shells, or aluminum shells.	12
Dry chemical, cartridge operated, with mild steel shells	

Fire Prevention

On site personnel will monitor the accumulation of flammable and combustible waste materials and residues that contribute to a fire.

Flammable substances are those liquids, solids or gases that have flashpoints below 100 degrees Fahrenheit. Some of the more common flammables are gasoline, natural gas, propane, methanol, and certain paints, primers and thinners.

Combustible substances are those liquids, solids or gases that have flash points greater than 100 degrees Fahrenheit. Some of the more common combustibles include grasses, paper, wood, paint, certain lubricating oils and greases.

Housekeeping and Maintenance

Good housekeeping and equipment maintenance are essential to keep fire hazards to a minimum. Listed below are house keeping and maintenance requirements for controlling the supply and accumulation of flammable and combustible substances:

Flammable liquids shall be stored in original or approved containers.

Larger quantities (25 gallons or more) of flammable liquids or gases shall be stored in an approved container outside of the building or in an approved fire rated storage cabinet when located inside the building.

Each flammable liquid container shall have a bonding and grounding cable attached between it and the receiving container while transferring or dispensing.

Oil-soaked rags shall be stored in a UL approved, covered metal container.

Scrap paper and wrapping or packing materials shall be removed from the work area immediately after unpacking and placed in the trash containers provided.

Weeds and grasses will not be allowed to grow or accumulate around outside flammable storage facilities, compressor stations, or regulator sets.

Signs

Fire prevention signs shall be posted in conspicuous locations and kept in good condition:

EXIT

Above all exit doorways

DANGER-NO SMOKING, MATCHES OR OPEN FLAMES

At entry point to plant or compressor stations

DANGER - FLAMMABLE

On doors of flammable storage cabinets

NO SMOKING

Posted in main office building

FIRE EXTINGUISHER

Signs or distinguishing markings above each fire extinguisher

Fire Extinguishers

Fire extinguishers will be placed at an appropriate distance throughout the facility.

Ignition Sources

Insulate or protect hot surfaces that might be sources of ignition against spillage or leakage of fuel.

Plant personnel are responsible to visually inspect heat producing equipment and ensure that good housekeeping and equipment maintenance are being performed to keep fire hazards to a minimum.

TRAINING

All Company personnel will receive annual training regarding fire hazards of the materials and processes to which they are exposed as well as the care and use of portable fire extinguishers, location of fire extinguishers and implementation of emergency plans including instruction on contacting local fire departments.

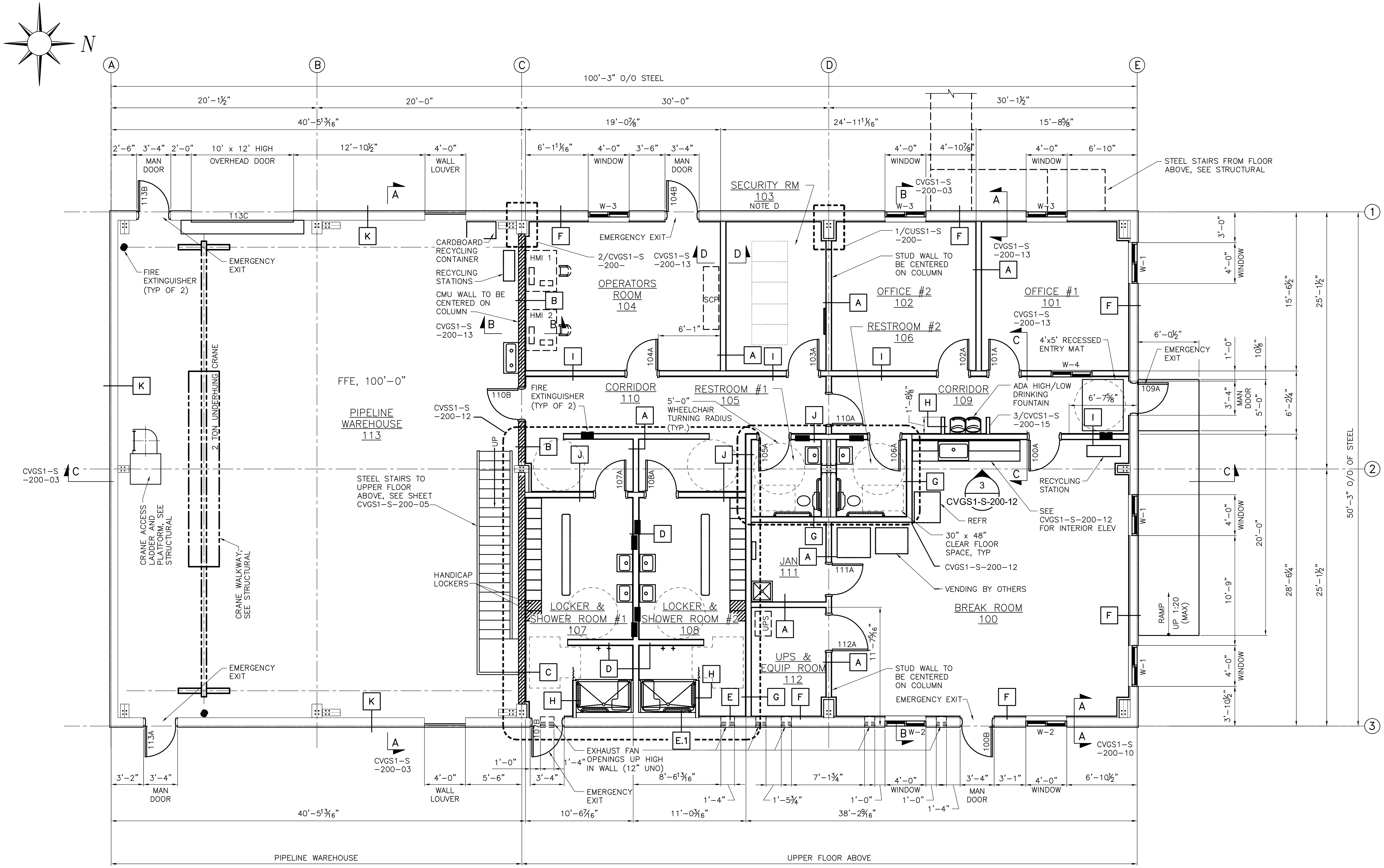
DOCUMENTATION

Monthly Inspections

Note the month of the inspection on the tag attached to the extinguisher. Also document the inspection on a fire extinguisher form and keep it on file.

Annual Inspections

Keep annual inspection records on file for a minimum of three years after last entry.



MAIN FLOOR PLAN

NOTES:

A. SEE SHEET CVGS1-S-200-02 AND CVGS1-S-200-03 FOR EXTERIOR ELEVATIONS

B. SEE SHEET CVGS1-S-200-XX FOR ABBREVIATIONS, SYMBOLS AND WALL TYPES

C. SEE CVGS1-004-1 THRU CVGS1-004-04 FOR SPECIFICATION NOTES AND MANDATORY MEASURES NOTE BLOCK.

D. SEE ELECTRICAL FOR ROOM AND EQUIPMENT LAYOUT

E. SEE ELECTRICAL, MECHANICAL, PLUMBING, AND STRUCTURAL DRAWINGS FOR ADDITIONAL INFORMATION. COORDINATE W/ METAL BUILDING SUPPLIER FOR FINAL WORK

LEGEND:

X — WALL TYPES, SEE SHEET XXX

X — SECTION CUT

DETAIL CALLOUT

CH2MHILL
2525 AIRPARK DRIVE
REDDING, CA 96001
(530) 243-5831

PREPARED BY:
ENGineering
7135 JANES AVENUE
WOODRIDGE, IL. 60517
TEL. 630-353-4000
FAX 630-353-7777
WWW.ENENGINEERING.COM

LICENSED ARCHITECT — STATE OF CALIFORNIA — C12184

REVISIONS

REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
E	04-19-11	JPR	100% FINAL CHECK SET	TWH	SF
D	03-25-11	JPR	CH2M HILL - 95% CHECK SET	TWH	SF
C	03-17-11	JPR	CH2M HILL - MODIFIED PLAN AND NOTES	TWH	SF
B	02-17-11	RSR	ADDED SINK & WATER HEATER; REMOVED MANDOOR; REVISED SHOWER #1 & #2		
A	01-28-11	FLH	ISSUED FOR BID	CCL	MPM

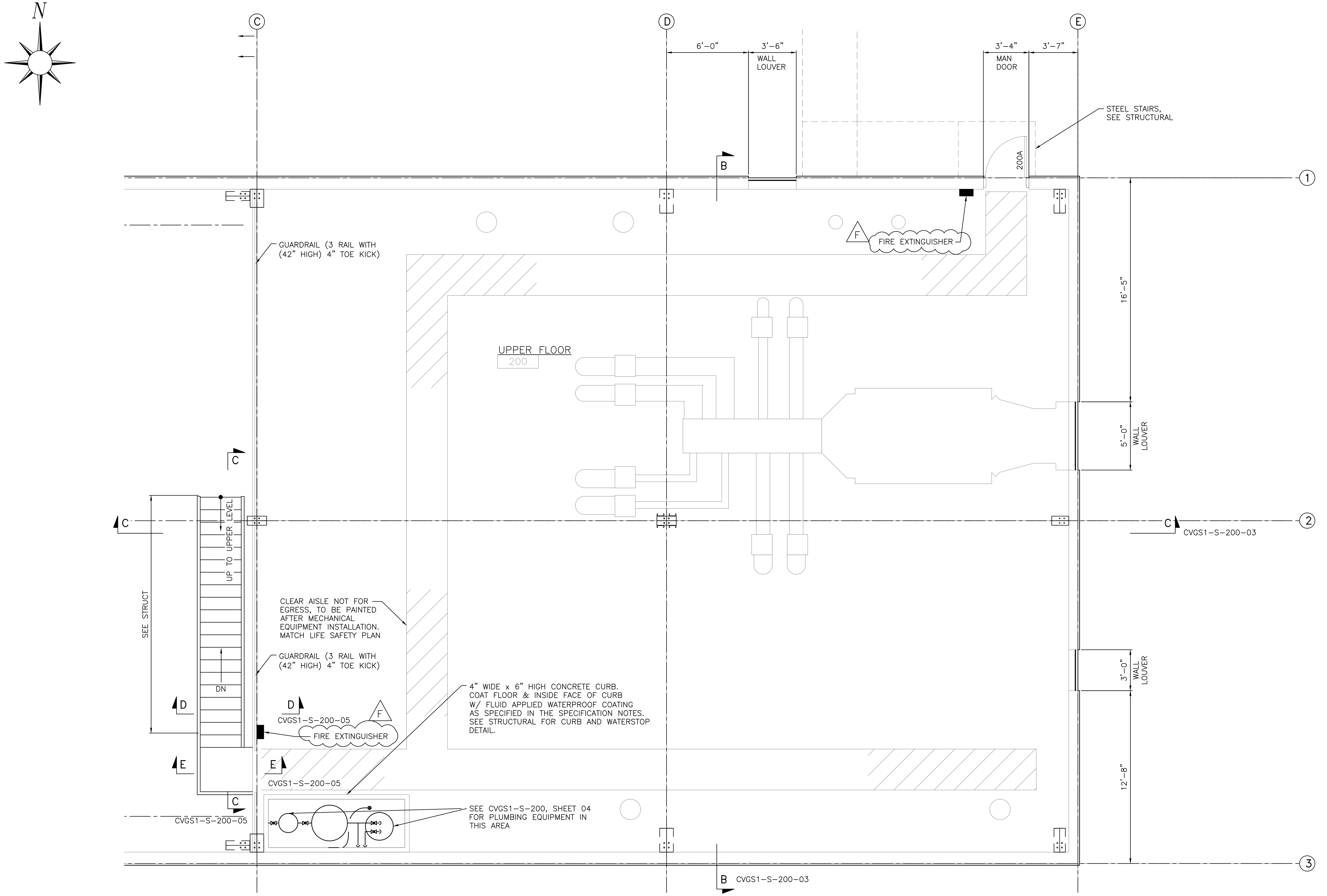
central Valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

COMPRESSOR STATION
AUXILIARY BUILDING
MAIN FLOOR PLAN

COLUSA COUNTY — CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
6-18-09	3/16" = 1'-0"	JM	-	CVGS1-S-200	01	B



UPPER LEVEL FLOOR PLAN

NOTES:

A. SEE MECHANICAL DRAWINGS FOR MECH EQUIP AND DUCT LAYOUT.
B. SEE LIFE SAFETY PLAN FOR EXITING.
C. SEE PLUMBING DRAWINGS FOR PLUMBING EQUIPMENT

CH2MHILL.
2525 AIRPARK DRIVE
REDDING, CA 96001
(530) 243-5831

PREPARED BY:
ENengineering
7135 JANES AVENUE
WOODRIDGE, IL. 60517
TEL. 630-353-4000
FAX 630-353-7777
WWW.ENENGINEERING.COM

REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
F	02-01-12	MJG	ISSUED FOR CONSTRUCTION	RS	MPM
E	04-29-11	JPR	CH2M HILL 100% CERTIFIED FINAL	TWH	SF
D	04-26-11	JPR	100% CORRECTED FINAL SET	TWH	SF
C	04-19-11	JPR	100% FINAL CHECK SET	TWH	SF
B	03-25-11	JPR	CH2M HILL - 95% CHECK SET	TWH	SF
A	01-28-11	RSR	ISSUED FOR BID	CCL	MPM

REVISIONS

central valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

COMPRESSOR STATION
AUXILIARY BUILDING
UPPER LEVEL FLOOR PLAN

COLUSA COUNTY — CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
4-29-11	⅛" = 1'-0"	JM	-	CVGS1-S-200	04	F

1. FIRE EXTINGUISHERS

A. TYPE: MULTIPURPOSE HAND FIRE EXTINGUISHERS WITH TRI-CLASS DRY CHEMICAL EXTINGUISHING AGENT IN PRESSURIZED, RED ENAMELED STEEL SHELL CYLINDER; ACTIVATED BY TOP SQUEEZE HANDLE; AGENT PROPELLED THROUGH HOSE OR OPENING AT TOP OF UNIT; FOR USE ON CLASS A, B, AND C FIRES; MINUMUM UL RATING 4A-60B:C, 10 POUND CAPACITY WITH ALL ACCESSORIES NECESSARY TO SECURE EXTINGUISHERS IN POSITION. ALL FIRE EXTINGUISHERS SHALL HAVE A TOP MOUNTING HEIGHT OF NO MORE THAN 48 INCHES IN ACCORDANCE WITH APPLICABLE CODES.

B. MANUFACTURERS:
1. AMEREX CORPORATION
2. ANSUL CORPORATION
3. GENERAL FIRE EXTINGUISHER CORPORATION

FIRE EXTINGUISHER CABINETS:

A. MANUFACTURERS:
1. J.L. INDUSTRIES
2. LARSEN'S MANUFACTURING CO.
3. MODERN METAL PRODUCTS

B. EXTINGUISHER CABINET TYPE:
1. SIZED TO FIT EXTINGUISHER.
2. METAL: FORMED STAINLESS STEEL; 0.036 INCH THICK BASE METAL.
3. TRIM: ROLLED.
4. DOOR: LOCK WITH BREAK GLASS ACCESS.

2. PROVIDE AND INSTALL A KNOX BOX MODEL 3275W/MOUNTING KIT FOR EACH EXTERIOR KEYED ENTRY DOOR.

DESIGNED IN ACCORDANCE WITH TITLE 49-PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

PREPARED BY:
ENEngineering
7135 JANES AVENUE
WOODRIDGE, IL. 60517
TEL. 630-353-4000
FAX 630-353-7777
WWW.ENENGINEERING.COM

REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
1	02-01-12	MJG	ISSUED FOR CONSTRUCTION	RS	MPM
0	08-02-11	AL	ISSUED FOR CONSTRUCTION	CCL	MPM
A	01-28-11	MJG	ISSUED FOR BID	CCL	

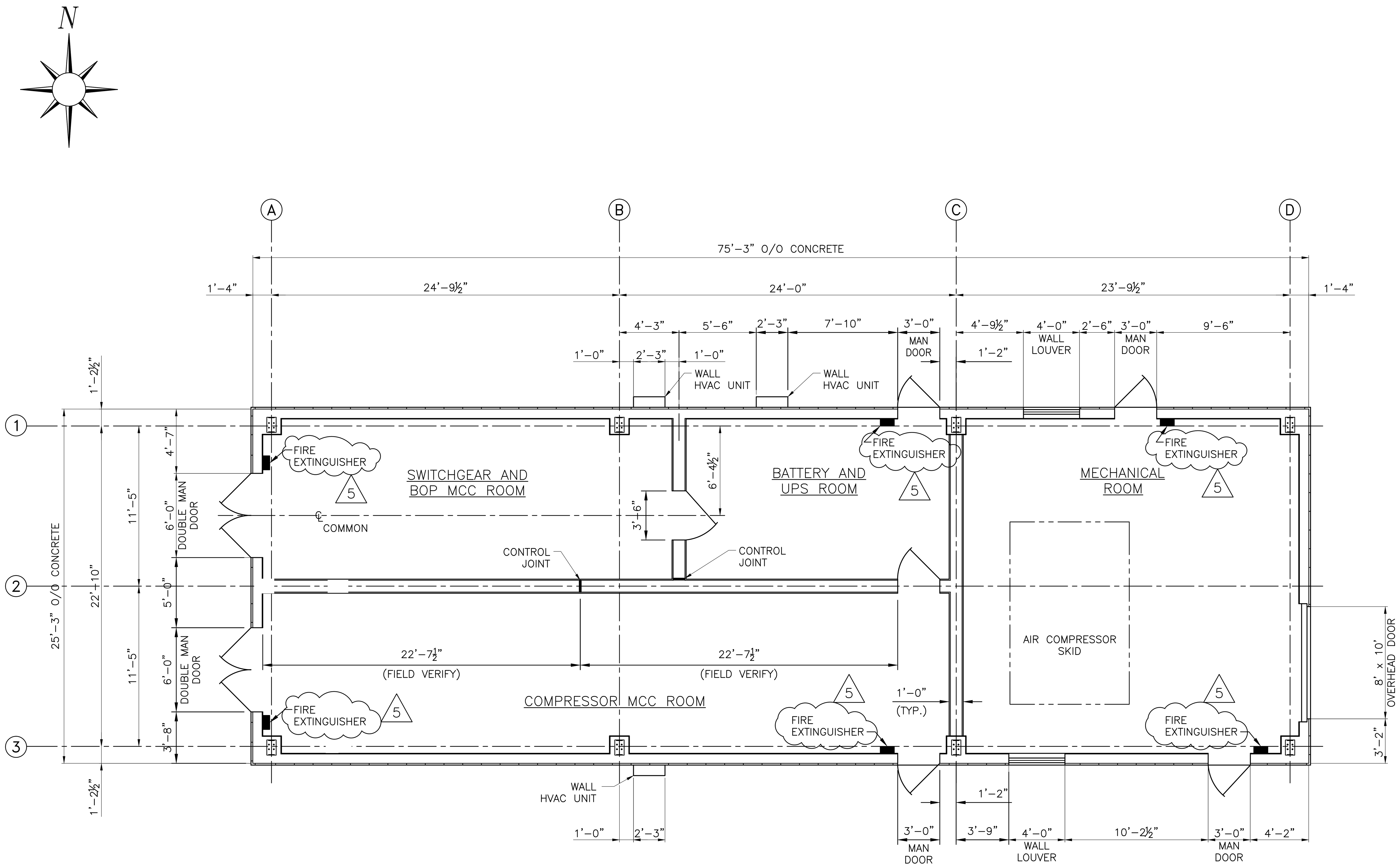
REVISIONS

CENTRAL VALLEY GAS STORAGE

COMPRESSOR STATION COMPRESSOR BUILDING PLAN

COLUSA COUNTY — CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
7-10-09	3/16" = 1'-0"	JM	-	CVGS1-S-201	01	1



UTILITY BUILDING PLAN

UTILITY BUILDING SPECIFICATIONS:

1. BUILDING TO BE RIGID FRAME, PURLIN AND GIRT TYPE CONSTRUCTION, UTILIZING ALL A-36 HOT ROLLED SECTIONS CONFORMING TO A.I.S.C. SPECIFICATIONS FOR THE DESIGN, FABRICATION & ERECTION OF STRUCTURAL STEEL BUILDINGS, (OR THE AISI SPECIFICATIONS FOR DESIGN OF LIGHT GAUGE COLD FORMED STEEL STRUCTURAL MEMBERS LATEST EDITION.)
2. BUILDING LOADING CRITERIA ARE PROVIDED IN THE BUILDING SPECIFICATION.
3. ALL STRUCTURAL STEEL SHALL BE HOT DIPPED GALVANIZED PER A.S.T.M. A-123 SPECIFICATION (2.3 OZ./SQ. FT.)
4. INSULATION, PANELS, LINING AND TRIM ARE TO BE FURNISHED BY THE BUILDING VENDOR AS DESCRIBED IN THE BUILDING SPECIFICATION.
5. STATION CONTRACTOR SHALL FURNISH AND INSTALL CONCRETE, REINFORCING STEEL (WELDED WIRE FABRIC), EXPANSION JOINTS AND COLORCRON SHALL ALSO BE FURNISHED AND INSTALLED BY THE STATION CONTRACTOR.

ACCESSORIES:

1. ONE (1) 8' X 10', "CAN TYPE", ROLL UP GALVANIZED STEEL DOORS, INSULATED ("R" VALUE OF 5.82), COMPLETE WITH CHAIN OPERATOR, FULL WEATHERSTRIPPING & PAINTED WHITE. OVERHEAD DOOR SHALL BE A MINIMUM OF 22 GAUGE, INSULATED TYPE DESIGN.
2. THREE (3) 3070 SINGLE SWING INDUSTRIAL STEEL DOORS, INSULATED URETHANE CORE (MIN. "R" VALUE 14.97), COMPLETED WITH PANIC HARDWARE, CLOSER, HINGES, THRESHOLD, WEATHERSTRIPPING, PAINTED WHITE AND FIELD GLAZED WITH ¼" ACRYLIC PANELS. ALL DOORS TO BE KEYED ALIKE. DOORS SHALL HAVE WINDOWS WITH ¼" THICK LAMINATED AND REINFORCED GLASS.
3. TWO (2) DOUBLE DOOR UNIT CONSISTING OF TWO (2) 3070 SINGLE SWING INDUSTRIAL STEEL DOORS, INSULATED URETHANE CORE (MIN. "R" VALUE 14.97), COMPLETE WITH 12" X 12" LOUVER, PANIC HARDWARE ONE SIDE, FIXED OTHER SIDE, CLOSER, HINGES, THRESHOLD, WEATHERSTRIPPING, PAINTED WHITE. ALL DOORS TO BE KEYED ALIKE.
4. THREE (3) DOOR CANOPIES, FABRICATED OF 10 GA. STEEL PREPAINTED WHITE, OVER-HEAD SUSPENDED DOOR CANOPY TO BE 5' x 6' WITH SLOPED ROOF.
5. TWO (2) DOOR CANOPY, FABRICATED OF 10 GA. STEEL PREPAINTED WHITE, OVERHEAD SUSPENDED DOOR CANOPY TO BE 5' x 9' WITH SLOPED ROOF.
6. THREE (3) 3070 1¾" SOLID CORE INTERIOR DOORS. REFER TO BUILDING "SCOPE OF WORK" FOR DOOR SPECIFICATIONS.
7. TWO (2) 48" x 48" ADJUSTABLE WALL LOUVERS, 120 VAC ELECTRIC OPERATED FACTORY INSTALLED (POWER TO OPEN/SPRING LOADED TO CLOSE) WITH BIRDSCREENS.
8. THREE (3) 24" x 48" ADJUSTABLE WALL LOUVERS, 120 VAC ELECTRIC OPERATED FACTORY INSTALLED (POWER TO OPEN/SPRING LOADED TO CLOSE) WITH BIRDSCREENS.
9. TWO (2) ROOF MOUNTED EXHAUST FANS, EACH WITH A TOTAL CAPACITY OF 1600 CFM, BACKDRAFT DAMPER AND BIRDSCREEN, SHALL BE PROVIDED BY THE BUILDING VENDOR. SOUND CRITERIA FOR LOUVERS AND VENTILATION EQUIPMENT ARE PROVIDED IN THE BUILDING SPECIFICATIONS. THE ROOF EXHAUST VENT SHALL INCLUDE A 36 INCH LONG SILENCER MOUNTED BETWEEN THE BUILDING SURFACE AND THE FAN.

NOTES:

REFER TO CENTRAL VALLEY STORAGE COMPRESSOR STATION UTILITY BUILDING INTERIOR ROUGH-IN AND FINISH SCOPE OF WORK" FOR EQUIPMENT SPECIFICATIONS.

1. STATION CONTRACTOR SHALL FURNISH AND INSTALL ALL BLOCK WALLS, SLABS AND SUPPORTING STEEL.
2. STATION CONTRACTOR SHALL FURNISH AND INSTALL ALL ACCESSORIES AND HVAC SYSTEM & COMPONENTS.
3. THE BUILDING VENDOR SHALL FURNISH AND THE STATION CONTRACTOR SHALL INSTALL ANCHOR BOLTS FOR BUILDING COLUMNS (CAST IN PLACE ⅝" AND LARGER). THE STATION CONTRACTOR SHALL FURNISH AND INSTALL ALL OTHER ANCHORS (½" AND SMALLER).
4. CONTRACTORS SHALL FABRICATE, CONSTRUCT AND INSTALL ALL MATERIALS IN ACCORDANCE WITH THE CURRENT CALIFORNIA BUILDING CODE AS WELL AS ANY COUNTY OR TOWNSHIP CODE THAT MAY APPLY TO A SPECIFIC SITE.
5. BUILDING VENDOR SHALL FURNISH LIGHTNING DISSIPATERS FOR ALL FOUR CORNERS, EACH ROOF EXHAUST FAN AND EVERY FIFTEEN FEET (15') ALONG THE ROOF RIDGE.
6. ALL LISTED ITEMS SHALL BE PROVIDED BY THE BUILDING VENDOR, UNLESS OTHERWISE NOTED.
7. THE BUILDING SHALL BE ERECTED BY THE STATION CONTRACTOR.

8. FIRE EXTINGUISHERS

A. TYPE: MULTIPURPOSE HAND FIRE EXTINGUISHERS WITH TRI-CLASS DRY CHEMICAL EXTINGUISHING AGENT IN PRESSURIZED, RED ENAMELED STEEL SHELL CYLINDER; ACTIVATED BY TOP SQUEEZE HANDLE; AGENT PROPELLED THROUGH HOSE OR OPENING AT TOP OF UNIT; FOR USE ON CLASS A, B, AND C FIRES; MINUMUM UL RATING 4A-60B:C, 10 POUND CAPACITY WITH ALL ACCESSORIES NECESSARY TO SECURE EXTINGUISHERS IN POSITION. ALL FIRE EXTINGUISHERS SHALL HAVE A TOP MOUNTING HEIGHT OF NO MORE THAN 48 INCHES IN ACCORDANCE WITH APPLICABLE CODES.

B. MANUFACTURERS:
1. AMEREX CORPORATION
2. ANSUL CORPORATION
3. GENERAL FIRE EXTINGUISHER CORPORATION

FIRE EXTINGUISHER CABINETS:

A. MANUFACTURERS:
1. J.L. INDUSTRIES
2. LARSEN'S MANUFACTURING CO.
3. MODERN METAL PRODUCTS

B. EXTINGUISHER CABINET TYPE:
1. SIZED TO FIT EXTINGUISHER.
2. METAL: FORMED STAINLESS STEEL; 0.036 INCH THICK BASE METAL.
3. TRIM: ROLLED.
4. DOOR: LOCK WITH BREAK GLASS ACCESS.

9. PROVIDE AND INSTALL A KNOX BOX MODEL 3275 W/MOUNTING KIT FOR EACH EXTERIOR KEYED ENTRY DOOR.

5

ISSUED FOR CONSTRUCTION 02/01/2012

DESIGNED IN ACCORDANCE WITH TITLE 49-PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

PREPARED BY:
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REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
5	02-01-12	MJG	ISSUED FOR CONSTRUCTION	RS	MPM
4	08-02-11	FLH	ISSUED FOR CONSTRUCTION	CCL	MPM
3	07-26-11	FLH	ISSUED FOR CONSTRUCTION	CCL	MPM
2	06-30-11	FLH	ISSUED FOR CONSTRUCTION	CCL	MPM
1	06-01-11	FLH	ISSUED FOR CONSTRUCTION	CCL	MPM
A	01-28-11	JM	ISSUED FOR BID		

REVISIONS

central valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

COMPRESSOR STATION UTILITY BUILDING PLAN

COLUSA COUNTY CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
6-24-09	3/16" = 1'-0"	JM/FLH	-	CVGS1-S-202	01	5

Appendix I

Measures Central Valley Gas Storage Has Undertaken to Identify and Minimize Risks

Appendix I.

Central Valley Gas Storage Measures to Identify and Minimize Risks:

A design stage Process Hazard Analysis (PHA) review of the preliminary design by EN Engineering (ENE) of the planned Central Valley Gas Storage (CVGS) facility was conducted and led by a third party on September 15, 16, and 17, 2010 in accordance with ENE's and CVGS's internal risk guidelines, to identify potential deviations from process design, maintenance, inspections, or operating practices which could lead to fires, explosions, or other events which could lead to personnel injury, equipment damage, or environmental impact, especially those involving high pressure natural gas releases. The PHA also addressed significant operability issues such as scenarios which could lead to a unit shutdown. The "What -If" methodology was used in this PHA.

The design stage PHA is included in this Appendix.

Prior to completion of construction and facility commissioning, a second PHA was conducted during May and June 2012. The intent of this PHA was to revalidate the design stage PHA, and to cover changes in original design following the design stage PHA. This PHA was conducted using both the "What-If" and "Haz-Op" methodologies.

A Pre-startup Safety Review (PSSR) was conducted prior to completion of putting the facilities in service to ensure that all safety and design requirements have been met.

FINAL
Design Stage Process Hazard Analysis
of the
Central Valley Gas Storage Facility
at the
Central Valley Gas Storage, LLC
Colusa County, CA

for

EN Engineering
Woodridge, IL

October, 2010

by
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EXECUTIVE SUMMARY

This report describes the results of a Design Stage Process Hazard Analysis (PHA) of EN Engineering's (ENE) preliminary design of the planned Central Valley Gas Storage Facility proposed for installation at the Central Valley Gas Storage, LLC (CVGS) facility in Colusa County, California (CA). Three PHA sessions were conducted on September 15^{th} through 17^{th}, 2010.

The Design Stage Process Hazard Analysis (PHA) systematically reviewed the Central Valley Gas Storage Facility using the What-If methodology. The purpose of this Process Hazards Analysis (PHA) was to conduct a Design Stage PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for CVGS in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. CVGS and ENE management have determined that the planned CVGS facility at the Colusa County site will not be covered by the Occupational Safety and Health Administration's (OSHA) "Process Safety Management of Highly Hazardous Chemicals" (PSM) regulation 29 CFR 1910.119 or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule, 40 CFR Part 68.

This Design Stage PHA was intended to identify potential deviations from process design, maintenance, inspection, or operating practices which could lead to fires, explosions, or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a unit shutdown. Where appropriate, improvements were recommended either in the form of adding additional safeguards to the proposed equipment or by suggesting revisions to the planned operating or preventive maintenance procedures.

The Design Stage Process Hazard Analysis was led by Mr. Fredrick H. (Rick) Knack, Principal Engineer, Primatech Inc., with team participation by key personnel from CVGS and ENE and CVGS.

Two hundred eighty-nine (289) potential What-If scenarios were identified during the Design Stage PHA for the Central Valley Gas Storage Facility. These scenarios resulted in three hundred eighteen (318) identified hazards which have the potential to cause accidental personnel injury, exposure to a release of natural gas or methanol, or equipment damage. There are, however, numerous existing safeguards, mitigating features, or operating procedures which were identified during the hazard analysis which can reduce the likelihood or severity of the release scenarios.

The Design Stage PHA resulted in seventy (70) recommendations which may involve equipment modifications or administrative issues such as procedures, maintenance, training, or emergency response which are intended to reduce the consequences or the likelihood of occurrence of an incident. Fifty-five (55) of the recommendations are assigned to ENE (Design/Hardware) (78.6%) and fifteen (15) have been assigned to CVGS (Procedural/Administrative) (21.4%).

It should also be noted that the Process Safety Information protocol, attached in Appendix E, contains only "Yes" answers, requiring no additional follow-up. There is one “NA (Not Applicable)” answer as there are no intended chemical reactions in this process.

1.0 INTRODUCTION

This report describes the results of a Design Stage Process Hazard Analysis (PHA) of EN Engineering's (ENE) preliminary design of the planned Central Valley Gas Storage Facility proposed for installation at the Central Valley Gas Storage, LLC (CVGS) facility in Colusa County, California (CA). Three PHA sessions were conducted on September 15th through 17th, 2010.

The Design Stage Process Hazard Analysis (PHA) systematically reviewed the Central Valley Gas Storage Facility using the What-If methodology. The purpose of this Process Hazards Analysis (PHA) was to conduct a Design Stage PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for CVGS in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. CVGS and ENE management have determined that the planned CVGS facility at the Colusa County, CA site will not be covered by the Occupational Safety and Health Administration's (OSHA) "Process Safety Management of Highly Hazardous Chemicals" (PSM) regulation 29 CFR 1910.119 or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule, 40 CFR Part 68.

This Design Stage PHA was intended to identify potential deviations from process design, maintenance, inspection, or operating practices which could lead to fires, explosions, or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a unit shutdown. Where appropriate, improvements were recommended either in the form of adding additional safeguards to the proposed equipment or by suggesting revisions to the planned operating or preventive maintenance procedures.

Section 1.1 of this report contains a brief description of the Central Valley Gas Storage Facility. Section 2 describes the purpose, scope and objectives of the work and identifies the study participants. Section 3 describes the study approach, Section 4 provides the results, and Section 5 lists the recommendations. Appendix A lists the systems, drawings, and equipment reviewed during the hazard analysis. Appendix B describes the What-If study technique. The action item report is included in Appendix C. The What-If worksheets and session identification sheets are included in Appendix D. The What-If protocol checklist (Process Safety Information) is included in Appendix E and the glossary of standard abbreviations for PHAs is listed in Appendix F.

Primatech's role in this project was to provide a team leader to facilitate the performance of a Design Stage Process Hazard Analysis (PHA) study by a team provided by EN Engineering and Central Valley Gas Storage, LLC. It was the responsibility of the team members from EN Engineering and Central Valley Gas Storage, LLC and not the team leader from Primatech, using their process knowledge, experience and other information available to them, to identify possible hazard scenarios and, optionally, identify possible recommendations for risk reduction. The results of the project depend on the accuracy and completeness of the information provided by EN Engineering and Central Valley Gas Storage, LLC for which Primatech shall not be responsible. The scope and objectives of the PHA study were defined by EN Engineering and Central Valley Gas Storage, LLC and are described later in this report. Primatech does not perform, and did not perform as part of this project, any design reviews, general safety reviews, engineering services, or process or equipment inspections. Primatech will have no responsibility for implementing recommendations since that is the responsibility and prerogative of EN Engineering and Central Valley Gas Storage, LLC.

This Design Stage PHA was performed in accordance with CVGS and EN Engineering (ENE) corporate internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. EN Engineering and Central Valley Gas Storage, LLC management have determined that the proposed Central Valley Gas Storage, LLC facility at the Colusa County, CA site is not a covered process under the Occupational Safety and Health Administration's (OSHA) "Process Safety Management of Highly Hazardous Chemicals" (PSM) regulation 29 CFR 1910.119 or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule, 40 CFR Part 68. However, federal regulations are subject to interpretation and Primatech cannot guarantee how they will be interpreted. Regardless of the effort exerted by the PHA team, there are necessarily hazard scenarios that may not be addressed in this study since no PHA technique can guarantee that all hazard scenarios will be identified. Primatech shall not be liable for any event or regulatory impact that occurs at the Central Valley Gas Storage, LLC facility.

EN Engineering and Central Valley Gas Storage, LLC should independently evaluate the recommendations recorded in the study, and alternatives to them, to ensure that the recommendations are feasible and are in the best interests of Central Valley Gas Storage, LLC. If the recommendations of this study are followed, the frequency or consequences of incidents and abnormal events may decrease. However, even if all the recommendations are followed, incidents and abnormal events may still occur. In addition, the physical act of implementing these recommendations may create hazards for EN Engineering, Central Valley Gas Storage, LLC or their employees. Therefore, EN Engineering and Central Valley Gas Storage, LLC should ensure that implementing these will not create unacceptable hazards and that safe practices are followed. Furthermore, there may be hazard scenarios identified in the study for which no recommendations were made during the study. In these cases, EN Engineering and Central Valley Gas Storage, LLC should determine whether any recommendations are needed to reduce risk.

This project was performed by Primatech solely for the benefit of EN Engineering and Central Valley Gas Storage, LLC and this report may not be disseminated or relied upon by third parties without Primatech's express prior written consent and no one can rely on it past 1 year from the date of issue. Neither Primatech nor any person acting on its behalf makes any warranty (express or implied), or assumes any liability to any third party, with respect to the use of any information or methods disclosed in this report.

1.1 Project Description (as provided by EN Engineering)

CVGS is proposing to convert the depleted Princeton Gas Field, near the unincorporated town of Princeton in Colusa County, California, into a high-deliverability, multi-cycle storage field. The field would ultimately be developed to provide 8 Bcf of working gas capacity. The working capacity would be phased in over 4 years, commencing with 5.5 Bcf in the first year. The field would be designed to achieve a maximum withdrawal and injection capability of 300 million standard cubic feet per day (MMscfd).[1]

CVGS would connect the storage field into the Pacific Gas and Electric PG&E Transmission System Line 400/401 near PG&E's Delevan Compressor Station, approximately 14.9 miles west of the storage field. The PG&E transmission system runs north–south along the western end of the project area. It transports natural gas from PG&E's connections with interstate pipelines, state gas fields, and local distribution infrastructure to the utility's local transmission and distribution system. The proposed

[1] A standard cubic foot is a measure of quantity of gas, sometimes but not always defined as a cubic foot of volume at 60°F and 14.7 pounds per square inch (PSI) of pr essure.

project involves constructing facilities necessary to convey natural gas from Line 400/401 to the Princeton Gas Field, storing the gas in the existing natural reservoir, withdrawing the stored gas, and conveying the withdrawn gas to Line 400/401 for delivery to customers.

The connection into PG&E would provide CVGS customers with access to Alberta, Rockies, San Juan, and Permian supplies through the many pipelines that connect to PG&E. Customers holding CVGS capacity would also have access to potential supplies from new natural gas facilities under development on the West Coast.

For a complete project description, see the Central Valley Gas Storage/- Central Valley Gas Storage Project Design Basis Manual.

List of Chemicals
Natural Gas
Triethylene Glycol
Methanol
Water
Urea

2.0 PURPOSE, SCOPE AND OBJECTIVES

2.1 Purpose

The purpose of this Process Hazards Analysis (PHA) was to conduct a Design Stage PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for CVGS in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. This PHA systematically reviews the planned CVGS Facility using the What-If methodology.

ENE and CVGS management have determined that the planned CVGS Facility will not be covered by the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) (29 CFR 1910.119) regulation or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule (40 CFR Part 68) requirements.

2.2 Scope

The scope of this PHA included the equipment, piping and instrumentation within the planned CVGS Facility in Colusa County, CA as shown on the process flow diagrams (PFDs) and piping and instrumentation diagrams (P&IDs) for this facility listed in Appendix A, including the main gas system (pipelines, compressors, filter separators, coolers, pressure reduction stations, and dehydration units) the blow down silencers, the glycol regeneration units, and associated tanks, valves, and instrumentations. The analysis includes anticipated start-up, normal (steady-state) operating and shutdown procedures, and global issues such as Services, Utilities, Facility Siting, and Emergency Procedures to the extent they interface with the CVGS Facility. By agreement between Primatech, CVGS and ENE, Human Factors was not addressed in the Design Stage

PHA but should be in subsequent studies.

2.3 Objective

The objective of the Design Stage PHA was to identify possible deviations from the planned process design, maintenance, inspection, or operating practices which could lead to fires, explosions or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving accidental natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a plant shutdown.

Failure of planned engineering and administrative controls and protections were evaluated for credible events which could lead to a hazardous scenario. Problems in the operation of utilities such as instrument air, electrical power, and plant water were implicitly reviewed for affect upon potential hazardous scenarios in the process.

Previous accidents in similar processes known of by CVGS and/or ENE were considered during the study. This included reportable releases, and process related incidents within the physical scope of the PHA review.

Global issues were considered for potential impact where they appeared to be plausible, including man-made or naturally occurring external events and facility siting such as proximity of equipment which could result in potential catastrophic effects.

2.4 Review Team

The PHA was led by Mr. Fredrick H. (Rick) Knack, PE, CSP, Principal Engineer, Primatech, with team participation from key ENE and CVGS personnel. Mr. Knack is knowledgeable in the technique of the hazard analysis employed and has considerable experience conducting hazard analyses, risk assessments, and safety reviews, of chemical processes. His qualifications include a MEng in Engineering Physics, a BS in Chemical Engineering, licensure as a Professional Engineer in the State of North Carolina certification as a Certified Safety Professional, and certification as a PHA Team Leader. He also served as the recorder for the review findings.

The EN Engineering and Central Valley Gas Storage, LLC personnel participating in the study are listed along with their descriptive functional titles.

Table 1: PHA Participants

Team Member	Job Title	Location	Process related experience/ qualification	√
Ernie Erickson	Senior Project Engineer, CVGS	Woodridge, IL	39 years	100%
Michael Fugate	Manager Storage Operations, CVGS	Woodridge, IL	33 years	100%
Myron Reicher	Senior Process Engineer, ENE	Woodridge, IL	40 Years	100%
Homer Savage, PE	Project Director Energy & Chemicals, Fluor[2]	Irving, TX	35 years	67%
Mike Miller	Senior Project Manager, ENE	Woodridge, IL	37 years	67%
Dave Fisher, PE	Senior Technical Lead, ENE	Woodridge, IL	35 years	67%
Jack Steiner	Senior Project Engineer, ENE	Woodridge, IL	30 years	33%
John Davis	Senior Technical Lead, ENE	Woodridge, IL	30 years	100%
Jim Kiefer	Project Director, Energy and Chemicals CVGS	Princeton, CA	32 years	33%
Ray Schnegelsberg	Manager Storage Development, CVGS	Princeton, CA	30 years	33%
Rick Knack, PE, CSP	Principal Engineer	Study Facilitator – Primatech		100%

Appendix D further lists the PHA session dates and attending team members.

[2] Fluor is to be the Prime Construction Contractor for the CVGS Storage Facility.

3.0 STUDY PROCEDURE AND APPROACH

The What-If methodology was chosen for the Design Stage PHA of the Central Valley Gas Storage Facility because it is a flexible technique which enables a knowledgeable team to analyze hazardous scenarios in an effective and efficient manner. This section provides an overview of the What-If procedures and the approach used during this PHA. Appendix B provides additional details on the What-If technique.

In order to facilitate the hazard analysis, the Central Valley Gas Storage Facility was subdivided into smaller logical subsystems. The subsystems were typically defined by the equipment or the operating mode. Appendix A includes a complete list of the systems, equipment, and the drawings reviewed.

The preparation for the process hazard analysis of the Central Valley Gas Storage Facility involved gathering relevant Piping and Instrumentation Diagrams (P&IDs) and data and discussing the design and operation of the system with EN Engineering and Central Valley Gas Storage, LLC personnel.

The What-If PHA worksheet contains four category columns with the following information:

The first category column is used to indicate the cause for the scenario in the worksheet. The following codes are considered:

EQ = Equipment Failures
HE = Human Error
HF = Human Factor
EX = External Event
FS = Facility Siting Issue
PI = Previous Incidents (on similar equipment)

SC = Failure of Safeguard or Control

SD = Startup/shutdown Issue

NO = Normal Operation

The second category column is used to classify the consequence for the scenario in the worksheet. The following codes are considered:

EM = Effect Onsite Personnel

EP = Effect Offsite Public

EV = Effects on the Environment

OP = Operability Problem

PD = Property Damage

The third category column is used to indicate the type of safeguard listed. The following codes are considered:

DT = Detection System

PS = Prevention System

MT = Mitigation

EN = Engineered

PR = Procedural

AD = Administrative

AC = Active

PA = Passive

ER = Emergency Response Procedure

SC = Secondary Containment

OF = Offsite Mitigation or Control

The last category column is used to indicate the type of recommendation for the scenario in the worksheet. The following codes are considered:

AD = Administrative

HW = Hardware

PR = Procedural

SW = Software

MN = Maintenance

TI = Testing/Inspection

TR = Training

ER = Emergency Response

AU = Audit

Equipment failures may include items such as vessel or line failures, leaks, pump failures, or instrumentation failures. Human errors may include the failure of an operator to perform a required specific function or performing it incorrectly. Human errors by involved personnel may also include faulty maintenance practices, or incorrect set points entered into a computer control system. External events consider situations such as loss of electricity, a fire in the processing area, or even issues related to facility siting. Failures of existing safeguards involve an assessment of the existing engineering and administrative controls associated with the system.

Analysis of What-If scenarios included:

- A qualitative evaluation of the potential hazards and consequences of the deviations on the employees in the workplace and on the surrounding environment;
- The identification of previous incidents in similar processes which had a likely potential for catastrophic consequences in the workplace or on the surrounding environment;
- An assessment of the planned engineering and administrative controls (safeguards), including natural gas and methanol release prevention and detection method. For assessment of this initial design stage PHA,

planned engineering and administrative controls (safeguards) which were documented on the P&IDs were treated as if they existed.

- An identification of preliminary recommendations, either equipment or procedural, designed to mitigate or minimize of the consequences or probability of occurrence of accidental natural gas and methanol releases.

3.1 Study Approach

For the Design Stage Process Hazard Analysis of the Central Valley Gas Storage Facility, the ENE/CVGS risk ranking system was used to rank hazard scenarios according to their estimated severity and likelihood. The risk ranking system accomplishes the ranking by using a scale of four levels for severity and four levels for likelihood. Values of the relative risk for each combination of severity and likelihood are defined in the risk matrix. The risk factors can be used to assign priorities to the recommendations developed during the PHA study. Risk ranking was applied only to scenarios considered to have credible potential for hazardous consequences. Operability scenarios were not risk ranked.

The risk ranking system includes values 1 (higher risk) through 5 (lower risk).

Table 2 Risk Ranking System

Severity (provided by ENE/CVGS; assigned to consequences without consideration of safeguards):

1 Major
2 Serious
3 Minor
4 Negligible

Likelihood (provided by ENE/CVGS; assigned to consequences with consideration of safeguards):

1 Frequent
2 Occasional
3 Seldom
4 Unlikely

Ranking Matrix:

LIKELIHOOD \ SEVERITY	1	2	3	4
1	1	2	3	5
2	1	2	3	5
3	2	3	4	5
4	4	5	5	5

4.0 RESULTS

Two hundred eighty-nine (289) unique potential What-If scenarios were identified during the Design Stage PHA for the Central Valley Gas Storage Facility. These scenarios could potentially be initiated by a variety of causes as shown in the breakdown by question category. Since some scenarios involve multiple potential causes, the total number of potential causes identified in the PHA is five hundred (500). The breakdown of the scenarios by cause category is as follows:

Table 3: Occurrences of the Question Category

Type of Cause	Frequency	
Equipment Failure(EQ)	238	47.6%
Human Error (HE)	227	45.4%
External Event (EX)	29	5.8%
Human Factor (HF)	3	0.6%
Normal Operation (NO)	2	0.4%
Facility Siting (FS)	1	0.2%
TOTAL	500	100%

(Percentages are rounded to the first decimal place; Causes s may have multiple category entries)

A What-If question does not necessarily result in a potentially hazardous consequence. Some may have no notable consequence or just an impact on process operability or product quality. Other questions may have more than one consequence or applicable categories. Approximately twenty-five percent (25.3%) of these scenarios have the potential to cause accidental personnel injury or exposure. Approximately fifty percent (50.2%) could result in potential equipment damage. Approximately sixteen percent (15.6%) were identified as having potential environmental impact and approximately nine percent (8.9%) of the scenarios were identified as presenting operability issues. The occurrences of the consequence categories are shown in the table below:

Table 4: Occurrences of the Consequence Category

Type of Consequence	Frequency	
Property Damage (PD)	219	50.2%
Effect Onsite Personnel (EM)	110	25.3%
Effects On the Environment (EV)	68	15.6%
Operability Problem (OP)	39	8.9%
TOTAL	436	100%

(Percentages are rounded to the first decimal place; Consequences may have multiple category entries)

Numerous engineered safeguards, mitigating features, operating procedures, or administrative controls which can reduce the likelihood or consequences of the hazardous scenarios were identified in the What-If worksheets associated with the Central Valley Gas Storage Facility. Recommendations were generally made only for hazardous scenarios where the review team felt that the existing safeguards were not sufficient to reduce the consequences of or to reduce the likelihood of occurrence of a potential incident. In some cases, even though existing safeguards were deemed sufficient by the team, recommendations were made to improve operability or documentation.

The table below shows the distribution of risk ranking value frequencies for the entire Central Valley Gas Storage Facility. Approximately seventy-nine percent (78.5%) of the potentially hazardous scenarios had a relatively low risk rating of 5. These relatively low risk values for the Central Valley Gas Storage Facility reflect the adequacy of the safeguards already included in the system design. Another fifteen percent (15.1%) of the scenarios had moderate risk ratings of 4 through 3, and only approximately six percent (6.3%) had the high risk ratings of 2 and 1. Risk ranking was applied only to scenarios considered to have credible potential for hazardous consequences. The risk ranking system includes values 1 (higher risk) through 5 (lower risk). Operability scenarios were not risk ranked unless it was desired by the team to document a recommendation for purposes of improving documentation, gather additional information.

Table 5: Risk Ranking Value Frequencies

Risk Rank Value	LOW	MODERATE		HIGH		RANKED ITEMS
	5	4	3	2	1	
Frequency	249	21	27	11	9	317
	78.5%	6.6%	8.5%	3.5%	2.8%	

(Numbers are rounded to nearest decimal and/or integer)

It should also be noted that the Process Safety Information protocol, attached in Appendix E, contains only "Yes" or “Not Applicable” (NA) answers, requiring no additional follow-up.

5.0 RECOMMENDATIONS

The Design Stage Process Hazard Analysis resulted in seventy (70) recommendations, which are intended to reduce either the consequences or the likelihood of occurrence of an incident. The recommendations are categorized according to the codes listed in Section 3, above. Recommendations may involve equipment modifications or administrative issues such as procedures, maintenance, training, or emergency response. The seventy (70) recommendations generated during the this study are listed in the Appendix C, What-If Action Items Report derived from Primatech's software PHAWorks® in context with the scenarios to which they refer. Fifty-five (55) of the recommendations are assigned to ENE (Design/Hardware) (78.6%) and fifteen (15) have been assigned to CVGS (Procedural/Administrative) (21.4%).

The last category column in the worksheets is used to indicate the type of recommendation. The breakdown of the seventy (70) recommendations by type is presented in Table 6. Since some recommendations involve multiple types, the total number of recommendation types identified in the PHA is seventy-three (73).

Table 6: Recommendations per Type

Type of Recommendation	Frequency	
Hardware (HW)	27	37.0%
Administrative (AD)	14	19.2%
Software (SW)	11	15.1%
Audit (AU)	8	11.0%
Procedural (PR)	7	9.6%
Maintenance (MN)	6	8.1%
TOTAL	**73**	**100%**

(Percentages are rounded to the first decimal place; Recommendations may have multiple category entries)

Since the primary purpose of the hazard analysis team was to identify potential problems, not necessarily to solve them, there may be a need for action items not noted herein. Any proposed action items should be carefully studied by appropriate engineering and operations personnel before implementation. ENE and CVGS personnel evaluating the action item should be sure to understand the nature of the problem identified by the study team. Additionally, alternative solutions to that expressed by the team may be available and should not be disregarded without proper evaluation. ENE and CVGS should consult their companies' guidelines to implement action items to address risk ranked recommendations on a timely basis.

APPENDIX A

Systems, Drawings, and Equipment Reviewed

Worksheet Summary

Printed: November 23, 2010, 8:30 AM
Company: EN Engineering
Location: Woodridge, IL
Facility: Central Valley Gas Storage, Princeton, CA
PHA Method: What-If
PHA Type: Initial

Process:

CVGS Facility, Design Stage PHA

File Description:

Final

Date:

September 15-17, 2010

Process Description:

As provided by EN Engineering

CVGS is proposing to convert the depleted Princeton Gas Field, near the unincorporated town of Princeton in Colusa County, California, into a high-deliverability, multi-cycle storage field. The field would ultimately be developed to provide 8 Bcf of working gas capacity. The working capacity would be phased in over 4 years, commencing with 5.5 Bcf in the first year. The field would be designed to achieve a maximum withdrawal and injection capability of 300 million standard cubic feet per day (MMscfd).

CVGS would connect the storage field into the PG&E Transmission System Line 400/401 near PG&E's Delevan Compressor Station, approximately 14.9 miles west of the storage field. The PG&E transmission system runs north-south along the western end of the project area. It transports natural gas from PG&E's connections with interstate pipelines, state gas fields, and local distribution infrastructure to the utility's local transmission and distribution system. The proposed project involves constructing facilities necessary to convey natural gas from Line 400/401 to the Princeton Gas Field, storing the gas in the existing natural reservoir, withdrawing the stored gas, and conveying the withdrawn gas to Line 400/401 for delivery to customers.
The connection into PG&E would provide CVGS customers with access to Alberta, Rockies, San Juan, and Permian supplies through the many pipelines that connect to PG&E. Customers holding CVGS capacity would also have access to potential supplies from new natural gas facilities under development on the West Coast.

For a complete project description, see the Central Valley Gas Storage/Nicor Central Valley Gas Storage Project Design Basis Manual.

Chemicals:

Natural gas
Triethylene Glycol
Methanol
Water
Urea

Purpose:

The purpose of this Process Hazards Analysis (PHA) was to conduct an Initial PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for Nicor in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. This PHA systematically reviews the planned CVGS Facility using the What-If methodology.

ENE and CVGS management have determined that the planned CVGS Facility will not be covered by the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) (29 CFR 1910.119) regulation or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule (40 CFR Part 68) requirements.

Scope:

The scope of this PHA included the equipment, piping and instrumentation within the planned CVGS Facility in Colusa County, CA as shown on the process flow diagrams (PFDs) and piping and instrumentation diagrams (P&IDs) for this facility listed in Appendix A, including the main gas system (pipelines, compressors, filter separators, coolers, pressure reduction stations, and dehydration units) the blow down silencers, the glycol regeneration units, and associated tanks, valves, and instrumentations. The analysis includes anticipated start-up, normal (steady-state) operating and shutdown procedures, and global issues such as Services, Utilities, Facility Siting, and Emergency Procedures to the extent they interface with the CVGS Facility. By agreement between Primatech, CVGS and ENE, Human Factors was not addressed in the Design Stage PHA but should be in subsequent studies.

Worksheet Summary

Objectives:

The objective of the Design Stage PHA was to identify possible deviations from the planned process design, maintenance, inspection, or operating practices which could lead to fires, explosions or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving accidental natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a plant shutdown.

Failure of planned engineering and administrative controls and protections were evaluated for credible events which could lead to a hazardous scenario. Problems in the operation of utilities such as instrument air, electrical power, and plant water were implicitly reviewed for affect upon potential hazardous scenarios in the process.

Previous accidents in similar processes known of by CVGS and/or ENE were considered during the study. This included reportable releases, and process related incidents within the physical scope of the PHA review.

Global issues were considered for potential impact where they appeared to be plausible, including man-made or naturally occurring external events and facility siting such as proximity of equipment which could result in potential catastrophic effects.

Project Notes:

The first category column is used to indicate the cause for the scenario in the worksheet. The following codes are considered:

EQ = Equipment Failures
HE = Human Error
HF = Human Factor
EX = External Event
FS = Facility Siting Issue
PI = Previous Incidents (on similar equipment)
SC = Failure of Safeguard or Control
SD = Startup/shutdown Issue
NO = Normal Operation

The second category column is used to classify the consequence for the scenario in the worksheet. The following codes are considered:
EM = Effect Onsite Personnel
EP = Effect Offsite Public
EV = Effects On the Environment
OP = Operability Problem
PD = Property Damage

The third category column is used to indicate the type of safeguard listed. The following codes are considered:
DT = Detection System
PS = Prevention System
MT = Mitigation
EN = Engineered
PR = Procedural
AD = Administrative
AC = Active
PA = Passive
ER = Emergency Response Procedure
SC = Secondary Containment
OF = Offsite Mitigation or Control

The last category column is used to indicate the type of recommendation for the scenario in the worksheet. The following codes are considered:
AD = Administrative
HW = Hardware
PR = Procedural
SW = Software
MN = Maintenance
TI = Testing/Inspection
TR = Training

ER = Emergency Response
AU = Audit

Filters: No Filter Applied

Worksheet Summary

1 Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings:
CVGS1-M-100 01 Rev C
CVGS1-M-100 021 Rev C
CVGS1-M-101 01 Rev D
CVGS1-M-110 01 Rev D

2 Compressor 5020, including Suction Pulsation Bottles CBL-1110 & 1130 and, Discharge Pulsation Bottles CBL-1100 & 1140, Suction Separators MBD-1090 & 1120 and Gas Cooler HAL-2020
Drawings:
CVGS1-M-102 01 Rev C
CVGS1-M-103 01 Rev D

3 Compressor 5030, including Suction Pulsation Bottles CBL-1160 & 1190, Discharge Pulsation Bottles CBL-1170 &1200, Suction Separators MBD-1150 & 1180 & Gas Cooler HAL-2030
Drawing: CVGS1-M-103 01 Rev D

4 High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings:
CVGS1-M-100 01 Rev C
CVGS1-M-100 021 Rev C
CVGS1-M-101 01 Rev D
CVGS1-M-102 01 Rev C
CVGS1-M-103 01 Rev D
CVGS1-M-104 01 Rev D

5 High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings:
CVGS1-M-100 01 Rev C
CVGS1-M-100 021 Rev C
CVGS1-M-101 01 Rev D
CVGS1-M-102 01 Rev C
CVGS1-M-103 01 Rev D
CVGS1-M-104 01 Rev D

6 High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings:
CVGS1-M-100 01 Rev C
CVGS1-M-100 021 Rev C
CVGS1-M-101 01 Rev D
CVGS1-M-102 01 Rev C
CVGS1-M-103 01 Rev D
CVGS1-M-104 01 Rev D

7 High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings:
CVGS1-M-104 01 Rev D

CVGS1-M-104 02 Rev D

8 West Meter run in withdrawal mode
Drawing: CVGS1-M-104 01 Rev D

9 East Meter run in withdrawal mode
Drawing: CVGS1-M-104 01 Rev D

10 Filter Separator MAK-1510 (withdrawal mode)
Drawings:
CVGS1-M-104 02 Rev D
CVGS1-M-112 01 Rev C

11 Pig Receiver MBP-1500 (withdrawal mode)
Drawing: CVGS1-M-104 02 Rev D

12 High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line A to West meter run)
Drawings:
CVGS1-M-104 01 Rev D
CVGS1-M-104 02 Rev D

13 High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line A to East meter run)
Drawings:
CVGS1-M-104 01 Rev D
CVGS1-M-104 02 Rev D

14 High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line B to West meter run)
Drawings:
CVGS1-M-104 01 Rev D
CVGS1-M-104 02 Rev D

15 High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line B to East meter run)
Drawings:
CVGS1-M-104 01 Rev D
CVGS1-M-104 02 Rev D

16 Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, withdrawal mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings:
CVGS1-M-105 01 Rev D
CVGS1-M-106 01 Rev D
CVGS1-M-107 01 Rev D

17 Fuel Gas System
Drawings:
CVGS1-M-104 01 Rev D
CVGS1-M-111 01 Rev D
CVGS1-M-111 02 Rev D

18 Wellheads and Wellhead Separators - withdrawal mode

Drawings:
- CVGS1-M-109 02 Rev D
- CVGS1-M-109 03 Rev C
- CVGS1-M-109 04 Rev C

1 Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330
2 Upper Sand Wellhead QAX-7040 and Upper Sand Wellhead Separator MBD-1290
3 Upper Sand Wellhead QAX-7020 and Upper Sand Wellhead Separator MBD-1270
4 Upper Sand Wellhead QAX-7010 and Upper Sand Wellhead Separator MBD-1260
5 Upper Sand Wellhead QAX-7030 and Upper Sand Wellhead Separator MBD-1280
6 Upper Sand Wellhead QAX-7050 and Upper Sand Wellhead Separator MBD-1300
7 Upper Sand Wellhead QAX-7060 and Upper Sand Wellhead Separator MBD-1310
8 Upper Sand Wellhead QAX-7070 and Upper Sand Wellhead Separator MBD-1320

19 High pressure gas in injection mode

Drawings:
- CVGS1-M-100 01 Rev C
- CVGS1-M-100 021 Rev C
- CVGS1-M-101 01 Rev D
- CVGS1-M-102 01 Rev C
- CVGS1-M-103 01 Rev D
- CVGS1-M-104 01 Rev D
- CVGS1-M-104 02 Rev D
- CVGS1-M-105 01 Rev D
- CVGS1-M-105 02 Rev D
- CVGS1-M-106 01 Rev D
- CVGS1-M-106 02 Rev D
- CVGS1-M-107 01 Rev D
- CVGS1-M-107 02 Rev D
- CVGS1-M-108 01 Rev C
- CVGS1-M-108 02 Rev D
- CVGS1-M-109 01 Rev D
- CVGS1-M-109 02 Rev D
- CVGS1-M-109 03 Rev C
- CVGS1-M-109 04 Rev C
- CVGS1-M-110 01 Rev D
- CVGS1-M-111 01 Rev D
- CVGS1-M-111 02 Rev D
- CVGS1-M-112 01 Rev C
- CVGS1-M-112 02 Rev C

20 Upper Sands Header System including Pig Launchers - withdrawal mode

Drawings:
- CVGS1-M-108 01 Rev C
- CVGS1-M-109 04 Rev C

21 Lower Sands Header System including Pig Launchers - withdrawal mode
22 Upper Sands Header System including Pig Launchers - injection mode

23 Lower Sands Header System including Pig Launchers - injection mode

24 High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)

Drawings:

- CVGS1-M-100 01 Rev C
- CVGS1-M-100 021 Rev C
- CVGS1-M-101 01 Rev D
- CVGS1-M-102 01 Rev C
- CVGS1-M-103 01 Rev D
- CVGS1-M-104 01 Rev D
- CVGS1-M-104 02 Rev D

25 Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)

Drawings:

- CVGS1-M-105 01 Rev D
- CVGS1-M-106 01 Rev D

26 Methanol Injection System

Drawings:

- CVGS1-M-109 02 Rev D
- CVGS1-M-109 03 Rev C
- CVGS1-M-109 04 Rev C
- CVGS1-M-117 01 Rev C

27 Global

Drawings:

- CVGS1-M-100 01 Rev C
- CVGS1-M-100 021 Rev C

1 Facility Siting
2 Human Factors
3 Process General

APPENDIX B

What-If Study Technique

WHAT-IF STUDY TECHNIQUE

GENERAL

The What-If technique is a means of systematically reviewing a process to identify potentially hazardous events or operability problems which could occur. A What-If study is conducted by a team of individuals led by a person knowledgeable with the What-If technique. It is conducted by posing a series of What-If questions, each representing a potential deviation from process design, maintenance/inspection or operating practices. The technique is based on the premise that a hazard does not occur if the process does not deviate from the design intent. The team determines if the deviation could realistically occur, and if so, do the consequences constitute a hazard as defined by the scope and objectives of the study. The team may then evaluate whether existing safeguards, both in the form of equipment or procedures are adequate considering the causes and consequences of the deviation. If necessary, the team makes an action item for improvement, for study to determine an optimal solution, or for additional investigation to determine whether a problem exists which warrants action.

TEAM CONCEPT

The What-If technique is a team technique. The interaction of the team members results in a more complete review than would be accomplished by each individual working separately on the same project. A team typically consists of 5-7 individuals. One member is a person trained and knowledgeable in the What-If technique. The other members are usually selected for their knowledge of the process operation and/or technical contribution to the team. There is no one perfect combination of team members. However, since the team members need to be knowledgeable of the process design and/or operation, at least some of the team should come from the operating facility. A typical team may consist of the following members:

- Team Leader
- Process Engineer
- Operations Supervisor
- Safety Engineer
- Maintenance/Inspection Supvr.
- Facilities/Mechanical Engr.

The actual composition of a specific team will depend upon the objectives of the study, the type of unit being studied, the titles used by the local facility and a variety of other considerations.

DEVELOPING WHAT-IF QUESTIONS

The What-If method involves experienced personnel posing a series of What-If questions for each part of the facility. The What-If questions evaluate the effects of equipment failures, human errors, or external events on the operation of the system. The What-If questions will include a group from structured checklists to insure consistency, but will not be limited and will be open to cover process safety concerns.

The success of a What-If study is highly dependent upon the thoroughness of the list of What-If questions posed. Typically, the team leader will prepare an initial list of What-If questions prior to team meetings. The Analysis Tools facility of PHAWorks® can be used to obtain some pertinent questions to get the study started. Alternatively lists of questions from previous studies may be used, or the team can brainstorm questions at the outset of the study. The What-If process is dynamic and as one question is asked other questions will occur to the team. These questions should be documented as they occur for later consideration.

It is useful if some structure is used in developing and categorizing What-If questions. For example, questions can be developed around the three basic causes of accidents: equipment failure, human error and external events. Questioning can also be focused on consequence categories such as personnel injury and equipment damage.

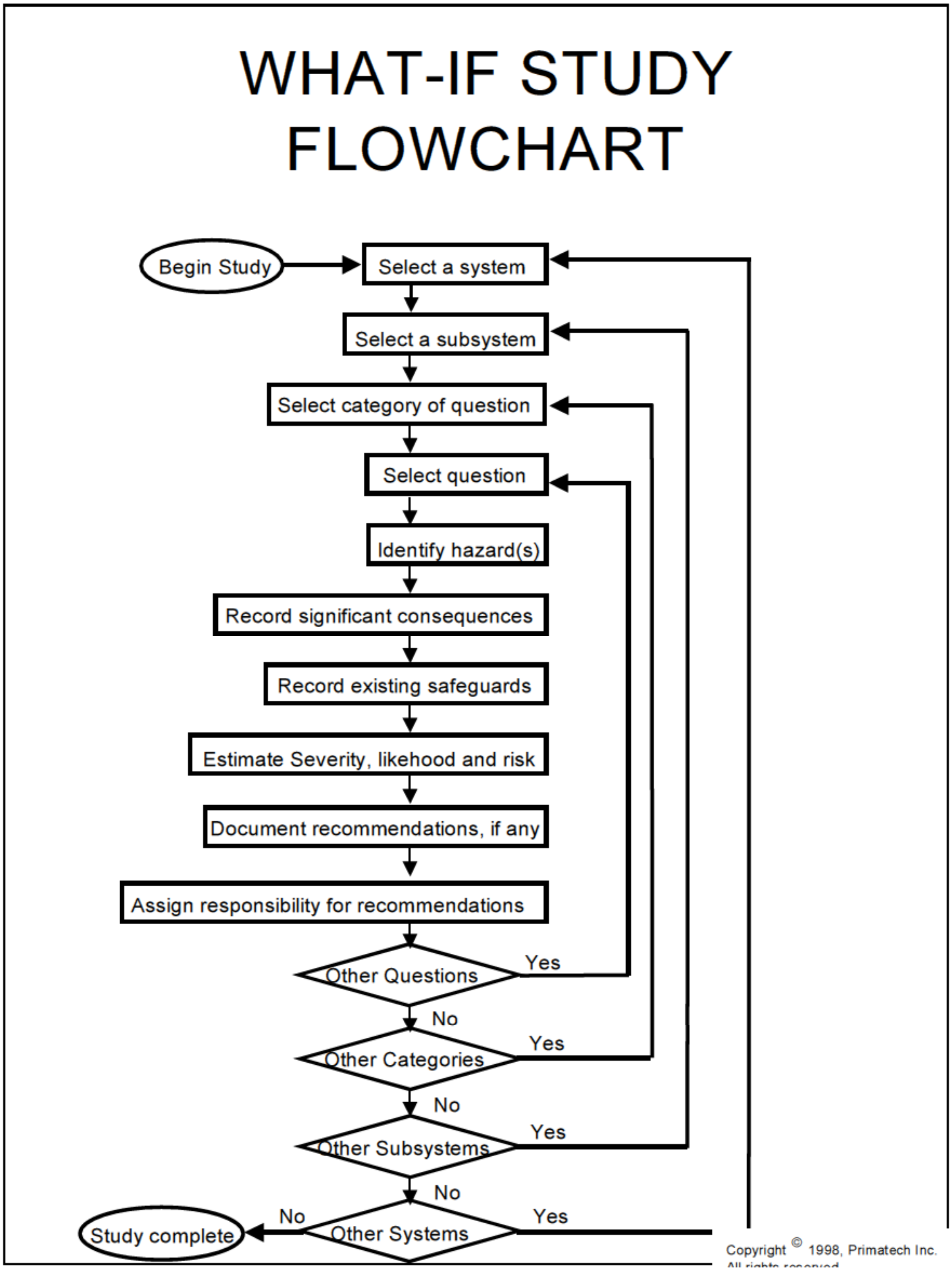
WHAT-IF SESSIONS

A typical process unit may take a number of hours to What-If. The team will therefore hold a number of meetings, or working sessions. Figure B-1 shows the procedure for a typical What-If session. The sessions are normally scheduled to last for periods of 3-4 hours.

At each session, the What-If team records their activities on a What-If worksheet. This documentation should indicate which segments of the process were reviewed, which What-If questions were considered, the hazards and consequences of a deviation, whether a potential problem exists, and if so, what action is recommended.

The basic purpose of the What-If study is to identify potentially hazardous scenarios. Therefore, the team should not spend significant time trying to engineer a solution if a potential problem is uncovered. If a solution to the problem is obvious, the team should correct the drawing or procedure immediately, or document their recommended solution. If a solution is not obvious, they should recommend that someone follow up and resolve the problem with the optimal solution. Also, if there is insufficient information available at the time to decide if a potential problem exists, the team should note it, assign someone to collect additional information and continue with the study.

Figure B-1 Typical What-If Session Procedure



Primatech's computer program, PHAWorks® facilitates the documentation of a What-If study. The program generates several standard reports. The primary report is the worksheet report. The What-If analysis is presented in a multi-column format. The top of the worksheet contains general information regarding the client and process being reviewed. The header box on the What-If worksheet contains the following information;

System	-	Convenient way to divide a facility into manageable parts or segments. Facility may be broken into process areas, buildings, units, etc.
Subsystem	-	Each system is typically divided into multiple subsystems. The level of resolution depends on how detailed a study is required. The analysis is usually conducted on the subsystem level.

The worksheet columns contain the following information:

What-If	-	A question indicating some way the system can malfunction or be misoperated. The intent is to ask pointed questions that are considered relevant by the team. The questions address potential causes of accidents.
Hazard	-	Potential hazards or hazardous scenarios associated with each question. In general, a hazard is considered to be a situation with the potential to do harm. A hazardous scenario is a specific but unplanned sequence of events that results in a hazard being realized.

Consequences	-	Indicate the possible effect on the process, or with respect to the potential for a chemical release, that might possibly occur assuming the hazardous scenario were to occur.
S(everity)	-	An estimate of the severity of the scenario if it were to occur.
L(ikelihood)	-	An estimate of how likely the scenario is to occur.
R(isk Ranking)	-	An estimate of the relative risk of the scenario. The risk ranking is a combination of the severity and the likelihood. The risk ranking is automatically input by PHAWorks® based on the relative rankings provided by EN Engineering and CVGS's Risk Ranking Matrix.
Safeguards	-	For each consequence, existing safeguards either in the design or operation of the facility, which may prevent the scenario from occurring or mitigate the consequences should it occur, are noted.
Recommendations	-	When a potential need for improvement, in either the physical facilities or the operating procedures is noted, an action item is made. Additionally, entries are made on follow-up items and to clarify some point that arise during the study.
By	-	Indicates an individual or other party responsible for ensuring that the action item is followed up on.
CAT	-	Indicates category of recommendation

Along with several of the columns previously described, reports may include a Ref # column, which is a sequential numbering of the unique action items and information needs assigned by PHAWorks®. Reports may also contain several columns (priority (P), date, comments and status (X)) which can be used to document the follow-up activities concerning the action items or the information needs.

APPENDIX C

What-If Action Items Report

Action Items

Printed: November 23, 2010, 8:31 AM
Company: EN Engineering
Location: Woodridge, IL
Facility: Central Valley Gas Storage, Princeton, CA
PHA Method: What-If
PHA Type: Initial

Process:

CVGS Facility, Design Stage PHA

File Description:

Final

Date:

September 15-17, 2010

Process Description:

As provided by EN Engineering

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For a complete project description, see the Central Valley Gas Storage/Nicor Central Valley Gas Storage Project Design Basis Manual.

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Water
Urea

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Scope:

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Action Items

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Global issues were considered for potential impact where they appeared to be plausible, including man-made or naturally occurring external events and facility siting such as proximity of equipment which could result in potential catastrophic effects.

Project Notes:

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AD = Administrative
AC = Active
PA = Passive
ER = Emergency Response Procedure
SC = Secondary Containment
OF = Offsite Mitigation or Control

The last category column is used to indicate the type of recommendation for the scenario in the worksheet. The following codes are considered:
AD = Administrative
HW = Hardware
PR = Procedural
SW = Software
MN = Maintenance
TI = Testing/Inspection
TR = Training

ER = Emergency Response
AU = Audit

Filters: No Filter Applied

Action Items

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
5. FCV-5019 closes too much during startup due to mechanical failure, control system failure, or human error?	EQ HE	5.1. Potential to start unit against pressure	5.1.1. Start-up failure or production inefficiency.	OP						1	5.1.1. Consider installing restricting orifice downstream of FCV-5019 to reduce potential operational issues.	ENE	HW
6. FCV-5019 closes too much during operation due to mechanical failure, control system failure, or human error?	EQ HE	6.2. Potential to exceed turndown limits on exhaust SCR	6.2.1. Potential catalyst damage in SCR	PD	6.2.1. High temperature interlock on SCR shuts system down, alarms and calls out off-site personnel.	PS	2	2	2	2	6.2.1. Consider providing system based on incorrect position of FCV-5019 to prevent damage to SCR catalyst on low flow.	ENE	HW
										3	6.2.2. Consider adding an alarm and system shutdown for SCR operating below minimum load limit to prevent damage to SCR catalyst on low flow.	ENE	HW
										4	6.2.3. Consider verifying that the planned high temperature shutdown for the SCR is specified.	ENE	AU
7. BV-5018 (blowdown) opens during operation due to mechanical failure, control system failure, or human error?	EQ HE	7.1. Release of gas to atmosphere	7.1.1. Economic loss of gas	PD	7.1.1. Position indicator ZYC-5018 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 7.1.2. Line size and RO-3311 limit flow to 3MM SCFH	PS EN	2	2	2	5	7.1.1. Consider adding pressure differential transmitter across RO-3311 to alarm and shutdown on flow in blowdown line during other than blowdown operation so that undesired flow is identified.	ENE	HW
9. BV-5018 doesn't open when required due to mechanical failure, control system failure, or human error?	EQ HE	9.1. Unable to blow unit down when required	9.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM EV PD	9.1.1. Blowdown control features are required to be tested annually. 9.1.2. Other safeguards exist to mitigate the specific situation requiring the shutdown.	PA DT PS EN	1	4	5	6	9.1.1. Consider scheduling ESD discussion between ENE and Nicor to more thoroughly define requirements and expectations for ESD actions during operations	ENE	AD
31. Suction Pulsation Bottles CBL-1040/1070...	EQ	31.1. Pulsation Bottles CBL-1040/1070	31.1.1. Release of gas in building with fire and...	EM	31.1.1. Pulsation Bottles CBL-1040/1070 is...	EN	1	4	5	7	31.1.1. Consider verifying that Pulsation Bottles...	ENE	AU

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...internals break due to equipment failure or external conditions?	EX	31.1. Pulsation Bottles CBL-1040/1070 (cont.)	...personnel injury	PD	...specified to be designed for service per ASME Code Section VIII.						...CBL-1040/1070 have been designed to ASME Code Section VIII.		
					31.1.2. Pulsation Bottles CBL-1040/1070 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
32. discharge Pulsation Bottles CBL-1050/1080 internals break due to equipment failure or external conditions?	EQ EX	32.1. Pulsation Bottles CBL-1050/1080	32.1.1. Release of gas in building with fire and personnel injury	PD	32.1.1. Pulsation Bottles CBL-1050/1080 is specified to be designed for service per ASME Code Section VIII.	EN	1	4	5	8	32.1.1. Consider verifying that Pulsation Bottles CBL-10450/1080 have been designed to ASME Code Section VIII.	ENE	AU
					32.1.2. Pulsation Bottles CBL-1050/1080 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
34. drain on Suction Separators MBD-1030/1060 sticks open due to mechanical failure, control system failure, or human error?	EQ HE	34.1. Pressure in Condensate Tank AGJ-3120	34.1.1. Potential to rupture Condensate Tank AGJ-3120 with release of gas and hydrocarbon liquids to atmosphere and environmental consequences	EV	34.1.1. PSE3121 on Condensate Tank AGJ-3120 is set to relieve at 6-12 in w.c.	MT	1	4	5	9	34.1.1. Consider adding means to identify continuous gas leakage into Condensate Tank AGJ-3120.	ENE	HW SW
					34.1.2. Conservent PSV3131 is set to relieve at 2 psig	MT							
					34.1.3. RO-3131 restricts flow to Condensate Tank AGJ-3120	EN							
36. strainer element in Strainer 1031/61 breaks due to pluggage?	EQ	36.1. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor CAE-5010	36.1.1. Damage to one cylinder of Compressor CAE-5010	PD	36.1.1. Differential Pressure switch PDIT-1031/1061 shuts system down on high DP across Strainer 1031/61, alarms and calls out off-site personnel.	PS	2	4	5	10	36.1.1. Consider establishing a means of monitoring Strainer 1031/61 for pluggage to prevent strainer failure.	CVGS	MN
					36.1.2. Suction Separators MBD-...	EN							

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
36. strainer element in Strainer 1031/61 breaks due to pluggage? (cont.)		36.1. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor CAE-5010 (cont.)	36.1.1. Damage to one cylinder of Compressor CAE-5010 (cont.)		...1030/1060 stops material from entering Compressor CAE-5010						36.1.1. Consider establishing a means of monitoring Strainer 1031/61 for pluggage to prevent strainer failure. (cont.)		
37. strainer element in Strainer 1031/61 breaks due to corrosion or vibration	EQ EX	37.1. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor CAE-5010	37.1.2. Damage to Suction Separators MBD-1030/1060	PD	37.1.3. Differential Pressure switch PDIT-1031/1061 shuts system down on high DP across Strainer 1031/61, alarms and calls out off-site personnel.	PS	3	3	4	11	37.1.1. Consider establishing a means of monitoring Strainer 1031/61 for corrosion/vibration damage to prevent strainer failure.	CVGS	MN
38. louvers on Gas Cooler HAL-2010 do not close when required due to mechanical failure, control system failure, or human error?	EQ HE	38.1. No hazard identified. Not to be developed further	38.1.1. Operational issues only.	OP						12	38.1.1. Consider removing louvers on Gas Cooler HAL-2010 as they are not needed.	ENE	HW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (2) Compressor 5020, including Suction Pulsation Bottles CBL-1110 & 1130 and, Discharge Pulsation Bottles CBL-1100 & 1140, Suction Separators MBD-1090 & 1120 and Gas Cooler HAL-2020
Drawings: CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
43. lose electrical power to FCV50219 and 50229 during an emergency situation due to equipment failure or external causes?	EQ EX	43.1. FCV50219/50229 fail open and cross-connect the suction headers	43.1.1. Inventory management issues.	OP						13	43.1.1. Consider reviewing the design of the recycle valve power supply during emergency situations to avoid potential inventory management issues.	ENE	HW
45. control system opens FCV50219 and 50229 during start and stop sequences or while unit is idling due to a control system failure?	EQ	45.1. This is the currently planned normal condition	45.1.1. Potential Compressor 5020 start-up issues	OP						14	45.1.1. Consider further reviewing the need for check valves or other backflow safeguards for Unit #2 to prevent start-up issues with FCV50219 and 50229 being open at the same time.	ENE	HW SW

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
50. BDV-0045 is open due to mechanical failure, control system failure, or human error?	EQ HE	50.1. Release of gas to atmosphere	50.1.1. Economic loss of gas	PD	50.1.1. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 50.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	PS EN	2	2	2	15 16	50.1.1. Consider adding an RO for valve BDV-0045 to permit fine tuning of the valve. 50.1.2. Consider providing a means for isolating valve BDV-0045 for annual testing.	ENE ENE	HW MN
52. BDV-0046 is open due to mechanical failure, control system failure, or human error?	EQ HE	52.1. Release of gas to atmosphere	52.1.1. Economic loss of gas	PD	52.1.1. Position indicator ZYC-0046 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 52.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	PS EN	2	2	2	17 18	52.1.1. Consider adding an RO for valve BDV-0046 to permit fine tuning of the valve. 52.1.2. Consider providing a means for isolating valve BDV-0046 for annual testing.	ENE ENE	HW MN
57. BV-00411 is open due to mechanical failure, control system failure, or human error?	EQ HE	57.1. Potential to bypass ESD and be unable to blow unit down when required	57.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD EV	57.1.1. Position indicator ZYC-00411 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 57.1.2. Station controller closes valve BV-00411in the event of an ESD, alarms and calls out off-site personnel.	PS PS	1	3	3	19 20	57.1.1. Consider adding ESD control to valve BV-00411. 57.1.2. Consider changing valve BV-00411 to a be a fail closed electro/hydraulic valve.	ENE ENE	SW HW
58. BV-00431 is open due to mechanical failure, control system failure, or human error?	EQ HE	58.1. Potential to bypass ESD and be unable to blow unit down when required	58.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD EV	58.1.1. Position indicator ZYC-00431 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	21 22	58.1.1. Consider adding ESD control to valve BV-00431. 58.1.2. Consider changing valve BV-00431 to a be...	ENE ENE	SW HW

Action Items

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
58. BV-00431 is open due to mechanical failure, control system failure, or human error? (cont.)		58.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	58.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency. (cont.)		58.1.2. Station controller closes valve BV-00431in the event of an ESD, alarms and calls out off-site personnel.	PS					...a fail closed electro/hydraulic valve.		

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
65. BDV-0056 is open due to mechanical failure, control system failure, or human error?	EQ HE	65.1. Release of gas to atmosphere	65.1.1. Economic loss of gas	PD	65.1.1. Position indicator ZYC-0056 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2	23	65.1.1. Consider adding an RO for valve BDV-0056 to permit fine tuning of the valve.	ENE	HW
					65.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN				24	65.1.2. Consider providing a means for isolating valve BDV-0056 for annual testing.	ENE	MN
71. BV-00531 is open due to mechanical failure, control system failure, or human error?	EQ HE	71.1. Potential to bypass ESD and be unable to blow unit down when required	71.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	71.1.1. Position indicator ZYC-00531 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	25	71.1.1. Consider adding ESD control to valve BV-00531.	ENE	SW
					71.1.2. Station controller closes valve BV-00413in the event of an ESD, alarms and calls out off-site personnel.	PS				26	71.1.2. Consider changing valve BV-00531 to a be a fail closed electro/hydraulic valve.	ENE	HW

Action Items

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
76. BDV-0055 is open due to mechanical failure, control system failure, or human error?	EQ HE	76.1. Release of gas to atmosphere	76.1.1. Economic loss of gas	PD	76.1.1. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 76.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	PS EN	2	2	2	27 28	76.1.1. Consider adding an RO for valve BDV-0055 to permit fine tuning of the valve. 76.1.2. Consider providing a means for isolating valve BDV-0055 for annual testing.	ENE ENE	HW MN
83. BV-00511 is open due to mechanical failure, control system failure, or human error?	EQ HE	83.1. Potential to bypass ESD and be unable to blow unit down when required	83.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	83.1.1. Position indicator ZYC-00511 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 83.1.2. Station controller closes valve BV-00511in the event of an ESD, alarms and calls out off-site personnel.	PS PS	1	3	3	29 30	83.1.1. Consider adding ESD control to valve BV-00511. 83.1.2. Consider changing valve BV-00511 to a be a fail closed electro/hydraulic valve.	ENE ENE	SW HW
84. BV-00531 is open due to mechanical failure, control system failure, or human error?	EQ HE	84.1. Potential to bypass ESD and be unable to blow unit down when required	84.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	84.1.1. Position indicator ZYC-00531 shuts system down on incorrect valve position, alarms and calls out off-site personnel. 84.1.2. Station controller closes valve BV-00531in the event of an ESD, alarms and calls out off-site personnel.	PS PS	1	3	3	31 32	84.1.1. Consider adding ESD control to valve BV-00531. 84.1.2. Consider changing valve BV-00531 to a be a fail closed electro/hydraulic valve.	ENE ENE	SW HW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (8) West Meter run in withdrawal mode
Drawings: CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
101. FCV-0082 is open more than required (free flow mode) due to mechanical failure, control system failure, or human error?	EQ HE	101.2. Pressure too high	101.2.1. Potential overpressure of downstream equipment and pipelines	PD	101.2.1. PCV-0083 controls downstream pressure. 101.2.2. PIT-0084 shuts down flow by closing BV-0043 and BV-0044 at 1110 psig, alarms and calls out off-site personnel.	PS PS	1	4	5	33	101.2.1. Consider changing the setpoints on PCV-0083 and 0093 to less than 1110 psig to be lower than the PIT-0084 set point.	ENE	SW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
118. Filter Separator MAK-1510 is shut-in due to mechanical failure, control system failure, or human error?	EQ HE	118.1. Potential overpressure of Filter Separator MAK-1510 due to temperature increase	118.1.1. potential damage to Filter Separator MAK-1510	PD	118.1.1. PSV-1511 opens at 1145 psig.	MT	2	4	5	34	118.1.1. Consider establishing standard operating procedure for maintenance turnover of Filter Separator MAK-1510 and similar equipment.	CVGS	PR
128. LV-1513 doesn't close due to mechanical failure, control system failure, or human error?	EQ HE	128.2. Pressure in Condensate Tank ABJ-3130	128.2.1. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	128.2.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5	35	128.2.1. Consider adding means on Condensate Tank ABJ-3130 to identify continuous gas leakage into tank so that leakage can be corrected.	ENE	HW
					128.2.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS				36	128.2.2. Consider reviewing failure modes of LV-1513/16 to ensure sufficient protection against potential failures.	ENE	AU
					128.2.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (11) Pig Receiver MBP-1500 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
136. BV-1501 is open due to mechanical failure, control system failure, or human error?	HE HE	136.1. gas in Pig Receiver MBP-1500	136.1.1. Potential for continuous fugitive emission of gas from Pig Receiver MBP-1500	EV	136.1.1. Standard procedure in similar operations is to require valves such as BV-1501 to be verified closed if not in use.	PR	4	3	5	37	136.1.1. Consider ensuring that procedures are written to ensure that valves such as BV-1501 are verified closed if not in use.	CVGS	PR
139. BDV-1508 is open due to mechanical failure, control system failure, or human error?	HE HE	139.1. Release of gas to atmosphere	139.1.1. Economic loss of gas	PD	139.1.1. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time. 139.1.2. Standard procedure in similar operations is to require valves such as BDV-1508 to be verified closed after maintenance.	EN PR	2	4	5	38	139.1.1. Consider ensuring that SOPs are written with checklists for valve positions for valves such as BDV-1508 and other manual valves both before and after maintenance to ensure that equipment is returned to service in a safe and operable condition.	CVGS	PR
141. BV-1501 and BV-1504 are left open after pig receiving because of human error?	HE	141.1. Potential to bypass ESD and be unable to blow unit down when required	141.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	141.1.1. Standard procedure in similar operations is to require valves such as BV-1501 and BV-1504 to be verified closed if not in use.	PR	1	3	3	39	141.1.1. Consider changing specification for valves BV-1501 and BV-1504 from normally closed to locked closed.	ENE	AD

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (16) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, withdrawal mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
142. BV-1211/1231 closed due to mechanical failure, control system failure, or human error (power mode)?	EQ HE	142.1. Loss of feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and Compressor CAE-5010	142.1.3. Potential to pull vacuum on Glycol Absorber Line B MAF-1210/Line A MAF-1230 and damage tower	PD	:No safeguards were identified.		1	2	1	40	142.1.1. Consider verifying with design calculations that Glycol Absorber Line B MAF-1210/Line A MAF-1230 will withstand full vacuum.	ENE	AD
145. have too much lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 due to mechanical failure, control system failure, or human error?	EQ HE	145.1. Back up glycol in Glycol Absorber Line B MAF-1210/Line A MAF-1230	145.1.1. Potential for gas to be out of specification.	OP	145.1.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel. 145.1.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS PS	4	4	5	41	145.1.1. Consider reviewing with Sivalls the protections for the Glycol Regeneration skids to ensure that sufficient protection is provided.	ENE	AD
154. have gas flow to second tower (tower is on low pressure formation while this tower is on other formation) due to mechanical failure, control system failure, or human error?	EQ HE	154.2. Carry glycol to Compressor CAE-5010	154.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	154.2.1. Suction Separators MBD-1030/1060 protects Compressor CAE-5010	PS	1	3	3	42	154.2.1. Consider providing safeguard based on valve position indicators for feed to Glycol Absorbers to prevent glycol carryover to compressors should two absorbers become interconnected while drawing from different formations.	ENE	HW SW

Action Items

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (17) Fuel Gas System
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-111 01 Rev D; CVGS1-M-111 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
157. BV-4011 and BV-0101closed due to operator error (free flow withdrawal, heater is on or off)?	HE	157.1. Loss of fuel to dehydration system	157.1.1. Potential for gas to be out of specification.	OP	157.1.1. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system 157.1.2. Moisture analyzers alarm and call out off-site personnel on high moisture gas. 157.1.3. Summary alarms call out off-site personnel.	AD AD AD	3	3	4	43	157.1.1. Consider developing with Nicor required actions to be taken to prevent producing out of specification gas or environmental issues if fuel is lost to the dehydration system.	ENE	AD
160. TCV-4011 fails to control temperature due to mechanical failure, control system failure, or human error (temperature high)?	EQ HE	160.1. 250ºF fuel gas	160.1.1. Potential to exceed pressure/ temperature rating of ANSI CL 600 flanges with flange rupture and release of gas and fire	EM PD	:No safeguards were identified		1	3	3	44	160.1.1. Consider specifying fuel gas burner management system to limit temperature to 200ºF or below.	ENE	AD
161. TCV-4011 fails to control temperature due to mechanical failure, control system failure, or human error (temperature low)?	EQ HE	161.1. Formation of hydrates in fuel system	161.1.1. Potential for valves to stick open and overpressure low pressure side of fuel gas system with release and fire	EM PD	:No safeguards were identified		1	3	3	45	161.1.1. Consider specifying fuel gas burner management system to require shutdown on low temperature of fuel gas.	ENE	AD
170. packaged equipment fuel gas systems review has not been accomplished to date?	HF	170.1. Various unidentified hazards	170.1.1. Various unidentified consequences	EM EV PD	:No safeguards were identified.		1	2	1	46	170.1.1. Consider reviewing the protections for the Generators, Fuel Gas Heater, and Regeneration Skids, Enerflex Main Engine/Compressor Units to ensure that they are sufficient.	ENE	AD

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
182. Wellhead Separator MDB-1330 fills with sand due to operating conditions?	EQ	182.1. Erosion damage to separator and downstream equipment	182.1.1. Potential sand and water carryover to Filter Separator MAK-1510	PD	182.1.1. Wells are designed to minimize sand production 182.1.2. Operational procedures are to be used to maintain gas flow within design limits	EN PR	1	3	3	47	182.1.1. Consider providing cleanout port on Filter Separator MAK-1510 to permit removing built up sand, water, etc.	ENE	HW
203. form hydrates at well head and hydrates subsequently break loose due to mechanical failure, control system failure, or human error?	EQ HE	203.1. Break piping	203.1.1. Potential to release gas with fire.	EM PD	203.1.1. Operational experience provides means for reducing and/or recognizing and removing hydrates 203.1.2. Methanol injection system provides means for preventing and removing hydrates	AD EN	2	4	5	48	203.1.1. Consider providing shutdown at well head in the event of loss of flow.	ENE	HW
204. wellhead flow valves are partially closed due to mechanical failure, control system failure, or human error?	EQ HE	204.1. Increased potential for valve erosion	204.1.1. Unable to shut off gas at well head with potential fire and explosion	EM PD	:No safeguards were identified		1	3	3	49	204.1.1. Consider establishing operating procedures to ensure that wellhead flow valves are operated fully open or fully closed to prevent premature failure.	CVGS	PR

Session: (3) 9/17/2010
System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
215. BV-0022 is open due to mechanical failure, control system failure, or human error?	EQ HE	215.1. Cross connect formations	215.1.1. Inventory management issues.	OP	:No safeguards were identified.					50	215.1.1. Consider need for a 2" equalizer across BV-0022 to prevent inventor management issues.	ENE	HW

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
246. LV-1214/1234 sticks open due to equipment failure?	EQ	246.1. Pressure in Condensate Tank ABJ-3130	246.1.1. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	246.1.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c. 246.1.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig 246.1.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS PS PS	1	4	5	51	246.1.1. Consider reviewing failure modes of LV-1214/1234 to ensure sufficient protection against potential failures.	ENE	AU

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
251. urea is put into Methanol Storage Tank ABJ-3170 due to human error?	HE	251.1. Contaminate methanol	251.1.1. Economic issue	OP	251.1.1. Operator is to be in attendance during material unloading.	AD	3	3	4	52	251.1.1. Consider writing SOPs for material unloading at the CVGS facility to prevent introducing methanol into incorrect tanks or incorrect materials into Methanol Storage Tank ABJ-3170.	CVGS	PR
					251.1.2. Labels on truck identify material to be unloaded.	AD							
					251.1.3. Labels on tank identify material in receiving vessel.	AD							
					251.1.4. Bill of lading identifies material to be unloaded.	AD							
					251.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
256. Methanol put into urea tank due to human error?	HE	256.1. Inject methanol into SCR	256.1.1. Potential explosion in SCR	EM PD	256.1.1. Operator is to be in attendance during material unloading.	AD	1	3	3	53	256.1.1. Consider making truck connections incompatible between methanol and other fluids to prevent introducing methanol into incorrect tanks or incorrect materials into Methanol Storage Tank ABJ-3170.	CVGS	HW
					256.1.2. Labels on truck identify material to be unloaded.	AD							
					256.1.3. Labels on tank identify material in receiving vessel.	AD							
					256.1.4. Bill of lading identifies material to be unloaded.	AD							
					256.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
257. lose nitrogen pad on Methanol Storage Tank ABJ-3170 due to mechanical failure, control system failure, or human error?	EQ HE	257.1. Flammable atmosphere in Methanol Storage Tank ABJ-3170	257.1.1. Potential for explosion in Methanol Storage Tank ABJ-3170.	EM PD	257.1.1. PSL-3171 alarms and calls out personnel on loss of nitrogen supply	AD	1	3	3	54	257.1.1. Consider providing means of identifying nitrogen loss in Methanol Storage Tank ABJ-3170 vapor space to allow recognition of a...	ENE	HW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
257. lose nitrogen pad on Methanol Storage Tank ABJ-3170 due to mechanical failure, control system failure, or human error? (cont.)		257.1. Flammable atmosphere in Methanol Storage Tank ABJ-3170 (cont.)	257.1.1. Potential for explosion in Methanol Storage Tank ABJ-3170. (cont.)		257.1.1. PSL-3171 alarms and calls out personnel on loss of nitrogen supply (cont.)						...potential flammable atmosphere in tank.		
258. nitrogen pressure goes too high due to mechanical failure, control system failure, or human error?	EQ HE	258.1. Overpressurize tank Methanol Storage Tank ABJ-3170.	258.1.1. Potential to damage Methanol Storage Tank ABJ-3170 and release methanol to dike with fire.	PD	258.1.1. Dike area electrical classification is Class I, Division 2. 258.1.2. PSV-3171 opens at 3 psig	EN MT	3	3	4	55	258.1.1. Consider providing high pressure relief for nitrogen supply to Methanol Storage Tank ABJ-3170 to prevent overpressurization of tank.	ENE	HW
264. methanol is between double walls of tank due to tank wall failure?	EQ	264.1. Methanol in undesired location	264.1.1. Operational issues only	OP	:No safeguards were identified		4	3	5	56	264.1.1. Consider reviewing design of double wall Methanol Storage Tank ABJ-3170 with respect to where overflow goes and make changes as required.	ENE	AD
269. flowraters are set incorrectly high due to human error?	HE	269.1. Deliver additional methanol to well head	269.1.1. Operational issues only.	OP	:No safeguards were identified.		4	4	5	57	269.1.1. Consider obtaining information on methanol flowraters and include on P&IDs for informational purposes.	ENE	AD

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (1) Facility Siting

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
273. there are other facility siting issues that have not been identified?	FS	273.1. Unidentified facility siting issues.	273.1.1. Since this is an initial design stage PHA and construction has not yet begun the following recommendation was made by the Team.	EM PD						58	273.1.1. Consider making a Facility Siting Checklist part of the PSSR for the facility.	CVGS	AU

Session: (3) 9/17/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (2) Human Factors

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
274. there are human factors issues that have not been identified?	HF	274.1. Unidentified Human Factors issues.	274.1.1. Since this is an initial design stage PHA and construction has not yet begun the following recommendation was made by the Team.	EM PD						59	274.1.1. Consider making a Human Factors Checklist part of the PSSR for the facility.	CVGS	AU

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
275. system is operated in manual mode?	HF	275.1. Improper sequencing of equipment	275.1.1. Damage to downstream equipment	PD OP	:No safeguards were identified.		1	2	1	60	275.1.1. Consider performing a PHA on the CVGS system operated in manual mode.	CVGS	AD
										61	275.1.2. Consider developing manual mode SOPs for the CVGS system.	CVGS	PR
										62	275.1.3. Consider adding safeguards in CVGS control system to identify and alarm on prolonged use of manual mode.	ENE	SW
278. Manual valve under pressure transmitter is closed due to human error?	HE	278.1. Computer loses knowledge of process conditions	278.1.1. Potential operational issues.	OP	:No safeguards were identified.		4	3	5	63	278.1.1. Consider reviewing pressure transmitters and determining where redundancy is required.	ENE	HW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
278. Manual valve under pressure transmitter is closed due to human error? (cont.)		278.1. Computer loses knowledge of process conditions (cont.)	278.1.1. Potential operational issues. (cont.)		:No safeguards were identified. (cont.)					64	278.1.2. Consider locking open pressure transmitter isolation valves	CVGS	AD
281. Maintenance vent valve leaks by due to equipment failure or human error?	EQ HE	281.1. Release of gas to area	281.1.1. Economic loss of gas	OP	281.1.1. Fugitive emission review are required to be done twice per year per CFR 192.706.	PS	3	3	4	65	281.1.1. Consider adding blind flange with bleed valve under maintenance vent valves for operational purposes.	ENE	HW
					281.1.2. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
282. Maintenance vent valve left open after maintenance due to human error.	HE	282.1. Release of gas to atmosphere	282.1.1. Economic loss of gas	PD	282.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PS	2	4	5	66	282.1.1. Consider ensuring that SOPs are written with checklists for valve positions both before and after maintenance to ensure safe turnover of equipment to and from maintenance.	CVGS	PR
					282.1.2. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD							
					282.1.3. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
284. Manual equalization valve left open due to human error (ESD path)?	HE	284.1. Potential to bypass ESD and be unable to blow unit down when required	284.1.1. Potential to be unable to use ESD shutdown in the event of an emergency situation.	EM PD EV	284.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PR	1	4	5	67	284.1.1. Consider adding "Locked Closed" notes to manual equalization valves at ESD valves on P&IDs to ensure safe turnover of equipment to and from maintenance.	ENE	AD
					284.1.2. Manual equalization valves in ESD paths are specified to be locked closed.	EN				68	284.1.2. Consider establishing a system to...	CVGS	AD

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
284. Manual equalization valve left open due to human error (ESD path)? (cont.)		284.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	284.1.1. Potential to be unable to use ESD shutdown in the event of an emergency situation. (cont.)		284.1.3. Blowdown control features are required to be tested annually. :Other safeguards as analyzed previously in this PHA.	AD					...ensure that locks are in place on manual equalization valves in ESD to ensure that ESD capability will not be compromised.		
286. automatic valves with limit switches are out of desired position due to equipment failure.	EQ	286.1. Various hazards as evaluated throughout this PHA.	286.1.1. Various consequences as evaluated throughout this PHA.	EM PD EV	286.1.1. Various position indicators ZYC-nnnnn alarm and call out off-site personnel out on incorrect valve position.	AD	1	3	3	69	286.1.1. Consider reviewing automatic valves with limit switches and verifying that the shutdown actions are as should be taken in the event of a malfunction alarm to minimize consequences of the fault situation.	ENE	AU
289. flow reverses unexpectedly on a header (i.e. withdrawal to injection or vice versa) due to equipment failure or human error?	EQ HE	289.1. Damage to filter elements	289.1.1. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	289.1.1. Various position indicators ZYC-nnnnn alarm and call out off-site personnel out on incorrect valve position.	AD	3	2	3	70	289.1.1. Consider adding automatic shutdown based on reversal of flow as detected by bi-directional meters to prevent equipment damage.	ENE	SW

Action Items - Index

APPENDIX D

What-If Worksheets and Session Identification Sheets

Worksheet

Printed: November 23, 2010, 8:32 AM
Company: EN Engineering
Location: Woodridge, IL
Facility: Central Valley Gas Storage, Princeton, CA
PHA Method: What-If
PHA Type: Initial

Process:

CVGS Facility, Design Stage PHA

File Description:

Final

Date:

September 15-17, 2010

Process Description:

As provided by EN Engineering

CVGS is proposing to convert the depleted Princeton Gas Field, near the unincorporated town of Princeton in Colusa County, California, into a high-deliverability, multi-cycle storage field. The field would ultimately be developed to provide 8 Bcf of working gas capacity. The working capacity would be phased in over 4 years, commencing with 5.5 Bcf in the first year. The field would be designed to achieve a maximum withdrawal and injection capability of 300 million standard cubic feet per day (MMscfd).

CVGS would connect the storage field into the PG&E Transmission System Line 400/401 near PG&E's Delevan Compressor Station, approximately 14.9 miles west of the storage field. The PG&E transmission system runs north-south along the western end of the project area. It transports natural gas from PG&E's connections with interstate pipelines, state gas fields, and local distribution infrastructure to the utility's local transmission and distribution system. The proposed project involves constructing facilities necessary to convey natural gas from Line 400/401 to the Princeton Gas Field, storing the gas in the existing natural reservoir, withdrawing the stored gas, and conveying the withdrawn gas to Line 400/401 for delivery to customers.
The connection into PG&E would provide CVGS customers with access to Alberta, Rockies, San Juan, and Permian supplies through the many pipelines that connect to PG&E. Customers holding CVGS capacity would also have access to potential supplies from new natural gas facilities under development on the West Coast.

For a complete project description, see the Central Valley Gas Storage/Nicor Central Valley Gas Storage Project Design Basis Manual.

Chemicals:

Natural gas
Triethylene Glycol
Methanol
Water
Urea

Purpose:

The purpose of this Process Hazards Analysis (PHA) was to conduct an Initial PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for Nicor in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. This PHA systematically reviews the planned CVGS Facility using the What-If methodology.

ENE and CVGS management have determined that the planned CVGS Facility will not be covered by the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) (29 CFR 1910.119) regulation or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule (40 CFR Part 68) requirements.

Scope:

The scope of this PHA included the equipment, piping and instrumentation within the planned CVGS Facility in Colusa County, CA as shown on the process flow diagrams (PFDs) and piping and instrumentation diagrams (P&IDs) for this facility listed in Appendix A, including the main gas system (pipelines, compressors, filter separators, coolers, pressure reduction stations, and dehydration units) the blow down silencers, the glycol regeneration units, and associated tanks, valves, and instrumentations. The analysis includes anticipated start-up, normal (steady-state) operating and shutdown procedures, and global issues such as Services, Utilities, Facility Siting, and Emergency Procedures to the extent they interface with the CVGS Facility. By agreement between Primatech, CVGS and ENE, Human Factors was not addressed in the Design Stage PHA but should be in subsequent studies.

Worksheet

Objectives:

The objective of the Design Stage PHA was to identify possible deviations from the planned process design, maintenance, inspection, or operating practices which could lead to fires, explosions or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving accidental natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a plant shutdown.

Failure of planned engineering and administrative controls and protections were evaluated for credible events which could lead to a hazardous scenario. Problems in the operation of utilities such as instrument air, electrical power, and plant water were implicitly reviewed for affect upon potential hazardous scenarios in the process.

Previous accidents in similar processes known of by CVGS and/or ENE were considered during the study. This included reportable releases, and process related incidents within the physical scope of the PHA review.

Global issues were considered for potential impact where they appeared to be plausible, including man-made or naturally occurring external events and facility siting such as proximity of equipment which could result in potential catastrophic effects.

Project Notes:

The first category column is used to indicate the cause for the scenario in the worksheet. The following codes are considered:

EQ = Equipment Failures
HE = Human Error
HF = Human Factor
EX = External Event
FS = Facility Siting Issue
PI = Previous Incidents (on similar equipment)
SC = Failure of Safeguard or Control
SD = Startup/shutdown Issue
NO = Normal Operation

The second category column is used to classify the consequence for the scenario in the worksheet. The following codes are considered:
EM = Effect Onsite Personnel
EP = Effect Offsite Public
EV = Effects On the Environment
OP = Operability Problem
PD = Property Damage

The third category column is used to indicate the type of safeguard listed. The following codes are considered:
DT = Detection System
PS = Prevention System
MT = Mitigation
EN = Engineered
PR = Procedural
AD = Administrative
AC = Active
PA = Passive
ER = Emergency Response Procedure
SC = Secondary Containment
OF = Offsite Mitigation or Control

The last category column is used to indicate the type of recommendation for the scenario in the worksheet. The following codes are considered:
AD = Administrative
HW = Hardware
PR = Procedural
SW = Software
MN = Maintenance
TI = Testing/Inspection
TR = Training

ER = Emergency Response
AU = Audit

Filters: No Filter Applied

Worksheet

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
1. valve BV-5011 or BV-5012 upstream of Suction Pulsation Bottle CBL-1040 or 1070 on compressor piping close due to mechanical failure, control system failure, or human error while operating?	EQ HE	1.1. Loss of feed to Compressor CAE-5010	1.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	1.1.1. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					1.1.2. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
			1.1.2. Potential for Caterpillar engine damage	PD	1.1.3. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					1.1.4. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
2. valve BV-5013 or BV-5014 downstream of Gas Cooler HAL-2010 on compressor piping close due to mechanical failure, control system failure, or human error while operating?	EQ HE	2.1. High discharge pressure on Compressor CAE-5010	2.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	2.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					2.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.1.3. PSV-50110 opens at 1525 psig	MT							
					2.1.4. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and...	PS							

Worksheet

Company: EN Engineering

Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010

System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.

Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
2. valve BV-5013 or BV-5014 downstream of Gas Cooler HAL-2010 on compressor piping close due to mechanical failure, control system failure, or human error while operating? (cont.)		2.1. High discharge pressure on Compressor CAE-5010 (cont.)	2.1.1. Potential for mechanical damage to Compressor CAE-5010 (cont.)		...calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			2.1.2. Potential for Caterpillar engine damage	PD	2.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					2.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.1.7. PSV-50110 opens at 1525 psig	MT							
					2.1.8. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
		2.2. Overpressure piping and vessels	2.2.1. Leaks from pipes and vessels with environmental consequences	EV	2.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					2.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.2.3. PSV-50110 opens at 1525 psig	MT							
					2.2.4. Position indicator ZYC-5013/5014 shut...	PS							

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
2. valve BV-5013 or BV-5014 downstream of Gas Cooler HAL-2010 on compressor piping close due to mechanical failure, control system failure, or human error while operating? (cont.)		2.2. Overpressure piping and vessels (cont.)	2.2.1. Leaks from pipes and vessels with environmental consequences (cont.)		...system down on incorrect valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			2.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	2.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					2.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.2.7. PSV-50110 opens at 1525 psig	MT							
					2.2.8. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					2.2.9. Gas detection in building alarms and calls out off-site personnel.	DT							
					2.2.10. Flame detection in building , alarms and calls out off-site personnel.	DT							
			2.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	2.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					2.2.12. PSH-5019 shuts system down on high discharge pressure,...	PS							

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Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
2. valve BV-5013 or BV-5014 downstream of Gas Cooler HAL-2010 on compressor piping close due to mechanical failure, control system failure, or human error while operating? (cont.)		2.2. Overpressure piping and vessels (cont.)	2.2.3. Leaks from pipes and vessels with fire (not in building) (cont.)		...alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					2.2.13. PSV-50110 opens at 1525 psig	MT							
					2.2.14. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			2.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	2.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					2.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.2.17. PSV-50110 opens at 1525 psig	MT							
					2.2.18. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			2.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	2.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					2.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
2. valve BV-5013 or BV-5014 downstream of Gas Cooler HAL-2010 on compressor piping close due to mechanical failure, control system failure, or human error while operating? (cont.)		2.2. Overpressure piping and vessels (cont.)	2.2.5. Potential rupture from pipes and vessels with fire in building (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					2.2.21. PSV-50110 opens at 1525 psig	MT							
					2.2.22. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					2.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			2.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	2.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					2.2.25. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					2.2.26. PSV-50110 opens at 1525 psig	MT							
					2.2.27. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
3. lose electrical power to FCV-5019 due to external causes?	EX	:No hazard identified. Not to be developed further											
4. FCV-5019 opens too far during operation due to mechanical failure, control system failure, or human...	EQ HE	4.1. Potential to recycle more gas than desired to inlet of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...error?		4.1. Potential to recycle more gas than desired to inlet of Compressor CAE-5010 (cont.)	:Production inefficiency. Not to be developed further. (cont.)										
5. FCV-5019 closes too much during startup due to mechanical failure, control system failure, or human error?	EQ HE	5.1. Potential to start unit against pressure	5.1.1. Start-up failure or production inefficiency.	OP						1	5.1.1. Consider installing restricting orifice downstream of FCV-5019 to reduce potential operational issues.	ENE	HW
6. FCV-5019 closes too much during operation due to mechanical failure, control system failure, or human error?	EQ HE	6.1. Potential for excess gas flow to customers	:Business issue. Not to be developed further.										
		6.2. Potential to exceed turndown limits on exhaust SCR	6.2.1. Potential catalyst damage in SCR	PD	6.2.1. High temperature interlock on SCR shuts system down, alarms and calls out off-site personnel.	PS	2	2	2	2	6.2.1. Consider providing system based on incorrect position of FCV-5019 to prevent damage to SCR catalyst on low flow.	ENE	HW
										3	6.2.2. Consider adding an alarm and system shutdown for SCR operating below minimum load limit to prevent damage to SCR catalyst on low flow.	ENE	HW
										4	6.2.3. Consider verifying that the planned high temperature shutdown for the SCR is specified.	ENE	AU
			6.2.2. Potential permit violation	EV	6.2.2. High temperature interlock on SCR shuts system down, alarms and calls out off-site personnel.	PS	2	2	2		:Same As 6.2.1. :Same As 6.2.2. :Same As 6.2.3.		
7. BV-5018 (blowdown) opens during operation...	EQ	7.1. Release of gas to atmosphere	7.1.1. Economic loss of gas	PD	7.1.1. Position indicator ZYC-5018 shuts system...	PS	2	2	2	5	7.1.1. Consider adding pressure differential...	ENE	HW

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...due to mechanical failure, control system failure, or human error?	HE	7.1. Release of gas to atmosphere (cont.)	7.1.1. Economic loss of gas (cont.)		...down on incorrect valve position, alarms and calls out off-site personnel.						...transmitter across RO-3311 to alarm and shutdown on flow in blowdown line during other than blowdown operation so that undesired flow is identified.		
					7.1.2. Line size and RO-3311 limit flow to 3MM SCFH	EN							
			7.1.2. Potential environmental issue	EV	7.1.3. Position indicator ZYC-5018 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	2	1		:Same As 7.1.1.		
					7.1.4. Line size and RO-3311 limit flow to 3MM SCFH	EN							
8. BV-5018 (blowdown) leaks during operation due to mechanical failure?	EQ	8.1. Release of gas to atmosphere	8.1.1. Economic loss of gas	PD	8.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					8.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
9. BV-5018 doesn't open when required due to mechanical failure, control system failure, or human error?	EQ HE	9.1. Unable to blow unit down when required	9.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM EV PD	9.1.1. Blowdown control features are required to be tested annually.	PA	1	4	5	6	9.1.1. Consider scheduling ESD discussion between ENE and Nicor to more thoroughly define requirements and expectations for ESD actions during operations	ENE	AD
					9.1.2. Other safeguards exist to mitigate the specific situation requiring the shutdown.	DT PS EN							
10. BV-5011 and 5012 (suction valves) are both open during operation due to mechanical failure, control system failure, or human error (withdrawal...	EQ HE	10.1. Connect headers at two different pressures	:Reverse flow until pressure is equalized between Header A and Header B at absorber towers. No consequences of interest identified by the Team....										

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...mode)?		10.1. Connect headers at two different pressures (cont.)	...Not to be developed further.										
11. BV-5011 and 5012 (suction valves) are both open during operation due to mechanical failure, control system failure, or human error (injection mode)?	EQ HE	11.1. Connect headers at two different pressures	:Potential to flow between two reservoirs. No consequences of interest identified by the Team. Not to be developed further.										
12. BV-5013 and 5014 (discharge block valves) are both open during operation due to mechanical failure, control system failure, or human error (injection mode)?	EQ HE	12.1. Connect headers at two different pressures	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
13. BV-5013 and 5014 (discharge block valves) are both open during operation due to mechanical failure, control system failure, or human error (withdrawal mode)?	EQ HE	13.1. Connect headers at two different pressures	:No consequences of interest identified by the Team. Not to be developed further.										
14. BV-5011 and 5012 are both open during shutdown due to mechanical failure, control system failure, or human error (withdrawal mode)?	EQ HE	14.1. Connect headers at two different pressures	:Reverse flow until pressure is equalized between Header A and Header B at absorber towers. No consequences of interest identified by the Team. Not to be developed further.										
15. BV-5011 and 5012 are both open during shutdown due to mechanical failure, control system failure, or human error (injection mode)?	EQ HE	15.1. Connect headers at two different pressures	:Potential to flow between two reservoirs. No consequences of interest identified by the Team. Not to be developed further.										
16. BV-5013 and 5014 are both open during shutdown due to mechanical failure, control system failure, or...	EQ HE	16.1. Connect headers at two different pressures	:Inventory and pressure management problems. No consequences of interest identified by the Team....										

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...human error (withdrawal mode)?		16.1. Connect headers at two different pressures (cont.)	...Not to be developed further.										
17. BV-5013 and 5014 are both open during shutdown due to mechanical failure, control system failure, or human error (injection mode)?	EQ HE	17.1. Connect headers at two different pressures	:Inventory and pressure management problems. No consequences of interest identified by the Team. Not to be developed further.										
18. BV-5016 or 5017 (pressurizing valve) do not open when called on due to mechanical failure, control system failure, or human error?	EQ HE	18.1. Unable to equalize pressure across BV-5011	:Potential for premature valve seat wear. No consequences of interest identified by the Team. Not to be developed further.										
19. BV-5016 or 5017 do not close after being called on due to mechanical failure, control system failure, or human error?	EQ HE	19.1. Bypasses Emergency Shutdown Valve	:Same As 9.1.1. Not to be developed further.										
20. BV-5015 (header blowdown valve) doesn't open when called on due to mechanical failure, control system failure, or human error?	EQ HE	20.1. Potential to trap a small amount of gas in the event of a blowdown	:No consequences of interest identified by the Team. Not to be developed further.										
21. BV-5015 fails open during operation due to mechanical failure or external conditions?	EQ EX	:No hazard identified. Not to be developed further											
22. BV-5015 doesn't close after need due to mechanical failure or external conditions?	EQ EX	:No hazard identified. Not to be developed further											
23. FSV 5011 (discharge check valve) doesn't open when required due to mechanical failure, control system failure, or human error?	EQ HE	:Same As 2.1. Not to be developed further.											

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
24. FSV 5011 (discharge check valve) doesn't close when required due to equipment failure?	EQ	:No hazard identified. Not to be developed further											
25. PSV 50110 (unit relief valve) leaks during operation due to equipment failure?	EQ	:Same As 8.1. Not to be developed further.											
26. excess vibration in Compressor CAE-5010 for equipment failure or external conditions?	EQ EX	26.1. Shaking of equipment, piping, and foundation	26.1.1. Potential equipment, piping, and foundation damage	PD	26.1.1. Vibration monitoring alarm and shutdown for Compressor CAE-5010 specified to be designed to industry standard.	EN	1	4	5		:No additional recommendations identified by Team.		
					26.1.2. Predictive monitoring and trend analysis identify developing vibration issues before they become critical.	AD							
					26.1.3. Standard CVGS preventive maintenance program checks loose fasteners at 10k hour intervals of operation.	AD							
27. excess differential pressure across Compressor CAE-5010 due to equipment failure or external conditions?	EQ EX HE	27.1. Excess strain on Compressor CAE-5010	27.1.1. Potential damage to Compressor CAE-5010	PD	27.1.1. Compressor CAE-5010 is specified to be designed for the maximum anticipate pressure differential.	EN	1	4	5		:No additional recommendations identified by Team.		
					27.1.2. High differential pressure (unnumbered transmitter on compressor skid) shuts system down on high differential pressure, alarms and calls out off-site personnel.	PS							
					27.1.3. High rod load (unnumbered transmitter on compressor skid) shuts system down on high rod load, alarms and calls out...	PS							

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
27. excess differential pressure across Compressor CAE-5010 due to equipment failure or external conditions? (cont.)		27.1. Excess strain on Compressor CAE-5010 (cont.)	27.1.1. Potential damage to Compressor CAE-5010 (cont.)		...off-site personnel.						:No additional recommendations identified by Team. (cont.)		
28. Compressor CAE-5010 overspeeds for due to equipment failure or external conditions?	EQ EX	28.1. Excess strain on Compressor CAE-5010	28.1.1. Potential damage to Compressor CAE-5010	PD	28.1.1. Governor (unnumbered transmitter on compressor skid) prevents compressor overspeed, alarms and calls out off-site personnel.	EN	1	4	5		:No additional recommendations identified by Team.		
					28.1.2. Electronic sensor (unnumbered transmitter on compressor skid) shuts system down on compressor overspeed, alarms and calls out off-site personnel.	PS							
29. Compressor CAE-5010 is overloaded due to equipment failure or external conditions?	EQ EX	29.1. Excess strain on Compressor CAE-5010	29.1.1. Potential damage to Compressor CAE-5010	PD	29.1.1. Unit control system calculates compressor horsepower, monitors engine horsepower and alarms and shuts down on overload, alarms and calls out off-site personnel.	EN	1	4	5		:No additional recommendations identified by Team.		
					29.1.2. Station control independently monitors engine horsepower shuts down system, alarms and calls out off-site personnel.	EN							
					29.1.3. Caterpillar engine is specified to have built-in overload shutdown	EN							
					29.1.4. Compressor is specified to be rated at double the rating of the Caterpillar engine	EN							
30. Caterpillar engine is overloaded due to equipment failure or...	EQ EX	30.1. Excess strain on Caterpillar	30.1.1. Damage to Caterpillar engine	PD	30.1.1. Unit control system calculates compressor horsepower, monitors...	EN	1	4	5		:No additional recommendations identified by Team.		

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...external conditions?		30.1. Excess strain on Caterpillar (cont.)	30.1.1. Damage to Caterpillar engine (cont.)		...engine horsepower shuts down on overload, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					30.1.2. Station control independently monitors engine horsepower and shuts down system, alarms and calls out off-site personnel.	EN							
					30.1.3. Caterpillar engine is specified to have built-in overload shutdown	EN							
31. Suction Pulsation Bottles CBL-1040/1070 internals break due to equipment failure or external conditions?	EQ EX	31.1. Pulsation Bottles CBL-1040/1070	31.1.1. Release of gas in building with fire and personnel injury	EM PD	31.1.1. Pulsation Bottles CBL-1040/1070 is specified to be designed for service per ASME Code Section VIII.	EN	1	4	5	7	31.1.1. Consider verifying that Pulsation Bottles CBL-1040/1070 have been designed to ASME Code Section VIII.	ENE	AU
					31.1.2. Pulsation Bottles CBL-1040/1070 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
		31.2. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor CAE-5010	31.2.1. Damage to one cylinder of Compressor CAE-5010	PD	31.2.1. Pulsation Bottles CBL-1040/1070 is specified to be designed for service per ASME Code Section VIII.	EN	2	4	5		:Same As 31.1.1.		
					31.2.2. Pulsation Bottles CBL-1040/1070 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
32. discharge Pulsation Bottles CBL-1050/1080 internals break due to equipment failure or external conditions?	EQ EX	32.1. Pulsation Bottles CBL-1050/1080	32.1.1. Release of gas in building with fire and personnel injury	PD	32.1.1. Pulsation Bottles CBL-1050/1080 is specified to be designed for service per ASME Code Section VIII.	EN	1	4	5	8	32.1.1. Consider verifying that Pulsation Bottles CBL-10450/1080 have been designed to ASME Code Section VIII.	ENE	AU
					32.1.2. Pulsation Bottles...	EN							

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Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
32. discharge Pulsation Bottles CBL-1050/1080 internals break due to equipment failure or external conditions? (cont.)		32.1. Pulsation Bottles CBL-1050/1080 (cont.)	32.1.1. Release of gas in building with fire and personnel injury (cont.)		...CBL-1050/1080 has been designed using pulsation analysis by firm specializing in this type of equipment						32.1.1. Consider verifying that Pulsation Bottles CBL-10450/1080 have been designed to ASME Code Section VIII. (cont.)		
		32.2. High discharge pressure on Compressor CAE-5010	32.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	32.2.1. Pulsation Bottles CBL-1050/1080 is specified to be designed for service per ASME Code Section VIII.	EN	1	4	5		:Same As 32.1.1.		
					32.2.2. Pulsation Bottles CBL-1050/1080 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
					32.2.3. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					32.2.4. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					32.2.5. PSV-50110 opens at 1525 psig	MT							
					32.2.6. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			32.2.2. Potential for Caterpillar engine damage	PD	32.2.7. Pulsation Bottles CBL-1050/1080 is specified to be designed for service per ASME Code Section...	EN	1	4	5		:Same As 32.1.1.		

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32. discharge Pulsation Bottles CBL-1050/1080 internals break due to equipment failure or external conditions? (cont.)		32.2. High discharge pressure on Compressor CAE-5010 (cont.)	32.2.2. Potential for Caterpillar engine damage (cont.)		...VIII.						Same As 32.1.1. (cont.)		
					32.2.8. Pulsation Bottles CBL-1050/1080 has been designed using pulsation analysis by firm specializing in this type of equipment	EN							
					32.2.9. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					32.2.10. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					32.2.11. PSV-50110 opens at 1525 psig	MT							
					32.2.12. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
33. LV1031/61 drain on Suction Separators MBD-1030/1060 doesn't dump due to mechanical failure, control system failure, or human error?	EQ HE	33.1. Carry liquid to Compressor CAE-5010	33.1.1. Potential damage to Compressor CAE-5010	PD	33.1.1. Level switch LSHH1061/31 shuts system down on high level in Suction Separators MBD-1030/1060, alarms and calls out off-site personnel.	PS	3	3	4				
34. drain on Suction Separators MBD-1030/1060 sticks open due to mechanical failure, control system failure, or human error?	EQ HE	34.1. Pressure in Condensate Tank AGJ-3120	34.1.1. Potential to rupture Condensate Tank AGJ-3120 with release of gas and hydrocarbon liquids to atmosphere and environmental consequences	EV	34.1.1. PSE3121 on Condensate Tank AGJ-3120 is set to relieve at 6-12 in w.c.	MT	1	4	5	9	34.1.1. Consider adding means to identify continuous gas leakage into Condensate Tank AGJ-3120.	ENE	HW SW
					34.1.2. Conservent PSV3131 is set to relieve at 2 psig	MT							

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System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
34. drain on Suction Separators MBD-1030/1060 sticks open due to mechanical failure, control system failure, or human error? (cont.)		34.1. Pressure in Condensate Tank AGJ-3120 (cont.)	34.1.1. Potential to rupture Condensate Tank AGJ-3120 with release of gas and hydrocarbon liquids to atmosphere and environmental consequences (cont.)		34.1.3. RO-3131 restricts flow to Condensate Tank AGJ-3120	EN					34.1.1. Consider adding means to identify continuous gas leakage into Condensate Tank AGJ-3120. (cont.)		
			34.1.2. Potential to rupture Condensate Tank AGJ-3120 with release of gas and hydrocarbon liquids to atmosphere and fire	PD	34.1.4. PSE3121 on Condensate Tank AGJ-3120 is set to relieve at 6-12 in w.c.	MT	1	4	5		:Same As 34.1.1.		
					34.1.5. Conservent PSV3131 is set to relieve at 2 osig	MT							
					34.1.6. RO-3131 restricts flow to Condensate Tank AGJ-3120	EN							
					34.1.7. Area in vicinity of Condensate Tank AGJ-3120 electrical classification is Class I, Division 2	EN							
			34.1.3. Potential to rupture Condensate Tank AGJ-3120 with release of gas and hydrocarbon liquids to atmosphere and personnel injury	EM	34.1.8. PSE3121 on Condensate Tank AGJ-3120 is set to relieve at 6-12 in w.c.	MT	1	4	5		:Same As 34.1.1.		
					34.1.9. Conservent PSV3131 is set to relieve at 2 osig	MT							
					34.1.10. RO-3131 restricts flow to Condensate Tank AGJ-3120	EN							
35. Strainer 1031/61 plugs due to equipment failure or external conditions?	EQ EX	35.1. Loss of suction pressure to Compressor CAE-5010	:Production inefficiency. Not to be developed further										
36. strainer element in Strainer 1031/61 breaks due to pluggage?	EQ	36.1. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor...	36.1.1. Damage to one cylinder of Compressor CAE-5010	PD	36.1.1. Differential Pressure switch PDIT-1031/1061 shuts system down on high DP across Strainer...	PS	2	4	5	10	36.1.1. Consider establishing a means of monitoring Strainer 1031/61 for pluggage...	CVGS	MN

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
36. strainer element in Strainer 1031/61 breaks due to pluggage? (cont.)		...CAE-5010	36.1.1. Damage to one cylinder of Compressor CAE-5010 (cont.)		...1031/61, alarms and calls out off-site personnel.						...to prevent strainer failure.		
					36.1.2. Suction Separators MBD-1030/1060 stops material from entering Compressor CAE-5010	EN							
37. strainer element in Strainer 1031/61 breaks due to corrosion or vibration	EQ EX	37.1. Ingestion of Suction Pulsation Bottles CBL-1040/1070 parts in Compressor CAE-5010	37.1.1. Damage to one cylinder of Compressor CAE-5010	PD	37.1.1. Strainers 1031/61 have been specified to be designed to withstand the corrosion an vibration in the expected service.	EN	2	4	5		:No additional recommendations identified by Team.		
					37.1.2. Suction Separators MBD-1030/1060 stops material from entering Compressor CAE-5010	EN							
			37.1.2. Damage to Suction Separators MBD-1030/1060	PD	37.1.3. Differential Pressure switch PDIT-1031/1061 shuts system down on high DP across Strainer 1031/61, alarms and calls out off-site personnel.	PS	3	3	4	11	37.1.1. Consider establishing a means of monitoring Strainer 1031/61 for corrosion/vibration damage to prevent strainer failure.	CVGS	MN
38. louvers on Gas Cooler HAL-2010 do not close when required due to mechanical failure, control system failure, or human error?	EQ HE	38.1. No hazard identified. Not to be developed further	38.1.1. Operational issues only.	OP						12	38.1.1. Consider removing louvers on Gas Cooler HAL-2010 as they are not needed.	ENE	HW
39. fan on Gas Cooler HAL-2010 fails to operate due to mechanical failure, control system failure, or human error?	EQ HE	39.1. Insufficient cooling of gas stream and exceed pressure/ temperature rating of downstream vessels	39.1.1. Potential damage to downstream vessels	PD	39.1.1. TE-2012 shuts system down on high temperature in the gas discharge stream, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
40. fan on Gas Cooler HAL-2010 runs too fast due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (1) Compressor CAE-5010, including Suction Pulsation Bottles CBL-1040/1070, Discharge Pulsation Bottles CBL-1050/1080, Suction Separators MBD-1030/1060 and Gas Cooler HAL-2010 and associated equipment.
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-110 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
41. fan on Gas Cooler HAL-2010 runs too slow due to mechanical failure, control system failure, or human error?	EQ HE	:Same As 39.1. Not to be developed further.											

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (2) Compressor 5020, including Suction Pulsation Bottles CBL-1110 & 1130 and, Discharge Pulsation Bottles CBL-1100 & 1140, Suction Separators MBD-1090 & 1120 and Gas Cooler HAL-2020
Drawings: CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
42. FCV5029 is open while FCV50219 is closed or vice versa due to mechanical failure, control system failure, or human error?	EQ HE	42.1. Uneven loading of the two sides of Compressor 5020	42.1.1. Potential vibration leading to damage of Compressor 5020.	PD	42.1.1. Vibration monitoring alarm and shutdown for Compressor CAE-5010 specified to be designed to industry standard	EN	1	4	5		:No additional recommendations identified by Team.		
					42.1.2. Predictive monitoring and trend analysis identify developing vibration issues before they become critical	AD							
					42.1.3. Standard CVGS preventive maintenance program checks loose fasteners at 10k hour intervals of operation.	AD							
			42.1.2. Horsepower per throw imbalance leading to damage of Compressor 5020.	PD	42.1.4. Compressor 5020 frame has been specified to be designed to withstand the potential uneven loading.	EN	1	4	5		:No additional recommendations identified by Team.		
					42.1.5. Vibration monitoring alarm and shutdown for Compressor CAE-5010 specified to be designed to industry standard	EN							
					42.1.6. Predictive monitoring and trend analysis identify developing vibration issues before they become critical	AD							
					42.1.7. Standard CVGS preventive maintenance program checks loose fasteners at 10k hour intervals of operation.	AD							
43. lose electrical power to FCV50219 and 50229 during an emergency situation due to equipment failure or external causes?	EQ EX	43.1. FCV50219/50229 fail open and cross-connect the suction headers	43.1.1. Inventory management issues.	OP						13	43.1.1. Consider reviewing the design of the recycle valve power supply during emergency situations...	ENE	HW

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (2) Compressor 5020, including Suction Pulsation Bottles CBL-1110 & 1130 and, Discharge Pulsation Bottles CBL-1100 & 1140, Suction Separators MBD-1090 & 1120 and Gas Cooler HAL-2020
Drawings: CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
43. lose electrical power to FCV50219 and 50229 during an emergency situation due to equipment failure or external causes? (cont.)		43.1. FCV50219/50229 fail open and cross-connect the suction headers (cont.)	43.1.1. Inventory management issues. (cont.)								...to avoid potential inventory management issues.		
44. control system opens FCV50219 and 50229 during operation due to a control system failure?	EQ	44.1. FCV50219/50229 fail open and cross-connect the suction headers	:Inventory management issues only. Not to be developed further.										
45. control system opens FCV50219 and 50229 during start and stop sequences or while unit is idling due to a control system failure?	EQ	45.1. This is the currently planned normal condition	45.1.1. Potential Compressor 5020 start-up issues	OP						14	45.1.1. Consider further reviewing the need for check valves or other backflow safeguards for Unit #2 to prevent start-up issues with FCV50219 and 50229 being open at the same time.	ENE	HW SW
:The Team has determined that, with the exception of the questions above, Unit #2 issues are the same as Unit #1. Not to be developed further.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (3) Compressor 5030, including Suction Pulsation Bottles CBL-1160 & 1190, Discharge Pulsation Bottles CBL-1170 &1200, Suction Separators MBD-1150 & 1180 & Gas Cooler HAL-2030
Drawings: CVGS1-M-103 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:The team has determined that Unit #3 is functionally identical to Unit #1. Not to be developed further.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
46. BV-0041 is closed due to mechanical failure, control system failure, or human error?	EQ HE	46.1. Loss of feed to Compressor CAE-5010	46.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	46.1.1. Position indicator ZYC-0041 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					46.1.2. PDIT-0041 shuts system down on high DP across BV-0041 or low suction pressure, alarms and calls out off-site personnel.	PS							
			46.1.2. Potential for Caterpillar engine damage	PD	46.1.3. Position indicator ZYC-0041 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					46.1.4. PDIT-0041 shuts system down on high DP across BV-0041 or low suction pressure, alarms and calls out off-site personnel.	PS							
47. BV-0042 is open or leaks by due to mechanical failure, control system failure, or human error?	EQ HE	47.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		47.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
48. BV-0043 is open for due to mechanical failure, control system failure, or human error?	EQ HE	48.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		48.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
49. BV-0044 is closed due to mechanical failure, control system failure, or human error?	EQ HE	49.1. High discharge pressure on Compressor CAE-5010	49.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	49.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					49.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.1.3. PSV-50110 opens at 1525 psig	MT							
					49.1.4. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			49.1.2. Potential for Caterpillar engine damage	PD	49.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					49.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.1.7. PSV-50110 opens at 1525 psig	MT							
					49.1.8. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
		49.2. Overpressure piping and vessels	49.2.1. Leaks from pipes and vessels with...	EV	49.2.1. High discharge pressure (unnumbered...	PS	4	4	5		:No additional recommendations...		

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
49. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		49.2. Overpressure piping and vessels (cont.)	...environmental consequences		...transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.						...identified by Team.		
					49.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.3. PSV-50110 opens at 1525 psig	MT							
					49.2.4. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			49.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	49.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					49.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.7. PSV-50110 opens at 1525 psig	MT							
					49.2.8. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					49.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
49. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		49.2. Overpressure piping and vessels (cont.)	49.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		49.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT					:No additional recommendations identified by Team. (cont.)		
			49.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	49.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					49.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.13. PSV-50110 opens at 1525 psig	MT							
					49.2.14. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			49.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	49.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					49.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.17. PSV-50110 opens at 1525 psig	MT							
					49.2.18. Position indicator ZYC-0044 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
49. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		49.2. Overpressure piping and vessels (cont.)	49.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			49.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	49.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					49.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.21. PSV-50110 opens at 1525 psig	MT							
					49.2.22. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					49.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			49.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	49.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					49.2.25. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					49.2.26. PSV-50110...	MT							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
49. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		49.2. Overpressure piping and vessels (cont.)	49.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...opens at 1525 psig						:No additional recommendations identified by Team. (cont.)		
					49.2.27. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
50. BDV-0045 is open due to mechanical failure, control system failure, or human error?	EQ HE	50.1. Release of gas to atmosphere	50.1.1. Economic loss of gas	PD	50.1.1. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2	15	50.1.1. Consider adding an RO for valve BDV-0045 to permit fine tuning of the valve.	ENE	HW
					50.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN				16	50.1.2. Consider providing a means for isolating valve BDV-0045 for annual testing.	ENE	MN
			50.1.2. Potential environmental issue	EV	50.1.3. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:Same As 50.1.1. :Same As 50.1.2.		
					50.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		50.2. Noise	50.2.1. Potential public nuisance with fines	EM	50.2.1. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 50.1.1. :Same As 50.1.2.		
					50.2.2. Valve is required to be tested on an annual basis	AD							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
50. BDV-0045 is open due to mechanical failure, control system failure, or human error? (cont.)		50.2. Noise (cont.)	50.2.1. Potential public nuisance with fines (cont.)		50.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN					:Same As 50.1.2. (cont.)		
51. BDV-0045 leaks by due to mechanical failure, control system failure, or human error?	EQ HE	51.1. Release of gas to atmosphere	51.1.1. Economic loss of gas	PD	51.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					51.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					51.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
52. BDV-0046 is open due to mechanical failure, control system failure, or human error?	EQ HE	52.1. Release of gas to atmosphere	52.1.1. Economic loss of gas	PD	52.1.1. Position indicator ZYC-0046 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2	17	52.1.1. Consider adding an RO for valve BDV-0046 to permit fine tuning of the valve.	ENE	HW
										18	52.1.2. Consider providing a means for isolating valve BDV-0046 for annual testing.	ENE	MN
					52.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			52.1.2. Potential environmental issue	EV	52.1.3. Position indicator ZYC-0046 shuts system down on incorrect valve...	PS	1	2	1		:Same As 52.1.1. :Same As 52.1.2.		

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
52. BDV-0046 is open due to mechanical failure, control system failure, or human error? (cont.)		52.1. Release of gas to atmosphere (cont.)	52.1.2. Potential environmental issue (cont.)		...position, alarms and calls out off-site personnel.						:Same As 52.1.2. (cont.)		
					52.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		52.2. Noise	52.2.1. Potential public nuisance with fines	EM	52.2.1. Position indicator ZYC-0046 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 52.1.1. :Same As 52.1.2.		
					52.2.2. Valve is required to be tested on an annual basis	AD							
					52.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
53. BDV-0046 leaks by due to mechanical failure or control system failure?	EQ	53.1. Release of gas to atmosphere	53.1.1. Economic loss of gas	PD	53.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					53.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					53.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize...	EN							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
53. BDV-0046 leaks by due to mechanical failure or control system failure? (cont.)		53.1. Release of gas to atmosphere (cont.)	53.1.1. Economic loss of gas (cont.)		...release to atmosphere while assuring blowdown with the prescribed time.						:No additional recommendations identified by Team. (cont.)		
54. BV-0047 is closed due to mechanical failure, control system failure, or human error?	EQ HE	54.1. High discharge pressure on Compressor CAE-5010	54.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	54.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					54.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.1.3. PSV-50110 opens at 1525 psig	MT							
					54.1.4. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			54.1.2. Potential for Caterpillar engine damage	PD	54.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					54.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.1.7. PSV-50110 opens at 1525 psig	MT							
					54.1.8. Position indicator ZYC-0047 shuts system down on incorrect valve...	PS							

Worksheet

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
54. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		54.1. High discharge pressure on Compressor CAE-5010 (cont.)	54.1.2. Potential for Caterpillar engine damage (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
		54.2. Overpressure piping and vessels	54.2.1. Leaks from pipes and vessels with environmental consequences	EV	54.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					54.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.2.3. PSV-50110 opens at 1525 psig	MT							
					54.2.4. Position indicator ZYC-0047 shuts shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			54.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	54.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					54.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.2.7. PSV-50110 opens at 1525 psig	MT							
					54.2.8. Position indicator ZYC-0047 shuts shut system down on incorrect...	PS							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
54. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		54.2. Overpressure piping and vessels (cont.)	54.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					54.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
					54.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
			54.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	54.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					54.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.2.13. PSV-50110 opens at 1525 psig	MT							
					54.2.14. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			54.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	54.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					54.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
54. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		54.2. Overpressure piping and vessels (cont.)	54.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					54.2.17. PSV-50110 opens at 1525 psig	MT							
					54.2.18. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			54.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	54.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					54.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					54.2.21. PSV-50110 opens at 1525 psig	MT							
					54.2.22. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					54.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			54.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	54.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					54.2.25. PSH-5019 shuts...	PS							

Worksheet

Session: (2) 9/16/2010
System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
54. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		54.2. Overpressure piping and vessels (cont.)	54.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...system down on high discharge pressure, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					54.2.26. PSV-50110 opens at 1525 psig	MT							
					54.2.27. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
55. BV-0048 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
56. FCV-0049 opens due to mechanical failure, control system failure, or human error?	EQ HE	56.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		56.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
57. BV-00411 is open due to mechanical failure, control system failure, or human error?	EQ HE	57.1. Potential to bypass ESD and be unable to blow unit down when required	57.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD EV	57.1.1. Position indicator ZYC-00411 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	19	57.1.1. Consider adding ESD control to valve BV-00411.	ENE	SW
										20	57.1.2. Consider changing valve BV-00411 to a be a fail closed electro/hydraulic valve.	ENE	HW
					57.1.2. Station controller closes valve BV-00411in the event of an ESD, alarms and calls out off-site personnel.	PS							
58. BV-00431 is open due to mechanical failure, control system failure, or human error?	EQ HE	58.1. Potential to bypass ESD and be unable to blow unit down when required	58.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD EV	58.1.1. Position indicator ZYC-00431 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	21	58.1.1. Consider adding ESD control to valve BV-00431.	ENE	SW
										22	58.1.2. Consider changing valve BV-...	ENE	HW

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System: (4) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
58. BV-00431 is open due to mechanical failure, control system failure, or human error? (cont.)		58.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	58.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency. (cont.)		58.1.2. Station controller closes valve BV-00431in the event of an ESD, alarms and calls out off-site personnel.	PS					...00431 to a be a fail closed electro/hydraulic valve.		

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System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
59. BV-0041 is closed due to mechanical failure, control system failure, or human error?	EQ HE	59.1. Loss of feed to Compressor CAE-5010	59.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	59.1.1. Position indicator ZYC-0041 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					59.1.2. PDIT-0041 shuts system down on high DP across BV-0041 or low suction pressure, alarms and calls out off-site personnel.	PS							
			59.1.2. Potential for Caterpillar engine damage	PD	59.1.3. Position indicator ZYC-0041 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					59.1.4. PDIT-0041 shuts system down on high DP across BV-0041 or low suction pressure, alarms and calls out off-site personnel.	PS							
60. BV-0042 is open or leaks by due to equipment failure?	EQ	60.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		60.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
61. BV-0043 is open due to mechanical failure, control system failure, or human error?	EQ HE	61.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		61.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										

Worksheet

Company: EN Engineering

Facility: Central Valley Gas Storage, Princeton, CA

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System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)

Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
62. BV-0054 is closed due to mechanical failure, control system failure, or human error?	EQ HE	62.1. High discharge pressure on Compressor CAE-5010	62.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	62.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					62.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.1.3. PSV-50110 opens at 1525 psig	MT							
					62.1.4. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			62.1.2. Potential for Caterpillar engine damage	PD	62.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					62.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.1.7. PSV-50110 opens at 1525 psig	MT							
					62.1.8. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
		62.2. Overpressure piping and vessels	62.2.1. Leaks from pipes and vessels with...	EV	62.2.1. High discharge pressure (unnumbered...	PS	4	4	5		:No additional recommendations...		

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
62. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		62.2. Overpressure piping and vessels (cont.)	...environmental consequences		...transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.						...identified by Team.		
					62.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.3. PSV-50110 opens at 1525 psig	MT							
					62.2.4. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			62.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	62.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					62.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.7. PSV-50110 opens at 1525 psig	MT							
					62.2.8. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					62.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							

Worksheet

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
62. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		62.2. Overpressure piping and vessels (cont.)	62.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		62.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT					:No additional recommendations identified by Team. (cont.)		
			62.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	62.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					62.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.13. PSV-50110 opens at 1525 psig	MT							
					62.2.14. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			62.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	62.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					62.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.17. PSV-50110 opens at 1525 psig	MT							
					62.2.18. Position indicator ZYC-0054 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
62. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		62.2. Overpressure piping and vessels (cont.)	62.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			62.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	62.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					62.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.21. PSV-50110 opens at 1525 psig	MT							
					62.2.22. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					62.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			62.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	62.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					62.2.25. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					62.2.26. PSV-50110...	MT							

Worksheet

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Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
62. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		62.2. Overpressure piping and vessels (cont.)	62.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...opens at 1525 psig						:No additional recommendations identified by Team. (cont.)		
					62.2.27. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
63. BDV-0045 is open due to mechanical failure, control system failure, or human error?	EQ	63.1. Release of gas to atmosphere	63.1.1. Economic loss of gas	PD	63.1.1. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2		:Same As 50.1.1. :Same As 50.1.2.		
					63.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			63.1.2. Potential environmental issue	EV	63.1.3. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:Same As 50.1.1. :Same As 50.1.2.		
					63.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		63.2. Noise	63.2.1. Potential public nuisance with fines	EM	63.2.1. Position indicator ZYC-0045 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 50.1.1. :Same As 50.1.2.		
					63.2.2. Valve is required to be tested on an annual basis	AD							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
63. BDV-0045 is open due to mechanical failure, control system failure, or human error? (cont.)		63.2. Noise (cont.)	63.2.1. Potential public nuisance with fines (cont.)		63.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN					:Same As 50.1.2. (cont.)		
64. BDV-0045 leaks by due to equipment failure?	EQ	64.1. Release of gas to atmosphere	64.1.1. Economic loss of gas	PD	64.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					64.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					64.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
65. BDV-0056 is open due to mechanical failure, control system failure, or human error?	EQ HE	65.1. Release of gas to atmosphere	65.1.1. Economic loss of gas	PD	65.1.1. Position indicator ZYC-0056 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2	23	65.1.1. Consider adding an RO for valve BDV-0056 to permit fine tuning of the valve.	ENE	HW
										24	65.1.2. Consider providing a means for isolating valve BDV-0056 for annual testing.	ENE	MN
					65.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			65.1.2. Potential environmental issue	EV	65.1.3. Position indicator ZYC-0056 shuts system down on incorrect valve...	PS	1	2	1		:Same As 65.1.1. :Same As 65.1.2.		

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
65. BDV-0056 is open due to mechanical failure, control system failure, or human error? (cont.)		65.1. Release of gas to atmosphere (cont.)	65.1.2. Potential environmental issue (cont.)		...position, alarms and calls out off-site personnel.						:Same As 65.1.2. (cont.)		
					65.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		65.2. Noise	65.2.1. Potential public nuisance with fines	EM	65.2.1. Position indicator ZYC-0056 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 65.1.1. :Same As 65.1.2.		
					65.2.2. Valve is required to be tested on an annual basis	AD							
					65.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
66. BDV-0056 leaks by due to equipment failure?	EQ	66.1. Release of gas to atmosphere	66.1.1. Economic loss of gas	PD	66.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					66.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					66.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize...	EN							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
66. BDV-0056 leaks by due to equipment failure? (cont.)		66.1. Release of gas to atmosphere (cont.)	66.1.1. Economic loss of gas (cont.)		...release to atmosphere while assuring blowdown with the prescribed time.						:No additional recommendations identified by Team. (cont.)		
67. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error?	EQ HE	67.1. High discharge pressure on Compressor CAE-5010	67.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	67.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					67.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.1.3. PSV-50110 opens at 1525 psig	MT							
					67.1.4. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			67.1.2. Potential for Caterpillar engine damage	PD	67.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					67.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.1.7. PSV-50110 opens at 1525 psig	MT							
					67.1.8. Position indicator ZYC-0047 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
67. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		67.1. High discharge pressure on Compressor CAE-5010 (cont.)	67.1.2. Potential for Caterpillar engine damage (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
		67.2. Overpressure piping and vessels	67.2.1. Leaks from pipes and vessels with environmental consequences	EV	67.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					67.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.2.3. PSV-50110 opens at 1525 psig	MT							
					67.2.4. Position indicator ZYC-0047 shuts shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			67.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	67.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					67.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.2.7. PSV-50110 opens at 1525 psig	MT							
					67.2.8. Position indicator ZYC-0047 shuts shut system down on incorrect...	PS							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
67. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		67.2. Overpressure piping and vessels (cont.)	67.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					67.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
					67.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
			67.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	67.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					67.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.2.13. PSV-50110 opens at 1525 psig	MT							
					67.2.14. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			67.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	67.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					67.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

Session: (2) 9/16/2010
System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
67. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		67.2. Overpressure piping and vessels (cont.)	67.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					67.2.17. PSV-50110 opens at 1525 psig	MT							
					67.2.18. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			67.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	67.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					67.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					67.2.21. PSV-50110 opens at 1525 psig	MT							
					67.2.22. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					67.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			67.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	67.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					67.2.25. PSH-5019 shuts...	PS							

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System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
67. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		67.2. Overpressure piping and vessels (cont.)	67.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...system down on high discharge pressure, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					67.2.26. PSV-50110 opens at 1525 psig	MT							
					67.2.27. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
68. BV-0048 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
69. FCV-0049 is open due to mechanical failure, control system failure, or human error?	EQ HE	69.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		69.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
70. BV-00411 is open due to mechanical failure, control system failure, or human error?	EQ HE	70.1. Potential to bypass ESD and be unable to blow unit down when required	70.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	70.1.1. Position indicator ZYC-00411 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 57.1.1. :Same As 57.1.2.		
					70.1.2. Station controller closes valve BV-00411in the event of an ESD, alarms and calls out off-site personnel.	PS							
71. BV-00531 is open due to mechanical failure, control system failure, or human error?	EQ HE	71.1. Potential to bypass ESD and be unable to blow unit down when required	71.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	71.1.1. Position indicator ZYC-00531 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	25	71.1.1. Consider adding ESD control to valve BV-00531.	ENE	SW
										26	71.1.2. Consider changing valve BV-...	ENE	HW

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System: (5) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
71. BV-00531 is open due to mechanical failure, control system failure, or human error? (cont.)		71.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	71.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency. (cont.)		71.1.2. Station controller closes valve BV-00413in the event of an ESD, alarms and calls out off-site personnel.	PS					...00531 to a be a fail closed electro/hydraulic valve.		

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
72. BV-0051 is closed due to mechanical failure, control system failure, or human error?	EQ HE	72.1. Loss of feed to Compressor CAE-5010	72.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	72.1.1. Position indicator ZYC-0051 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					72.1.2. PDIT-0051 shuts system down on high DP across BV-0051 or low suction pressure, alarms and calls out off-site personnel.	PS							
			72.1.2. Potential for Caterpillar engine damage	PD	72.1.3. Position indicator ZYC-0051 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					72.1.4. PDIT-0051 shuts system down on high DP across BV-0051 or low suction pressure, alarms and calls out off-site personnel.	PS							
73. BV-0052 is open or leaks by due to equipment failure?	EQ	73.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		73.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
74. BV-0053 is open due to mechanical failure, control system failure, or human error?	EQ EX HE	74.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		74.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
75. BV-0044 is closed due to mechanical failure, control system failure, or human error?	EQ HE	75.1. High discharge pressure on Compressor CAE-5010	75.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	75.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					75.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.1.3. PSV-50110 opens at 1525 psig	MT							
					75.1.4. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			75.1.2. Potential for Caterpillar engine damage	PD	75.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					75.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.1.7. PSV-50110 opens at 1525 psig	MT							
					75.1.8. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
		75.2. Overpressure piping and vessels	75.2.1. Leaks from pipes and vessels with...	EV	75.2.1. High discharge pressure (unnumbered...	PS	4	4	5		:No additional recommendations...		

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
75. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		75.2. Overpressure piping and vessels (cont.)	...environmental consequences		...transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.						...identified by Team.		
					75.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.3. PSV-50110 opens at 1525 psig	MT							
					75.2.4. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			75.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	75.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					75.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.7. PSV-50110 opens at 1525 psig	MT							
					75.2.8. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					75.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
75. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		75.2. Overpressure piping and vessels (cont.)	75.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		75.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT					:No additional recommendations identified by Team. (cont.)		
			75.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	75.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					75.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.13. PSV-50110 opens at 1525 psig	MT							
					75.2.14. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			75.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	75.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					75.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.17. PSV-50110 opens at 1525 psig	MT							
					75.2.18. Position indicator ZYC-0044 shuts system down on incorrect valve...	PS							

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
75. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		75.2. Overpressure piping and vessels (cont.)	75.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			75.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	75.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					75.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.21. PSV-50110 opens at 1525 psig	MT							
					75.2.22. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					75.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			75.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	75.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					75.2.25. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					75.2.26. PSV-50110...	MT							

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
75. BV-0044 is closed due to mechanical failure, control system failure, or human error? (cont.)		75.2. Overpressure piping and vessels (cont.)	75.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...opens at 1525 psig						:No additional recommendations identified by Team. (cont.)		
					75.2.27. Position indicator ZYC-0044 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
76. BDV-0055 is open due to mechanical failure, control system failure, or human error?	EQ HE	76.1. Release of gas to atmosphere	76.1.1. Economic loss of gas	PD	76.1.1. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2	27	76.1.1. Consider adding an RO for valve BDV-0055 to permit fine tuning of the valve.	ENE	HW
					76.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN				28	76.1.2. Consider providing a means for isolating valve BDV-0055 for annual testing.	ENE	MN
			76.1.2. Potential environmental issue	EV	76.1.3. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:Same As 76.1.1. :Same As 76.1.2.		
					76.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		76.2. Noise	76.2.1. Potential public nuisance with fines	EM	76.2.1. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 76.1.1. :Same As 76.1.2.		
					76.2.2. Valve is required to be tested on an annual basis	AD							

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
76. BDV-0055 is open due to mechanical failure, control system failure, or human error? (cont.)		76.2. Noise (cont.)	76.2.1. Potential public nuisance with fines (cont.)		76.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN					:Same As 76.1.2. (cont.)		
77. BDV-0055 leaks by due to equipment failure?	EQ	77.1. Release of gas to atmosphere	77.1.1. Economic loss of gas	PD	77.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					77.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					77.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
78. BDV-0046 is open due to mechanical failure, control system failure, or human error?	EQ HE	78.1. Release of gas to atmosphere	78.1.1. Economic loss of gas	PD	78.1.1. Position indicator ZYC-0046 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2		:Same As 52.1.1. :Same As 52.1.2.		
					78.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			78.1.2. Potential environmental issue	EV	78.1.3. Position indicator ZYC-0046 shuts system down on incorrect valve...	PS	1	2	1		:Same As 52.1.1. :Same As 52.1.2.		

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
78. BDV-0046 is open due to mechanical failure, control system failure, or human error? (cont.)		78.1. Release of gas to atmosphere (cont.)	78.1.2. Potential environmental issue (cont.)		...position, alarms and calls out off-site personnel.						:Same As 52.1.2. (cont.)		
					78.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		78.2. Noise	78.2.1. Potential public nuisance with fines	EM	78.2.1. Position indicator ZYC-0046 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 52.1.1. :Same As 52.1.2.		
					78.2.2. Valve is required to be tested on an annual basis	AD							
					78.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
79. BDV0046 leaks by due to equipment failure?	EQ	79.1. Release of gas to atmosphere	79.1.1. Economic loss of gas	PD	79.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					79.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					79.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize...	EN							

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
79. BDV0046 leaks by due to equipment failure? (cont.)		79.1. Release of gas to atmosphere (cont.)	79.1.1. Economic loss of gas (cont.)		...release to atmosphere while assuring blowdown with the prescribed time.						:No additional recommendations identified by Team. (cont.)		
80. BV-0047 is closed due to mechanical failure, control system failure, or human error?	EQ HE	80.1. High discharge pressure on Compressor CAE-5010	80.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	80.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					80.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.1.3. PSV-50110 opens at 1525 psig	MT							
					80.1.4. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			80.1.2. Potential for Caterpillar engine damage	PD	80.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					80.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.1.7. PSV-50110 opens at 1525 psig	MT							
					80.1.8. Position indicator ZYC-0047 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
80. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		80.1. High discharge pressure on Compressor CAE-5010 (cont.)	80.1.2. Potential for Caterpillar engine damage (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
		80.2. Overpressure piping and vessels	80.2.1. Leaks from pipes and vessels with environmental consequences	EV	80.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					80.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.2.3. PSV-50110 opens at 1525 psig	MT							
					80.2.4. Position indicator ZYC-0047 shuts shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			80.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	80.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					80.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.2.7. PSV-50110 opens at 1525 psig	MT							
					80.2.8. Position indicator ZYC-0047 shuts shut system down on incorrect...	PS							

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
80. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		80.2. Overpressure piping and vessels (cont.)	80.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					80.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
					80.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
			80.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	80.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					80.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.2.13. PSV-50110 opens at 1525 psig	MT							
					80.2.14. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			80.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	80.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					80.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

Session: (2) 9/16/2010
System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
80. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		80.2. Overpressure piping and vessels (cont.)	80.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					80.2.17. PSV-50110 opens at 1525 psig	MT							
					80.2.18. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			80.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	80.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					80.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					80.2.21. PSV-50110 opens at 1525 psig	MT							
					80.2.22. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					80.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			80.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	80.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					80.2.25. PSH-5019 shuts...	PS							

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System: (6) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
80. BV-0047 is closed due to mechanical failure, control system failure, or human error? (cont.)		80.2. Overpressure piping and vessels (cont.)	80.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...system down on high discharge pressure, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					80.2.26. PSV-50110 opens at 1525 psig	MT							
					80.2.27. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
81. BV-0048 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
82. FCV-0049 is open due to mechanical failure, control system failure, or human error?	EQ HE	82.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		82.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
83. BV-00511 is open due to mechanical failure, control system failure, or human error?	EQ HE	83.1. Potential to bypass ESD and be unable to blow unit down when required	83.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	83.1.1. Position indicator ZYC-00511 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	29	83.1.1. Consider adding ESD control to valve BV-00511.	ENE	SW
										30	83.1.2. Consider changing valve BV-00511 to a be a fail closed electro/hydraulic valve.	ENE	HW
					83.1.2. Station controller closes valve BV-00511in the event of an ESD, alarms and calls out off-site personnel.	PS							
84. BV-00531 is open due to mechanical failure, control system failure, or human error?	EQ HE	84.1. Potential to bypass ESD and be unable to blow unit down when required	84.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	84.1.1. Position indicator ZYC-00531 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3	31	84.1.1. Consider adding ESD control to valve BV-00531.	ENE	SW
										32	84.1.2. Consider changing valve BV-...	ENE	HW

Worksheet

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
84. BV-00531 is open due to mechanical failure, control system failure, or human error? (cont.)		84.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	84.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency. (cont.)		84.1.2. Station controller closes valve BV-00531in the event of an ESD, alarms and calls out off-site personnel.	PS					...00531 to a be a fail closed electro/hydraulic valve.		

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Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
85. BV-0051 is closed due to mechanical failure, control system failure, or human error?	EQ HE	85.1. Loss of feed to Compressor CAE-5010	85.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	85.1.1. Position indicator ZYC-0051 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					85.1.2. PDIT-0051 shuts system down on high DP across BV-0051 or low suction pressure, alarms and calls out off-site personnel.	PS							
			85.1.2. Potential for Caterpillar engine damage	PD	85.1.3. Position indicator ZYC-0051 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					85.1.4. PDIT-0051 shuts system down on high DP across BV-0051 or low suction pressure, alarms and calls out off-site personnel.	PS							
86. BV-0052 is open or leaks by due to equipment failure?	EQ	86.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		86.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
87. BV-0053 is open due to mechanical failure, control system failure, or human error?	EQ HE	87.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		87.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
88. BV-0054 is closed due to mechanical failure, control system failure, or human error?	EQ HE	88.1. High discharge pressure on Compressor CAE-5010	88.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	88.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					88.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.1.3. PSV-50110 opens at 1525 psig	MT							
					88.1.4. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			88.1.2. Potential for Caterpillar engine damage	PD	88.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					88.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.1.7. PSV-50110 opens at 1525 psig	MT							
					88.1.8. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
		88.2. Overpressure piping and vessels	88.2.1. Leaks from pipes and vessels with...	EV	88.2.1. High discharge pressure (unnumbered...	PS	4	4	5		:No additional recommendations...		

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System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
88. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		88.2. Overpressure piping and vessels (cont.)	...environmental consequences		...transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.						...identified by Team.		
					88.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.3. PSV-50110 opens at 1525 psig	MT							
					88.2.4. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			88.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	88.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					88.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.7. PSV-50110 opens at 1525 psig	MT							
					88.2.8. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					88.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
88. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		88.2. Overpressure piping and vessels (cont.)	88.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		88.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT					:No additional recommendations identified by Team. (cont.)		
			88.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	88.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					88.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.13. PSV-50110 opens at 1525 psig	MT							
					88.2.14. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			88.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	88.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					88.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.17. PSV-50110 opens at 1525 psig	MT							
					88.2.18. Position indicator ZYC-0054 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
88. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		88.2. Overpressure piping and vessels (cont.)	88.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			88.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	88.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					88.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.21. PSV-50110 opens at 1525 psig	MT							
					88.2.22. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					88.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			88.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	88.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					88.2.25. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					88.2.26. PSV-50110...	MT							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
88. BV-0054 is closed due to mechanical failure, control system failure, or human error? (cont.)		88.2. Overpressure piping and vessels (cont.)	88.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...opens at 1525 psig						:No additional recommendations identified by Team. (cont.)		
					88.2.27. Position indicator ZYC-0054 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
89. BDV-0055 is open due to mechanical failure, control system failure, or human error?	EQ HE	89.1. Release of gas to atmosphere	89.1.1. Economic loss of gas	PD	89.1.1. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2		:Same As 76.1.1. :Same As 76.1.2.		
					89.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			89.1.2. Potential environmental issue	EV	89.1.3. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:Same As 76.1.1. :Same As 76.1.2.		
					89.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		89.2. Noise	89.2.1. Potential public nuisance with fines	EM	89.2.1. Position indicator ZYC-0055 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 76.1.1. :Same As 76.1.2.		
					89.2.2. Valve is required to be tested on an annual basis	AD							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
89. BDV-0055 is open due to mechanical failure, control system failure, or human error? (cont.)		89.2. Noise (cont.)	89.2.1. Potential public nuisance with fines (cont.)		89.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN					:Same As 76.1.2. (cont.)		
90. BDV-0055 leaks by due to equipment failure?	EQ	90.1. Release of gas to atmosphere	90.1.1. Economic loss of gas	PD	90.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					90.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					90.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
91. BDV-0056 is open due to mechanical failure, control system failure, or human error?	EQ HE	91.1. Release of gas to atmosphere	91.1.1. Economic loss of gas	PD	91.1.1. Position indicator ZYC-0056 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	2	2		:Same As 65.1.1. :Same As 65.1.2.		
					91.1.2. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
			91.1.2. Potential environmental issue	EV	91.1.3. Position indicator ZYC-0056 shuts system down on incorrect valve...	PS	1	2	1		:Same As 65.1.1. :Same As 65.1.2.		

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
91. BDV-0056 is open due to mechanical failure, control system failure, or human error? (cont.)		91.1. Release of gas to atmosphere (cont.)	91.1.2. Potential environmental issue (cont.)		...position, alarms and calls out off-site personnel.						:Same As 65.1.2. (cont.)		
					91.1.4. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
		91.2. Noise	91.2.1. Potential public nuisance with fines	EM	91.2.1. Position indicator ZYC-0056 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	2	4	5		:Same As 65.1.1. :Same As 65.1.2.		
					91.2.2. Valve is required to be tested on an annual basis	AD							
					91.2.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN							
92. BDV-0056 leaks by due to equipment failure?	EQ	92.1. Release of gas to atmosphere	92.1.1. Economic loss of gas	PD	92.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	3	3	4		:No additional recommendations identified by Team.		
					92.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
					92.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize...	EN							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
92. BDV-0056 leaks by due to equipment failure? (cont.)		92.1. Release of gas to atmosphere (cont.)	92.1.1. Economic loss of gas (cont.)		...release to atmosphere while assuring blowdown with the prescribed time.						:No additional recommendations identified by Team. (cont.)		
93. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error?	EQ HE	93.1. High discharge pressure on Compressor CAE-5010	93.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	93.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					93.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.1.3. PSV-50110 opens at 1525 psig	MT							
					93.1.4. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			93.1.2. Potential for Caterpillar engine damage	PD	93.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					93.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.1.7. PSV-50110 opens at 1525 psig	MT							
					93.1.8. Position indicator ZYC-0047 shuts system down on incorrect valve...	PS							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
93. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		93.1. High discharge pressure on Compressor CAE-5010 (cont.)	93.1.2. Potential for Caterpillar engine damage (cont.)		...position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
		93.2. Overpressure piping and vessels	93.2.1. Leaks from pipes and vessels with environmental consequences	EV	93.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					93.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.2.3. PSV-50110 opens at 1525 psig	MT							
					93.2.4. Position indicator ZYC-0047 shuts shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			93.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	93.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					93.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.2.7. PSV-50110 opens at 1525 psig	MT							
					93.2.8. Position indicator ZYC-0047 shuts shut system down on incorrect...	PS							

Session: (2) 9/16/2010
System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
93. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		93.2. Overpressure piping and vessels (cont.)	93.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					93.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
					93.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
			93.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	93.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					93.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.2.13. PSV-50110 opens at 1525 psig	MT							
					93.2.14. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			93.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	93.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					93.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

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System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
93. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		93.2. Overpressure piping and vessels (cont.)	93.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					93.2.17. PSV-50110 opens at 1525 psig	MT							
					93.2.18. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			93.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	93.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					93.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					93.2.21. PSV-50110 opens at 1525 psig	MT							
					93.2.22. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					93.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			93.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	93.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					93.2.25. PSH-5019 shuts...	PS							

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System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
93. BV-0057 is closed is closed due to mechanical failure, control system failure, or human error? (cont.)		93.2. Overpressure piping and vessels (cont.)	93.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...system down on high discharge pressure, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					93.2.26. PSV-50110 opens at 1525 psig	MT							
					93.2.27. Position indicator ZYC-0047 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
94. BV0058 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
95. FCV-0059 is open due to mechanical failure, control system failure, or human error?	EQ HE	95.1. Unintended recycle of gas back to suction of Compressor CAE-5010	:Production inefficiency. Not to be developed further.										
		95.2. Unintended flow to other formation.	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
96. BV-00511 is open due to mechanical failure, control system failure, or human error?	EQ HE	96.1. Potential to bypass ESD and be unable to blow unit down when required	96.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	96.1.1. Position indicator ZYC-00511 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 83.1.1. :Same As 83.1.2.		
					96.1.2. Station controller closes valve BV-00511in the event of an ESD, alarms and calls out off-site personnel.	PS							
97. BV-00531 is open due to mechanical failure, control system failure, or human error?	EQ HE	97.1. Potential to bypass ESD and be unable to blow unit down when required	97.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency.	EM PD	97.1.1. Position indicator ZYC-00531 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 84.1.1. :Same As 84.1.2.		

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

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System: (7) High pressure gas discharge across compressor units through metering station and Filter Separator to line (power withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
97. BV-00531 is open due to mechanical failure, control system failure, or human error? (cont.)		97.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	97.1.1. Potential to be unable to use building shutdown in the event of an emergency situation which could result in exacerbating the emergency. (cont.)		97.1.2. Station controller closes valve BV-00531in the event of an ESD, alarms and calls out off-site personnel.	PS					:Same As 84.1.2. (cont.)		

Session: (2) 9/16/2010
System: (8) West Meter run in withdrawal mode
Drawings: CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
98. BV-0081 is closed during operation due to mechanical failure, control system failure, or human error?	EQ HE	98.1. High discharge pressure on Compressor CAE-5010	98.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	98.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					98.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					98.1.3. PSV-50110 opens at 1525 psig	MT							
99. BV-0084 is closed during operation due to mechanical failure, control system failure, or human error?	EQ HE	99.1. High discharge pressure on Compressor CAE-5010	99.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	99.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					99.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					99.1.3. PSV-50110 opens at 1525 psig	MT							
100. FCV-0082 is open more than required (power mode) due to mechanical failure, control system failure, or human error	EQ HE	:Valve is to be full open. The team identified no cause for this deviation. Not to be developed further.											
101. FCV-0082 is open more than required (free flow mode) due to mechanical failure, control system failure, or human error?	EQ HE	101.1. Flow too high	:Business issues only. Not to be developed further.										
		101.2. Pressure too high	101.2.1. Potential overpressure of downstream equipment and pipelines	PD	101.2.1. PCV-0083 controls downstream pressure.	PS	1	4	5	33	101.2.1. Consider changing the setpoints on PCV-0083 and 0093 to less than 1110 psig to be lower than the...	ENE	SW
					101.2.2. PIT-0084 shuts down flow by closing BV-...	PS							

Session: (2) 9/16/2010
System: (8) West Meter run in withdrawal mode
Drawings: CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
101. FCV-0082 is open more than required (free flow mode) due to mechanical failure, control system failure, or human error? (cont.)		101.2. Pressure too high (cont.)	101.2.1. Potential overpressure of downstream equipment and pipelines (cont.)		...0043 and BV-0044 at 1110 psig, alarms and calls out off-site personnel.						...PIT-0084 set point.		
102. FCV-0082 partially closed (power mode) due to mechanical failure, control system failure, or human error?	EQ HE	102.1. Excess pressure drop in line	:Business issues only. Not to be developed further.										
103. FCV-0082 is closed more than required (free flow mode) due to mechanical failure, control system failure, or human error?	EQ HE	103.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
104. PCV-0083 allows pressure too high due to mechanical failure, control system failure, or human error?	EQ HE	104.1. Pressure too high	104.1.1. Potential overpressure of downstream equipment and pipelines	PD	104.1.1. PIT-0084 shuts down flow by closing BV-0043 and BV-0044 at 1110 psig, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					104.1.2. Pressure override on FCV-0082 controls limits pressure based on PIT-0082	PS							
105. PCV-0083 allows pressure too low due to mechanical failure, control system failure, or human error?	EQ HE	105.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
106. Flow meter FIT-0061 reads high due to equipment failure?	EQ	106.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
107. Flow meter FIT-0061 reads low due to equipment failure?	EQ	107.1. Over-deliver to customer	:Business issues only. Not to be developed further.										

Session: (2) 9/16/2010
System: (9) East Meter run in withdrawal mode
Drawings: CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
108. BV-0091 is closed during operation due to mechanical failure, control system failure, or human error	EQ HE	108.1. High discharge pressure on Compressor CAE-5010	108.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	108.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					108.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					108.1.3. PSV-50110 opens at 1525 psig	MT							
109. BV-0094 is closed during operation due to mechanical failure, control system failure, or human error?	EQ HE	109.1. High discharge pressure on Compressor CAE-5010	109.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	109.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					109.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					109.1.3. PSV-50110 opens at 1525 psig	MT							
110. FCV-0092 is open more than required (power mode) due to mechanical failure, control system failure, or human error?	EQ HE	:Valve is to be full open. The team identified no cause for this deviation. Not to be developed further.											
111. FCV0092 is open more than required (free flow mode) due to mechanical failure, control system failure, or human error?	EQ HE	111.1. Flow too high	:Business issues only. Not to be developed further.										
		111.2. Pressure too high	111.2.1. Potential overpressure of downstream equipment and pipelines	PD	111.2.1. PCV-0093 controls downstream pressure	PS	1	4	5		:Same As 101.2.1.		
					111.2.2. PIT-0094 shuts down flow by closing BV-...	PS							

Worksheet

Session: (2) 9/16/2010
System: (9) East Meter run in withdrawal mode
Drawings: CVGS1-M-104 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
111. FCV0092 is open more than required (free flow mode) due to mechanical failure, control system failure, or human error? (cont.)		111.2. Pressure too high (cont.)	111.2.1. Potential overpressure of downstream equipment and pipelines (cont.)		...0043 and BV-0044 at 1110 psig, alarms and calls out off-site personnel.						:Same As 101.2.1. (cont.)		
112. FCV-0092 partially closed (power mode) due to mechanical failure, control system failure, or human error?	EQ HE	112.1. Excess pressure drop in line	:Business issues only. Not to be developed further.										
113. FCV-0092 is closed more than required (free flow mode) due to mechanical failure, control system failure, or human error?	EQ HE	113.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
114. PCV-0093 allows pressure too high due to mechanical failure, control system failure, or human error?	EQ HE	114.1. Pressure too high	114.1.1. Potential overpressure of downstream equipment and pipelines	PD	114.1.1. PIT-0094 shuts down flow by closing BV-0043 and BV-0044 at 1110 psig, alarms and calls out off-site personnel. 114.1.2. Pressure override on FCV-0092 controls limits pressure based on PIT-0092	PS PS	1	4	5		:No additional recommendations identified by Team.		
115. PCV-0093 allows pressure too low due to mechanical failure, control system failure, or human error?	EQ HE	115.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
116. Flow meter FIT-0071 reads high due to equipment failure?	EQ	116.1. Under-deliver to customer	:Business issues only. Not to be developed further.										
117. Flow meter FIT-0071 reads low due to equipment failure?	EQ	117.1. Over-deliver to customer	:Business issues only. Not to be developed further.										

Worksheet

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
118. Filter Separator MAK-1510 is shut-in due to mechanical failure, control system failure, or human error?	EQ HE	118.1. Potential overpressure of Filter Separator MAK-1510 due to temperature increase	118.1.1. potential damage to Filter Separator MAK-1510	PD	118.1.1. PSV-1511 opens at 1145 psig.	MT	2	4	5	34	118.1.1. Consider establishing standard operating procedure for maintenance turnover of Filter Separator MAK-1510 and similar equipment.	CVGS	PR
		118.2. Potential underpressure of Filter Separator MAK-1510 due to temperature decrease	:Filter Separator MAK-1510 is rated for full vacuum. Not to be developed further.										
119. BV-1511 is open due to mechanical failure, control system failure, or human error?	EQ HE	119.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
120. BV-1512 is open due to mechanical failure, control system failure, or human error?	EQ HE	120.1. High discharge pressure on Compressor CAE-5010	120.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	120.1.1. Position indicator ZYC-1512 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					120.1.2. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					120.1.3. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					120.1.4. PSV-50110 opens at 1525 psig	MT							
121. BV-1513 is closed due to mechanical failure, control system failure, or human error?	EQ HE	121.1. High discharge pressure on Compressor CAE-5010	121.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	121.1.1. Position indicator ZYC-1513 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
121. BV-1513 is closed due to mechanical failure, control system failure, or human error? (cont.)		121.1. High discharge pressure on Compressor CAE-5010 (cont.)	121.1.1. Potential for mechanical damage to Compressor CAE-5010 (cont.)		121.1.2. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS					:No additional recommendations identified by Team. (cont.)		
					121.1.3. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					121.1.4. PSV-50110 opens at 1525 psig	MT							
122. BV-1516 is open due to mechanical failure, control system failure, or human error?	EQ HE	122.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
123. BV-1518 is closed due to mechanical failure, control system failure, or human error	EQ HE	123.1. High discharge pressure on Compressor CAE-5010	123.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	123.1.1. Position indicator ZYC-1518 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					123.1.2. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					123.1.3. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					123.1.4. PSV-50110 opens at 1525 psig	MT							
124. filter cartridges rupture due to high...	EQ	124.1. Bypass Filter Separator MAK-1510	124.1.1. Carry over of glycol, lube oil and filter...	PD	124.1.1. PDIT-1511 shuts system down on high...	PS	3	4	5		:No additional recommendations...		

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...differential pressure?		124.1. Bypass Filter Separator MAK-1510 (cont.)	...material. with pipeline maintenance issue.		...differential pressure, alarms and calls out off-site personnel.						...identified by Team.		
125. filter cartridges collapse due to high differential pressure?	EQ	125.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
126. LV-1513 doesn't open due to mechanical failure, control system failure, or human error	EQ HE	126.1. Condensate build up in Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
			126.1.1. Increased potential for failure of filter elements. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	126.1.1. LSHH-1511 shuts system down on high high level in Filter Separator MAK-1510, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					126.1.2. LT-1511 shuts system down on high high level in Filter Separator MAK-1510, alarms and calls out off-site personnel.	PS							
127. LV-1516 doesn't open due to mechanical failure, control system failure, or human error?	EQ HE	127.1. Condensate build up in Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
			127.1.1. Increased potential for failure of filter elements. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	127.1.1. LSHH-1512 shuts system down on high high level in Filter Separator MAK-1510, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					127.1.2. LT-1513 shuts system down on high high level in Filter Separator MAK-1510, alarms and calls out off-site personnel.	PS							
128. LV-1513 doesn't close due to mechanical...	EQ	128.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil tc...										

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...failure, control system failure, or human error?	HE	128.1. Bypass Filter Separator MAK-1510 (cont.)	...customer. Contractual issues only. Not to be developed further.										
		128.2. Pressure in Condensate Tank ABJ-3130	128.2.1. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	128.2.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5	35	128.2.1. Consider adding means on Condensate Tank ABJ-3130 to identify continuous gas leakage into tank so that leakage can be corrected.	ENE	HW
					128.2.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					128.2.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS				36	128.2.2. Consider reviewing failure modes of LV-1513/16 to ensure sufficient protection against potential failures.	ENE	AU
			128.2.2. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	128.2.4. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					128.2.5. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					128.2.6. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
					128.2.7. Area electrical classification is Class I, Division 2	EN							
129. LV-1516 doesn't close due to mechanical failure, control system failure, or human error?	EQ HE	129.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
		129.2. Pressure in Condensate Tank ABJ-3130	129.2.1. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental...	EV	129.2.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					129.2.2. Conservent PSV-3131 on Condensate...	PS							

Worksheet

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
129. LV-1516 doesn't close due to mechanical failure, control system failure, or human error? (cont.)		129.2. Pressure in Condensate Tank ABJ-3130 (cont.)	...consequences		...Tank ABJ-3130 opens at 2 osig						:Same As 128.2.1. (cont.)		
					129.2.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
			129.2.2. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	129.2.4. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					129.2.5. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					129.2.6. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
					129.2.7. Area electrical classification is Class I, Division 2	EN							
130. 1" manual drain valve on each end of Filter Separator MAK-1510 is open due to human error or mechanical failure?	EQ HE	130.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
		130.2. Pressure in Condensate Tank ABJ-3130	130.2.1. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	130.2.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					130.2.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					130.2.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
			130.2.2. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	130.2.4. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					130.2.5. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (10) Filter Separator MAK-1510 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D; CVGS1-M-112 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
130. 1" manual drain valve on each end of Filter Separator MAK-1510 is open due to human error or mechanical failure? (cont.)		130.2. Pressure in Condensate Tank ABJ-3130 (cont.)	130.2.2. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire (cont.)		130.2.6. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS					:Same As 128.2.1. (cont.)		
					130.2.7. Area electrical classification is Class I, Division 2	EN							
131. BV-15110 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
132. BV-15111 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
133. BV-15112 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
134. BV-15110 and BV-15112 are open at the same time due to mechanical failure, control system failure, or human error?	EQ HE	134.1. Bypass Filter Separator MAK-1510	:Potential to carry over of glycol and lube oil to customer. Contractual issues only. Not to be developed further.										
135. External fire occurs at Bypass Filter Separator MAK-1510 due to external situation?	EX	135.1. Pressure in Condensate Tank ABJ-3130	135.1.1. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	135.1.1. Design precludes flammables from vicinity of the Condensate Tank ABJ-3130.	EN	1	4	5		:No additional recommendations identified by Team.		
			135.1.2. Potential rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	135.1.2. Design precludes flammables from vicinity of the Condensate Tank ABJ-3130.	EN	1	4	5		:No additional recommendations identified by Team.		

Session: (2) 9/16/2010
System: (11) Pig Receiver MBP-1500 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
136. BV-1501 is open due to mechanical failure, control system failure, or human error?	HE HE	136.1. gas in Pig Receiver MBP-1500	136.1.1. Potential for continuous fugitive emission of gas from Pig Receiver MBP-1500	EV	136.1.1. Standard procedure in similar operations is to require valves such as BV-1501 to be verified closed if not in use.	PR	4	3	5	37	136.1.1. Consider ensuring that procedures are written to ensure that valves such as BV-1501 are verified closed if not in use.	CVGS	PR
137. BV-1502 is closed due to mechanical failure, control system failure, or human error?	EQ HE	137.1. High discharge pressure on Compressor CAE-5010	137.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	137.1.1. Position indicator ZYC-1502 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					137.1.2. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					137.1.3. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					137.1.4. PSV-50110 opens at 1525 psig	MT							
138. BDV-1507 is open due to mechanical failure, control system failure, or human error?	HE HE	138.1. gas in Pig Receiver MBP-1500	138.1.1. Potential for continuous fugitive emission of gas from Pig Receiver MBP-1500	EV	138.1.1. Standard procedure in similar operations is to require valves such as BV-1507 to be verified closed if not in use.	PR	4	3	5		:Same As 136.1.1.		
139. BDV-1508 is open due to mechanical failure, control system failure, or human error?	HE HE	139.1. Release of gas to atmosphere	139.1.1. Economic loss of gas	PD	139.1.1. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN	2	4	5	38	139.1.1. Consider ensuring that SOPs are written with checklists for valve positions for valves such as BDV-1508 and other manual valves both before and after maintenance to ensure that equipment is returned to service...	CVGS	PR
					139.1.2. Standard...	PR							

Session: (2) 9/16/2010
System: (11) Pig Receiver MBP-1500 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
139. BDV-1508 is open due to mechanical failure, control system failure, or human error? (cont.)		139.1. Release of gas to atmosphere (cont.)	139.1.1. Economic loss of gas (cont.)		...procedure in similar operations is to require valves such as BDV-1508 to be verified closed after maintenance.						...in a safe and operable condition.		
			139.1.2. Potential environmental issue	EV	139.1.3. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN	2	4	5		:Same As 139.1.1.		
					139.1.4. Standard procedure in similar operations is to require valves such as BDV-1508 to be verified closed after maintenance.	PR							
		139.2. Noise	139.2.1. Potential public nuisance with fines	EM	139.2.1. The design has been specified so that the combination of valve size, line size, and RO (if needed) will minimize release to atmosphere while assuring blowdown with the prescribed time.	EN	2	4	5		:Same As 139.1.1.		
					139.2.2. Standard procedure in similar operations is to require valves such as BDV-1508 to be verified closed after maintenance.	PR							
140. BV-1504 is open due to mechanical failure, control system failure, or human error?	HE HE	140.1. gas in Pig Receiver MBP-1500	140.1.1. Potential for continuous fugitive emission of gas from Pig Receiver MBP-1500	EV	140.1.1. Standard procedure in similar operations is to require valves such as BV-1504 to be verified closed if not in use.	PR	4	3	5		:Same As 136.1.1.		
141. BV-1501 and BV-1504 are left open after pig receiving because of...	HE	141.1. Potential to bypass ESD and be unable to blow unit...	141.1.1. Potential to be unable to use building shutdown in the event of...	EM PD	141.1.1. Standard procedure in similar operations is to require...	PR	1	3	3	39	141.1.1. Consider changing specification for valves BV-1501...	ENE	AD

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (11) Pig Receiver MBP-1500 (withdrawal mode)
Drawings: CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...human error?		...down when required	...an emergency situation which could result in exacerbating the emergency.		...valves such as BV-1501 and BV-1504 to be verified closed if not in use.						...and BV-1504 from normally closed to locked closed. :Same As 136.1.1.		

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (12) High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line A to West meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that free flow mode presents the same or lesser consequence scenarios as the power withdrawal mode. Not to be developed further.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (13) High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line A to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that free flow mode presents the same or lesser consequence scenarios as the power withdrawal mode. Not to be developed further.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (14) High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line B to West meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that free flow mode presents the same or lesser consequence scenarios as the power withdrawal mode. Not to be developed further.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (15) High pressure gas discharge across compressor units through metering station and Filter Separator to line (free flow withdrawal mode from Line B to East meter run)
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that free flow mode presents the same or lesser consequence scenarios as the power withdrawal mode. Not to be developed further.													

Session: (2) 9/16/2010
System: (16) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, withdrawal mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
142. BV-1211/1231 closed due to mechanical failure, control system failure, or human error (power mode)?	EQ HE	142.1. Loss of feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and Compressor CAE-5010	142.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	142.1.1. Position indicator ZYC-1211/1311 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					142.1.2. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS							
			142.1.2. Potential for Caterpillar engine damage	PD	142.1.3. Position indicator ZYC-1211/1311 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					142.1.4. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS							
			142.1.3. Potential to pull vacuum on Glycol Absorber Line B MAF-1210/Line A MAF-1230 and damage tower	PD	:No safeguards were identified.		1	2	1	40	142.1.1. Consider verifying with design calculations that Glycol Absorber Line B MAF-1210/Line A MAF-1230 will withstand full vacuum.	ENE	AD
143. BV-1211/1231 closed due to mechanical failure, control system failure, or human error (free flow mode)?	EQ HE	:No hazard identified. Not to be developed further											
144. BV-1214/1234 closed due to mechanical failure, control system failure, or human error?	HE HE	144.1. Loss of lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and fail to dehydrate gas	144.1.1. Potential for gas to be out of specification.	OP	144.1.1. FT-4031 (drawing 105-2) shuts off gas flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 in the event of low flow of glycol, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					144.1.2. SY-4021/22 shuts off gas flow to Glycol...	PS							

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (2) 9/16/2010
System: (16) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, withdrawal mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
144. BV-1214/1234 closed due to mechanical failure, control system failure, or human error? (cont.)		144.1. Loss of lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and fail to dehydrate gas (cont.)	144.1.1. Potential for gas to be out of specification. (cont.)		...Absorber Line B MAF-1210/Line A MAF-1230 if at least one glycol pump is not running, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					144.1.3. AE0071/0061 stop gas flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 in the event of high moisture in gas, alarms and calls out off-site personnel. (drawing 104-1)	PS							
145. have too much lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 due to mechanical failure, control system failure, or human error?	EQ HE	145.1. Back up glycol in Glycol Absorber Line B MAF-1210/Line A MAF-1230	145.1.1. Potential for gas to be out of specification.	OP	145.1.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5	41	145.1.1. Consider reviewing with Sivalls the protections for the Glycol Regeneration skids to ensure that sufficient protection is provided.	ENE	AD
					145.1.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
		145.2. Carry glycol to Compressor CAE-5010	145.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	145.2.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					145.2.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					145.2.3. Suction Separators MBD-1030/1060 protects...	PS							

Session: (2) 9/16/2010
System: (16) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, withdrawal mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
145. have too much lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 due to mechanical failure, control system failure, or human error? (cont.)		145.2. Carry glycol to Compressor CAE-5010 (cont.)	145.2.1. Potential for mechanical damage to Compressor CAE-5010 (cont.)		...Compressor CAE-5010						:No additional recommendations identified by Team. (cont.)		
		145.3. Carry glycol to pipeline	145.3.1. Potential for gas to be out of specification.	OP	145.3.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					145.3.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					145.3.3. Filter Separator MAK-1510 removes glycol before gas goes to pipeline	PS							
146. LV-1213/11233 closed due to mechanical failure, control system failure, or human error?	EQ HE	146.1. Loss of flow of rich glycol from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and back up glycol in Glycol Absorber Line B MAF-1210/Line A MAF-1230	146.1.1. Potential for gas to be out of specification.	OP	146.1.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:Same As 145.1.1.		
					146.1.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
147. LV-1213/1233 is too far open due to mechanical failure, control system failure, or human error?	EQ HE	147.1. Excess glycol return from Glycol Absorber Line B MAF-1210/Line A MAF-1230 with gas at regenerator skid	147.1.1. Potential to overpressure regenerator skid with release of gas to atmosphere and fire	PD EM	147.1.1. LT1211/1231 shut down glycol feed pumps on low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		

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Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
147. LV-1213/1233 is too far open due to mechanical failure, control system failure, or human error? (cont.)		147.1. Excess glycol return from Glycol Absorber Line B MAF-1210/Line A MAF-1230 with gas at regenerator skid (cont.)	147.1.1. Potential to overpressure regenerator skid with release of gas to atmosphere and fire (cont.)		147.1.2. LSLL1211/1231 shut down glycol feed pumps on low low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS					:No additional recommendations identified by Team. (cont.)		
					147.1.3. Regenerator skid pressure switch closes BV-4029 in the event of high pressure at the Regenerator skid, alarms and calls out off-site personnel.	PS							
		147.2. carry glycol to Compressor CAE-5010	147.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	147.2.1. LT1211/1231 shut down glycol feed pumps on low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					147.2.2. LSLL1211/1231 shut down glycol feed pumps on low low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					147.2.3. Suction Separators MBD-1030/1060 protects Compressor CAE-5010	PS							
		147.3. carry glycol to pipeline	147.3.1. Potential for gas to be out of specification.	OP	147.3.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					147.3.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-...	PS							

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Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
147. LV-1213/1233 is too far open due to mechanical failure, control system failure, or human error? (cont.)		147.3. carry glycol to pipeline (cont.)	147.3.1. Potential for gas to be out of specification. (cont.)		...site personnel.						:No additional recommendations identified by Team. (cont.)		
					147.3.3. Filter Separator MAK-1510 removes glycol before gas goes to pipeline	PS							
148. BV-2141/2341 closed due to mechanical failure, control system failure, or human error (power mode)?	HE HE	148.1. Loss of gas flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and to Compressor CAE-5010	148.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	148.1.1. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 139.1.1.		
					148.1.2. Standard procedure in similar operations is to require valves such as BV-2141/2341 to be verified in correct position for return to service after maintenance.	PR							
			148.1.2. Potential for Caterpillar engine damage	PD	148.1.3. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 139.1.1.		
					148.1.4. Standard procedure in similar operations is to require valves such as BV-2141/2341 to be verified in correct position for return to service after maintenance.	PR							
149. BV-2141/2341 closed due to mechanical failure, control system failure, or human error (free flow mode)?	HE HE	:Loss of gas flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230. No hazard identified. Not to be developed further											
150. BV-1218 is closed due to human error?	HE	150.1. Loss of condensate flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and carryover of glycol into gas stream.	150.1.1. Potential for gas to be out of specification.	OP	150.1.1. LT-12111/12311 shut down gas feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230,...	PS	4	4	5		:No additional recommendations identified by Team.		

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Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
150. BV-1218 is closed due to human error? (cont.)		150.1. Loss of condensate flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and carryover of glycol into gas stream. (cont.)	150.1.1. Potential for gas to be out of specification. (cont.)		...alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					150.1.2. LSHH1211 shut down gas feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 on high high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
151. LV-1214/1234 sticks open due to mechanical failure, control system failure, or human error?	EQ HE	151.1. Pressure in Condensate Tank ABJ-3130	151.1.1. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	151.1.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					151.1.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					151.1.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
			151.1.2. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	151.1.4. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					151.1.5. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					151.1.6. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
					151.1.7. Area electrical classification is Class I, Division 2	EN							
152. have gas flow to second tower (tower is on standby) due to mechanical failure, control system failure, or human error?	EQ HE	152.1. Wet gas	152.1.1. Potential for gas to be out of specification.	OP	152.1.1. Position indicator ZYC-1216/136 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					152.1.2. FIT1221 shuts off...	PS							

Worksheet

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Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-107 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
152. have gas flow to second tower (tower is on standby) due to mechanical failure, control system failure, or human error? (cont.)		152.1. Wet gas (cont.)	152.1.1. Potential for gas to be out of specification. (cont.)		...gas flow to pipe line and stops compressors on flow to second tower, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
153. have gas flow to second tower (tower is on shutdown) due to mechanical failure, control system failure, or human error	EQ HE	153.1. Wet gas	153.1.1. Potential for gas to be out of specification.	OP	153.1.1. Position indicator ZYC-1216/136 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					153.1.2. FIT1221 shuts off gas flow to pipe line and stops compressors on flow to second tower, alarms and calls out off-site personnel.	PS							
154. have gas flow to second tower (tower is on low pressure formation while this tower is on other formation) due to mechanical failure, control system failure, or human error?	EQ HE	154.1. Cross flow between two formations	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
		154.2. Carry glycol to Compressor CAE-5010	154.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	154.2.1. Suction Separators MBD-1030/1060 protects Compressor CAE-5010	PS	1	3	3	42	154.2.1. Consider providing safeguard based on valve position indicators for feed to Glycol Absorbers to prevent glycol carryover to compressors should two absorbers become interconnected while drawing from different formations.	ENE	HW SW
155. Bypass absorber tower during withdrawal mode due to mechanical failure, control system failure, or human error?	EQ HE	155.1. Wet gas	155.1.1. Potential for gas to be out of specification.	OP	155.1.1. Valve limit switches shut off gas flow to pipe line and stop compressors, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					155.1.2. Moisture analyzer shuts off gas flow to pipe line and stop compressors, alarms and calls out off-site personnel.	PS							

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System: (17) Fuel Gas System
Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-111 01 Rev D; CVGS1-M-111 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
156. BV-4011 and BV-0101closed due to operator error (free flow injection, heater is on or off)?	HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard. Not to be developed further.											
157. BV-4011 and BV-0101closed due to operator error (free flow withdrawal, heater is on or off)?	HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard. Not to be developed further.											
		157.1. Loss of fuel to dehydration system	157.1.1. Potential for gas to be out of specification.	OP	157.1.1. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	3	4	43	157.1.1. Consider developing with Nicor required actions to be taken to prevent producing out of specification gas or environmental issues if fuel is lost to the dehydration system.	ENE	AD
					157.1.2. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
					157.1.3. Summary alarms call out off-site personnel.	AD							
			157.1.2. Hydrocarbon emissions to atmosphere	EV	157.1.4. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	3	4		:Same As 157.1.1.		
					157.1.5. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
158. BV-4011 and BV-0101closed due to operator error (power injection, heater is on or off)?	HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard....											

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
158. BV-4011 and BV-0101closed due to operator error (power injection, heater is on or off)? (cont.)		...Not to be developed further.											
		158.1. Loss of fuel gas to compressor engines	:No consequences of interest identified by the Team. Not to be developed further.										
159. BV-4011 and BV-0101closed due to operator error (power withdrawal, heater is on or off)?	HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard. Not to be developed further.											
		159.1. Loss of fuel gas to compressor engines	:No consequences of interest identified by the Team. Not to be developed further.										
		159.2. Loss of fuel to dehydration system	159.2.1. Potential for gas to be out of specification.	OP	159.2.1. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	4	5		:No additional recommendations identified by Team.		
					159.2.2. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
					159.2.3. Summary alarms call out off-site personnel.	AD							
					159.2.4. Flow will stop because of loss of compressors	PS							
			159.2.2. Hydrocarbon emissions to atmosphere	EV	159.2.5. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	4	5		:No additional recommendations identified by Team.		
					159.2.6. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							

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Drawings: CVGS1-M-104 01 Rev D; CVGS1-M-111 01 Rev D; CVGS1-M-111 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
159. BV-4011 and BV-0101closed due to operator error (power withdrawal, heater is on or off)? (cont.)		159.2. Loss of fuel to dehydration system (cont.)	159.2.2. Hydrocarbon emissions to atmosphere (cont.)		159.2.7. Flow will stop because of loss of compressors	PS					:No additional recommendations identified by Team. (cont.)		
160. TCV-4011 fails to control temperature due to mechanical failure, control system failure, or human error (temperature high)?	EQ HE	160.1. 250ºF fuel gas	160.1.1. Potential to exceed pressure/ temperature rating of ANSI CL 600 flanges with flange rupture and release of gas and fire	EM PD	:No safeguards were identified		1	3	3	44	160.1.1. Consider specifying fuel gas burner management system to limit temperature to 200ºF or below.	ENE	AD
161. TCV-4011 fails to control temperature due to mechanical failure, control system failure, or human error (temperature low)?	EQ HE	161.1. Formation of hydrates in fuel system	:Potential to lose fuel gas and shutdown system. No consequences of interest identified by the Team. Not to be developed further.										
			161.1.1. Potential for valves to stick open and overpressure low pressure side of fuel gas system with release and fire	EM PD	:No safeguards were identified		1	3	3	45	161.1.1. Consider specifying fuel gas burner management system to require shutdown on low temperature of fuel gas.	ENE	AD
162. fuel gas heater is shut down due to mechanical failure, control system failure, or human error?	EQ HE	162.1. Low temperature of fuel gas	:Potential to lose fuel gas and shutdown system. No consequences of interest identified by the Team. Not to be developed further.										
			162.1.1. Potential for valves to stick open and overpressure low pressure side of fuel gas system with release and fire	EM PD	:No safeguards were identified		1	3	3		:Same As 161.1.1.		
163. gas regulator station fails to control pressure to setpoint due to mechanical failure, control system failure, or human error?	EQ HE	163.1. high pressure to downstream piping and equipment	163.1.1. Potential gas release and fire damage to equipment	EM PD	163.1.1. The existing pressure control design is industry standard and is deemed by ENE and CVGS to be intrinsically safe.	PS	1	4	5		:No additional recommendations identified by Team.		
164. there is no demand for fuel gas due to mechanical failure, control system failure, or human...	EQ HE	164.1. high pressure to downstream piping and equipment	164.1.1. Potential gas release and fire damage to equipment	EM PD	164.1.1. PSV-0101 relieves at 150 psig	MT	1	4	5		:No additional recommendations identified by Team.		

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...error?		164.1. high pressure to downstream piping and equipment (cont.)	164.1.1. Potential gas release and fire damage to equipment (cont.)		164.1.1. PSV-0101 relieves at 150 psig (cont.)						:No additional recommendations identified by Team. (cont.)		
165. fuel gas filter plugs due to equipment failure or human error?	EQ HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard. Not to be developed further.											
		165.1. Loss of fuel to dehydration system	165.1.1. Potential for gas to be out of specification.	OP	165.1.1. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	3	4		:Same As 157.1.1.		
					165.1.2. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
					165.1.3. Summary alarms call out off-site personnel.	AD							
			165.1.2. Hydrocarbon emissions to atmosphere	EV	165.1.4. PIT-0103 alarms and calls out off-site personnel on low pressure in fuel gas system	AD	3	3	4		:Same As 157.1.1.		
					165.1.5. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
		165.2. filter element ruptures	165.2.1. Dirt and filter parts into downstream equipment	PD	165.2.1. DP transmitter alarms and calls out off-site personnel on high DP across fuel gas filter	PS	4	4	5				
		165.3. Loss of fuel gas to compressor engines	:No consequences of interest identified by the Team. Not to be developed further.										
166. fuel gas line to...	HE	166.1. Loss of fuel to...	166.1.1. Potential for gas...	OP	166.1.1. PIT-0103 alarms...	AD	3	4	5		:No additional...		

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...dehydration system unit is closed due to human error?		...dehydration system	...to be out of specification.		...and calls out off-site personnel on low pressure in fuel gas system						...recommendations identified by Team.		
					166.1.2. Moisture analyzers alarm and call out off-site personnel on high moisture gas.	AD							
					166.1.3. Summary alarms call out off-site personnel.	AD							
					166.1.4. Flow will stop, alarms and calls out off-site personnel because of loss of compressors	PS							
167. fuel gas line to compressor engines is closed due to human error?	HE	167.1. Loss of fuel gas to compressor engines	:Potential to shutdown system. No consequences of interest identified by the Team. Not to be developed further.										
168. fuel gas line to standby generators is closed due to human error?	HE	:Loss of fuel to standby generators. This deviation does not present a specific hazard but does represent the potential loss of a safeguard. Not to be developed further.											
169. BDV-0021 blocks and vents when blowdown is not needed due to mechanical failure, control system failure, or human error?	EQ HE	169.1. Loss of fuel gas to compressor engines	:Potential to shutdown system. No consequences of interest identified by the Team. Not to be developed further.										
		169.2. Release of small amount of gas to atmosphere	:No consequences of interest identified by the Team. Not to be developed further.										
170. packaged equipment fuel gas systems review has not been accomplished to date?	HF	170.1. Various unidentified hazards	170.1.1. Various unidentified consequences	EM EV PD	:No safeguards were identified.		1	2	1	46	170.1.1. Consider reviewing the protections for the Generators, Fuel Gas Heater, and...	ENE	AD

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
170. packaged equipment fuel gas systems review has not been accomplished to date? (cont.)		170.1. Various unidentified hazards (cont.)	170.1.1. Various unidentified consequences (cont.)		:No safeguards were identified. (cont.)						...Regeneration Skids, Enerflex Main Engine/Compressor Units to ensure that they are sufficient.		

Session: (3) 9/17/2010
System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
171. MV-7081 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
172. MV-7081 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
173. WV-7081 is closed due to mechanical failure, control system failure, or human error?	EQ HE	173.1. No hazard											
174. WV-7081 is open?	NO	:Normal operating condition. Not to be developed further?											
175. WV-7082 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
176. WV-7082 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
177. CHA-7082 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
178. CHA-7082 is open due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
179. SSV-7081 is closed due to mechanical failure, control system failure, or human error?	EQ HE	:No hazard identified. Not to be developed further											
180. SSV-7081 is open?	NO	:Normal operating condition. Not to be developed further.											

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
181. SSV-7081 leaks by in an ESD mode due to wear in seat?	EQ	181.1. Continued supply of gas to system during an emergency shutdown.	181.1.1. Potential to be unable to stop fire with ongoing damage.	EM PD	181.1.1. Multiple systems alarm with operator call out and ability to close manual valves and stop flow.	MT	1	4	5		:No additional recommendations identified by Team.		
			181.1.2. Potential to be unable to stop flow to line break with ongoing release of gas	PD EV	181.1.2. Multiple systems alarm with operator call out and ability to close manual valves and stop flow.	MT	1	4	5		:No additional recommendations identified by Team.		
			181.1.3. Inability to blow system down when required.	OP	181.1.3. Multiple systems alarm with operator call out and ability to close manual valves and stop flow.	MT	3	4	5		:No additional recommendations identified by Team.		
182. Wellhead Separator MDB-1330 fills with sand due to operating conditions?	EQ	182.1. Erosion damage to separator and downstream equipment	182.1.1. Potential sand and water carryover to Filter Separator MAK-1510	PD	182.1.1. Wells are designed to minimize sand production 182.1.2. Operational procedures are to be used to maintain gas flow within design limits	EN PR	1	3	3	47	182.1.1. Consider providing cleanout port on Filter Separator MAK-1510 to permit removing built up sand, water, etc.	ENE	HW
		182.2. Drain line on Filter Separator MAK-1510 plugs with water carryover into system.	:No consequences of interest identified by the Team. Not to be developed further.										
183. sand damages internals of Wellhead Separator MDB-1330 equipment failure or external conditions?	EQ EX	183.1. Erosion damage to separator and downstream equipment	183.1.1. Potential sand and water carryover to Filter Separator MAK-1510	PD	183.1.1. Wells are designed to minimize sand production 183.1.2. Operational procedures are to be used to maintain gas flow within design limits	EN PR	1	3	3		:Same As 182.1.1.		
184. wall thickness of pressure containing equipment is eroded due to equipment failure or human error?	EQ HE	184.1. Loss of containment of gas	184.1.1. Major fire with property damage and injuries.	EM PD	184.1.1. Piping is designed to maintain flow rates below erosion velocities. 184.1.2. Vessels are inspected as required by operational need using established industry criteria.	EN AD	1	4	5		:No additional recommendations identified by Team.		
185. Wellhead Separator MDB-1330 fills with...	EQ	185.1. Water carry over to system	:No consequences of interest identified by the...										

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...water due to mechanical failure, control system failure, or human error?	HE	185.1. Water carry over to system (cont.)	...Team. Not to be developed further.										
186. Wellhead Separator MDB-1330 plugs with salt due to equipment failure or external conditions?	EQ EX	186.1. Water carry over to system	:No consequences of interest identified by the Team. Not to be developed further.										
187. Wellhead Separator MDB-1330 drain line fills with sand due to equipment failure or external conditions?	EQ EX	187.1. Water carry over to system	:No consequences of interest identified by the Team. Not to be developed further.										
188. Christmas tree is damaged and won't shut off due to mechanical failure, control system failure, or human error?	EQ HE	188.1. Loss of flow control	:No consequences of interest identified by the Team. Not to be developed further.										
189. Christmas tree is damaged and leaks externally due to impact from external equipment?	EX	189.1. Release of gas to atmosphere	189.1.1. Environmental issue	EV	189.1.1. Work over methods involving third parties exist to shut well off	MT	2	4	5		:No additional recommendations identified by Team.		
190. Christmas tree is ruptured due to impact from external equipment?	EX	190.1. Release of gas to atmosphere	190.1.1. Environmental issues	EV	190.1.1. Work over methods involving third parties exist to shut well off	MT	1	4	5		:No additional recommendations identified by Team.		
			190.1.2. Fire with damage to equipment	EM PD	190.1.2. Specialized fire fighting crew exist to put the fire out.	MT	1	4	5		:No additional recommendations identified by Team.		
					190.1.3. Work over methods involving third parties exist to shut well off	MT							
			190.1.3. Damage to adjacent well heads	PD	190.1.4. Specialized fire fighting crew exist to put the fire out.	MT	1	4	5		:No additional recommendations identified by Team.		
					190.1.5. Work over methods involving third parties exist to shut well off	MT							
191. there is an external...	EX	191.1. Fire	191.1.1. Damage to...	EM	191.1.1. Methanol pumps...	MT	1	4	5		:No additional...		

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Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...fire (methanol) in the area of the well head?		191.1. Fire (cont.)	...wellhead equipment with increased leaks and larger fire	EV PD	...can be turned off in the event of fire. 191.1.2. Manually tripped ESD system shuts down methanol pumps	 MT					...recommendations identified by Team.		
192. there is an external fire (other than methanol) in the area of the well head?	EX	192.1. Fire	192.1.1. Damage to wellhead equipment with increased leaks and larger fire	EM EV PD	192.1.1. Design precludes flammables other than methanol from vicinity of the vessel	EN	1	4	5		:No additional recommendations identified by Team.		
193. CHA-7081 is closed due to mechanical failure, control system failure, or human error?	EQ EX	193.1. Loss of gas flow	:No consequences of interest identified by the Team. Not to be developed further.										
194. BV-1331 is closed due to mechanical failure, control system failure, or human error?	EQ EX	194.1. Loss of gas flow	:No consequences of interest identified by the Team. Not to be developed further.										
195. flow meter doesn't work due to equipment failure or human error?	EQ HE	195.1. Unable to track inventory	:No consequences of interest identified by the Team. Not to be developed further.										
196. Wellhead Separator MDB-1330 is isolated due to human error?	HE	196.1. Thermal expansion in Wellhead Separator MDB-1330	196.1.1. Potential for pressure buildup and Wellhead Separator MDB-1330 leak with release of gas	EV	196.1.1. Thermal PSV-1331 relieves at 1540 psig	PS	3	4	5		:No additional recommendations identified by Team.		
197. Wellhead Separator MDB-1330 is isolated due to human error and external fire occurs?	HE EX	197.1. Thermal expansion in Wellhead Separator MDB-1330	197.1.1. Potential for pressure buildup and vessel rupture with release of gas and fire	EM PD	197.1.1. Methanol pumps can be turned off in the event of fire. 197.1.2. Manually tripped ESD system shuts down methanol pumps 197.1.3. Design precludes flammables other than methanol from vicinity of the vessel	MT MT EN	1	4	5		:No additional recommendations identified by Team.		

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Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
198. LV-1331 doesn't open due to mechanical failure, control system failure, or human error?	EQ HE	:Same As 185.1. Not to be developed further.											
199. LV-1331 sticks open due to equipment failure?	EQ	199.1. Gas blows into Produced Water Tank	199.1.1. Potential to rupture Produced Water Tank with fire.	EM PD	199.1.1. LSV-1332 provides redundant low level shut off, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					199.1.2. RO-1331 limits flow of gas to Produced Water Tank	EN							
					199.1.3. Produced Water Tank is open vented with flame arrestor	EN							
					199.1.4. PSE-3201 opens at less than 3 psig to protect Produced Water Tank	MT							
			199.1.2. Potential to rupture Produced Water Tank with environmental event	EV	199.1.5. LSV-1332 provides redundant low level shut off, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					199.1.6. RO-1331 limits flow to Produced Water Tank	EN							
					199.1.7. Produced Water Tank is open vented with flame arrestor	EN							
					199.1.8. PSE-3201 opens at less than 3 psig to protect Produced Water Tank	MT							
200. LSV-1332 doesn't open due to mechanical failure, control system failure, or human error?	EQ HE	:Same As 185.1. Not to be developed further.											
201. LSV1332 sticks open due to equipment failure?	EQ	201.1. Gas blows into Produced Water Tank	201.1.1. Potential to rupture Produced Water Tank with fire.	EM PD	201.1.1. LSV-1331 provides redundant low level shut off, alarms and calls out off-...	PS	1	4	5		:No additional recommendations identified by Team.		

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WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
201. LSV1332 sticks open due to equipment failure? (cont.)		201.1. Gas blows into Produced Water Tank (cont.)	201.1.1. Potential to rupture Produced Water Tank with fire. (cont.)		...site personnel.						:No additional recommendations identified by Team. (cont.)		
					201.1.2. RO-1331 limits flow to Produced Water Tank	EN							
					201.1.3. Produced Water Tank is open vented with flame arrestor	EN							
					201.1.4. PSE-3201 opens at less than 3 psig to protect Produced Water Tank	MT							
			201.1.2. Potential to rupture Produced Water Tank with environmental event	EV	201.1.5. LSV-1331 provides redundant low level shut off, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					201.1.6. RO-1331 limits flow to Produced Water Tank	EN							
					201.1.7. Produced Water Tank is open vented with flame arrestor	EN							
					201.1.8. PSE-3201 opens at less than 3 psig to protect Produced Water Tank	MT							
202. form hydrates at well head due to mechanical failure, control system failure, or human error?	EQ HE	202.1. Block flow from well head.	:No consequences of interest identified by the Team. Not to be developed further.										
203. form hydrates at well head and hydrates subsequently break loose due to mechanical failure, control system failure, or human error?	EQ HE	203.1. Break piping	203.1.1. Potential to release gas with fire.	EM PD	203.1.1. Operational experience provides means for reducing and/or recognizing and removing hydrates	AD	2	4	5	48	203.1.1. Consider providing shutdown at well head in the event of loss of flow.	ENE	HW
					203.1.2. Methanol injection system provides means for preventing and removing hydrates	EN							

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (1) Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
204. wellhead flow valves are partially closed due to mechanical failure, control system failure, or human error?	EQ HE	:Same As 202.1. Not to be developed further. 204.1. Increased potential for valve erosion	204.1.1. Unable to shut off gas at well head with potential fire and explosion	EM PD	:No safeguards were identified		1	3	3	49	204.1.1. Consider establishing operating procedures to ensure that wellhead flow valves are operated fully open or fully closed to prevent premature failure.	CVGS	PR

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Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (2) Upper Sand Wellhead QAX-7040 and Upper Sand Wellhead Separator MBD-1290

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7040 and Upper Sand Wellhead Separator MBD-1290 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (3) Upper Sand Wellhead QAX-7020 and Upper Sand Wellhead Separator MBD-1270

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7020 and Upper Sand Wellhead Separator MBD-1270 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be...													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (3) Upper Sand Wellhead QAX-7020 and Upper Sand Wellhead Separator MBD-1270

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (4) Upper Sand Wellhead QAX-7010 and Upper Sand Wellhead Separator MBD-1260

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7010 and Upper Sand Wellhead Separator MBD-1260 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (5) Upper Sand Wellhead QAX-7030 and Upper Sand Wellhead Separator MBD-1280

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7030 and Upper Sand Wellhead Separator MBD-1280 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (6) Upper Sand Wellhead QAX-7050 and Upper Sand Wellhead Separator MBD-1300

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7050 and Upper...													

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Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (6) Upper Sand Wellhead QAX-7050 and Upper Sand Wellhead Separator MBD-1300

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...Sand Wellhead Separator MBD-1300 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (7) Upper Sand Wellhead QAX-7060 and Upper Sand Wellhead Separator MBD-1310

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7060 and Upper Sand Wellhead Separator MBD-1310 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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System: (18) Wellheads and Wellhead Separators - withdrawal mode
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C
Subsystem: (8) Upper Sand Wellhead QAX-7070 and Upper Sand Wellhead Separator MBD-1320

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Upper Sand Wellhead QAX-7070 and Upper Sand Wellhead Separator MBD-1320 present the same or lesser consequence scenarios as the Lower Sand Wellhead QAX-7080 and Lower Sand Wellhead Separator MBD-1330. Not to be developed further.													

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Session: (3) 9/17/2010
System: (19) High pressure gas in injection mode
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D; CVGS1-M-105 01 Rev D; CVGS1-M-105 02 Rev D; CVGS1-M-106 01 Rev D; CVGS1-M-106 02 Rev D; CVGS1-M-107 01 Rev D; CVGS1-M-107 02 Rev D; CVGS1-M-108 01 Rev C; CVGS1-M-108 02 Rev D; CVGS1-M-109 01 Rev D; CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-110 01 Rev D; CVGS1-M-111 01 Rev D; CVGS1-M-111 02 Rev D; CVGS1-M-112 01 Rev C; CVGS1-M-112 02 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
205. sand or other foreign material is carried into well head due to external conditions?	EX	205.1. Well plugging	:No consequences of interest identified by the Team. Not to be developed further.										
206. glycol or compressor oil is carried into the well head due to external conditions? :Team discussed injection mode of operation and determined that with the exception of the above questions, the hazards involved with injection are the same or less severe than the withdrawal mode of operation. Not to be developed further.	EX	206.1. Loss of productivity	:No consequences of interest identified by the Team. Not to be developed further.										

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System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
207. BV-1471 is open due to mechanical failure, control system failure, or human error?	EQ HE	207.1. Gas into sphere launcher	:No consequences of interest identified by the Team. Not to be developed further.										
208. BV-1472 is open due to mechanical failure, control system failure, or human error?	EQ HE	208.1. Cross connect two different well lines	:No consequences of interest identified by the Team. Not to be developed further.										
209. BV-1474 is open due to mechanical failure, control system failure, or human error?	EQ HE	209.1. Gas to vent into Produced Water Tank	:These deviations were analyzed in System 18, Wellheads and Wellhead Separators - withdrawal mode. Not to be developed further.										
210. BV-1485 is open due to mechanical failure, control system failure, or human error?	EQ HE	210.1. Cross connect two different well lines	:No consequences of interest identified by the Team. Not to be developed further.										
211. BV-132X (redline addition to drawing 109-3) is open due to mechanical failure, control system failure, or human error?	EQ HE	211.1. Cross connect two different well lines	:No consequences of interest identified by the Team. Not to be developed further.										
212. BV-1241 is closed due to mechanical failure, control system failure, or human error?	EQ HE	212.1. Block flow of gas to station	:No consequences of interest identified by the Team. Not to be developed further.										
213. BV-1242 is open due to mechanical failure, control system failure, or human error?	EQ HE	213.1. Bypass Filter Separator MAK-1240 on withdrawal and get sand and water into header	213.1.1. Potential to damage downstream equipment.	PD	213.1.1. Position indicator ZYC-1242 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					213.1.2. LSHH-1212 shuts system down on high high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS							
					213.1.3. LSHH-1212 shuts system down on high high level in Glycol Absorber...	PS							

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Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
213. BV-1242 is open due to mechanical failure, control system failure, or human error? (cont.)		213.1. Bypass Filter Separator MAK-1240 on withdrawal and get sand and water into header (cont.)	213.1.1. Potential to damage downstream equipment. (cont.)		...system, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
214. BV-1243 is closed due to mechanical failure, control system failure, or human error?	EQ HE	214.1. Block flow of gas to station	:No consequences of interest identified by the Team. Not to be developed further.										
215. BV-0022 is open due to mechanical failure, control system failure, or human error?	EQ HE	215.1. Cross connect formations	215.1.1. Inventory management issues.	OP	:No safeguards were identified.					50	215.1.1. Consider need for a 2" equalizer across BV-0022 to prevent inventor management issues.	ENE	HW
216. BV-1244/45 is open due to mechanical failure, control system failure, or human error?	EQ HE	216.1. Gas blows into Produced Water Tank	216.1.1. Potential to rupture Produced Water Tank with fire.	EM PD	216.1.1. RO1241/42 limit flow of gas to Produced Water Tank	PS	1	4	5		:No additional recommendations identified by Team.		
					216.1.2. Produced Water Tank is open vented with flame arrestor	EN							
					216.1.3. PSE-3201 opens at less than 3 psig to protect Produced Water Tank	MT							
217. BV-1249/48 is closed due to mechanical failure, control system failure, or human error?	EQ HE	217.1. Build up liquid in Filter Separator MAK-1240	217.1.1. Increased potential for failure of filter elements. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	217.1.1. LSHH1241/42 shut system down on high high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					217.1.2. LIT1241/42 shuts system down on high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS							
218. BV-0031 is closed due to mechanical failure, control system failure, or human error?	EQ HE	218.1. Block flow of gas to station	:No consequences of interest identified by the Team. Not to be developed further.										
219. BV-0031 doesn't close when required due...	EQ	219.1. Unable to isolate pipeline during an ESD	219.1.1. Potential to be unable to stop gas...	EM	219.1.1. Design of ESD system provides...	EN	1	4	5		:No additional recommendations...		

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System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...to mechanical failure, control system failure, or human error?	HE	219.1. Unable to isolate pipeline during an ESD (cont.)	...release if well pad rupture or fire occurs	PD	...redundant means of isolation						...identified by Team.		
					219.1.2. Design of valve actuator minimizes potential failure	EN							
					219.1.3. Valve is required to be tested annually	AD							
		219.2. Unable to isolate well pad during line break	219.2.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	219.2.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					219.2.2. Design of valve actuator minimizes potential failure	EN							
					219.2.3. Valve is required to be tested annually	AD							
220. LV-1243/46 doesn't open when required due to mechanical failure, control system failure, or human error?	EQ HE	220.1. Unable to isolate pipeline during an ESD	220.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	220.1.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					220.1.2. Design of valve actuator minimizes potential failure	EN							
					220.1.3. Valve is required to be tested annually	AD							
		220.2. Unable to isolate well pad during line break	220.2.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	220.2.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					220.2.2. Design of valve actuator minimizes potential failure	EN							
					220.2.3. Valve is required to be tested annually	AD							
221. LV-1243/46 sticks open due to mechanical failure, control system failure, or human error?	EQ HE	221.1. Unable to isolate pipeline during an ESD	221.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	221.1.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					221.1.2. Design of valve...	EN							

Worksheet

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System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
221. LV-1243/46 sticks open due to mechanical failure, control system failure, or human error? (cont.)		221.1. Unable to isolate pipeline during an ESD (cont.)	221.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs (cont.)		...actuator minimizes potential failure						:No additional recommendations identified by Team. (cont.)		
					221.1.3. Valve is required to be tested annually	AD							
		221.2. Unable to isolate well pad during line break	221.2.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	221.2.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					221.2.2. Design of valve actuator minimizes potential failure	EN							
					221.2.3. Valve is required to be tested annually	AD							
222. LSV-1244/45 doesn't open when required due to mechanical failure, control system failure, or human error?	EQ HE	222.1. Unable to isolate pipeline during an ESD	222.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	222.1.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					222.1.2. Design of valve actuator minimizes potential failure	EN							
					222.1.3. Valve is required to be tested annually	AD							
		222.2. Unable to isolate well pad during line break	222.2.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	222.2.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					222.2.2. Design of valve actuator minimizes potential failure	EN							
					222.2.3. Valve is required to be tested annually	AD							
223. LSV-1244/45 sticks open due to equipment failure?	EQ	223.1. Unable to isolate pipeline during an ESD	223.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	223.1.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					223.1.2. Design of valve actuator minimizes potential failure	EN							
					223.1.3. Valve is required...	AD							

Session: (3) 9/17/2010
System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
223. LSV-1244/45 sticks open due to equipment failure? (cont.)		223.1. Unable to isolate pipeline during an ESD (cont.)	223.1.1. Potential to be unable to stop gas release if well pad rupture or fire occurs (cont.)		...to be tested annually						:No additional recommendations identified by Team. (cont.)		
		223.2. Unable to isolate well pad during line break	223.2.1. Potential to be unable to stop gas release if well pad rupture or fire occurs	EM PD	223.2.1. Design of ESD system provides redundant means of isolation	EN	1	4	5		:No additional recommendations identified by Team.		
					223.2.2. Design of valve actuator minimizes potential failure	EN							
					223.2.3. Valve is required to be tested annually	AD							
224. LV-1341 sticks open due to equipment failure?	EQ	224.1. Gas blows into Produced Water Tank	224.1.1. Potential to rupture Produced Water Tank with fire.	EM PD	224.1.1. LSV-1342 provides redundant shut off for high level in Wellhead Separator MDB-1340, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					224.1.2. RO-1341 limits flow to Produced Water Tank	EN							
					224.1.3. Produced Water Tank is open vented with flame arrestor	EN							
					224.1.4. PSE-3201 opens at less than 3 psig to protect tank	MT							
					224.1.5. Position indicator ZYC-1341 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			224.1.2. Potential to rupture Produced Water Tank with environmental event	EV	224.1.6. LSV-1342 provides redundant shut off for high level in Wellhead Separator MDB-1340, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					224.1.7. RO-1341 limits flow to Produced Water...	EN							

Session: (3) 9/17/2010
System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
224. LV-1341 sticks open due to equipment failure? (cont.)		224.1. Gas blows into Produced Water Tank (cont.)	224.1.2. Potential to rupture Produced Water Tank with environmental event (cont.)		...Tank						:No additional recommendations identified by Team. (cont.)		
					224.1.8. Produced Water Tank is open vented with flame arrestor	EN							
					224.1.9. PSE-3201 opens at less than 3 psig to protect tank	MT							
					224.1.10. Position indicator ZYC-1341 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
225. LSV-1332 doesn't open due to mechanical failure, control system failure, or human error?	EQ HE	225.1. Fill Filter Separator MAK-1240 with water	225.1.1. Increased potential for failure of filter elements. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	225.1.1. LSHH1241/42 shut system down on high high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					225.1.2. LIT1241/42 shuts system down on high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS							
226. LSV-1342 sticks due to equipment failure?	EQ HE	226.1. Gas blows into Produced Water Tank	226.1.1. Potential to rupture Produced Water Tank with fire.	EM PD	226.1.1. LSV-1341 provides redundant shut off for high level in Wellhead Separator MDB-1340, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					226.1.2. RO-1341 limits flow to Produced Water Tank	PS							
					226.1.3. Produced Water Tank is open vented with flame arrestor	EN							
					226.1.4. PSE-3201 opens at less than 3 psig to protect tank	MT							
					226.1.5. Position indicator ZYC-1342 shuts system...	PS							

Session: (3) 9/17/2010
System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
226. LSV-1342 sticks due to equipment failure? (cont.)		226.1. Gas blows into Produced Water Tank (cont.)	226.1.1. Potential to rupture Produced Water Tank with fire. (cont.)		...down on incorrect valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
			226.1.2. Potential to rupture Produced Water Tank with environmental event	EV	226.1.6. LSV-1341 provides redundant shut off for high level in Wellhead Separator MDB-1340, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					226.1.7. RO-1341 limits flow to Produced Water Tank	PS							
					226.1.8. Produced Water Tank is open vented with flame arrestor	EN							
					226.1.9. PSE-3201 opens at less than 3 psig to protect tank	MT							
					226.1.10. Position indicator ZYC-1342 shuts system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
227. too much sand gets into Filter Separator MAK-1240 due to equipment failure or external conditions?	EX EQ	227.1. Drain lines plug with increased potential to fill Filter Separator MAK-1240 with water	227.1.1. Increased potential for failure of filter elements. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	227.1.1. LSHH1241/42 shut system down on high high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					227.1.2. LIT1241/42 shuts system down on high level in Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS							
228. filter cartridges rupture due to high differential pressure?	EQ	228.1. Bypass Filter Separator MAK-1240	228.1.1. Carry over of produced water and filter material. Pipeline maintenance issue.	PD	228.1.1. PDIT-1241 shuts down on high DP across Filter Separator MAK-1240, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
229. filter cartridges...	EQ	229.1. Bypass Filter...	229.1.1. Carry over of...	PD	229.1.1. PDIT-1241 shuts...	PS	3	4	5		:No additional...		

Session: (3) 9/17/2010
System: (20) Upper Sands Header System including Pig Launchers - withdrawal mode
Drawings: CVGS1-M-108 01 Rev C; CVGS1-M-109 04 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...collapse due to high differential pressure?		...Separator MAK-1240	...produced water and filter material. Pipeline maintenance issue. :Send free water to Glycol Absorption system with loss of efficiency. No consequences of interest identified by the Team. Not to be developed further.		...down on high DP across Filter Separator MAK-1240, alarms and calls out off-site personnel.						...recommendations identified by Team.		
230. external fire occurs at Filter Separator MAK-1240?	EX	230.1. Overpressure Filter Separator MAK-1240	230.1.1. Potential rupture of Filter Separator MAK-1240 with gas and liquid release and fire	EM PD	230.1.1. Design precludes flammables from vicinity of the Filter Separator MAK-1240	EN	1	4	5		:No additional recommendations identified by Team.		
231. Filter Separator MAK-1240 is shut-in due to mechanical failure, control system failure, or human error?	EQ HE	231.1. Overpressure Filter Separator MAK-1240 due to temperature increase	231.1.1. Potential damage to Filter Separator MAK-1240	PD	231.1.1. PSV-1241 opens at 1540 psig	MT	2	4	5		:Same As 118.1.1.		
		231.2. Underpressure Filter Separator MAK-1240 due to temperature due to temperature decrease	:Filter Separator MAK-1240 is rated for full vacuum. Not to be developed further.										

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (21) Lower Sands Header System including Pig Launchers - withdrawal mode
Drawings:

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Lower Sands Header System including Pig Launchers - withdrawal mode presents the same or lesser consequence scenarios as the Upper Sands Header System including Pig Launchers - withdrawal mode. Not to be developed further.													

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (22) Upper Sands Header System including Pig Launchers - injection mode
Drawings:

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
232. Filter Separator MAK-1240 is not bypassed during injection mode due to mechanical failure, control system failure, or human error? :Team has determined that, with the exception of the above question, the Upper Sands Header System including Pig Launchers - injection mode presents the same or lesser consequence scenarios as the Upper Sands Header System including Pig Launchers - withdrawal mode. Not to be developed further.	EQ HE	232.1. Damage to filter cartridges	:Transfer debris toward wells. Operational issue only. Not to be developed further.										

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (23) Lower Sands Header System including Pig Launchers - injection mode
Drawings:

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
:Team has determined that the Lower Sands Header System including Pig Launchers - injection mode presents the same or lesser consequence scenarios as the Upper Sands Header System including Pig Launchers - injection mode.													

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
233. BV-0041 is open due to mechanical failure, control system failure, or human error?	EQ HE	233.1. Bypass compressors	:No consequences of interest identified by the Team. Not to be developed further.										
234. BV-0042 is closed due to mechanical failure, control system failure, or human error?	EQ HE	234.1. High discharge pressure on Compressor CAE-5010	234.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	234.1.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					234.1.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.1.3. PSV-50110 opens at 1525 psig	MT							
					234.1.4. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			234.1.2. Potential for Caterpillar engine damage	PD	234.1.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					234.1.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.1.7. PSV-50110 opens at 1525 psig	MT							
					234.1.8. Position indicator ZYC-5013/5014 shut system down on incorrect...	PS							

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
234. BV-0042 is closed due to mechanical failure, control system failure, or human error? (cont.)		234.1. High discharge pressure on Compressor CAE-5010 (cont.)	234.1.2. Potential for Caterpillar engine damage (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
		234.2. Overpressure piping and vessels	234.2.1. Leaks from pipes and vessels with environmental consequences	EV	234.2.1. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					234.2.2. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.2.3. PSV-50110 opens at 1525 psig	MT							
					234.2.4. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			234.2.2. Leaks from pipes and vessels with fire (in building)	EM PD	234.2.5. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					234.2.6. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.2.7. PSV-50110 opens at 1525 psig	MT							
					234.2.8. Position indicator ZYC-5013/5014 shut system down on incorrect...	PS							

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
234. BV-0042 is closed due to mechanical failure, control system failure, or human error? (cont.)		234.2. Overpressure piping and vessels (cont.)	234.2.2. Leaks from pipes and vessels with fire (in building) (cont.)		...valve position, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					234.2.9. Gas detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
					234.2.10. Flame detection in building alerts personnel, alarms and calls out off-site personnel.	DT							
			234.2.3. Leaks from pipes and vessels with fire (not in building)	EM PD	234.2.11. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	2	4	5		:No additional recommendations identified by Team.		
					234.2.12. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.2.13. PSV-50110 opens at 1525 psig	MT							
					234.2.14. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			234.2.4. Potential rupture and release from pipes and vessels with environmental consequences	EV	234.2.15. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	3	4	5		:No additional recommendations identified by Team.		
					234.2.16. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site...	PS							

Worksheet

Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
234. BV-0042 is closed due to mechanical failure, control system failure, or human error? (cont.)		234.2. Overpressure piping and vessels (cont.)	234.2.4. Potential rupture and release from pipes and vessels with environmental consequences (cont.)		...personnel.						:No additional recommendations identified by Team. (cont.)		
					234.2.17. PSV-50110 opens at 1525 psig	MT							
					234.2.18. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
			234.2.5. Potential rupture from pipes and vessels with fire in building	EM PD	234.2.19. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					234.2.20. PSH-5019 shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS							
					234.2.21. PSV-50110 opens at 1525 psig	MT							
					234.2.22. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
					234.2.23. Building electrical classification is Class I, Division 2, maintained by ventilation.	EN							
			234.2.6. Potential rupture from pipes and vessels with fire not in building	EM PD	234.2.24. High discharge pressure (unnumbered transmitter on compressor skid) shuts system down on high discharge pressure, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					234.2.25. PSH-5019 shuts...	PS							

Worksheet

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
234. BV-0042 is closed due to mechanical failure, control system failure, or human error? (cont.)		234.2. Overpressure piping and vessels (cont.)	234.2.6. Potential rupture from pipes and vessels with fire not in building (cont.)		...system down on high discharge pressure, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					234.2.26. PSV-50110 opens at 1525 psig	MT							
					234.2.27. Position indicator ZYC-5013/5014 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS							
235. BV-0043 is closed due to mechanical failure, control system failure, or human error?	EQ HE	235.1. Loss of feed to Compressor CAE-5010	235.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	235.1.1. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					235.1.2. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
			235.1.2. Potential for Caterpillar engine damage	PD	235.1.3. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					235.1.4. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
236. BV-0044 is open due to mechanical failure, control system failure, or human error? :Team has determined that, with the exception of the above questions,...	EQ HE	236.1. Bypass compressors	:No consequences of interest identified by the Team. Not to be developed further.										

Session: (3) 9/17/2010
System: (24) High pressure gas discharge across compressor units through metering station and Filter Separator to line (injection mode from Line A to East meter run)
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C; CVGS1-M-101 01 Rev D; CVGS1-M-102 01 Rev C; CVGS1-M-103 01 Rev D; CVGS1-M-104 01 Rev D; CVGS1-M-104 02 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...injection mode presents the same or lesser consequence scenarios as the withdrawal mode. Not to be developed further.													

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
237. BV-1211/1231 closed due to mechanical failure, control system failure, or human error (power mode)?	EQ HE	237.1. Loss of feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and Compressor CAE-5010	237.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	237.1.1. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					237.1.2. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
			237.1.2. Potential for Caterpillar engine damage	PD	237.1.3. Position indicator ZYC-5011/5012 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					237.1.4. PDIT-5011/5012 shut system down on high DP across BV-5011/5012 or low suction pressure, alarms and calls out off-site personnel.	PS							
			237.1.3. Potential to pull vacuum on Glycol Absorber Line B MAF-1210/Line A MAF-1230 and damage tower	PD	:No safeguards were identified.		1	2	1		:Same As 142.1.1.		
238. BV-1211/1231 closed due to mechanical failure, control system failure, or human error (free flow mode)	EQ HE	:No hazard identified. Not to be developed further											
239. BV-1214/1234 closed due to mechanical failure, control system failure, or human error?	EQ HE	239.1. Loss of lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and fail to dehydrate gas	239.1.1. Potential for gas to be out of specification.	OP	239.1.1. FT-4031 (drawing 105-2) shuts off gas flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 in the event of low flow of glycol, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					239.1.2. SY-4021/22 shuts off gas flow to Glycol...	PS							

Worksheet

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
239. BV-1214/1234 closed due to mechanical failure, control system failure, or human error? (cont.)		239.1. Loss of lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 and fail to dehydrate gas (cont.)	239.1.1. Potential for gas to be out of specification. (cont.)		...Absorber Line B MAF-1210/Line A MAF-1230 if at least one glycol pump is not running, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					239.1.3. AE0071/0061 stop gas flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 in the event of high moisture in gas, alarms and calls out off-site personnel. (drawing 104-1)	PS							
240. have too much lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 due to mechanical failure, control system failure, or human error?	EQ HE	240.1. Back up glycol in Glycol Absorber Line B MAF-1210/Line A MAF-1230	240.1.1. Potential for gas to be out of specification.	OP	240.1.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:Same As 145.1.1.		
					240.1.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
		240.2. Carry glycol to Compressor CAE-5010	240.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	240.2.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					240.2.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					240.2.3. Suction Separators MBD-1030/1060 protects...	PS							

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
240. have too much lean glycol flow to Glycol Absorber Line B MAF-1210/Line A MAF-1230 due to mechanical failure, control system failure, or human error? (cont.)		240.2. Carry glycol to Compressor CAE-5010 (cont.)	240.2.1. Potential for mechanical damage to Compressor CAE-5010 (cont.)		...Compressor CAE-5010						:No additional recommendations identified by Team. (cont.)		
		240.3. Carry glycol to pipeline	240.3.1. Potential for gas to be out of specification.	OP	240.3.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					240.3.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					240.3.3. Filter Separator MAK-1510 removes glycol before gas goes to pipeline	PS							
241. LV-1213/11233 closed due to mechanical failure, control system failure, or human error?	EQ HE	241.1. Loss of flow of rich glycol from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and back up glycol in Glycol Absorber Line B MAF-1210/Line A MAF-1230	241.1.1. Potential for gas to be out of specification.	OP	241.1.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:Same As 145.1.1.		
					241.1.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
242. LV-1213/1233 is too far due to mechanical failure, control system failure, or human error?	EQ HE	242.1. Excess glycol return from Glycol Absorber Line B MAF-1210/Line A MAF-1230 with gas at regenerator skid	242.1.1. Potential to overpressure regenerator skid with release of gas to atmosphere and fire	PD EM	242.1.1. LT1211/1231 shut down glycol feed pumps on low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
242. LV-1213/1233 is too far due to mechanical failure, control system failure, or human error? (cont.)		242.1. Excess glycol return from Glycol Absorber Line B MAF-1210/Line A MAF-1230 with gas at regenerator skid (cont.)	242.1.1. Potential to overpressure regenerator skid with release of gas to atmosphere and fire (cont.)		242.1.2. LSLL1211/1231 shut down glycol feed pumps on low low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS					:No additional recommendations identified by Team. (cont.)		
					242.1.3. Regenerator skid pressure switch closes BV-4029 in the event of high pressure at the Regenerator skid, alarms and calls out off-site personnel.	PS							
		242.2. carry glycol to Compressor CAE-5010	242.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	242.2.1. LT1211/1231 shut down glycol feed pumps on low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	1	4	5		:No additional recommendations identified by Team.		
					242.2.2. LSLL1211/1231 shut down glycol feed pumps on low low level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
					242.2.3. Suction Separators MBD-1030/1060 protects Compressor CAE-5010	PS							
		242.3. carry glycol to pipeline	242.3.1. Potential for gas to be out of specification.	OP	242.3.1. LT-12111/12311 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					242.3.2. LSHH1211 shut down glycol feed pumps on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-...	PS							

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
242. LV-1213/1233 is too far due to mechanical failure, control system failure, or human error? (cont.)		242.3. carry glycol to pipeline (cont.)	242.3.1. Potential for gas to be out of specification. (cont.)		...site personnel.						:No additional recommendations identified by Team. (cont.)		
					242.3.3. Filter Separator MAK-1510 removes glycol before gas goes to pipeline	PS							
243. BV-2141/2341 closed due to mechanical failure, control system failure, or human error (power mode)?	HE HE	243.1. Loss of gas flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and to Compressor CAE-5010	243.1.1. Potential for mechanical damage to Compressor CAE-5010	PD	243.1.1. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 139.1.1.		
					243.1.2. Standard procedure in similar operations is to require valves such as BV-2141/2341 to be verified in correct position for return to service after maintenance.	PR							
			243.1.2. Potential for Caterpillar engine damage	PD	243.1.3. PDIT-5011/5012 shut system down on low suction pressure, alarms and calls out off-site personnel.	PS	1	3	3		:Same As 139.1.1.		
					243.1.4. Standard procedure in similar operations is to require valves such as BV-2141/2341 to be verified in correct position for return to service after maintenance.	PR							
244. BV-2141/2341 closed due to mechanical failure, control system failure, or human error (free flow mode)?	HE HE	:Loss of gas flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230. No hazard identified. Not to be developed further											
245. BV-1218 is closed due to human error?	HE	245.1. Loss of condensate flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and carryover of glycol into gas stream.	245.1.1. Potential for gas to be out of specification.	OP	245.1.1. LT-12111/12311 shut down gas feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 on high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230,...	PS	4	4	5		:No additional recommendations identified by Team.		

Worksheet

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
245. BV-1218 is closed due to human error? (cont.)		245.1. Loss of condensate flow from Glycol Absorber Line B MAF-1210/Line A MAF-1230 and carryover of glycol into gas stream. (cont.)	245.1.1. Potential for gas to be out of specification. (cont.)		...alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
					245.1.2. LSHH1211 shut down gas feed to Glycol Absorber Line B MAF-1210/Line A MAF-1230 on high high level in Glycol Absorber Line B MAF-1210/Line A MAF-1230, alarms and calls out off-site personnel.	PS							
246. LV-1214/1234 sticks open due to equipment failure?	EQ	246.1. Pressure in Condensate Tank ABJ-3130	246.1.1. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with environmental consequences	EV	246.1.1. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
										51	246.1.1. Consider reviewing failure modes of LV-1214/1234 to ensure sufficient protection against potential failures.	ENE	AU
					246.1.2. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					246.1.3. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
			246.1.2. Potential to rupture Condensate Tank ABJ-3130 with release of gas and hydrocarbon liquids to atmosphere with fire	EM PD	246.1.4. PSE-3121 on Condensate Tank ABJ-3130 opens at 6-12 in w.c.	PS	1	4	5		:Same As 128.2.1.		
					246.1.5. Conservent PSV-3131 on Condensate Tank ABJ-3130 opens at 2 osig	PS							
					246.1.6. RO-3131 restricts flow to Condensate Tank ABJ-3130	PS							
					246.1.7. Area electrical classification is Class I, Division 2	EN							
247. have gas flow to second tower (tower is on standby) due to mechanical failure, control system failure, or human error?	EQ HE	247.1. Wet gas	247.1.1. Potential for gas to be out of specification.	OP	247.1.1. Position indicator ZYC-1216/136 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					247.1.2. FIT1221 shuts off...	PS							

Session: (3) 9/17/2010
System: (25) Glycol Absorber Line B MAF-1210 and Glycol Absorber Line A MAF-1230 (towers isolated from each other, injection mode) (Backup Glycol Absorber MAF-1220 considered implicitly)
Drawings: CVGS1-M-105 01 Rev D; CVGS1-M-106 01 Rev D

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
247. have gas flow to second tower (tower is on standby) due to mechanical failure, control system failure, or human error? (cont.)		247.1. Wet gas (cont.)	247.1.1. Potential for gas to be out of specification. (cont.)		...gas flow to pipe line and stops compressors on flow to second tower, alarms and calls out off-site personnel.						:No additional recommendations identified by Team. (cont.)		
248. have gas flow to second tower (tower is on shutdown) due to mechanical failure, control system failure, or human error?	EQ HE	248.1. wet gas	248.1.1. Potential for gas to be out of specification.	OP	248.1.1. Position indicator ZYC-1216/136 shut system down on incorrect valve position, alarms and calls out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					248.1.2. FIT1221 shuts off gas flow to pipe line and stops compressors on flow to second tower, alarms and calls out off-site personnel.	PS							
249. have gas flow to second tower (tower is on low pressure formation while this tower is on other formation) due to mechanical failure, control system failure, or human error?	EQ HE	249.1. Cross flow between two formations	:Inventory and pressure management issues. No consequences of interest identified by the Team. Not to be developed further.										
		249.2. Carry glycol to Compressor CAE-5010	249.2.1. Potential for mechanical damage to Compressor CAE-5010	PD	249.2.1. Suction Separators MBD-1030/1060 protects Compressor CAE-5010	PS	1	3	3		:Same As 154.2.1.		
250. Bypass absorber tower during withdrawal mode due to mechanical failure, control system failure, or human error?	EQ HE	250.1. Wet gas	250.1.1. Potential for gas to be out of specification.	OP	250.1.1. Valve limit switches shut off gas flow to pipe line and stop compressors, alarm and call out off-site personnel.	PS	4	4	5		:No additional recommendations identified by Team.		
					250.1.2. Moisture analyzer shuts off gas flow to pipe line and stops compressors, alarms and calls out off-site personnel.	PS							

Worksheet

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
251. urea is put into Methanol Storage Tank ABJ-3170 due to human error?	HE	251.1. Contaminate methanol	251.1.1. Economic issue	OP	251.1.1. Operator is to be in attendance during material unloading.	AD	3	3	4	52	251.1.1. Consider writing SOPs for material unloading at the CVGS facility to prevent introducing methanol into incorrect tanks or incorrect materials into Methanol Storage Tank ABJ-3170.	CVGS	PR
					251.1.2. Labels on truck identify material to be unloaded.	AD							
					251.1.3. Labels on tank identify material in receiving vessel.	AD							
					251.1.4. Bill of lading identifies material to be unloaded.	AD							
					251.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
252. glycol is put into Methanol Storage Tank ABJ-3170 due to human error?	HE	252.1. Contaminate methanol	252.1.1. Economic issue	OP	252.1.1. Operator is to be in attendance during material unloading.	AD	3	3	4		:Same As 251.1.1.		
					252.1.2. Labels on truck identify material to be unloaded.	AD							
					252.1.3. Labels on tank identify material in receiving vessel.	AD							
					252.1.4. Bill of lading identifies material to be unloaded.	AD							
					252.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
253. lube oil is put into Methanol Storage Tank ABJ-3170 due to human error?	HE	253.1. Contaminate methanol	253.1.1. Economic issue	OP	253.1.1. Operator is to be in attendance during material unloading.	AD	3	3	4		:Same As 251.1.1.		
					253.1.2. Labels on truck identify material to be...	AD							

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
253. lube oil is put into Methanol Storage Tank ABJ-3170 due to human error? (cont.)		253.1. Contaminate methanol (cont.)	253.1.1. Economic issue (cont.)		...unloaded.						:Same As 251.1.1. (cont.)		
					253.1.3. Labels on tank identify material in receiving vessel.	AD							
					253.1.4. Bill of lading identifies material to be unloaded.	AD							
					253.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
254. TEG is put into Methanol Storage Tank ABJ-3170 due to human error?	HE	254.1. Contaminate methanol	254.1.1. Economic issue	OP	254.1.1. Operator is to be in attendance during material unloading.	AD	3	3	4		:Same As 251.1.1.		
					254.1.2. Labels on truck identify material to be unloaded.	AD							
					254.1.3. Labels on tank identify material in receiving vessel.	AD							
					254.1.4. Bill of lading identifies material to be unloaded.	AD							
					254.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
255. Methanol put into incorrect tank due to human error?	HE	255.1. Potential for electrostatic ignition of methanol on filling	255.1.1. Fire and loss of storage tank	PD	255.1.1. Operator is to be in attendance during material unloading.	AD	2	3	3		:Same As 251.1.1.		
					255.1.2. Labels on truck identify material to be unloaded.	AD							
					255.1.3. Labels on tank identify material in receiving vessel.	AD							

Worksheet

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
255. Methanol put into incorrect tank due to human error? (cont.)		255.1. Potential for electrostatic ignition of methanol on filling (cont.)	255.1.1. Fire and loss of storage tank (cont.)		255.1.4. Bill of lading identifies material to be unloaded.	AD					:Same As 251.1.1. (cont.)		
					255.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
					255.1.6. Methanol is a polar liquid reducing static buildup	PS							
256. Methanol put into urea tank due to human error?	HE	256.1. Inject methanol into SCR	256.1.1. Potential explosion in SCR	EM PD	256.1.1. Operator is to be in attendance during material unloading.	AD	1	3	3		:Same As 251.1.1.		
										53	256.1.1. Consider making truck connections incompatible between methanol and other fluids to prevent introducing methanol into incorrect tanks or incorrect materials into Methanol Storage Tank ABJ-3170.	CVGS	HW
					256.1.2. Labels on truck identify material to be unloaded.	AD							
					256.1.3. Labels on tank identify material in receiving vessel.	AD							
					256.1.4. Bill of lading identifies material to be unloaded.	AD							
					256.1.5. Methanol Storage Tank ABJ-3170 is in separate area from other tanks.	EN							
257. lose nitrogen pad on Methanol Storage Tank ABJ-3170 due to mechanical failure, control system failure, or human error?	EQ HE	257.1. Flammable atmosphere in Methanol Storage Tank ABJ-3170	257.1.1. Potential for explosion in Methanol Storage Tank ABJ-3170.	EM PD	257.1.1. PSL-3171 alarms and calls out personnel on loss of nitrogen supply	AD	1	3	3	54	257.1.1. Consider providing means of identifying nitrogen loss in Methanol Storage Tank ABJ-3170 vapor space to allow recognition of a potential flammable atmosphere in tank.	ENE	HW
258. nitrogen pressure goes too high due to mechanical failure, control system failure, or human...	EQ HE	258.1. Overpressurize tank Methanol Storage Tank ABJ-3170.	258.1.1. Potential to damage Methanol Storage Tank ABJ-3170 and release methanol to dike with fire.	PD	258.1.1. Dike area electrical classification is Class I, Division 2.	EN	3	3	4	55	258.1.1. Consider providing high pressure relief for nitrogen supply to Methanol Storage...	ENE	HW

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...error?		258.1. Overpressurize tank Methanol Storage Tank ABJ-3170. (cont.)	258.1.1. Potential to damage Methanol Storage Tank ABJ-3170 and release methanol to dike with fire. (cont.)		258.1.2. PSV-3171 opens at 3 psig	MT					...Tank ABJ-3170 to prevent overpressurization of tank.		
259. methanol injection pump fails off due to mechanical failure, control system failure, or human error?	EQ HE	259.1. Loss of methanol to well head	:Potential to create hydrates if operate for long term. No consequences of interest identified by the Team. Not to be developed further.										
260. both methanol injection pumps run at same time due to human error or control system failure?	HE EQ	260.1. Deliver additional methanol to well head	:No consequences of interest identified by the Team. Not to be developed further.										
261. back pressure valve PCV-6111 fails closed due to equipment failure?	EQ	261.1. High pressure in methanol lines	261.1.1. Potential equipment damage and release of methanol to diked area	PD	261.1.1. Methanol injection pumps have been specified to have internal relief.	EN	2	4	5		:No additional recommendations identified by Team.		
262. valve on suction side of methanol injection pump is closed due to mechanical failure, control system failure, or human error?	EQ HE	262.1. Loss of methanol to well head	:Potential to create hydrates if operate for long term. No consequences of interest identified by the Team. Not to be developed further.										
263. valve on discharge side of methanol injection pump is closed due to mechanical failure, control system failure, or human error?	EQ HE	263.1. High pressure in methanol lines	263.1.1. Potential equipment damage and release of methanol to diked area	PD	263.1.1. Methanol injection pumps have been specified to have internal relief. 263.1.2. PCV-6111 relieves downstream pressure	EN MT	2	4	5		:No additional recommendations identified by Team.		
264. methanol is between double walls of tank due to tank wall failure?	EQ	264.1. Methanol in undesired location	264.1.1. Operational issues only	OP	:No safeguards were identified		4	3	5	56	264.1.1. Consider reviewing design of double wall Methanol Storage Tank ABJ-3170 with respect to where overflow goes and make changes as required.	ENE	AD
265. methanol leaks into dike due to tank failure?	EQ	265.1. Flammable material in diked area	265.1.1. Potential fire and equipment damage	PD	265.1.1. Methanol Storage Tank ABJ-3170 is double...	EN	2	4	5		:No additional recommendations...		

Session: (3) 9/17/2010
System: (26) Methanol Injection System
Drawings: CVGS1-M-109 02 Rev D; CVGS1-M-109 03 Rev C; CVGS1-M-109 04 Rev C; CVGS1-M-117 01 Rev C

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
265. methanol leaks into dike due to tank failure? (cont.)		265.1. Flammable material in diked area (cont.)	265.1.1. Potential fire and equipment damage (cont.)		...wall tank						...identified by Team.		
					265.1.2. Dike area electrical classification is Class I, Division 2.	EN							
266. one methanol valve at a well head is closed when needed to be open due to mechanical failure, control system failure, or human error?	EQ HE	266.1. Loss of methanol to well head	:Potential to create hydrates if operate for long term. No consequences of interest identified by the Team. Not to be developed further.										
267. all methanol valves at well head are closed when needed to be open due to mechanical failure, control system failure, or human error?	EQ HE	267.1. High pressure in methanol lines	267.1.1. Potential equipment damage and release of methanol to diked area	PD	267.1.1. Methanol injection pumps have been specified to have internal relief.	EN	2	4	5		:No additional recommendations identified by Team.		
					267.1.2. PCV-6111 relieves downstream pressure	MT							
		267.2. Loss of methanol to well head	:Potential to create hydrates if operate for long term. No consequences of interest identified by the Team. Not to be developed further.										
268. flowraters are set incorrectly low due to human error?	HE	268.1. Insufficient methanol to well head	:Potential to create hydrates if operate for long term. No consequences of interest identified by the Team. Not to be developed further.										
269. flowraters are set incorrectly high due to human error?	HE	269.1. Deliver additional methanol to well head	269.1.1. Operational issues only.	OP	:No safeguards were identified.		4	4	5	57	269.1.1. Consider obtaining information on methanol flowraters and include on P&IDs for informational purposes.	ENE	AD
270. methanol line leaks at well head due to mechanical failure, control system failure, or human error?	EQ HE	270.1. Release of small amount of methanol to gravel	:No consequences of interest identified by the Team. Not to be developed further.										

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (3) 9/17/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (1) Facility Siting

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
271. unit relief valve fails open during operation due to equipment failure?	EQ	271.1. Release of gas	271.1.1. Economic loss of gas	OP	271.1.1. PSHH on each unit relief valve shuts system down on flow in relief line, alarms and calls out off-site personnel.	MT	2	4	5		:No additional recommendations identified by Team.		
					271.1.2. Annual PM of relief valves are required	AD							
					271.1.3. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
			271.1.2. Environmental issue	EV	271.1.4. PSHH on each unit relief valve shuts system down on flow in relief line, alarms and calls out off-site personnel.	MT	1	4	5		:No additional recommendations identified by Team.		
					271.1.5. Annual PM of relief valves are required	AD							
					271.1.6. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
272. unit relief valve leaks during operation due to equipment failure?	EQ	272.1. Release of gas	272.1.1. Economic loss of gas	OP	272.1.1. PSHH on each unit relief valve shuts system down on flow in relief line, alarms and calls out off-site personnel.	MT	3	4	5		:No additional recommendations identified by Team.		
					272.1.2. Annual PM of relief valves are required	AD							
					272.1.3. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
273. there are other facility siting issues that have...	FS	273.1. Unidentified facility siting issues.	273.1.1. Since this is an initial design stage PHA...	EM						58	273.1.1. Consider making a Facility...	CVGS	AU

Session: (3) 9/17/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (1) Facility Siting

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...not been identified?		273.1. Unidentified facility siting issues. (cont.)	...and construction has not yet begun the following recommendation was made by the Team.	PD							...Siting Checklist part of the PSSR for the facility.		

Session: (3) 9/17/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (2) Human Factors

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
274. there are human factors issues that have not been identified?	HF	274.1. Unidentified Human Factors issues.	274.1.1. Since this is an initial design stage PHA and construction has not yet begun the following recommendation was made by the Team.	EM PD						59	274.1.1. Consider making a Human Factors Checklist part of the PSSR for the facility.	CVGS	AU

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
275. system is operated in manual mode?	HF	275.1. Improper sequencing of equipment	275.1.1. Damage to downstream equipment	PD OP	:No safeguards were identified.		1	2	1	60	275.1.1. Consider performing a PHA on the CVGS system operated in manual mode.	CVGS	AD
										61	275.1.2. Consider developing manual mode SOPs for the CVGS system.	CVGS	PR
										62	275.1.3. Consider adding safeguards in CVGS control system to identify and alarm on prolonged use of manual mode.	ENE	SW
276. manual vent valve is open due to human error?	HE	276.1. Release gas to area	276.1.1. Potential for excess noise and emissions.	EM EV	276.1.1. Valves are specified to be blinded and plugged.	EN	3	4	5		:No additional recommendations identified by Team.		
277. manual isolation valve under a gage is...	HE	277.1. Lose gage reading	:Potential operational issues. Not to be...										

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
...closed due to human error?		277.1. Lose gage reading (cont.)	...developed further.										
278. Manual valve under pressure transmitter is closed due to human error?	HE	278.1. Computer loses knowledge of process conditions	278.1.1. Potential operational issues.	OP	:No safeguards were identified.		4	3	5	63	278.1.1. Consider reviewing pressure transmitters and determining where redundancy is required.	ENE	HW
										64	278.1.2. Consider locking open pressure transmitter isolation valves	CVGS	AD
279. flange leak occurs due to equipment failure or human error?	EQ HE	279.1. Release gas to area	279.1.1. Potential for excess noise and emissions.	EM EV	279.1.1. Fugitive emission review are required to be done twice per year per CFR 192.706.	PS	4	3	5		:No additional recommendations identified by Team.		
					279.1.2. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
280. instrument leak occurs due to equipment failure or human error?	EQ HE	280.1. Release gas to area	280.1.1. Potential for excess noise and emissions.	EM EV	280.1.1. Fugitive emission review are required to be done twice per year per CFR 192.706.	PS	4	3	5		:No additional recommendations identified by Team.		
					280.1.2. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							
281. Maintenance vent valve leaks by due to equipment failure or human error?	EQ HE	281.1. Release of gas to area	281.1.1. Economic loss of gas	OP	281.1.1. Fugitive emission review are required to be done twice per year per CFR 192.706.	PS	3	3	4	65	281.1.1. Consider adding blind flange with bleed valve under maintenance vent valves for operational purposes.	ENE	HW
					281.1.2. Operators are at the site 40 hours per week to identify and report abnormal operating conditions.	AD							

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
282. Maintenance vent valve left open after maintenance due to human error.	HE	282.1. Release of gas to atmosphere	282.1.1. Economic loss of gas	PD	282.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PS	2	4	5	66	282.1.1. Consider ensuring that SOPs are written with checklists for valve positions both before and after maintenance to ensure safe turnover of equipment to and from maintenance.	CVGS	PR
					282.1.2. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD							
					282.1.3. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
		282.2. Noise	282.2.1. Public nuisance with fines.	EV	282.2.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PS	3	4	5		:Same As 282.1.1.		
					282.2.2. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD							
					282.2.3. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD							
283. manual equalization valve left open due to human error (non ESD path)?	HE	283.1. Creates a flow path around a block valve that is intended to be closed.	283.1.1. Same as the individual valves not being closed which were analyzed previously in this PHA.	EM PD EV	283.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PR	1	4	5		:Same As 282.1.1.		
					:Other safeguards as analyzed previously in this PHA.								
284. Manual equalization valve left open due to human error (ESD path)?	HE	284.1. Potential to bypass ESD and be unable to blow unit down when required	284.1.1. Potential to be unable to use ESD shutdown in the event of an emergency situation.	EM PD	284.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PR	1	4	5		:Same As 282.1.1.		
										67	284.1.1. Consider adding "Locked...	ENE	AD

Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
284. Manual equalization valve left open due to human error (ESD path)? (cont.)		284.1. Potential to bypass ESD and be unable to blow unit down when required (cont.)	284.1.1. Potential to be unable to use ESD shutdown in the event of an emergency situation. (cont.)	EV							...Closed" notes to manual equalization valves at ESD valves on P&IDs to ensure safe turnover of equipment to and from maintenance.		
					284.1.2. Manual equalization valves in ESD paths are specified to be locked closed.	EN							
					284.1.3. Blowdown control features are required to be tested annually.	AD				68	284.1.2. Consider establishing a system to ensure that locks are in place on manual equalization valves in ESD to ensure that ESD capability will not be compromised.	CVGS	AD
					:Other safeguards as analyzed previously in this PHA.								
285. manual equalization valve leaks by due to equipment failure or human error?	EQ HE	285.1. Release of gas to atmosphere	:Inventory management issue. Not to be developed further.										
286. automatic valves with limit switches are out of desired position due to equipment failure.	EQ	286.1. Various hazards as evaluated throughout this PHA.	286.1.1. Various consequences as evaluated throughout this PHA.	EM PD EV	286.1.1. Various position indicators ZYC-nnnnn alarm and call out off-site personnel out on incorrect valve position.	AD	1	3	3	69	286.1.1. Consider reviewing automatic valves with limit switches and verifying that the shutdown actions are as should be taken in the event of a malfunction alarm to minimize consequences of the fault situation.	ENE	AU
287. isolation valve under PSV is left closed due to human error?	HE	287.1. Overpressure or protected system	287.1.1. Rupture of vessel or pipe with release of gas and fire.	EM PD EV	287.1.1. SOPs are to be written with checklists for valve positions both before and after maintenance.	PR	1	3	3		:Same As 282.1.1.		
					287.1.2. Isolation valve under PSVs are specified to be locked open.	EN							
288. valve stem packing leaks to atmosphere due to equipment failure?	EQ	288.1. Release of gas to atmosphere	288.1.1. Fugitive emission issue.	EV	288.1.1. Fugitive emission reviews are required to be done twice per year per CFR 192.706 to identify fugitive emission points.	AD	4	3	5		:No additional recommendations identified by Team.		

Worksheet

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

Session: (1) 9/15/2010
System: (27) Global
Drawings: CVGS1-M-100 01 Rev C; CVGS1-M-100 021 Rev C
Subsystem: (3) Process General

WHAT IF...	CAT	HAZARD	CONSEQUENCES	CAT	SAFEGUARDS	CAT	S	L	R	REF#	RECOMMENDATIONS	BY	CAT
288. valve stem packing leaks to atmosphere due to equipment failure? (cont.)		288.1. Release of gas to atmosphere (cont.)	288.1.1. Fugitive emission issue. (cont.)		288.1.2. Operators are at the site 40 hours per week and are to be trained to identify and report abnormal operating conditions.	AD					:No additional recommendations identified by Team. (cont.)		
289. flow reverses unexpectedly on a header (i.e. withdrawal to injection or vice versa) due to equipment failure or human error?	EQ HE	289.1. Damage to filter elements	289.1.1. Carry over of glycol, lube oil and filter material. with pipeline maintenance issue.	PD	289.1.1. Various position indicators ZYC-nnnnn alarm and call out off-site personnel out on incorrect valve position.	AD	3	2	3	70	289.1.1. Consider adding automatic shutdown based on reversal of flow as detected by bi-directional meters to prevent equipment damage.	ENE	SW

Worksheet - Index

Session

Company: EN Engineering
Location: Woodridge, IL
Facility: Central Valley Gas Storage, Princeton, CA
PHA Method: What-If
PHA Type: Initial

Process:

CVGS Facility, Design Stage PHA

File Description:

Final

Date:

September 15-17, 2010

Process Description:

As provided by EN Engineering

CVGS is proposing to convert the depleted Princeton Gas Field, near the unincorporated town of Princeton in Colusa County, California, into a high-deliverability, multi-cycle storage field. The field would ultimately be developed to provide 8 Bcf of working gas capacity. The working capacity would be phased in over 4 years, commencing with 5.5 Bcf in the first year. The field would be designed to achieve a maximum withdrawal and injection capability of 300 million standard cubic feet per day (MMscfd).

CVGS would connect the storage field into the PG&E Transmission System Line 400/401 near PG&E's Delevan Compressor Station, approximately 14.9 miles west of the storage field. The PG&E transmission system runs north-south along the western end of the project area. It transports natural gas from PG&E's connections with interstate pipelines, state gas fields, and local distribution infrastructure to the utility's local transmission and distribution system. The proposed project involves constructing facilities necessary to convey natural gas from Line 400/401 to the Princeton Gas Field, storing the gas in the existing natural reservoir, withdrawing the stored gas, and conveying the withdrawn gas to Line 400/401 for delivery to customers.
The connection into PG&E would provide CVGS customers with access to Alberta, Rockies, San Juan, and Permian supplies through the many pipelines that connect to PG&E. Customers holding CVGS capacity would also have access to potential supplies from new natural gas facilities under development on the West Coast.

For a complete project description, see the Central Valley Gas Storage/Nicor Central Valley Gas Storage Project Design Basis Manual.

Chemicals:

Natural gas
Triethylene Glycol
Methanol
Water
Urea

Purpose:

The purpose of this Process Hazards Analysis (PHA) was to conduct an Initial PHA of EN Engineering's (ENE's) preliminary design of the planned Central Valley Gas Storage (CVGS) Facility for Nicor in Colusa, CA that is in accordance with ENE and CVGS's internal risk guidelines to identify potential fire or explosion scenarios with catastrophic potential and recommend appropriate protective measures via a hazards analysis. The study was also conducted in accordance with good engineering practices for performing PHAs. This PHA systematically reviews the planned CVGS Facility using the What-If methodology.

ENE and CVGS management have determined that the planned CVGS Facility will not be covered by the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) (29 CFR 1910.119) regulation or the Environmental Protection Agency's (EPA) Risk Management Program (RMP) Rule (40 CFR Part 68) requirements.

Scope:

The scope of this PHA included the equipment, piping and instrumentation within the planned CVGS Facility in Colusa County, CA as shown on the process flow diagrams (PFDs) and piping and instrumentation diagrams (P&IDs) for this facility listed in Appendix A, including the main gas system (pipelines, compressors, filter separators, coolers, pressure reduction stations, and dehydration units) the blow down silencers, the glycol regeneration units, and associated tanks, valves, and instrumentations. The analysis includes anticipated start-up, normal (steady-state) operating and shutdown procedures, and global issues such as Services, Utilities, Facility Siting, and Emergency Procedures to the extent they interface with the CVGS Facility. By agreement between Primatech, CVGS and ENE, Human Factors was not addressed in the Design Stage PHA but should be in subsequent studies.

Session

Objectives:

The objective of the Design Stage PHA was to identify possible deviations from the planned process design, maintenance, inspection, or operating practices which could lead to fires, explosions or toxic releases of chemicals from within the process potentially involving personnel injury, equipment damage, or environmental impact, especially those involving accidental natural gas or methanol releases. The analysis also addressed significant operability issues such as scenarios which could lead to a plant shutdown.

Failure of planned engineering and administrative controls and protections were evaluated for credible events which could lead to a hazardous scenario. Problems in the operation of utilities such as instrument air, electrical power, and plant water were implicitly reviewed for affect upon potential hazardous scenarios in the process.

Previous accidents in similar processes known of by CVGS and/or ENE were considered during the study. This included reportable releases, and process related incidents within the physical scope of the PHA review.

Global issues were considered for potential impact where they appeared to be plausible, including man-made or naturally occurring external events and facility siting such as proximity of equipment which could result in potential catastrophic effects.

Project Notes:

The first category column is used to indicate the cause for the scenario in the worksheet. The following codes are considered:

EQ = Equipment Failures
HE = Human Error
HF = Human Factor
EX = External Event
FS = Facility Siting Issue
PI = Previous Incidents (on similar equipment)
SC = Failure of Safeguard or Control
SD = Startup/shutdown Issue
NO = Normal Operation

The second category column is used to classify the consequence for the scenario in the worksheet. The following codes are considered:
EM = Effect Onsite Personnel
EP = Effect Offsite Public
EV = Effects On the Environment
OP = Operability Problem
PD = Property Damage

The third category column is used to indicate the type of safeguard listed. The following codes are considered:
DT = Detection System
PS = Prevention System
MT = Mitigation
EN = Engineered
PR = Procedural
AD = Administrative
AC = Active
PA = Passive
ER = Emergency Response Procedure
SC = Secondary Containment
OF = Offsite Mitigation or Control

The last category column is used to indicate the type of recommendation for the scenario in the worksheet. The following codes are considered:
AD = Administrative
HW = Hardware
PR = Procedural
SW = Software
MN = Maintenance
TI = Testing/Inspection
TR = Training

Session

ER = Emergency Response
AU = Audit

Session 1 Date: September 15, 2010 Time: 9:00 AM Duration: 8:00

Session Notes:

Rick Knack, PE, CSP - Leader, Scribe
Ernie Erickson
Michael Fugate
Myron Reicher
Homer Savage, PE
Mike Miller
Dave Fisher, PE
Jack Steiner
John Davis

Session 2 Date: September 16, 2010 Time: 8:00 AM Duration: 10:00

Session Notes:

Rick Knack, PE, CSP - Leader, Scribe
Ernie Erickson
Michael Fugate
Myron Reicher
Dave Fisher, PE
John Davis

Session 3 Date: September 17, 2010 Time: 8:00 AM Duration: 6:00

Session Notes:

Rick Knack, PE, CSP - Leader, Scribe
Ernie Erickson
Michael Fugate
Myron Reicher
Homer Savage, PE
Mike Miller
Dave Fisher, PE
John Davis
Jim Kiefer
Ray Schnegelsberg

APPENDIX E

What-If Protocol Checklist

(Process Safety Information)

Protocol

Printed: November 23, 2010, 8:29 AM
Company: EN Engineering
Location: Woodridge, IL
Facility: Central Valley Gas Storage, Princeton, CA
PHA Method: What-If
PHA Type: Initial

Process:

CVGS Facility, Design Stage PHA

File Description:

Final

Date:

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Protocol

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HW = Hardware
PR = Procedural
SW = Software
MN = Maintenance
TI = Testing/Inspection
TR = Training

ER = Emergency Response
AU = Audit

Filters: No Filter Applied

PSI needed for PHA

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

QUESTION	A	JUSTIFICATION	COMMENTS
1. Do you have available information pertaining to the hazards of the highly hazardous chemicals used or produced by the process (MSDS's)?	Yes		
2. Do you have available a block flow diagram or simplified process flow diagram (PFD)?	Yes		
3. Do you have available information on process chemistry?	NA		
4. Do you have available information on maximum intended inventory?	Yes	Tankage sheets	
5. Do you have available safe upper and lower limits for process parameters such as temperatures, pressures, flows, and compositions?	Yes		
6. Do you have available an evaluation of the consequences of deviations of operating beyond the process limits, including those affecting the safety and health of employees?	Yes		
7. Do you have available information on materials of construction?	Yes		
8. Do you have available piping and instrument diagrams [P&ID's]	Yes		
9. Do you have available information on electrical classifications?	Yes	Class I, Division 1 and 2. Drawings exist	
10. Do you have available information on relief system design and design basis?	Yes		
11. Do you have available information on ventilation system design?	Yes	Compressor Building	
12. Do you have available design codes and standards employed to establish good engineering practice?	Yes		
13. Do you have available material and energy balances for processes built after May 26, 1992?		Not justified for this process	

PSI needed for PHA

Company: EN Engineering
Facility: Central Valley Gas Storage, Princeton, CA

QUESTION	A	JUSTIFICATION	COMMENTS
14. Do you have available information on safety systems (e.g., interlocks, detection or suppressions systems)?	Yes		

APPENDIX F

Glossary of Standard Abbreviations for PHAs

Bcf	-	Billion cubic feet
CCPS	-	Center for Chemical Process Safety
CVGS	-	Central Valley Gas Storage, LLC
DCS	-	Distributed Control System
ENE	-	EN Engineering
EPA	-	Environmental Protection Agency
ESD	-	Emergency Shutdown (System)
HAZOP	-	Hazard and Operability Study
in w.c.	-	inches of water column
MMscfd	-	Million standard cubic feet per day
MOC	-	Management of Change
MSDS	-	Material Safety Data Sheet
OSHA	-	Occupational Safety and Health Administration
osig	-	Ounces per square inch, gage
P&ID	-	Piping and Instrumentation Diagram
PFD	-	Process Flow Diagram
PG&E	-	Pacific Gas and Electric
PHA	-	Process Hazard Analysis
PM	-	Preventive Maintenance
PPE	-	Personal Protective Equipment
PSV	-	Pressure Safety Valve
PSI	-	Process Safety Information
psig	-	Pounds per square inch, gage
PSM	-	Process Safety Management
PSSR	-	Pre-Startup Safety Review
RMP	-	Risk Management Program

RO	-	Restrictive Orifice
SCR	-	Selective Catalytic Reduction (Unit)
SHE	-	Safety, Health & Environment
SOP	-	Standard Operating Procedure

Appendix II

Central Valley Gas Storage Safety-Related Systems

Appendix II.

Central Valley Gas Storage Safety-Related Systems:

CVGS is protecting employees, the public, and the environment through use of modern gas control systems that enhance operational efficiencies and provide for greater safety. Primary control room equipment includes a state of the art automated Human Machine Interface (HMI) control system, personal computers, and programmable logic controllers, which provide automation of control and monitoring functions. Specific safety features of the project are listed below. **Additional details regarding these systems, including design documents, are available upon request.**

<u>Monitoring/Detection/Automated Shut-Down Systems:</u>

- Gas, fire, and vibration detection systems monitor equipment inside the compressor building and are able to both alarm or if needed, safely shut down equipment automatically if the alarm and/or shutdown set-points of each system are met. An automatic call-out system is used to contact personnel in emergencies.
    - The gas detection system will alarm if the atmosphere in the building reaches 20% of the lower explosive limit (LEL). The system will shut down all compressors, actuate valves to a closed position and vent all gas piping within the building at 40% LEL.
    - The fire detection system (infrared sensors) will shut down all compressors and block and vent all gas piping within the building, should one of seven sensors in the compressor building pick up an indication of a flame or fire.
    - Vibration sensors (accelerometers) are installed on each gas compressor/engine and will alarm and automatically shut down the unit if vibration exceeds a preset level. The alarm setpoint is 0.6 thousandths of an inch per sec^2 of acceleration (mils) and the shutdown setpoint is 0.8 mils.

- Flow, temperature, and pressure are monitored at the compressor station, well pad sites, and the PG&E Line 400/401 interconnection. In addition to being monitored and controlled by local programmable logic controllers (PLC), the station PLC and the HMI control system prevent overpressure of the facilities, the entire system is designed with pressure monitor valves and relief valves to provide redundant overpressure protection.
    - Valves that control the flow of gas into and out of the compressor station and the meter station have pneumatic and/or electric actuators installed, allowing them to be remotely operated from the control room, locally at the valve, or automatically in the event of an emergency shutdown (ESD). During an ESD these valves block off the compressor station from the main 24-inch pipeline, wells, and 16-inch gathering pipelines, and the entire compressor station is vented. Also, in the event of an immediate loss of pipeline pressure, on the 24-inch mainline, these valves will actuate to the closed position to block off the affected area.
    - Gas flows and pressures are measured at each of the storage wells and signaled back to the control room to allow proper monitoring of the characteristics and performance of the gas storage reservoir. This information provides instantaneous inventory data to enable proper reservoir management and underground placement of the gas.

- At the PG&E meter station, a gas chromatograph and a moisture analyzer monitors gas composition, ensuring that the gas delivered to or received by PG&E meets both PG&E's and CVGS's quality specifications. In addition, a chromatograph and moisture analyzers at the CVGS compressor station will monitor gas composition being received by or delivered to PG&E, to verify gas quality meets both parties' quality specifications.
    - If either parties' equipment indicates that the gas is out of specification, notice will be provided immediately by one party to the other. Both parties have the right to refuse gas from the other, upon notice of gas being out of specification, until the issue is resolved to the satisfaction of the party that gave notice.

Other Project Design-Related Safety Features:

- Fire prevention and response measures in the compressor station include smoking area restrictions and work area restrictions, as well as the fire detection equipment in the compressor building.
    - Dry chemical fire extinguishers are placed at appropriate locations at the compressor facility, meter station and well pad.
    - In the event of a fire, the most effective means of control is to block in and vent the gas from the facility or affected area. The Operations staff will be trained to respond accordingly.

- The compressor station, meter station, pipelines and the Well Pad piping and well casings are cathodically protected against corrosion.

- All CVGS pipelines are identified in compliance with regulations issued by the United States Department of Transportation (DOT) and administered by the California Public Utility Commission (CPUC). Aboveground markers are placed along the pipeline corridor, within the line of sight, identifying the type of utility, listing the 811 national one-call number, and a 24-Hour number to call in case of emergency.

- Relief valves and key safety valves (those facilitating remote operation and emergency shutdown) are inspected and maintained in compliance with regulations issued by the DOT and the CPUC. CVGS maintains inspection and maintenance records for regulatory review.

Appendix III

Central Valley Gas Storage's MAOP Determination

Appendix III.

Central Valley Gas Storage MAOP Determination:

CVGS follows appropriate protocols for determining the Maximum Allowable Operating Pressure (MAOP) on its pipeline segments. Specifically, in its pipeline design CVGS complies with the regulations issued by the U.S. Department of Transportation (DOT) in part 192 of Title 49 of the Code of Federal Regulations.

The table below lists the MAOP and design pressure calculations at various sections of the 24" pipeline between the CVGS compressor facility and the PG&E interconnect and the two 16" pipelines between the compressor facility and the well pad. The MAOP of the 24" pipeline is 1100 pounds per square inch (psi) and the MAOP of the 16" pipelines is 1456 psi.

CVGS pipelines are almost entirely in Class 1 locations. More stringent (lower) design factors are used in sections that cross or encroach on the rights-of way of hard-surface public roads and railroads. The California Department of Transportation required a design factor of 0.5 in granting a permit to cross the right-of way of Interstate Highway 5 and the same pipe segment crosses a railroad right-of-way. CVGS decided to design certain sections with a Class 3 design factor as noted below.

The table shows design factors for CVGS pipeline segments by location category, size, the yield strength of the steel, the wall thickness of the installed pipe, the design pressure calculated using the formula specified in 49 CFR sections 192.105 and the MAOP CVGS has assigned the segment. In all cases, the MAOP assigned by CVGS is lower than the design pressure calculated by the formula.

Category\1	Design Factor	Outside Diameter (in)	Yield Strength (psi)	Installed WT	Calculated Design Pressure \4	MAOP (psig)
Location Class 1	0.72	24	65,300	0.312	1,222	1,100
	0.72	16	52,000	0.500	2,340	1,456
Road Crossings in Location Class 1	0.60	24	65,300	0.406	1,325	1,100
Location Class 3 \2	0.50	24	65,300	0.438	1,191	1,100
	0.50	16	52,000	0.500	1,625	1,456
I-5 HDD - Caltrans Permit \3	0.50	24	65,300	0.406	1,105	1,100

Notes:
1) Class location determined in accordance with 49 CFR 192.5
2) Location Class 3 pipe is installed from the south fence of the compressor station to a point south of Southam Road due to truck repair facility in the immedidate vicinity.
3) Caltrans permit for I-5 crossing requires a design factor of 0.5 equivalent to a Location Class 3
4) Design pressure is calculated using the Barlow formula in accordance with 49 CFR 192 .105.

Appendix IV

Overview of Central Valley Gas Storage Design Standards

Appendix IV.

Central Valley Gas Storage Design Standards:

CVGS is meeting or exceeding minimum standards for safe design, construction, installation, operation and maintenance of its gas transmission and storage facilities in compliance with the regulations issued by the U.S. Department of Transportation (DOT) in part 192 of Title 49 of the Code of Federal Regulations.

Construction and Installation:
CVGS has constructed its facilities and installed its equipment in compliance with 49 CFR Part 192 requirements. **CVGS maintains construction records at its facility for regulatory review.**

Operation and Maintenance:
CVGS is following the Operation and Maintenance Plan, as well as the Operator Qualification Plan, Integrity Management Plan, and Emergency Response Plan, included with this submittal. All of these plans are designed to comply with 49 CFR Part 192 requirements issued by the DOT.

Design:
Specific design standards followed CVGS facilities are listed below. **Additional details regarding the design, including design documents, are available upon request.**

Compressor, Metering, and Pipeline Facilities: The latest edition of the following codes and standards were utilized for civil and mechanical design:

- 49 CFR 192 and all references
- ASME B16.5-2009 - Pipe Flanges and Flanged Fittings
- ASME B16.9-2007 - Factory-Made Wrought Butt Welding Fittings
- ASME B16.49-2007 - Factory Made, Wrought Steel, Butt Welding Induction Bends for Transportation and Distribution Systems
- ASME B31.8-2010 - Gas Transmission and Distribution Piping Systems
- API 5L - 44th Ed - Specification for Line Pipe
- AP RP 5L1 – 7th Ed - Recommended Practice for Railroad Transportation of Line Pipe
- AP RP 5L9 – 1st Ed - External Fusion Bonded Epoxy Coating of Line Pipe
- API 1102 – 7th Ed - Steel Pipelines Crossing Railroads and Highways
- API 1104 - 20th Ed - Welding of Pipelines and Related Facilities
- 29 CFR 1910.119 (Process Safety Management)
- SP0169 - Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- SP0177 - Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

Electrical: The latest edition of the following codes and standards were utilized for the electrical and controls system design:

- National Fire Protection Association (NFPA) as appropriate
- NFPA 70E Standard For Electrical Safety In The Workplace
- State of California, California Electrical Code 2007 Edition
- American Gas Association Catalog #XF0277 Classification of Gas Utility Areas for Electrical Installations
- National Association of Corrosion Engineers (NACE) Standard RP – 01 – 69
- Institute of Electrical and Electronic Engineers (IEEE) as appropriate

Electrical Equipment:

- Underwriters Laboratories (UL) as appropriate
- Factory Mutual (FM) as appropriate
- National Electrical Manufacturers Association (NEMA) as appropriate
- Institute of Electrical and Electronic Engineers (IEEE) as appropriate
- American National Standards Institute (ANSI) as appropriate

Appendix V

Central Valley Gas Storage
Staffing, Qualification and Training

Appendix V.

Central Valley Gas Storage Staffing, Qualifications and Training:

Staffing:

CVGS has budgeted positions for, and is entering into operations with, a complement of seven (7) full time employees (FTEs). The FTEs are comprised of:

- Operations Manager
- Administrative Assistant
- Instrument and Electrical Technician
- Plant Operators (2)
- Mechanic
- Maintenance Specialist

Qualifications:

CVGS employees will be qualified according to the Operator Qualification Plan included in this submittal.

Training:

The CVGS Staff will be trained to safely operate and maintain the facilities by internal and external resources that are subject matter experts. Examples of the various training that will be conducted include, but may not be limited to, the following:

- PHMSA/CPUC required training including Operator Qualification (OQ), emergency response, abnormal operating conditions, locating and marking pipelines or other facilities, Control Room Management (CRM), damage prevention, purging and packing pipelines and facilities, pigging operations, monitoring pipeline and facility pressures, patrolling and leak detection, inspecting and servicing valves, overpressure protection, Emergency Shut Down (ESD) systems, equipment Start/Stop guidelines, Hazardous Materials Transportation (HazMat), and strength and leak testing pipe and fittings.
- OSHA required safety training including medical first aid, bloodborne pathogens, confined space entry, lockout/tagout, hearing conservation, basic fire safety and emergency evacuation, electrical safety, management of change, personal protective equipment, forklift operator, respirator protection, excavation/trenching and shoring, and hot work.

- Environmental training including Spill Prevention and Control and Countermeasure (SPCC), Hazardous Waste Operations and Emergency Response (Hazwoper), waste management, and managing used oil.
- Training for operation and maintenance of various pieces of equipment including Arc Flash, use of a pipe locator, engine and compressor maintenance and troubleshooting, measuring water dew point and dehydration of gas, gas measurement and chromatograph operation and maintenance, UREA injection systems, and others.

Attachment 10

Central Valley Gas Storage
Valve Location Plan

Central Valley Gas Storage
An AGL Resources Company

Central Valley Gas Storage LLC
3333 Warrenville Road
Suite 300
Lisle, IL 60532

Phone 630 245-6150
Fax 630 245-7835
Internet www.cvgasstorage.com

December 28, 2012

California Public Utilities Commission
505 Van Ness Ave
San Francisco, CA 94610

Subject: Central Valley Gas Storage Valve Location Plan

In response to an e-mail received from Sunil Shori at the California Public Utilities Commission dated December 11, 2012, Central Valley Gas Storage (CVGS) hereby submits documents comprising its Valve Location Plan consistent with the requirements of California Public Utilities Code §957.

The contents of the CVGS Plan are as follows:

- An Automated Block Valve Listing of automated valves controlling every CVGS pipeline segment, including the locations (by milepoint) and the operating mode of each valve. Note that the entire CVGS pipeline system was installed after September 2010. Automated valves at either end of the CVGS 24" pipeline and both 16" gathering lines were included in the original CVGS design to facilitate line isolation for both emergency shut down and routine maintenance activities.

- A map showing the layout of the CVGS pipeline system including the length of each pipeline segment and the three locations where automated valves can isolate a CVGS pipeline segment. The map documents that the 24" pipeline from the CVGS Compressor Station is 14.6 miles (77,063 feet) in length and both of the 16" gathering lines from the CVGS Well Pad to the CVGS Compressor Station are 0.47 miles (2,481 feet) in length. Note that there are no areas along any CVGS pipeline segment that constitute a High Consequence Area or are categorized as a Class 3 or 4 location. All areas along the CVGS pipeline system are categorized as a Class 1 location.

- Valve diagrams for each of the three locations where automated valves can isolate a CVGS pipeline segment: (1) the CVGS Compressor Station, (2) the CVGS Well Pad, and (3) the PG&E Interconnect Area. These diagrams have already been submitted to the CPUC as part of the Emergency Response Plan included in the CVGS Safety Plan. On this version the valves referenced on the Automated Block Valve Listing are identified using color-coded ovals.

- Since CVGS has no areas along any pipeline segment that constitute a High Consequence Area or that are categorized as a Class 3 or 4 location, there will be no cases of an open break in the pipeline occurring near any Class 3, 4, or High Consequence Area location. Nonetheless, CVGS is including calculations showing the time that would be required to blow-down each pipeline segment, assuming a full open break in the pipeline, via venting through the breach and any other measures CVGS procedures would allow to be used for venting purposes. On the 24-inch pipeline from its compressor station to the PG&E interconnect area, automated valves are designed to actuate automatically when a loss of pressure is detected in the pipeline and the calculation shows the time required for blow-down following this occurrence. On each of the 16-inch gathering lines from the well pad to the compressor station, the valves require operator actuation via remote control and the calculation also includes the estimated time necessary for an operator to make determinations related to valve closures and initiate the closure of the last valve necessary for isolation of the breach. CVGS also has included estimates for the time necessary to blow-down the 24-inch line through installed blow-down vents instead of through a full-open breach.

- A revision to Element 1 (page 10) of the CVGS Integrity Management Plan which clarifies that CVGS will evaluate the need for additional automated valve installations at the same time it completes its annual evaluation to determine if High Consequence Areas are present.

There are no portions of any CVGS pipeline segment that traverse an active seismic earthquake fault. The CPUC previously reviewed the application of CVGS, including the analysis of seismic information. In 2010, the CPUC issued a Mitigated Negative Declaration (MND) in which it and its consultants concluded on Page 5.7-9:

> **"Active faults that have potential for future surface rupture are designated as Alquist-Priolo Earthquake Fault Zones by the California Geological Survey. There are no Alquist-Priolo Earthquake Fault Zones crossing the project area (California Geological Survey 2009). The only earthquake in the Sacramento Valley known to have resulted in surface rupture occurred in neighboring Butte County."**
>
> **"The closest Holocene active fault, the Bartlett Springs Fault, is located approximately 33 miles west of the proposed metering station site."**

Because there are no areas along any CVGS pipeline segment that constitute a High Consequence Area or are categorized as a Class 3 or 4 location and because there are no portions of any CVGS pipeline segment that traverse an active seismic earthquake fault, CVGS has no plans at this time to install additional automated valves on any of its pipeline segments. If the annual review conducted by CVGS identifies a High Consequence Area, CVGS will recommend any necessary additional valve installations at locations suitable to protect the public and will install such valves as quickly as is reasonably possible.

CVGS has no other concerns or suggestions related to automated valve installations at this time.

Sincerely,

John Boehme

John Boehme
Manager Regulatory Affairs
Storage and Fuels (North/West)
AGL Resources

Central Valley Gas Storage

*An **AGL Resources** Company*

Valve Location Plan

December 2012 Version

Central Valley Gas Storage
An AGL Resources Company

Automated Block Valve Listing

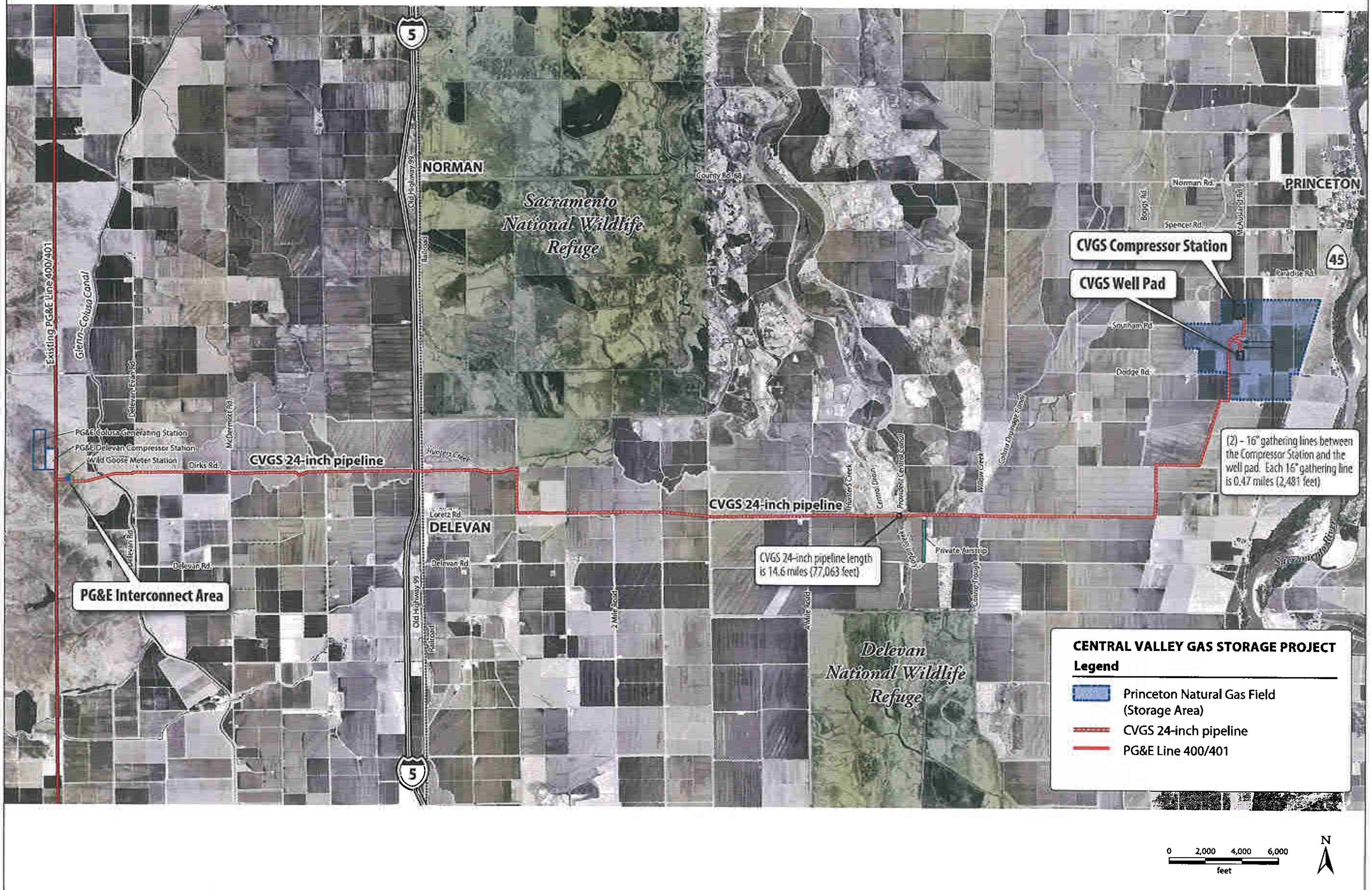
Central Valley Gas Storage
An AGL Resources Company

Automated Block Valve Listing

	Valve Number	Milepoint	Opearting Mode	Purpose
CVGS Compressor Station Automated Block Valves				
Line 401 16" Valve	BV-1502	0.00	Automatic	Isolate 24" Pipeline to PG&E Interconnect Area
Line B Glycol Tower MAF-1210 Gas Inlet 16" Block Valve	BV-1211	0.00	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Well Pad
Line B Glycol Tower MAF-1210 Gas Pressurizing 2" Block Valve	BV-1216	0.00	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Well Pad
Line B Backup Glycol Tower MAF-1220 Gas Inlet 16" Block Valve	BV-1221	0.00	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Well Pad
Line B Backup Glycol Tower MAF-1220 Gas Pressurizing 2" Block Valve	BV-1226	0.00	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Well Pad
Line A Backup Glycol Tower MAF-1220 Gas Inlet 16" Block Valve	BV-12213	0.00	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Well Pad
Line A Backup Glycol Tower MAF-1220 Gas Pressurizing 2" Block Valve	BV-12214	0.00	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Well Pad
Line A Glycol Tower MAF-1230 Gas Inlet 16" Block Valve	BV-1231	0.00	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Well Pad
Line A Glycol Tower MAF-1230 Gas Pressurizing 2" Block Valve	BV-1236	0.00	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Well Pad
Line B Glycol Tower 16" Bypass Valve	BV-1223	0.00	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Well Pad
Line A Glycol Tower 16" Bypass Valve	BV-1233	0.00	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Well Pad
CVGS Well Pad Automated Block Valves				
Lower Sand ESD 16" Block Valve	BV-0021	0.47 (GL)	Operator Actuated	Isolate 16" Lower Sand Gathering Line to Compressor Station
Upper Sand ESD 16" Block Valve	BV-0031	0.47 (GL)	Operator Actuated	Isolate 16" Upper Sand Gathering Line to Compressor Station
PG&E Interconnect Area Automated Valve				
Line 401 12" Control Valve	PCV-1011	14.60 (PL)	Automatic	Isolate 24" Pipeline to Compressor Station

Central Valley Gas Storage
An AGL Resources Company

Map



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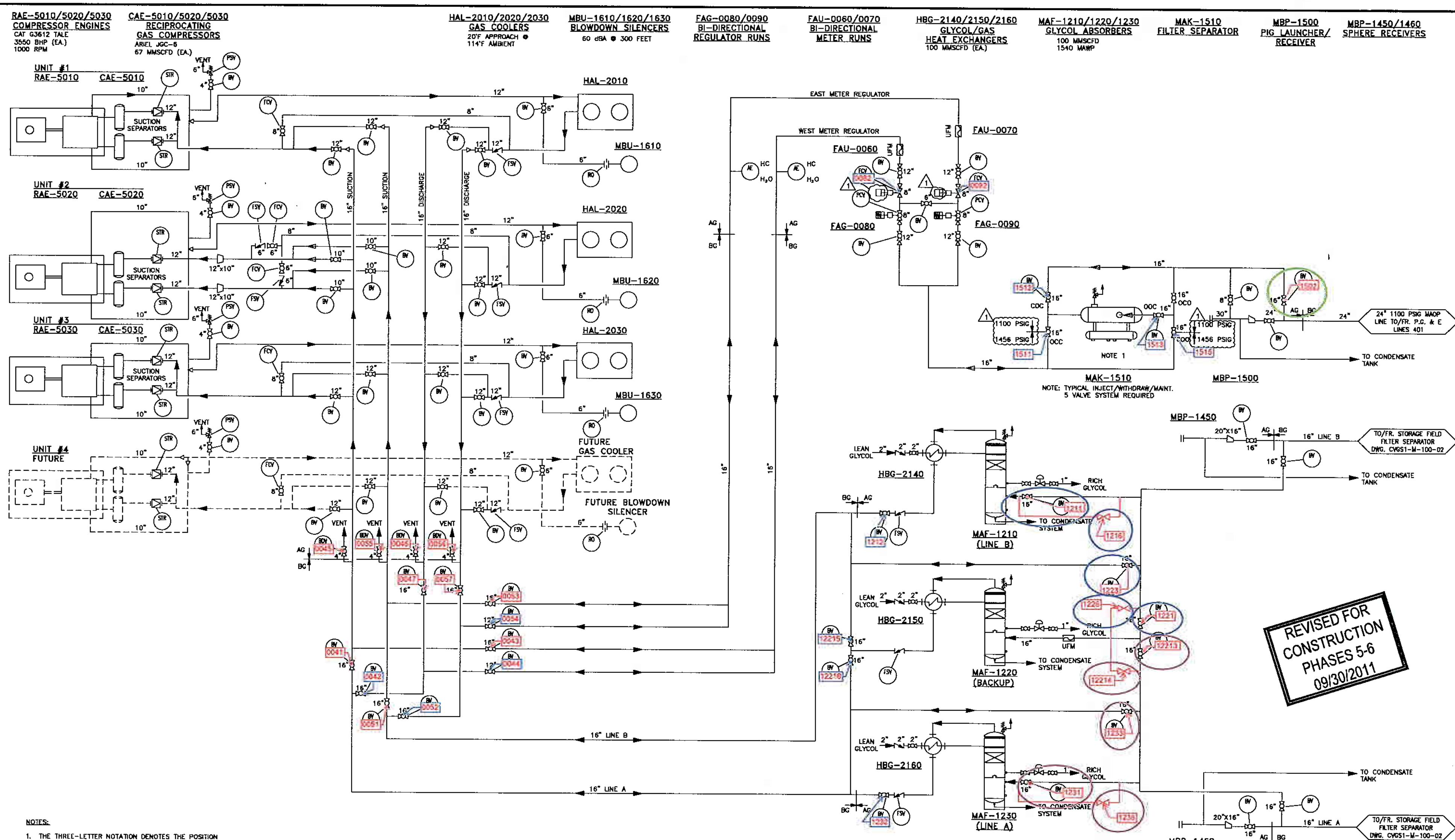
ICF INTERNATIONAL

Central Valley Natural Gas Facility Pipeline System

Central Valley Gas Storage
An AGL Resources Company

Valve Diagrams



NOTES:

1. THE THREE-LETTER NOTATION DENOTES THE POSITION OF THAT VALVE AS "O"PEN OR "C"LOSED IN ONE OF THREE MODES OF OPERATION, STARTING FROM THE LEFT THESE MODES ARE: INJECTION, WITHDRAWAL & BY-PASS MODES.

DESIGNED IN ACCORDANCE WITH TITLE 49-PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

PREPARED BY:

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REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
1	09/30/11	CLA	REVISED FOR CONSTRUCTION		
0	07/22/11	TSR	ISSUED FOR CONSTRUCTION		
F	03/16/11	RSR	RE-ISSUED FOR BID		
E	01/28/11	AGM	ISSUED FOR BID		

MR MPM

REVISIONS

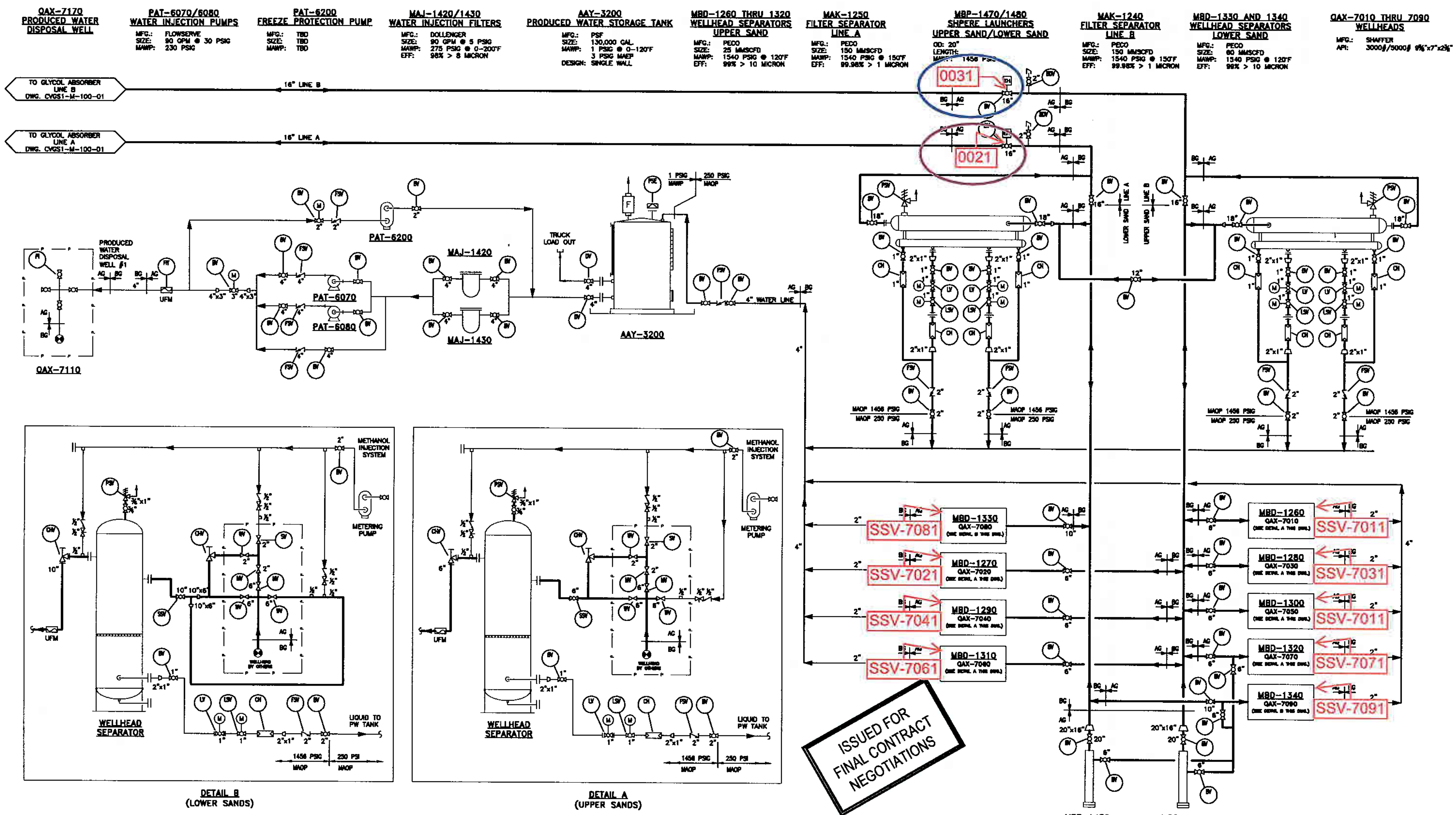
central Valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

HIGH PRESSURE GAS PROCESS FLOW DIAGRAM COMPRESSOR STATION SITE

COLUSA COUNTY — CALIFORNIA

DATE	SCALE	DRAWN BY	LOC. NO.	DRAWING NUMBER	SHEET NO.	REV.
04/05/10	NONE	TSR	-	CVGS1-M-100	01	1



DESIGNED IN ACCORDANCE WITH TITLE 49-PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

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REV LEVEL	DATE	BY	DESCRIPTION	CK	APP.
D	06/12/11	AGM	ISSUED FOR FINAL CONTRACT NEGOTIATIONS	MR	MPM

REVISIONS

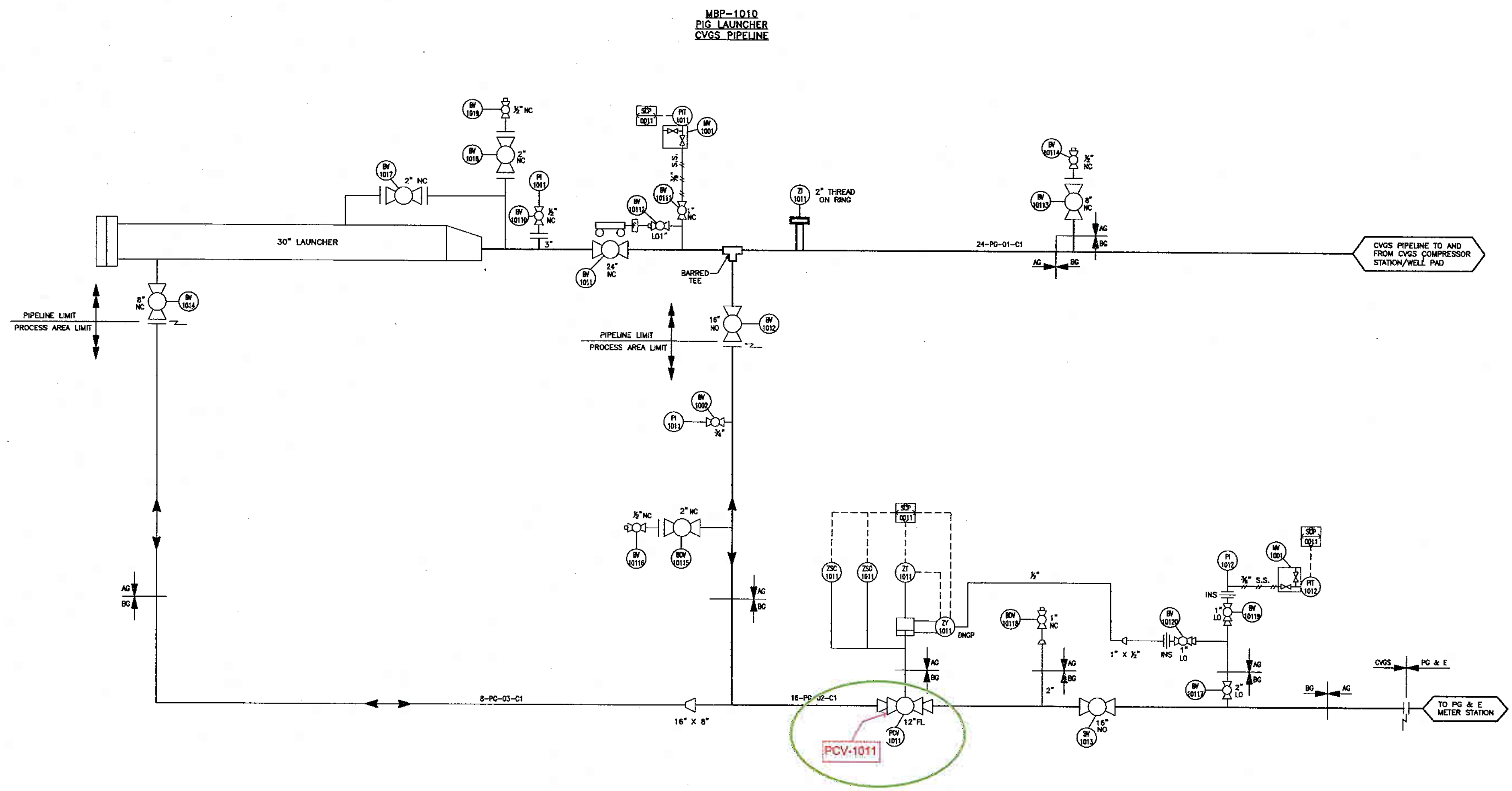
central Valley gas storage LLC

CENTRAL VALLEY GAS STORAGE

HIGH PRESSURE GAS AND PRODUCED WATER PROCESS FLOW DIAGRAM WELL PAD SITE

COLUSA COUNTY — CALIFORNIA

DATE:	SCALE:	DRAWN BY	LOC. NO.	DRAWING NUMBER:	SHEET NO.	REV.
07/02/08	NONE	TSR	-	CVGS1-M-100	02	D



DESIGNED IN ACCORDANCE WITH TITLE 49 PART 192 OF MINIMUM FEDERAL SAFETY STANDARDS AND GPTC GUIDE FOR GAS TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS, LATEST EDITION.

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REGISTERED PROFESSIONAL ENGINEER JOHN MALLINCKRODT M 34551 STATE OF CALIFORNIA
8-12-11

REV LEVEL	DATE	BY	DESCRIPTION	CK.	APP.
0	08/11/11	HP	ISSUED FOR CONSTRUCTION	PCG	

REVISIONS

central Valley gas storage LLC

ISSUED FOR CONSTRUCTION
08/11/2011

CENTRAL VALLEY GAS STORAGE

HIGH PRESSURE GAS L-401 METER STATION LAUNCHER/RECEIVER PIPING AND INSTRUMENT DIAGRAM

COLUSA COUNTY — CALIFORNIA

DATE:	SCALE:	DRAWN BY:	LOC. NO:	DRAWING NUMBER:	SHEET NO:	REV:
08/14/10	NONE	HP(ENE)	-	CVGS2-M-100	00	0

Central Valley Gas Storage
An AGL Resources Company

Segment Blow-down Calculations

Segment Blow-down Calculations

Central Valley Gas Storage has utilized modeling simulation software to estimate the time required to bring pressure down in each of its pipeline segments in the event of a full-open break. The results of the simulations are presented below:

Scenario 1: Rupture of the 24" line between the CVGS Compressor Station and the PG&E Interconnect Area

Parameters:

Pipeline Length:	77,063' (~14.6 miles)
Pipeline Diameter:	24" diameter
Pipeline Wall Thickness:	primarily 0.312"
MAOP:	1,100 psi

Assumptions:

1. Pipeline pressure is kept at 1,100 psig while the isolation valves are closing (20 seconds) after the remote sensing device initiates the shut down process, then the source of pressure is shut off.

2. Blow down is through a full 24" cut opening in the pipe (full pipe rupture).

Results: 21 minutes

Scenario 2: Rupture of either 16" line between the CVGS Compressor Station and the CVGS Well Pad

Parameters:

Pipeline Length:	2,481' (~0.47 miles)
Pipeline Diameter:	16" diameter
Pipeline Wall Thickness:	0.500"
MAOP:	1,456 psi

Assumptions:

1. Pipeline pressure remains at 1456 psig for 5 minutes to allow the operator to react to the line rupture and to trigger the isolation valves to operate and fully close.

2. Blow down is through a full 16" opening (full pipe rupture)

3. The 16" lines are tied together and operating in common so both lines are blown-down. (Time would be reduced if the lines are operating separately.)

Results: 5.3 minutes (including operator reaction time)

In addition to calculating the time required to vent natural gas in the event of a full-open breach, Central Valley Gas Storage has calculated the time required to bring pressure in its 24" pipeline down to atmospheric levels using 8" blow-down vents at the CVGS compressor station and/or the PG&E Interconnect Area. In the event that the pipeline wall is punctured in a manner that does not constitute a full-open break, this is a more likely scenario. Note that these 8" ball valves require manual operation, so there will be time required for operator recognition and in the case of the valve at the PG&E Interconnect, time required for travel to the PG&E Interconnect site.

Scenario 3: Puncture of the 24" line between the CVGS Compressor Station and the PG&E Interconnect Area – Blow-down through one 8" vent.

Parameters:

Pipeline Length:	77,063' (~14.6 miles)
Pipeline Diameter:	24" diameter
Pipeline Wall Thickness:	primarily 0.312"
MAOP:	1,100 psi

Assumptions:

1. Pipeline pressure is kept at 1,100 psig while the isolation valves are closing (20 seconds) after the remote sensing device initiates the shut down process, then the source of pressure is shut off.

2. Blow down is through the 8" ball-valve vent at the CVGS compressor station.

Results: 141 minutes

Scenario 4: Puncture of the 24" line between the CVGS Compressor Station and the PG&E Interconnect Area – Blow-down through two 8" vents

Parameters:

Pipeline Length:	77,063' (~14.6 miles)
Pipeline Diameter:	24" diameter
Pipeline Wall Thickness:	primarily 0.312"
MAOP:	1,100 psi

Assumptions:

1. Pipeline pressure is kept at 1,100 psig while the isolation valves are closing (20 seconds) after the remote sensing device initiates the shut down process, then the source of pressure is shut off.

2. Blow down is through both the 8" ball-valve vent at the CVGS compressor station and the 8" ball-valve vent at the PG&E Interconnect Area.

Results: 67 minutes

Central Valley Gas Storage
An AGL Resources Company

Integrity Management Plan Update

Requirements If There are No HCAs:

CVGS is not required to develop an integrity management program if there are no high consequence areas on its system. But, CVGS must complete an evaluation to determine that no high consequence areas exist, and this evaluation must be maintained and available for inspection. Even if no HCAs exist, however, there are some requirements in Subpart O with which CVGS must comply. These requirements include the following:

1) Once per calendar year not to exceed 18 months, CVGS will evaluate its pipeline to determine if new HCAs have been created. Changes along the pipeline route, including housing construction and creation of new facilities meeting criteria in the definition of identified sites could cause HCAs to come into existence. CVGS will demonstrate that it has periodically evaluated its pipeline to assure that there continue to be no HCAs. As part of this evaluation, CVGS will determine if installation of additional automated sectionalizing block valves would be prudent to enhance the safety of the public in light of any such changes along the pipeline route.

2) For transmission pipelines operating below 30 percent of SMYS in class 3 or 4 locations but not in an HCA, enhanced protection against third-party damage will be implemented in accordance with 192.935(d).

3) CVGS will submit semi-annual "performance measure" reports in accordance with 192.945(a) indicating that there are no HCAs on its system.

If the periodic evaluation identifies that a new HCA exists, then CVGS will prepare an integrity management plan and meet all the requirements of subpart O.

[FAQ #150]

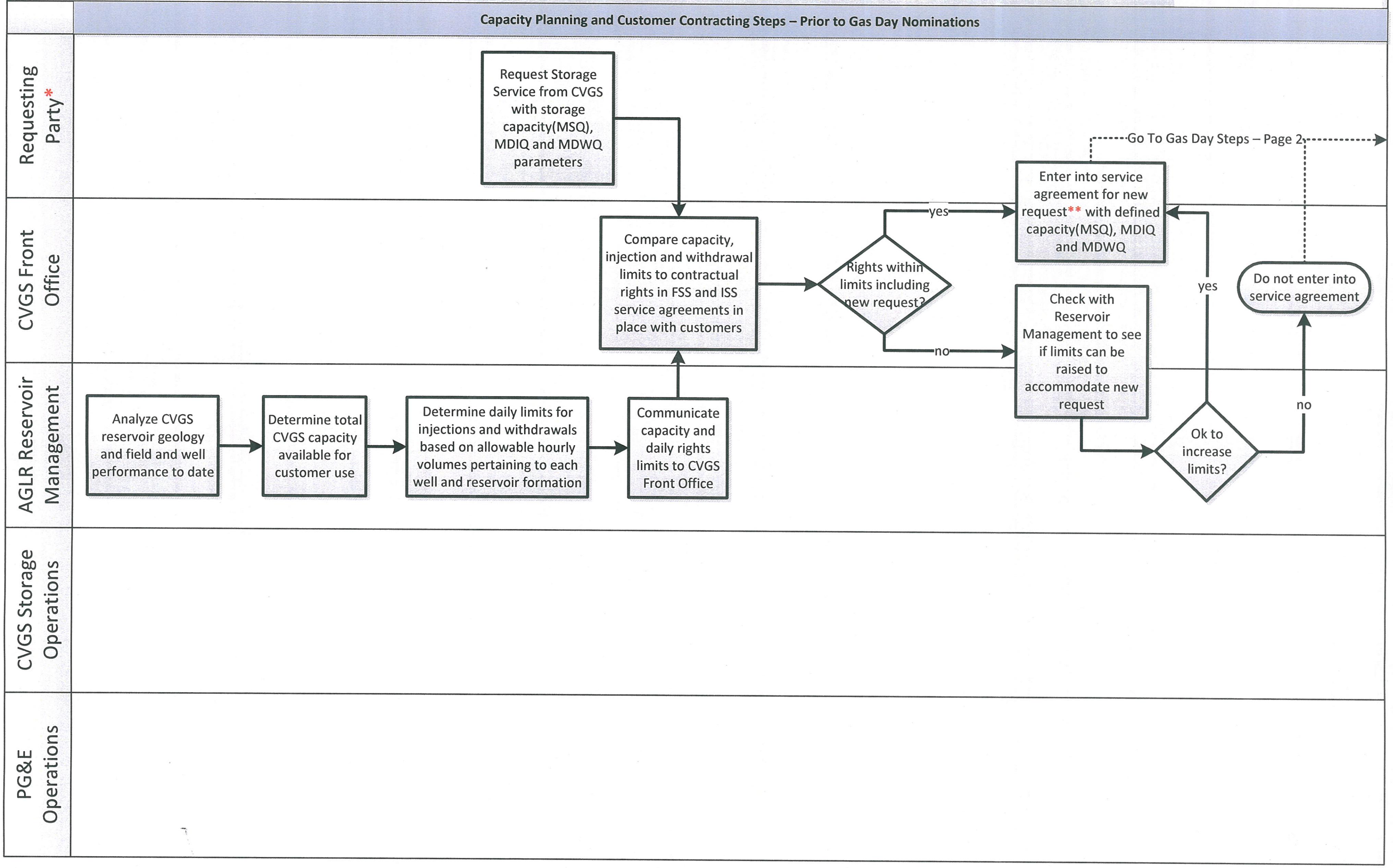
How CVGS Will Address Idle and Out of Service Lines (Not Fully Abandoned):

In-service idle pipe (i.e., that contains gas, but is not presently being used to transport gas) represents a potential hazard to public health and the environment, even though idle. If such pipe leaks or ruptures, an explosion could result. Leaks may go undetected for some time, since idle pipe may not be covered by operator's SCADA systems. For these reasons, CVGS will meet all requirements and deadlines for pipe that contains gas.

Attachment 11

Central Valley Gas Storage Capacity Process

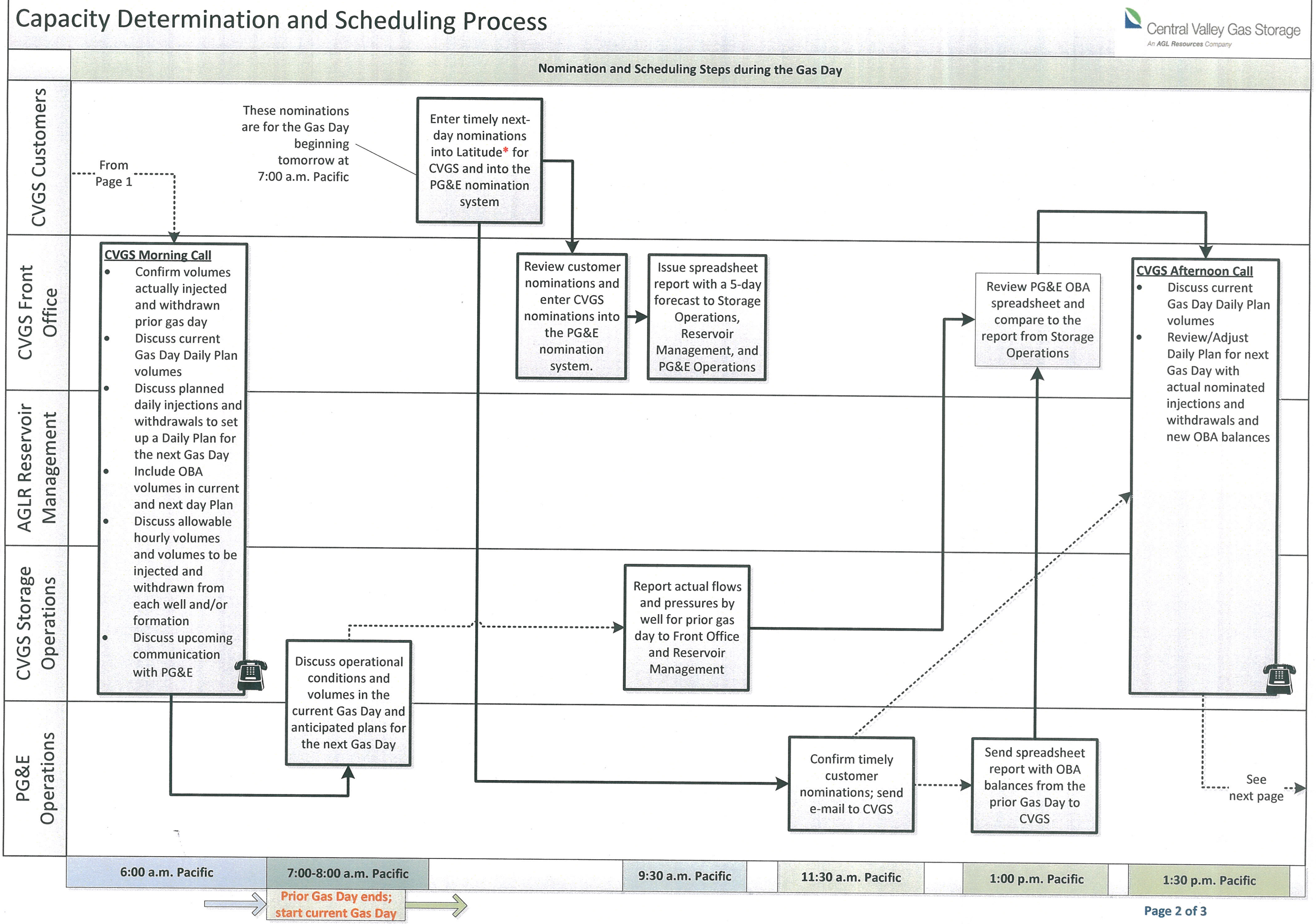
Capacity Determination and Scheduling Process



* CVGS customer or potential customer desiring storage Service under CVGS Tariff terms.

** Assuming mutually agreeable commercial terms within CVGS Tariff parameters.

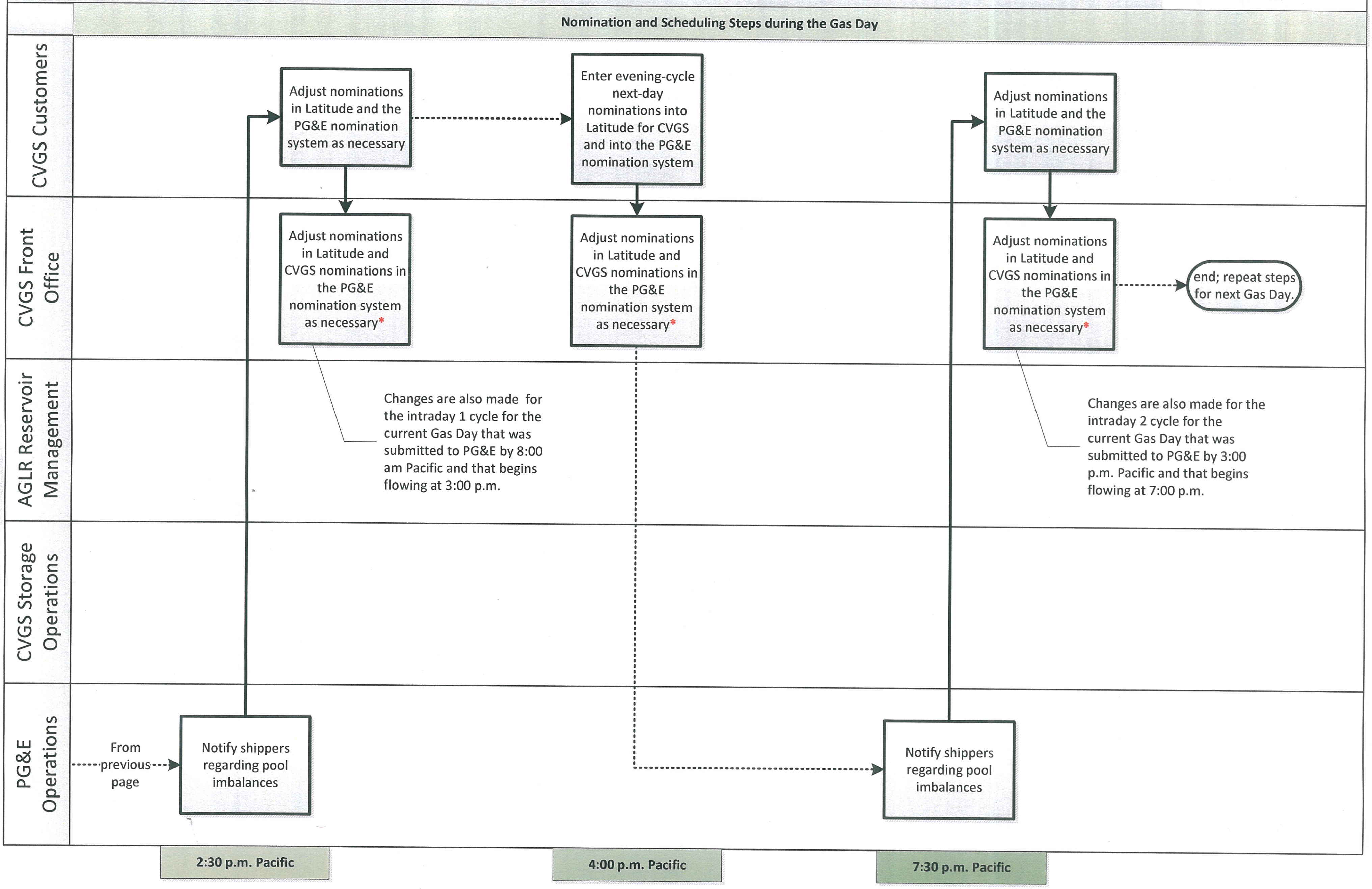
Capacity Determination and Scheduling Process



* - Nomination volumes (injection or withdrawal) in Latitude are limited by rights established in Latitude by Front Office at the time a Service Agreement is established.

Capacity Determination and Scheduling Process

Central Valley Gas Storage
An AGL Resources Company



* Latitude automatically sends an e-mail to Front Office and Storage Operations with changes.