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Element #1 HCA Identification

Element #2 Threats

Element #3 Baseline Assessments

Element #4 Direct Assessments (N/A)

Element #5 Remediation

Element #6 Continual Evaluation

Element #7 Confirmatory Direct Assessment

Element #8 Preventive Measures

Element #9 Performance Measures

Element #10 Record Keeping

Element #11 Management of Change

Element #12 Quality Assurance

Element #13 Communication Plan

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Element #15 Environmental and Safety

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #1: ID of Pipeline Segments Impacting HCAs

**Ref: 49 CFR 192.901- 915** **Updated: Nov 2010**

***In This Element*:**


**1.1 Objectives and Purpose**
**1.2 Applicability of Gas IMP Rule**
**1.3 Definitions Applicable to ID of HCAs**
**1.4 Process for ID of HCAs**
**1.5 Annual Review of Pipeline Segments for New HCAs**
**1.6 Notification to OPS for Changing HCA ID Method**
**1.7 Review and Updates of IMP**
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**1.9 Source References**
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**Flow Chart: Rule Applicability & ID of HCAs**
**Figure E.I.A.: Determining High Consequence Areas**
**HCA Proration Calculation**


### 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, LGS has developed these ID of HCA procedures to assist in this effort.

### 1.2 Applicability of Gas IMP Rule [192.901]

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.

In determining if an intrastate pipeline meets the definition of a transmission line set out in Part 192.3, LGS will consider the factors listed in 49 CFR 192.3(a)-(c) of the pipeline safety regulations. For a pipeline to be designated as distribution or gathering, LGS will document the reason(s) the pipeline does not meet one of the factors listed in 192.3(a)-(c) or why the pipeline segment is gathering as defined in 192.1-192.9.

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. LGS 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]

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Requirements If There are No HCAs:

LGS is not required to develop an integrity management program if there are no high consequence areas on its system. But, LGS 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 LGS must comply. These requirements include the following:

1) LGS will periodically 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. LGS will demonstrate that it has periodically evaluated its pipeline to assure that there continue to be no HCAs.

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) LGS 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 LGS will prepare an integrity management plan and meet all the requirements of subpart O.
[FAQ #150]

How LGS 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, LGS 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 LGS Will Address Facilities:

LGS 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 LGS Will Address Gases other Than Natural Gas:

The rule does apply to transmission pipelines for gases other than natural gas. If the LGS has transmission pipelines transporting other gases, LGS will adjust the formula for determining potential impact circles to reflect the constant appropriate for the gas transported. [FAQ #3]

How LGS Will Address Lines Transporting Both Gas and Liquids:

Lines that transport both liquids and gas must meet requirements applicable to both. In practice, this means that the more stringent requirements will be met. [FAQ #12]

### 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 outside 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 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. (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

(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.

Potential Impact Circle is a circle of radius equal to the potential impact radius (PIR).

Potential Impact Radius (PIR) 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-2001 (supplement to ASME B31.8; ibr, see 192.7) to calculate the impact radius formula.

### 1.4 Process for ID of HCAs [192.905]

LGS 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.

General:

To determine which segments of LGS's transmission pipeline system are covered by this subpart, LGS will identify the high consequence areas and document this review. LGS will use method (1) or (2) from the definition in 192.903 to identify high consequence areas. LGS may apply one method to its entire pipeline system or LGS may apply one method to individual portions of the pipeline system. LGS may also choose to include sections of class 1 or class 2 pipelines into the IM program.

LGS will describe in its integrity management program documentation ***which method it is applying to each portion of the LGS's pipeline system.*** The description will include the potential impact radius when utilized to establish a high consequences 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. See figure E1A at the end of this IMP element. LGS 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, LGS'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: 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. The 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. Ten feet will be added to aerial photography over lay to account for potential minimum errors in alignment sheets and/or collection of GPS data points.

*Step #2: Identified Site Surveys from Public and Emergency Officials*

LGS will make a reasonable effort to identify sites meeting the criteria for "identified sites." LGS will attempt to contact officials with safety, emergency response or planning responsibilities to assist in locating identified sites. LGS will use Pipeline Association for Public Awareness (PAPA) to send a letter to the public and emergency officials requesting information on identified sites or conduct face to face meetings when appropriate. [Element #1: Record #10] 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.

*Step #3: Identified Site Surveys from Routine O&M Activities*

As another option to the identified site survey, LGS will use information from routine operation and maintenance activities as listed in section #1.4. Use form #1-1C (HCA Identified Site Survey) or equivalent to document this review.

Also, if a public official with safety or emergency response or planning responsibilities informs LGS that it does not have the information to identify an identified site, LGS 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.

If LGS uses Method 1 to identify HCAs, then all of its class 3 and 4 pipelines will be HCA and LGS need not separately look for identified sites on that pipeline. LGS would need to consider identified sites on any class 1 or 2 pipeline that LGS also operates. [FAQ #191]

If LGS only has a limited amount of pipeline, LGS can elect to treat its entire pipeline as an HCA and need not determine if potential impact circles contain 20 houses nor locate identified sites. [FAQ #192]

Newly Identified Areas:

When LGS 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, LGS 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 LGS's baseline assessment plan as a high consequence area within one year from the date the area is identified.

How LGS Operating Employees Will be Considered in HCA Analysis

LGS 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 LGS 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, LGS 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, LGS 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 LGS 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:

The rule does not include a single home housing a disable person to 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 operators 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 shall 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 this 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]

### 1.5 Annual Review of Pipeline Segments for New HCAs or Change in HCAs

LGS will conduct a review once per calendar year not to exceed 18 months for change in conditions along their pipelines. Pipeline throughput, changes in population and/or environment will be periodically reviewed. When LGS 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 collect the information for potential changes to HCAs, include the following:

1) Annual Reports, O&M 1.04 [Element #1: Record #11]
2) Onshore Gas Gathering Determination, O&M #4.02 [Element #1: Record #12]
3) Continuing Surveillance, O&M #5.01[Element #1: Record #13]
4) Pipeline Patrols, O&M #5.03 [Element #1: Record #14]
5) Maximum Allowable Operating Pressure (MAOP), O&M #8.01 [Element #1: Record #15]
6) Pipeline Uprating, O&M #12.01 [Element #1: Record #16]
7) Conversion of Service, O&M #12.02 [Element #1: Record #17]

Form 1-1D (Change in Operation Affecting HCA) or equivalent will be used to document this review.

LGS will assure that their HCA definitions are current. In an area in which there is rapid growth or change in the use of buildings near the pipeline, that may require frequent updating. In an area where less growth is occurring, updates could occur more

infrequently. In any event, OPS would expect that operators would evaluate conditions along their pipelines once per calendar year not to exceed 18 months to determine if they have changed. [FAQ #117]

A newly-identified HCA must be incorporated into the integrity management program within one 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.

How LGS 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 continue to apply. 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). [FAQ #10]

### 1.6 Notification to OPS for Changing HCA ID Method

If LGS 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 #18]

Also, integration of acquired pipe into LGS'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

LGS 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 (continual evaluation and assessment). When changes to the plan occur, LGS will document any

modifications to the plan and the reasons for the modification as shown in the gas IMP record of revisions. [Element #1: Record #19]

### 1.8 Review and Implementation of Element #1

LGS will use the agenda, "Gas IMP Element #1, ID of HCA Agenda and Action Items", for review and implementation of this element. LGS 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 #11]

- 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

### 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: Nov 2010**

### 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. | 1.1 | Jurisdictional determination | IMP Leader | AR | 5 yrs | Co. intranet |
| 2. | 1.3 | Gas IMP List of HCAs with PIR calculation | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 1.3 | Form #1-1A (HCA Identification Survey Method #1) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 4. | 1.3 | Form #1-1B (HCA Identification Survey Method #2) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 5. | 1.3 | Form #1-1C (HCA Identified Site Survey) | OM – Maint. | 1x/yr[1] | 5 yrs | Co. intranet |
| 6. | 1.3 | Form #1-1D (Change in Operation Affecting HCA) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 7. | 1.3 | GPS instrument manufacturer's technical info on accuracy | N/A | 1x/yr[1] | 5 yrs | Co. intranet |
| 8. | 1.3 | Aerial photography or survey maps | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 9. | 1.3 | As-built drawing alignment sheets | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 10. | 1.3 | Public Officials/Em. Officials Identified Site Survey Letter | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 11. | 1.4 | Annual Reports, O&M #1.04 | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 12. | 1.4 | Onshore Gas Gathering Determination, O&M #4.02 | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 13. | 1.4 | Continuing Surveillance, O&M #5.01 | OM – Maint. | 1x/yr[1] | 5 yrs | Co. intranet |
| 14. | 1.4 | Pipeline Patrols, O&M #5.03 | OM – Maint. | 1x/yr[1] | 5 yrs | Co. intranet |
| 15. | 1.4 | Maximum Allowable Operating Pressure, O&M #8,01 | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 16. | 1.4 | Pipeline Uprating, O&M #12.01 | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 17. | 1.4 | Conversion of Service, O&M #12.02 | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 18. | 1.5 | Notification to OPS for change in HCA method | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 19. | 1.6 | Gas IMP record of revisions | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 20. | 1.7 | Element #1 agenda | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |

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|---|---|---|---|---|---|---|
| 21. | 1.7 | 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.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

Objectives for ID of HCAs:

- Verify all pipeline systems and segments are reviewed for HCAs and properly documented
- Verify that proper HCA identification methods were used (class locations, identified sites, PIRs, etc.)
- Verify all new pipelines and changes to pipeline operations have been evaluated for potential impacts to HCAs
- Verify all new HCAs have been properly documented with MOC and communicated to the appropriate personnel
- Verify all required processes in element #1 have been properly documented

Who Should Attend ID of HCAs:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

| Ref: 49 CFR 192.903, 905 | Updated: Oct 2011 |
|---|---|

Frequency of ID of HCA Review:

- This agenda and these actions items shall be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve the ID of HCA process and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review ID of HCAs:

- Element #1 Procedure: ID of Pipeline Segments Affecting HCAs
- 49 CFR 192.903 & 192.905
- FAQs: General and Rule Applicability
- FAQs: HCA Identification
- Gas IMP Protocol Area A With Cross Reference, Identify HCAs
- ASME B31.8S-2004, Gas Integrity Management

| Ref: 49 CFR 192.903, 905 | Updated: Oct 2011 |
|---|---|

Forms and Documents Required For This Review:

- Form #1-A, HCA Identification Survey Method 1
- Form #1-B, HCA Identification Survey Method 2
- Form #1-C, HCA Identification Site Survey
- Form #1-D, HCA Change in Operations Affecting HCAs
- Form #1-2, Gas IMP HCA List With PIR Calc
- BAP Ranking, Scheduling, and RA Worksheet
- HCA Survey Maps and Records
- Class Location Survey, O&M #4.01
- Continuing Surveillance Review, O&M #5.01
- Patrol Reports, O&M Form #5.02
- ASME B31.8S, Gas Integrity Management

Record Keeping for ID of HCAs:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #1: ID OF HCA ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Program Requirements [protocol #A.01]**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Review the company pipeline operations for ID of HCA segments and verify that the methods defined in 192.903 High Consequence Area (1) and/or 192.903 High Consequence Area (2) are applied to each pipeline for the identification of high consequence areas.* | **A.01** | | | | | |
| 1 | Verify each company HCA segment includes documented processes on how to implement methods (1) and (2) in order to identify high consequence areas. | **A.01.a** | 1.3,1.4 HCA forms | 905(a) | IMP Leader | 1x/yr | Complete. See procedures in Element 1 tab of IMP procedures binder. See HCA survey docs in Element 1 tab of IMP record binder. |
| 2 | Verify that each company HCA segment process requires that the method used for each portion of the pipeline system be documented. | **A.01.b** | 1.3,1.4 HCA forms | 905(a) | IMP Leader | 1x/yr | Complete. See HCA survey docs and list of HCAs in Element 1 tab of IMP record binder. |
| 3 | Verify the company's integrity management program includes system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas. | **A.01.c** | 1.3,1.4 HCA forms | 905(a) | IMP Leader | 1x/yr | Complete. See maps with aerial views in Element 1 tab of IMP record binder. |
| 4 | Review company HCA records to verify that identification of pipeline segments in high consequence areas was completed by December 17, 2004. | **A.01.d** | 1.1 | 907, 911(a) | | | There is no completed hardcopy HCA form, but the identified HCA's were reported on that period's online reporting website. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Potential Impact Radius [protocol #A.02]**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Verify that the definition and use of potential impact radius for establishment of high consequence areas meets the following requirements:* | **A.02** | | | | | |
| 5 | Verify that the company's formula for calculation of the potential impact radius is consistent with 192.903 requirements ($r = 0.69*(p*d^2)^{0.5}$) and that the pressure used in the formula is based on maximum allowable operating pressure (MAOP). Verify inaccuracies of instrumentation (GPS, laser range finder, Google, etc.) are accounted for in HCA survey.<br><br>Note, for gases other than natural gas, verify that the operator has documented processes for the use of ASME B31.8S-2004, Section 3.2 to calculate the impact radius formula. | **A.02.a** | 1.3 HCA forms | 903, 905(a) | IMP Leader | 1x/yr | Complete.<br>See IMP procedures and HCA with PIR worksheet in Element 1 tab of IMP record binder. |
| 6 | In cases where potential impact circles are used to identify high consequence areas, verify that the program requires that high consequence areas 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. | **A.02.b** | 1.3 HCA forms | 903 | IMP Leader | 1x/yr | Complete.<br>See IMP procedures in Element 1 tab of IMP procedures binder. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identified Sites [protocol #A.03]**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Verify that the company's identification of identified sites includes the sources listed in 192.905(b) for those buildings or outside areas meeting the criteria specified by 192.903, and that the source of information selected is documented.* | **A.03** | | | | | |
| 7 | Identified sites must include the following:<br>1. Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12 month period (days need not be consecutive),<br>2. Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (days and weeks need not be consecutive), and<br>3. Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to evacuate. | **A.03.a** | 1.3 HCA forms | 903, 905(b) | IMP Leader | 1x/yr | Complete.<br>See IMP procedures and HCA survey forms in Element 1 tab of IMP procedures binder. |

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identified Sites [protocol #A.03] (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 8 | Identified sites must be identified using the following sources of information:<br><br>1. Information from routine operation and maintenance activities and input from public officials with safety or emergency response or planning responsibilities<br>2. In the absence of public official input, the operator must use one of the following in order to identify an identified site:<br>1. Visible markings such as signs, or<br>2. Facility licensing or registration data on file with Federal, State, or local government agencies, or<br>3. Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public. | **A.03.b** | 1.3 HCA forms | 905(b) | IMP Leader | 1x/yr | Complete.<br>See IMP procedures and HCA survey forms in Element 1 tab of IMP procedures binder.<br><br>See PAPA documentation for identified sites in Element 1 tab of IMP record binder. |

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identification Using Method 1 (class locations) [protocol #A.04]**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *If the company's integrity management program relies on 192.903 High Consequence Area definition (1) for identification of high consequence areas, verify compliance with the following:* | **A.04** | | | | | |
| 9 | Verify the integrity management program includes Class 3 and Class 4 piping locations as high consequence areas consistent with the criteria of 192.5(b)(3), 192.5(b)(4), and 192.5(c). | **A.04.a** | 1.3, 1.4 HCA forms | 192.903 HCA (1)(i) and (ii)] | IMP Leader | 1x/yr | Complete.<br>LGS uses Method 1. See HCA with PIR worksheet in Element 1 tab of IMP record binder. |
| 10 | For Class 1 and Class 2 locations with the potential impact radius greater than 660 feet, verify the integrity management program includes piping locations as high consequence areas if the area within the associated potential impact circle contains 20 or more buildings intended for human occupancy.<br><br>As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: | **A.04.b** | 1.3, 1.4 HCA forms | 192.903 | IMP Leader | 1x/yr | N/A.<br>PIR is less than 660 ft. |

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identification Using Method 1 (class locations) [protocol #A.04] (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 10 (cont.) | Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]$^2$ or<br><br>Building Count within 200 meters = 20 x [200 (m) / PIR (m)]$^2$<br><br>If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. | **A.04.b** | 1.3, 1.4 HCA forms | 192.903 | IMP Leader | 1x/yr | N/A.<br>PIR is less than 660 ft. |
| 11 | Verify the program includes as a high consequence area, any area in Class 1 and Class 2 piping locations where the potential impact circle contains an identified site. | **A.04.c** | 1.3, 1.4 HCA forms | 192.903 | IMP Leader | 1x/yr | Complete.<br>See HCA with PIR worksheet in Element 1 tab of IMP record binder. |

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identification Using PIR (Method 2) [protocol #A.05]**

| # Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *If the company's integrity management program relies on 192.903 High Consequence Area definition (2) for identification of high consequence areas, verify compliance with the following:* | **A.05** | | | | | |
| 12 | Verify the integrity management program includes piping locations as high consequence areas if the area within a potential impact circle contains 20 or more buildings intended for human occupancy:<br><br>As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula:<br><br>Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]$^2$ or<br>Building Count within 200 meters = 20 x [200 (m) / PIR (m)]$^2$ If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. | **A.05.a** | 1.3, 1.4 HCA forms | 192.903 | IMP Leader | 1x/yr | N/A, method 1 used. |

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- Identification Using PIR (Method 2) [protocol #A.05] (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 13 | Verify the program includes piping locations as high consequence areas if the area within the potential impact circle contains an identified site. | **A.05.b** | 1.3, 1.4 HCA forms | 192.903 | IMP Leader | 1x/yr | N/A, method 1 used. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #1: ID of HCAs Agenda

**Ref: 49 CFR 192.903, 905** **Updated: Oct 2011**

**Element #1: Identification of HCAs- ID and Evaluation of Newly Identified HCAs [protocol #A.06]**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Review the company's integrity management program to verify processes are in place for evaluation of new information that may show that a pipeline segment impacts an HCA.* | **A.06** | | | | | |
| 14 | Verify the company's program to identify and analyze changes for impacts on pipeline segments potentially affecting high consequence areas. Issues the program must consider include but are not limited to:<br>1) Changes in pipeline maximum allowable operating pressure (MAOP),<br>2) Pipeline modifications affecting piping diameter,<br>3) Changes in the commodity transported in the pipeline,<br>4) Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites,<br>5) Change in the use of existing buildings (e.g., hotel or house converted to nursing home),<br>6) Installation of new pipeline,<br>7) Change in pipeline class location (e.g., class 2 to 3) or class location boundary,<br>8) Pipeline reroutes<br>9) Corrections to erroneous pipeline center line data. | **A.06.a** | 1.5 HCA form #1-1D | 905(c) | IMP Leader | 1x/yr | Complete.<br>See IMP records (form #1-1D) in Element 1 tab of IMP record binder. |

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #2: Threats, Data Integration, and Risk Analysis

| Ref: 49 CFR 192.917 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


2.1 Objectives and Purpose
2.2 Summary of Requirements for Threats, Data Integration, and Risk Analysis
2.3 Definitions Applicable to Element #2
2.4 Threat Identification
2.5 Actions to Address Particular Threats
2.6 Data Gathering
2.7 Data Integration and Analysis
2.8 Risk Assessment, Including Validation
2.9 Plastic Transmission Pipeline
2.10 Review and Implementation of Element #2
2.11 Source References
2.12 List of Required Ongoing Documentation

Threat Identification and Risk Assessment Flowchart


### 2.1 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, LGS has developed these threats, data integration, and risk analysis procedures to assist in this effort.

### 2.2 Summary of Requirements for Threats, Data Integration, and Risk Analysis [192.917]

LGS must identify and evaluate all potential threats to the covered segment. LGS 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 LGS identified any of the following threats, it must take specific actions to address the threats:

- Third Party Damage – LGS 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 – LGS must use cyclic fatigue analysis to prioritize baseline assessments and reassessments
- Manufacturing and Construction Defects – LGS 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.

### 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 LGS'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 LGS. For the purposes of this document it also includes damage caused by LGS's personnel or LGS'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)]

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.

LGS will identify and evaluate all potential threats to each covered pipeline segment. LGS will use the prescriptive approach in identifying and evaluating all potential threats.

| Ref: 49 CFR 192.917 | Updated: Nov 2010 |
|---|---|

Using Appendix A of ASME/ANSI B31.8S, LGS 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-2001, 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, Section 2.2]. [192.917(a)]

In general, a threat shall be included for a segment if LGS's failure history includes failures due to the threat on the segment or similar segments (both covered segments and other segments in the LGS 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, LGSs 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

LGS 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
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 review and 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.

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) For particular threats listed below, take specific actions to address those threats

## 2.5 Actions to Address Particular Threats

When LGS identifies any of the following threats, LGS will take the following actions to address the threat.

### 2.5.1 Third Party Damage (TPD)

### Data Integration

LGS will utilize the data integration required in 192.917(b) and ASME/ANSI B31.8S, appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. When TPD is identified through data integration, LGS will implement comprehensive additional preventative measures in accordance with 192.935 and monitor the effectiveness of the preventive measures.

If, in conducting a baseline assessment under 192.921, or a reassessment under 192.937, LGS uses an internal inspection tool or external corrosion direct assessment, LGS 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. LGS 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, LGSs 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, LGS 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]

### Additional Preventive and Mitigative Measures for TPD

See element #8, section #8.4 for additional TPD preventive and mitigative measures.

### DA Requirements for TPD

**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, LGS 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

LGS 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. LGS 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 LGS 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 LGS identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, LGS 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. LGS 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, LGS 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 reasonable be anticipated, a pipeline movement monitoring program shall be establish and appropriate intervention activities undertaken. [ASME B31.8S, 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 constructions characteristics coexist with external or outside force potential. [ASME B31.8S, A5.3]

How Manufacturing and Construction Defects Will Be Addressed If Subpart J Tested:

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. LGS 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, Section 2.2, and establish its assessment plans accordingly.

Assessments addressing the threat of manufacturing and construction defects are required for pipe that has never been tested to Subpart J requirements if operating conditions on the line change. [FAQ #219]

Assessments for manufacturing and construction defects generally are not required for pipe that has successfully passed a Subpart J pressure test even if these changes in operating conditions occur. [FAQ #220]

How Manufacturing and Construction Defects Will Be Addressed If The Segment Has Not Been Subpart J Tested:

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. LGS 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, 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]

Pressure Test to Establish M&C Threats are Stable

Section 192.917(e)(3) requires that LGSs 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) specify 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 consider 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. LGSs 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, 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, LGS will select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. LGS 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 LGS's BAP, these segments will uniquely identified.

### 2.5.5 Corrosion

If LGS identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in 192.933), LGS will evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. LGS will establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with LGS's established operating and maintenance procedures under part 192 for testing and repair.

Corrosion Rates Related to Soil Resistivity [ASME B31.8, table B1]

| 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 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

Review relief and regulator valve inspections to determine if there is set point drift. If drift is found, extra scrutiny or inspections may be required.~~Certain relief and regulator valves are known to have their set points drift. These equipment types may require extra scrutiny.~~

Review maintenance records to determine if ~~C~~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.

LGS 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 LGS's risk assessment, the results of which support decisions in all other integrity management program elements.

LGS 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 have 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, 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. [Element #2: record #2]

**Data Elements for Prescriptive Pipeline IM Program [ASME B31.8, 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) LGS will use the prescriptive approach as described in ASME B31.8, non-mandatory appendix A to data gathering, reviewing, and integration
2) LGS 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, Non-Mandatory Appendix A]**

| Threat Category: | # | Data Description: |
|---|---|---|
| External Corrosion [ASME B31.8, 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, 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, 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, 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, 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)<br><br>[ASME B31.8, 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)<br><br>[ASME B31.8, 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, A8.2] | 8.1 | Procedure review information |
| | 8.2 | Audit information |
| | 8.3 | Failures caused by incorrect operations |
| | | |
| Weather Related and Outside Force | 9.1 | Joint method (mechanical coupling, acetylene weld, arc weld) |
| | 9.2 | Topography and soil conditions (unstable slopes, |

| | | |
|---|---|---|
| (earth movement, heavy rains or floods, cold weather, lighting)<br><br>[ASME B31.8, A9.2] | | 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 GIS Facility Explorer database.

   Key data for inputting into the GIS Facility Explorer database include the following:
   1) Stationing and/or GPS points
   2) Smart pig results
   3) Pressure tests
   4) ECDA report and/or CIS, DCVG
   5) Guided wave
   6) CP surveys
   7) Soil resistivity
   8) Exposed pipe reports
   9) Outside force areas
   10) Repairs

Gathering Information From the Entire Pipeline:

LGS will consider information from portions of pipelines not in HCAs when developing my integrity management program. Section 192.917(b) requires that LGS 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. Non-covered pipeline has generally been subject to the same operational and maintenance practices, corrosion control,

etc., and experience on it is relevant to the likelihood of problems in covered segments.

LGS 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 LGS 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). In this manner, OPS expects that the data on which LGSs base their IM programs will improve over time, and that the risk analyses and data integration that are part of the program will similarly improve. [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. LGS will use a GIS system and 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.

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:

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 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, LGS. The pipeline does not fail but now contains a stress concentrator that could lead to future failure. Sometime after the damage, LGS 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, LGS 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. LGS 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) LGS will use the prescriptive approach as described in ASME B31.8, 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 GIS mapping system~~the 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

LGS 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 is 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 are *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, LGS 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 threat analysis worksheet [Element #2: Record #1]~~"Data Sources" 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.

LGS will ***validate the data for accuracy***. If LGS lacks sufficient data or where data quality is suspect, LGS will follow the requirements in ASME/ANS B31.8S, section 4.2.1, section 4.4, and Appendix A and summarized below.
[ASME B31.8S, 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.
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, LGS may use two different vendors to conduct cathodic protection surveys.
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]

LGS 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, LGS must gather and evaluate the set of data specified in appendix A to ASME/ANSI B31.8S. 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

LGS 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

LGS's risk assessment will support the following objectives: [ASME B31.8S, 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 LGS 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 LGS risk assessment:

- How the risk assessment is conducted including how RA results that will be produced

- 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)

How the RA is Conducted

LGS will conduct a risk assessment that follows the ASME/ANSI B31.8S, section #5 and consider the identified threats for each covered segment. LGS will initially use the ***Subject Matter Expert (SME) risk approach*** as described in ASME/ANSI B31.8S section #5.5.

Specific steps to RA process using the "BAP and Mitigation" Excel worksheet:
[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 at 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 SEVERITY of 1 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 LIKLIHOOD would be for the risk factor and assign a LIKLIHOOD 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 LIKLIHOOD 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 |
| 3-4 | Orange = risk is not desirable |
| 5-7~~8~~ | Blue = risk is acceptable with controls in place |
| 8~~9~~-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.

LGS 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, section 5.7(a)]
- Considers the frequency and consequences of past events, using LGS and industry data [ASME B31.8S, section 5.7(c)]
- Integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S, 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, section 5.7(i)]
- Incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S, section 5.7(k)];

Subject Matter Expert (SME) Qualifications

ASME/ANSI B31.8S defines "subject matter experts" as "individuals that have expertise in a specific area of operation or engineering." Section 192.915 requires that an operator's IM program provide criteria for qualifications. Each operator 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. Operators should 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.

GS 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, 5.11, 5.7(c)]

2) LGS will integrate the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. [ASME B31.8S, 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, 5.12]
4) LGS will use a feedback mechanism to ensure that the risk model is subject to continuous validation and improvement. [192.917(c); ASME B31.8S, 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

LGS will conduct the following processes to validate the results of the risk assessments as required by §192.917(c) and ASME B31.8S, §5.12.

- IMP team review of results (annual agenda reviews)
- SME reviews
- Review of lessons learned from industry

What LGS Will Consider in Prioritizing Pipe Segments For Assessment and Re-assessment [08/17/2004]

The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. Risks must be evaluated using a risk assessment that meets ASME/ANSI B31.8S, Section 5, as required by 192.917(c). Section 5.10 of the standard specifically addresses use of risk assessment for prioritizing pipe segments for assessment. [FAQ #28]

How LGS Will Apply Different Risk Ranking Systems For Lines in HCAs [04/08/2004]

When conducting integrity management inspections, OPS expects to review a risk ranking of all HCA segments as part of the Baseline Assessment Plan review. LGS must have a process that is consistently and uniformly applied across all of its covered segments, considers all factors that affect the likelihood and consequences of pipeline failure, and that produces a risk ranking of HCA pipeline segments. This same process can also be applied to other pipeline segments outside of HCAs. [FAQ #78]

How LGS Will Re-Prioritize Each Time a New Segment is Added:

The rule specifies a ten (10) year assessment schedule for newly identified segments. LGS 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]

How LGS will Handle Risk Ranking of Piggable Sections:

The rule requires that LGS must use risk assessment to prioritize covered segments for baseline assessments and reassessments (192.917(c)). OPS expects to see a ranking by covered segment. LGS will manage their assessments with input from piggable sections. Such input can mask important information, however. For example, a number of low-risk covered segments in a piggable section could result in that section being determined to be of moderate risk even though it contains the highest risk covered segment in LGS's program. LGS must understand the relative risk of individual covered segments so that they can appropriately plan their assessment activities. [FAQ #125]

Qualifications Standards Apply to Subject Matter Experts (SME):

ASME/ANSI B31.8S defines "subject matter experts" as "individuals that have expertise in a specific area of operation or engineering." Section 192.915 requires that LGS's IM program provide criteria for qualifications. LGS 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. LGS will document the qualification of their SMEs. OPS inspections may include examination of the qualification of SMEs. [FAQ #166]

How LGS Will Handle Segments With Specific Threats as "high risk Segments":

The rule requires that LGS evaluate the risk posed by their covered segments, identifying those that pose the highest risk. The situations in which the rule requires that a covered segment be treated as a high-risk segment are those that experience has shown to be significant contributors to pipeline risk. OPS expect these segments to be given special consideration in developing an assessment schedule.
[FAQ #169]

How LGS Will Use Risk Assessment Data to Defend Longer Intervals Between Integrity Assessments**:**

When LGS's integrity management program meets the criteria for exceptional performance in 192.913, LGS can implement performance-based programs in which they can establish longer reassessment intervals. One of those criteria is a comprehensive process for risk analysis. OPS expects a thorough risk analysis and integration of other information regarding pipeline integrity to be key elements in establishing longer reassessment intervals under performance-based programs.
[FAQ #45]

How LGS Will Consider External Conditions Such as Earthquake Fault Lines or Mining Subsidence in their Integrity Management Program**:**

As part of the information and risk analysis required by 192.917 (b) and (c), LGS will consider all information that can affect the likelihood and consequences of pipeline failure. 192.917 (b) requires that LGS gather and evaluate, as a minimum, the data specified in Appendix A to ASME/ANSI B31.8S. Section A9 of that Appendix addresses weather related and outside force threats, and includes topography, soil conditions, and earthquake faults among the data to be integrated. Thus, if such external risk factors are significant, they must be considered by LGS. [FAQ #83]

How LGS Will Assess and Control Risk Caused by Third-Parties Over which they have no Direct Control**:**

As part of a comprehensive risk analysis required by 192.917 (c), LGS will determine the risk associated with third party damage to pipeline segments that could affect an HCA. LGS will follow section 5 of ASME/ANSI B31.8S, which contains guidance on risk assessments.

OPS will not prescribe specific risk analysis methods that LGS must use. OPS understands outside force damage prevention is challenging because it involves factors outside of LGS's control. Nonetheless, there are a number of actions LGSs can take to reduce the likelihood of third party damage. If a pipeline segment is in an HCA, and third party damage is determined to be a significant risk (e.g., as might be expected in a high population area, with new construction near the line), LGS must implement the comprehensive additional preventive measures in 192.935. [FAQ #91]

How LGS Will Handle Potential Business Consequences (e.g., Curtailments, Plant Shutdown) in their Risk Determinations**:**

The focus of the integrity management rule is reducing the risk of pipeline failures to high consequence areas. The integrity management programs developed to comply with rule requirements must include the use of risk analysis to support LGS's integrity decisions. LGS's risk analysis processes require the evaluation and measurement of both the probability and consequences of pipeline failures. The appropriate consequences to be included in these risk analyses depend on the decisions that are being supported by the risk analysis results.
In the context of fulfilling requirements of the integrity management rule, LGS will maintain a focus on the risk of failures to high consequence areas.

If consequences considered in the risk analysis are expanded to include consequences related to LGS's business performance, then LGS will provide assurance that this approach does not skew decisions away from protection of HCAs. For example, consideration of LGS's business performance consequences shall not result in pipeline segments with high risk to HCAs being given lower priority for integrity assessments than segments with low risks to HCAs but higher business consequences.

There may be situations in which business impacts have secondary related safety consequences. LGS may include these consequences in the overall assessment of risk related to an integrity decision. It is necessary, however, that such secondary consequences are evaluated and balanced appropriately with other safety consequences in the risk analysis. [FAQ #102]

Discussion of Four Risk Analysis Methods**:**

The four risk assessment approaches described in ASME/ANSI B31.8S are all valid. The approach that is appropriate for an individual LGS will often be driven by circumstances specific to that LGS, including the size/complexity of their system and

the expertise/experience of their personnel. Some LGSs, particularly those with few miles of transmission pipeline, may conclude that the SME approach is sufficient. [FAQ #168]

## 2.9 Plastic Transmission Pipeline

LGS does not have plastic transmission pipeline at this time. If LGS constructs or obtains plastic transmission pipeline, LGS will develop procedures for addressing specific threats as required by 192.917(d).

## 2.10 Review and Implementation of Element #2

LGS will use the agenda, "Gas IMP Element #2, Threats, Data Integration Agenda and Action Items", for review and implementation of this element. LGS 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~~8~~: Record #7~~21~~]

## 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 a 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, 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: Nov 2010**

### 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. | 2.5 | Threat Identification Worksheet | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 2. | 2.6 | All data required by ASME data gathering guidelines | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 2.7 | Data integration using GIS Facility Explorer 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~~6~~. | 2.10 | ~~Review and Implementation Agenda for~~ Element #2 Action Items | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program – Agenda
## Element #2: Threats, Data Integration, and Risk Analysis

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

Element #2: Threats, Data Integration, and Risk Analysis Objectives:

- Verify each HCA segment is reviewed for all applicable threats including segment specific threats and that the threat review is properly documented
- Verify each pipeline system is reviewed for all applicable data that could be relevant to a covered segment and that the data has been assembled and integrated (including non-HCA segments)
- Verify the risk assessment includes all the identified threats and follows the process of ASME B31.8S, section #5
- Verify the risk assessment is validated and the validation process is documented
- Verify applicable threats were used if there is plastic transmission pipeline

Who Should Attend ID of HCAs:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

| Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A | Updated: Oct 2011 |
|---|---|

Frequency of Threats, Data Integration, and Risk Analysis Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve threats, data integration, and risk analysis review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Threats, Data Integration, and Risk Analysis Review:

- Element #2 Procedure: Threats, Data Integration, and Risk Analysis
- 49 CFR 192.935, 192.917(b)
- ASME section #4, Gathering, Reviewing, and Integrating Data
- ASME section #5, Risk Assessment
- FAQs: Threats, Risk Analysis, and ID of Threats
- FAQs: Risk Analysis and Prioritization, Specific Threats
- FAQs: Data Integration
- Gas IMP Protocol Area C With Cross Reference, Identify Threats, Data Integration, and Risk Assessment
- ASME B31.8S, Gas Integrity Management

| Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A | Updated: Oct 2011 |
|---|---|

Forms and Documents Required For This Review:

- BAP Ranking, Scheduling, and RA Worksheets Including Instructions
- ASME/ANSI B31.8, Appendix A, Threat Process Charts & Prescriptive Management Plans
- Data Gathering Forms and Review Comments Including Any Assumptions (taken from ASME/ANSI B31.8, Table A)
- All applicable O&M forms, reports, inspections, drawings, maps, etc. as required by ASME/ANSI B31.8, Appendix A
- Management of Change Procedures and records
- Assessment data (ILI reports, pressure reports, DA reports, Other reports)
- SME resume/job history
- Validation dig reports and/or other validation records

Record Keeping for Threats, Data Integration, and Risk Analysis:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #2: THREATS, DATA INTEGRATION, AND RISK ANALYSIS

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.01 Threat Identification**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the company identifies and evaluates all potential threats to each covered pipeline segment. [192.917(a)]* | **C.01** | | | | | |
| 1 | If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated: [192.917(a) and ASME B31.8S-2004, Section 2.2]<br><br>1. external corrosion,<br>2. internal corrosion,<br>3. stress corrosion cracking;<br>4. 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];<br>5. welding- or fabrication-related defects,<br>6. equipment failures;<br>7. third party/mechanical damage [192.917(e)(1)],<br>8. incorrect operations (including human),<br>9. weather-related and outside force damage,<br>10. cyclic fatigue or other loading condition [192.917(e)(2)],<br>11. all other potential threats. | **C.01.a** | 2.3 | 192.917(a) | IMP Leader | 1x/yr | Complete.<br>See threat analysis worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.01 Threat Identification (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 2 | If the company is following the performance-based approach, verify that all 21 of the threats associated with the first nine failure categories listed above have been considered. | **C.01.b** | 2.3 | 192.917(a) | IMP Leader | 1x/yr | NA, prescriptive method used. |
| 3 | Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME B31.8S-2004, Section 2.2]. | **C.01.c** | 2.3 | 192.917(a) | IMP Leader | 1x/yr | Complete. See threat analysis worksheet in Element 2 tab of IMP records binder. |
| 4 | Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment. [ASME B31.8S-2004, Section 5.10] | **C.01.d** | 2.3 | 192.917(a) | IMP Leader | 1x/yr | Complete. See threat analysis worksheet in Element 2 tab of IMP procedures binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.02 Data Gathering and Integration**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the company gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated.* | **C.02** | | | | | |
| 5 | Verify that the company has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4] | **C.02.a** | 2.6 | 192.917(b) | IMP Leader | 1x/yr | Complete.<br>See LGS Gas IMP Data Collection Requirements worksheet in Element 2 tab of IMP records binder and procedure in Element 2 tab of IMP procedure binder. |
| 6 | Verify that the company has assembled data sets for threat identification and risk assessment according to the requirements in ASME B31.8S-2004, Section 4.2, ASME B31.8S-2004, Section 4.3, and ASME B31.8S-2004, Section 4.4. At a minimum, an operator must gather and evaluate the set of data specified in ASME B31.8S-2004, Appendix A (summarized in ASME B31.8S-2004, Table 1) and consider the following on covered segments and similar non-covered segments:<br>1) Past incident history<br>2) Corrosion control records<br>3) Continuing surveillance records<br>4) Patrolling records<br>5) Maintenance history<br>6) Internal inspection records | **C.02.b** | 2.6 | 192.917(b) | IMP Leader | 1x/yr | Complete.<br>See LGS Gas IMP Data Collection Requirements worksheet in Element 2 tab of IMP records binder and procedure in Element 2 tab of IMP procedure binder. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 7) All other conditions specific to each pipeline. | | | | | | |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.02 Data Gathering and Integration (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 7 | Verify that the company has utilized the data sources listed in ASME B31.8S-2004, Table 2, for initiation of the integrity management program. [ASME B31.8S-2004, Section 4.3] | **C.02.c** | 2.6 | 192.917(b) | IMP Leader | 1x/yr | Complete.<br>See LGS Gas IMP Data Collection Requirements worksheet in Element 2 tab of IMP records binder and procedure in Element 2 tab of IMP procedure binder. |
| 8 | Verify that the company has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME B31.8S-2004, Section 4.1, ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, ASME B31.8S-2004, Section 5.7(e), and ASME B31.8S-2004, Appendix A]:<br>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.<br>2) Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority.<br>3) Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered. | **C.02.d** | 2.6 | 192.917(b) | IMP Leader | 1x/yr | Complete.<br>See LGS Gas IMP Data Collection Requirements worksheet in Element 2 tab of IMP records binder and procedure in Element 2 tab of IMP procedure binder. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 4) Depending on the importance of the data, additional inspection actions or field data collection efforts may be required. | | | | | | |

**Element #2: Threats, Data Integration, and Risk Assessment – C.02 Data Gathering and Integration (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 9 | Verify that the company's program includes measures to ensure that new information is incorporated in a timely and effective manner, as addressed in Protocol K. [192.911(k), ASME B31.8S-2004, Section 11(b) and ASME B31.8S-2004, Section 11(d)] | **C.02.e** | 2.6<br>2.7 | 192.911(k) | IMP Leader | 1x/yr | Complete.<br>See LGS Gas IMP Data Collection Requirements worksheet in Element 2 tab of IMP records binder. |
| 10 | Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes:<br><br>1. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S-2004, Section 4.5];<br>2. 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. | **C.02.f** | 2.6<br>2.7 | 192.917(e)(1) | IMP Leader | 1x/yr | Pending, see action items.<br><br>Currently working with pipeline integrity department to produce data integration alignment sheets for HCA system. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.03 Risk Assessment**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the company has conducted a risk assessment that follows ASME B31.8S-2004, Section 5, and that considers the identified threats for each covered segment.*<br>*[Note: Application of the risk assessment to prioritize the covered segments for the baseline assessment is covered in Protocol B, continual reassessments in Protocol F, and additional preventive and mitigative measures in Protocol H.]* | **C.03** | | | | | |
| 2-11 | Verify that the company's risk assessment supports the following objectives [ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.4]:<br>1) prioritization of pipelines/segments for scheduling integrity assessments and mitigating action<br>2) assessment of the benefits derived from mitigating action<br>3) determination of the most effective mitigation measures for the identified threats<br>4) assessment of the integrity impact from modified inspection intervals<br>5) assessment of the use of or need for alternative inspection methodologies<br>6) more effective resource allocation<br>7) facilitation of decisions to address risks along a pipeline or within a facility | **C.03.a** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete.<br>See BAP and mitigation worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.03 Risk Assessment (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 12 | Verify that the company utilizes one or more of the following risk assessment approaches [ASME B31.8S-2004, Section 5.5]:<br><br>1. Subject matter experts (SMEs),<br>2. Relative assessment models,<br>3. Scenario-based models, or<br>4. Probabilistic models | **C.03.b** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete.<br>SME approach used. |
| 13 | Verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential releases, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment. [ASME B31.8S-2004, Section 3.1, ASME B31.8S-2004, Section 3.3, ASME B31.8S-2004, Section 5.2, ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.7(j)] Verify that the risk assessment approach includes the following characteristics: | **C.03.c** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete.<br>See BAP and mitigation worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 13 (cont.) | Risk Assessment Characteristics:<br><br>1. The risk assessment approach contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, Section 5.7(a)];<br>2. The risk assessment considers the frequency and consequences of past events, using company and industry data [ASME B31.8S-2004, Section 5.7(c)];<br>3. The risk assessment approach integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S-2004, Section 5.7(d)];<br>4. The risk assessment process 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)];<br>5. The risk assessment process incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S-2004, Section 5.7(k)]. | | | | | | |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.03 Risk Assessment (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 14 | Verify that the company's process provides for revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments. Verify that the provisions for change to the risk assessment address the following areas:<br>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, Section 5.11, and ASME B31.8S-2004, Section 5.7(c)]<br>2. the operator integrates the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. [ASME B31.8S-2004, Section 5.4]<br>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) and ASME B31.8S-2004, Section 5.12]<br>4. the operator uses a feedback mechanism to ensure that the risk model is subject to continuous validation and improvement. [192.917(c) and ASME B31.8S-2004, Section 5.7(f)] | **C.03.d** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete.<br>See BAP and mitigation worksheet in Element 2 tab of IMP records binder and Element 2 tab of IMP procedures binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.03 Risk Assessment (cont.)**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 15 | Verify that adequate time and personnel have been allocated to permit effective completion of the selected risk assessment approach. [ASME B31.8S-2004, Section 5.7(b)] | **C.03.e** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete. See Team Charter in Element 12 tab of IMP records binder, and sign-in sheets and BAP and mitigation worksheet in Element 2 tab of IMP records binder. |

**Element #2: Threats, Data Integration, and Risk Assessment – C.04 Validation of the Risk Assessment**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the integrity management program identifies and documents a process to validate the results of the risk assessments. [192.917(c) and ASME B31.8S-2004, Section 5.12]* | **C.04** | | | | | |
| 16 | Verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience. [192.917(c) and ASME B31.8S-2004, Section 5.12] | **C.04.a** | 2.5 | 192.917(c) | IMP Leader | 1x/yr | Complete. See BAP and mitigation worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917(b), ASME section #4, Appendix A, Table A** **Updated: Oct 2011**

**Element #2: Threats, Data Integration, and Risk Assessment – C.05 Plastic Transmission Pipeline**

| Agenda Line # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *If the company has plastic transmission pipelines, verify that the operator assesses applicable threats to each covered segment of plastic line. [192.917(d)]* | **C.05** | | | | | |
| 17 | If the operator has plastic transmission lines, verify that the information in ASME B31.8S-2004, Section 4 and ASME B31.8S-2004, Section 5, and any unique threats to the integrity of plastic pipe have been considered when assessing the threats to each covered segment of plastic pipeline. [192.917(d)] | **C.05.a** | 2.5 | 192.917(d) | IMP Leader | 1x/yr | NA, no plastic pipe. |

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #3: Baseline Assessments

| Ref: 49 CFR 192.919 & 921 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


3.1 Objectives and Purpose of Baseline Assessment
3.2 Definitions Applicable to Element #3
3.3 Assessment Methods
3.4 Prioritized Schedule
3.5 Use of Prior Assessments
3.6 Newly Identified HCAs & Newly Installed Pipe
3.7 Consideration of Environmental and Safety Risks
3.8 Changes and Updates to the BAP
3.9 Review and Implementation of Element #3
3.10 Source References
3.11 List of Required Ongoing Documentation

Baseline Assessment Flowchart


### 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, LGS has developed these baseline assessment procedures to assist in this effort.

### 3.2 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 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 CO2, O2, 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.

### 3.3 Assessment Methods [192.921]

Based on the priorities and threats determined by risk assessment, LGS 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***

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]

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)
- Stress Corrosion Cracking (Must comply with ASME/ANSI B31.8S)

The integrity assessment method will be based on the threats 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 LGS 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 LGS will demonstrate by historical records such as gas quality, internal inspections, etc. that an internal corrosion problem does not exist. When LGS 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]*

### 3.3.1 In-line Inspection (ILI)

If internal inspection tools are selected, LGS will follow ASME B31.8S-2001, 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 the use of ILI tools for certain threats.

LGS 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 LGS may choose to run a second tool capable of determing the extent of mechanical damage (normally a deformation tool).

Using the remediation worksheet or other appropriate documentation, LGS will record the as found condition versus the assessment tool finding. [Element #3: record #3] LGS 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]

LGS shall specify the threshold for vendor reporting of anomalies. At this time, LGS 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), 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).***[FAQ #68]**

### 3.3.2 Pressure Testing

LGS will follow ASME B31.8S-2001, Section 6.3 in selecting the pressure test as the appropriate assessment method. LGS will consider the results of the risk assessment and the types of anomalies expected to determine when to conduct inspections utilizing pressure testing. If a pressure test is specified by LGS 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.

LGS 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]

LGS's 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 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.

*Pressure reduction is not an assessment method. Although a pressure reduction can provide an equivalent margin to failure as a pressure test, a pressure reduction provides no information about the condition of the pipeline. One of the primary objectives of this rule is for operators to obtain a better understanding of the condition of their pipe so they can make well-founded technical decisions to reduce risk and protect HCAs. Section 192.933(a) specifies that a reduction in operating pressure taken to provide an immediate improvement in safety cannot extend more than 365 days without the operator providing a technical justification that continued pressure restriction will not jeopardize the integrity of the pipeline. [FAQ #55]*

*How Manufacturing and Construction Defects Will Be Addressed If Subpart J Tested:*

*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. LGS 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, Section 2.2, and establish its assessment plans accordingly.*

*Assessments addressing the threat of manufacturing and construction defects are required for pipe that has never been tested to Subpart J requirements if operating conditions on the line change. [FAQ #219]*

*How Manufacturing and Construction Defects Will Be Addressed If The Segment Has Not Been Subpart J Tested:*

*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. LGS 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, Section 2.2, and establish its assessment plans accordingly.*

*Assessments for manufacturing and construction defects generally are not required for pipe that has successfully passed a Subpart J pressure test even if these changes in operating conditions occur. [FAQ #220]*

*Operators may use straight-line interpolation to determine acceptable intervals between the 5, 10, 15, and 20 year intervals listed in ASME/ANSI B31.8 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]*

*How Spike Test May be Used:*

*A spike test can be very useful for assessing some threats, including seam issues. If LGS decides to use spike test as the sole assessment method, it would constitute "other technology" and LGS 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]*

### 3.3.3 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 LGS 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:

LGS may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. LGS 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 LGS uses direct assessment as a primary assessment method, LGS will develop a plan that complies with the requirements in:

1) ASME/ANSI B31 (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, section 6.4 and appendix B2, and 192.927 if addressing internal corrosion (ICDA).
3) ASME/ANSI B31.8S, appendix A3, and 192.9298 if addressing stress corrosion cracking (SCCDA).

DA as Supplemental Method:

If LGS uses direct assessment as a supplemental assessment method for any applicable threat, LGS will have a plan that follows the requirements of confirmatory direct assessment in 192.931.

### 3.3.4 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 LGS 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.

For performance-based integrity management programs, techniques other than those published by consensus standards organization may be utilized, however LGS shall follow the performance requirements of this standard and shall be diligent in confirming and documenting the validity of this approach to confirm that a higher level of integrity or integrity assurance was achieved.

If the LGS decides to perform assessments using other technology, the LGS 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, LGS will notify OPS within 180 days before conducting the assessment. Also, LGS 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]*

*Use of Guided Wave UT is used as part of the ICDA process:*

*ICDA is based on the use of a model to predict areas within which internal corrosion is most likely to occur. Once identified, those areas must be examined to determine if corrosion exists. (The number and required location of examinations differs depending on the circumstances of the assessment).*

*If guided wave technology is being used as a tool to examine the predicted locations to determine if corrosion exists, then it is being used in a manner consistent with the ICDA process and would not be considered "other technology". If, on the other hand, the intent is to use guided wave technology in some other manner to assess internal corrosion (e.g., not first analyzing the pipeline to determine likely locations for internal corrosion), then its use would be different from the normal ICDA process and it would be considered "other technology". [FAQ #235]*

Validation of Assessment Results

After ILI tools are run, LGS 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 LGS 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. LGS 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, a least one other excavation dig shall be performed. LGS 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.

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. LGS 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 inline inspection tools is listed below:

1) Soil ph
2) Soil resistivity
3) Test for MIC
4) Soil type
5) Coating type
6) Wall thickness of pipe
7) Pipe type

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.

The engineer reviewing the inline inspection report shall request feedback from the vendor in regards to the tool performance and results. This report shall be maintained as part of the IMP records.

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, 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, the LGS 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, section 6.3 states that the details for conducting pressure tests are in ASME B31.8. 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

The LGS will review the results of integrity assessments in a timely manner. The LGS 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 the LGS can demonstrate that it is impracticable to obtain the information within this limit.

### 3.4 Prioritized Schedule [192.919(c), 921(b) & (d)]

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***. LGS 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:

1) Segments that contain ***low frequency resistance welded (ERW) pipe*** or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2001, Appendix A4.3 and ASME B31.8S-2001, 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 lines that affect HCAs shall be listed although if the line is inactive (no hazardous gas content) its baseline assessment will be postponed.

*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. A baseline assessment 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]*

*Manufacturing and Construction Defects if Subpart J Tested*

*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. An operator 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, Section 2.2, and establish its assessment plans accordingly.*

*Assessments addressing the threat of manufacturing and construction defects are required for pipe that has never been tested to Subpart J requirements if operating conditions on the line change. [FAQ #219]*

*Manufacturing and Construction Defects if Never Subpart J Tested*

*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. An operator 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, Section 2.2, and establish its assessment plans accordingly.*

*Assessments for manufacturing and construction defects generally are not required for pipe that has successfully passed a Subpart J pressure test even if these changes in operating conditions occur. [FAQ #220]*

*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]*

*Considerations When Prioritizing Segments*

*The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. Risks must be evaluated using a risk assessment that meets ASME/ANSI B31.8S, Section 5, as required by 192.917(c). Section 5.10 of the standard specifically addresses use of risk assessment for prioritizing pipe segments for assessment. [FAQ #28]*

How LGS Will Count Mileage:

For purpose of satisfying the progress requirements, LGS will use the cumulative mileage of covered segments. LGS will not use the total miles assessed in making a determination of whether the 50% criteria has been satisfied. For example, when the LGS uses internal inspection with pig launchers and receivers at a greater distance than just the portion of the pipeline that can affect an HCA, only the HCA portion will be counted towards the 50% criterion.

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) LGS will 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.

### 3.5 Use of Prior Assessment

LGS will not use prior assessments in the BAP. Prior assessments are those that were completed prior to December 17, 2002.

### 3.6 Newly Identified HCAs & Newly Installed Pipe

LGS will monitor conditions along their pipelines. Pipeline throughput, changes in population and/or environment will be periodically reviewed. When LGS 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, LGS 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 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. [Element #3: record #11]

LGS 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.

Step #3: Complete BAP during annual agenda review

*Inheritance of 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 continue to apply. 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]*

*Accountability Following Transfer of Assets:*

*Typically, OPS inspects the operator for compliance with the pipeline safety regulations, however, compliance responsibility would have to be determined on a case by case basis*

*and is contingent on the terms of contracts, operating agreements, and any other relevant correspondence between the involved parties. Depending on the terms of the agreement, either or both could be held responsible. [FAQ #11]*

*Re-Prioritization when New HCAs are identified:*

*The rule specifies a ten (10) year assessment schedule for newly identified segments. Operators must 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]*

*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]*

### 3.7 Consideration of Environmental and Safety Risks

LGS will address requirements for conducting the baseline assessment and reassessments in a manner that minimizes environmental and safety risks. LGS will utilize existing DOT pipeline O&M procedures and LGS 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 LGS 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 #15: Record #1]

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

[Element #3: record #12]

### 3.8 Changes and Updates to the BAP

The baseline assessment plan will be modified whenever there are changes to the pipeline in HCAs. Examples of the the BAP will be updated:

1) LGS 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 year after their identification. These pipeline segments will be assessed within ten years of their identification.

The Baseline Assessment Plan will also be modified when LGS 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. LGS 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.

LGS will review and update the integrity management program and procedures once every three years as described in element #6 of this plan (program evaluation). When changes to the plan occur, LGS will document the following for each change:

- Reasons for the modification
- Authority for approving change
- Analysis of implications
- Communication of change to affected parties

*Conditions Requiring Modification to BAP*

*The Baseline Assessment Plan must be modified whenever there are changes to the pipeline in HCAs. For example, if an operator identifies a new HCA through monitoring its right-of-way or through its process for identification and assessment of newly-identified HCAs [as required by 192.911(p)], this newly identified pipeline segment must be included in the Plan. Pipeline segments in newly-identified HCAs must be included in the Baseline Assessment Plan within one year after their identification. These pipeline segments must be assessed within ten years of their identification.*

*The Baseline Assessment Plan can also be modified if the operator 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. The operator must document all Plan modifications and the reason(s) for the changes. This documentation must be available for OPS review during an inspection. [FAQ #25]*

*Seeking Waivers when Changing Assessment Schedules*

*OPS understands 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, OPS 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]*

*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]*

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]*

*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]*

### 3.9 Review and Implementation of Element #3

LGS 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. LGS 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 #13]

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~~8~~: Record #14~~21~~]

### 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

### 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. | 3.3 | BAP, RA, and Mitigation worksheet | IMP Leader | AR | Life of pipeline | Co. intranet |
| 2. | 3.3.1 | ILI Tool selection | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 3.3.1 | Remediation worksheet to document "as found" anomaly | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 4. | 3.3.1 | Report to ILI vendor for potential re-calibration of ILI tool, "as reported" versus "as found" anomoly | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 5. | 3.3.1 | ILI vendor tool criteria and specifications | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 6. | 3.3.2 | Pressure test records | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 7. | 3.3.2 | Documentation for extended assessment intervals | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 8. | 3.3.2 | Metallurgical examination of failed pipe during pres. test | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 9. | 3.3.3 | Direct assessment records | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 10. | 3.3.4 | Other technology records | IMP Leader | 1x/yr[1] | | Co. intranet |
| 11. | 3.6 | ID on new HCA using BAP | IMP Leader | 1x/yr[1] | | Co. intranet |
| 12. | 3.7 | Safe work permits, safety procedures | IMP Leader | 1x/yr[1] | | Co. intranet |
| 13. | 3.9 | Annual agenda review | IMP Leader | 1x/yr[1] | | Co. intranet |
| 14. | 3.9 | Element #3 Action Items | IMP Leader | 1x/yr1 | | Co. intranet |

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program – Agenda
## Element #3: Baseline Assessment

| Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6 | Updated: Oct 2011 |
|---|---|

Element #3: Baselines Assessment Agenda Objectives:

- Verify the company's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment
- Verify the company followed ASME B31.8S-2001, Section 6 and that the methods selected address all of the threats identified to the covered segments
- Verify the BAP contains a schedule for completing the assessment activities for all covered segments and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule
- Verify if prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of §192.921(a) and that remedial actions have been carried out to address conditions listed in §192.933.
- Verify the company updates the baseline assessment plan for newly identified HCAs and newly installed pipe
- Verify the company addresses requirements for conducting the baseline assessments in a manner that minimizes environmental and safety risks
- Verify the company keeps the BAP up-to-date with respect to newly arising information

Who Should Attend Baseline Assessment:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |

| Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6 | Updated: Oct 2011 |
|---|---|

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

Frequency of Baseline Assessment Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve baseline assessment review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Baseline Assessment:

- Element #3 Procedure: Baseline Assessment
- Element #3 Procedure: Continual Evaluation and Assessments
- 49 CFR 192.919, 192.929, 192.937, 939, 941, 943
- ASME section #4, Gathering, Reviewing, and Integrating Data

| Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6 | Updated: Oct 2011 |
|---|---|

- ASME section #5, Risk Assessment
- FAQs: Continual Evaluation and Assessment
- Gas IMP Protocol Area B With Cross Reference, Baseline Assessment Plan
- Gas IMP Protocol Area F With Cross Reference, Continual Evaluation and Assessment

Forms and Documents Required For This Review:

- Element #3 Agenda, Action Items, Process Improvement
- Risk Ranking and Risk Assessment Worksheets Including Instructions
- ASME/ANSI B31.8, Appendix A, Threat Process Charts & Prescriptive Management Plans
- Data Gathering Forms and Review Comments Including Any Assumptions (taken from ASME/ANSI B31.8, Table A)
- All applicable O&M forms, reports, inspections, drawings, maps, etc. as required by ASME/ANSI B31.8, Appendix A
- Management of Change Procedures and records
- Assessment data (ILI reports, pressure reports, DA reports, Other reports)
- SME resume/job history
- Validation dig reports and/or other validation record

Record Keeping for Baseline Assessment:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## Attendance List

### Element#3: Baseline Assessment

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment - B.01 Assessment Methods**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | Verify that the company's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment. | **B.01** | | | | | |
| 3-1 | Verify that the company followed ASME B31.8S-2004, Section 6.2 and that the assessment method selected for each covered segment addresses all of the threats identified for the segment. More than one assessment tool may be necessary to address all applicable threats to a covered segment. | **B.01.a** | 3.4.1 | 919(b), 921(a), 921(c), 921(h) | IMP Leader | 1x/yr | Complete. See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |
| 3-2 | If internal inspection tools are selected, verify that the operator followed ASME B31.8S-2004, Section 6.2 in selecting the appropriate internal inspection tool for the covered segment.<br>1) Verify that the operator has evaluated 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. Refer to ASME B31.8S-2004, Section 6.2.5. | **B.01.b** | 3.4.1 | 921(a)(1) | | | Complete. See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment - B.01 Assessment Methods (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 3-3 | If a pressure test is specified, verify that the test is required to be conducted in accordance with Part 192, Subpart J requirements. Verify that the operator followed ASME B31.8S-2004, Section 6.3 in selecting the pressure test as the appropriate assessment method. | **B.01.c** | 3.4.2 & RA | 921(a)(2) | IMP Leader | 1x/yr | NA, pressure test not used. |
| 3-4 | If the company specifies the use of "other technology," verify that notification to PHMSA is required in accordance with Part 192.949, 180 days before conducting the assessment.<br><br>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 PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. | **B.01.d** | 3.4.4 & RA | 921(a)(4) | IMP Leader | 1x/yr | NA, use of other technology for primary assessment is not used at this time. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment - B.01 Assessment Methods (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 3-5 | If a covered pipeline segment contains low frequency electric resistance welded pipe (***ERW***) or lap welded pipe that satisfies 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 verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion anomalies. | **B.01.e** | 3.4 & RA | 917(e)(4) | IMP Leader | 1x/yr | NA, no pre 1970 ERW pipe. |
| 3-6 | If the threat analysis required in 192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, verify that the operator documents an acceptable justification for the use of an alternative assessment method that will address the identified threats to the covered segment. | **B.01.f** | 3.4 & RA | 917(d), 917(h), | | | NA, no plastic pipe. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.02 Prioritized Schedule**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | Verify that the BAP contains a schedule for completing the assessment activities for all covered segments; and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule. | **B.02** | | | | | |
| 3-7 | Verify that the BAP schedule includes all covered segments not already assessed. | **B.02.a** | 3.3 & RA | 921(a) | IMP Leader | 1x/yr | Complete. See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |
| 3-8 | Verify that the BAP schedule prioritizes the covered segments based on potential threats and applicable risk analysis, and that the risk ranking is appropriate. | **B.02.b** | 3.3 & RA | 917(c), 921(a) | IMP Leader | 1x/yr | Complete. See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.02 Prioritized Schedule (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 3-9 | Verify that covered segments meeting the following conditions are prioritized as high-risk segments.<br><br>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.<br>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. | **B.02.c** | 3.3 | 917(e)(3), 917(e)(4) | IMP Leader | 1x/yr | Complete.<br>See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder.<br><br>No known high risk conditions. |

**Element #3: Baseline Assessment – B.02 Prioritized Schedule (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 3-10 | Verify that the BAP schedule requires 50% of the covered segments, beginning with the highest risk segments, to be assessed by December 17, 2007; and that baseline assessments shall be completed for all covered segments by December 17, 2012. | **B.02.d** | 3.3 & RA | 921(d) | IMP Leader | 1x/yr | Complete.<br>See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |
| 3-11 | Review the company's implementation progress to date and verify that:<br>1. Assessments scheduled for completion by the date of the inspection were in fact completed.<br>2. Assessment methods used for completed assessments were as described in the plan.<br>3. The date assessment field activities were completed is recorded so the operator understands the time frame allowable for compliance with the provisions of 192.933. | **B.02.e** | 3.3 & RA | 921 | IMP Leader | 1x/yr | Complete.<br>See BAP Schedule and RA worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.03 Use of Prior Assessments**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | If prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of 192.921(a) and that remedial actions have been carried out to address conditions listed in 192.933. Prior assessments are those that were completed prior to December 17, 2002. | **B.03** | | | | | |
| 3-12 | Verify that threats to these pipeline sections were identified as required under 192.919(a). | **B.03.a** | 3.7 & RA | 921(a) | IMP Leader | 1x/yr | NA, use of prior assessment not used. |
| 3-13 | Verify that the methods used for these prior assessments were appropriate for the threats per ANSI B31.8S-2001 as required under 192.919(b) and 192.919(d). | **B.03.b** | 3.7 & RA | 921(b), 921(d) | IMP Leader | 1x/yr | NA, use of prior assessment not used. |
| 3-14 | Verify that anomalies satisfying the requirements of 192.933 were repaired. | **B.03.c** | 3.7 & RA | 933 | IMP Leader | 1x/yr | NA, use of prior assessment not used. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.04 New HCAs/Newly Installed Pipe**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | Verify that the company updates the baseline assessment plan for new HCAs and newly installed pipe. | **B.04** | | | | | |
| 3-15 | If new HCAs have been identified or new pipe has been installed that is covered by this subpart, verify that applicable segment(s) have been incorporated into the operator's baseline assessment plan within one year from the date the area or pipe is identified and assessments have been appropriately scheduled and/or completed. | **B.04.a** | 3.7 & RA | 905(c) | IMP Leader | 1x/yr | NA, new pipe installed in Non- HCA locations and No New HCA's identified. |
| 3-16 | For new HCAs, verify that the company completes a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified. | **B.04.b** | 3.7 & RA | 921(f) | IMP Leader | 1x/yr | NA, new pipe installed in Non- HCA locations and No New HCA's identified |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.04 New HCAs/Newly Installed Pipe (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 3-17 | For newly installed pipe that is covered by this subpart and impacts an HCA, verify that the company completes a baseline assessment within ten (10) years from the date the pipe is installed. | **B.04.c** | 3.7 & RA | 921(g) | IMP Leader | 1x/yr | NA, new pipe installed in Non-HCA locations and No New HCA's identified |
| 3-18 | Verify that threats to these pipeline sections were identified as required under 192.919(a). | **B.04.d** | 3.7 & RA | 919(a), 921(b) | IMP Leader | 1x/yr | NA, new pipe installed in Non-HCA locations and No New HCA's identified |
| 3-19 | Verify that the assessment methods used were appropriate for the threats per ASME B31.8S-2004 as required under 192.919(b) and 192.919(d). | **B.04.e** | 3.7 & RA | 919(b), 919(d) | IMP Leader | 1x/yr | NA, new pipe installed in Non-HCA locations and No New HCA's identified |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.05 Consideration of Environmental and Safety Risk**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the operator addresses requirements for conducting the integrity assessments (baseline and reassessment) in a manner that minimizes environmental and safety risks. [§192.919(e) and §192.911(o)]* | **B.05** | 3.10 & RA | 919(e), 911(o) | IMP Leader | 1x/yr | Complete.<br>See LGS O&M procedures and company safety procedures.<br><br>See agenda #13, #14, #15 also. |
| 3-20 | Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of gas) during assessments. [§192.919(e) and §192.911(o)] | **B.05.a** | 3.10 & RA | 919(e), 911(o) | IMP Leader | 1x/yr | Complete.<br>See LGS O&M procedures and company safety procedures.<br><br>See agenda #13, #14, #15 also. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.06 Changes**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | Verify that the company keeps the BAP up-to-date with respect to newly arising information. Also refer to Protocol K. [192.911(k) and ASME B31.8S-2004, Section 11] | **B.06** | | | | | |
| 3-21 | Verify that the company's process has requirements to keep the BAP up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method. [192.911(k) & ASME B31.8S-2004, Section 11] | **B.06.a** | 3.8, 3.9 & RA, MOC | 911(k) | IMP Leader | 1x/yr | Complete. See BAP Schedule and Mitigation RA worksheet and annual agendas in Element 2 of IMP records binder. |
| 3-22 | Verify that required BAP changes have been made and that for all changes, the following are documented: [ASME B31.8S-2004, Section 11(a)]<br>1. Reason for change<br>2. Authority for approving change<br>3. Analysis of implications<br>4. Communication of change to affected parties | **B.06.b** | 3.8, 3.9 & RA, MOC | 911(k) | IMP Leader | 1x/yr | Complete. See LGS/BPL MOC procedures. |

# Lodi Gas Storage
# Integrity Management Plan
## Element #4: Direct Assessments

| Ref: 49 CFR 192.923, 925, 927, 929 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


4.1 Summary of Direct Assessment Requirements
4.2 Objective and Purpose
4.3 Definitions Applicable to Element #4
4.4 Direct Assessment General


### 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, LGS will use these direct assessment procedures to assist LGS 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]

LGS **will not use** direct assessment as the primary assessment method. LGS may use direct assessment process and selected procedures to supplement other assessment methods allowed under the IMP regulations. If LGS 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.

# Lodi Gas Storage
# Integrity Management Plan
## Element #5: Remediation and Repair

| Ref: 49 CFR 192.933, 935 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


5.1 Summary of Remediation Requirements
5.2 Objectives and Purpose
5.3 Definitions Applicable to Element #5
5.4 Program Requirements for Discovery
5.5 Evaluation and Remediation Scheduling
5.6 Classification & Remediation of Anomalies
5.7 Requirements When Timelines Can Not Be Met
5.8 Review and Implementation of Element #5
5.9 Source References
5.10 List of Required Ongoing Documentation

Remediation Flowchart


### 5.1 Summary of Requirements for Remediation [192.933, 935]

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

### 5.2 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. To ensure that the IMP achieves these objectives, LGS will use these remediation and repair procedures to assist LGS in meeting these objectives.

### 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.

**Need definition for Immediate!**

**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 LGS. For the purposes of this document it also includes damage caused by LGS's personnel or the LGS's contractors.

**Discovery** of a condition occurs when LGS has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, LGS may have adequate information when LGS receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when LGS receives the final internal inspection report. LGS is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless LGS can demonstrate that the 180-day period is impractical.

**One-Year Conditions** are conditions requiring remediation within one year of discovery.

**Monitored conditions** are conditions which must be monitored until the next assessment.

### 5.4 Program Requirements for Discovery [192.933]

Discovery of a condition occurs when LGS 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. For example LGS may have adequate information when LGS gathers and integrates information from other inspections or when LGS receives the final internal inspection report.

LGS is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless LGS can demonstrate that the 180-day period is impractical.

If there is a situation where the ILI was seriously under calling defects, and LGS request the smart pig vendor to redo the report, LGS 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, this would be the following:

- 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 an LGS 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) LGSs 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*

LGS 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. LGS 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]

LGS 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 paragraph (d) of section 192.933 (IMP section #5.4 below), LGS will follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4. If LGS cannot meet the schedule for any condition, LGS 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. LGS processes for conducting ILI assessments shall investigate and have the necessary controls in place to provide reasonable assurance that all integrity threats are discovered and remediated.

Two key aspects of discovering anomalies are:

1. Integrated information analysis

2. ILI vendor contract specifications

Integrated Information Analysis *Step #2:*

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 LGS 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-calls, encroachments, ROW surveys, 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.)

ILI Vendor Contract Specifications *Step #3:*

ILI vendors have a tremendous affect on the effectiveness and quality of ILI assessments. LGS has formal, contractual controls in place to properly manage ILI assessments and assure that integrity threats are discovered in a timely manner.

LGS 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) LGS shall specify the threshold for vendor reporting of anomalies. LGS will specify that the vendor shall report all metal loss anomalies greater than 10% WT. LGS 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. LGS will use ASME B31G interaction criterion.
5) Anomaly reporting classification (including the prompt reporting within five days 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.)

Criteria for Scheduling Remediation of Anomalies

*Step #4* 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) Remediation Scheduling Priority #1:
   Any anomaly meeting the criteria of an immediate condition under the IMP rule will be the first priority.

2) Remediation Scheduling Priority #2:
   Any anomaly meeting the criteria of a~~n~~ one year condition under the IMP rule will be the second priority.

3) Remediation Scheduling Priority #3:
   Using the ILI report, anomalies with percentage of 20% or more will be integrated with one or more of the following and will be scheduled secondly (interactive threats)

- 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 ~~anomaly~~the percentage greater than 40% will be ~~considered for~~ scheduled thirdly.

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.

LGS 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 LGS remediation schedule for documentation of criteria used.

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]

LGS 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] LGS 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 LGS'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)]

LGS 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 LGS 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, Section 7.2.1]

5) All indications of stress corrosion cracks; [ASME B31.8S, 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, 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. In some cases, LGS may have to take time to handle customer demand and critical supply issues, which could be a legitimate reason for some short delays, depending on the circumstances. For instance, interruptions of critical or sole source gas supplies used for heating during winter months could itself represent a safety hazard to customers.

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) LGS can use B31.G or RSTRENG to calculate Psafe. This calculation, in either case, includes a safety factor of 0.72.
2) LGS can reduce pressure to 80% of its level at the time the defect was discovered. OPS considers that a reduction of this magnitude includes sufficient safety margin.
3) LGS can use B31.G or RSTRENG to calculate Pfailure and can then apply safety margins to determine a new safe operating pressure. LGSs that can demonstrate and justify reliable defect growth rates using empirical data 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 LGS 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~~Immediate 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 LGS 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)]

LGS 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 threats listed above.

ASME B31.8S-2004, Section 7, Figure 4, provides a graph that instructs LGS 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, LGS 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 | Formula to Find Response Time | Not to Exceed |
|---|---|---|

| Level | (Years) | 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 LGS Finds Corrosion or Other Anomalies During an Assessment of Segments in HCA [Element #5: Record #9]

Section 192.917(e)(5) requires that if LGS 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, LGS 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, LGS shall consider non-covered segments where coating and environmental conditions are similar to those resulting in the immediate corrosion condition in the covered segment. LGS shall conduct a root cause evaluation to identify the factors (e.g., coating and environmental conditions, equipment or LGS 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 LGS 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]

LGS 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, LGSs are 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 more strict 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. LGS 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, LGS 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 LGS O&M procedures #9.01 Repairs.

### 5.7 Requirements When Timelines Can Not Be Met [192.933(a)]

General

LGS is not using exceptional performance criteria. Therefore, LGS will not attempt to deviate from the timelines for remediation as provided in §192.933 by demonstrating exceptional performance.

LGS 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. LGS must also notify the State pipeline safety authority (i.e., California Public Utilities Commission) 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, LGS 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

LGS will use ASME B31G to determine the appropriate pressure reduction required by the rule, or LGS 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, the LGS 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. LGS 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.

### 5.8 Implementation of Element #5

LGS will use the attached agenda, "Gas IMP Element #5, Remediation Agenda and Action Items", for implementation of this element. LGS 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~~1~~]

- 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~~1~~]

### 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: Nov 2010**

### 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:<br>• Date of discovery [5.5]<br>• Scheduling priority [5.6]<br>• Type of anomaly<br>• Size of anomaly<br>• How anomaly repaired<br>• 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<br>• ILI (preliminary and final)<br>• Pressure test<br>• DA<br>• 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 |
| 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 |

**Ref: 49 CFR 192.933, 935** **Updated: Nov 2010**

### 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 |
|---|---|---|---|---|---|---|
| 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~~6~~. | 5.8 | Element #5 Agenda | IMP Leader | 1x/yr1 | 5 yrs | Co. intranet |
| 16~~5~~. | 5.8 | Gas IMP Element #5 Action Items | IMP Leader | 1x/yr1 | 5 yrs | Co. intranet |
| ~~16.~~ | ~~5.8~~ | ~~Element #5 Agenda~~ | ~~IMP Leader~~ | ~~1x/yr1~~ | ~~5 yrs~~ | ~~Co. intranet~~ |

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #5: Remediation and Repair Agenda

| Ref: 49 CFR 192.933, 935 | Updated: Oct 2011 |
|---|---|

Objectives for Remediation and Repair:

- Verify prioritized schedule exists for evaluation and remediation of all anomalies and remediation was conducted according to the schedule
- Verify remediation activities are sufficient to ensure that the anomaly is unlikely to threaten the integrity before the next scheduled assessment
- Verify, for immediate repair conditions that there is a temporary pressure reduction determined in accordance with the standard and that the pressure reduction does not exceed 365 days
- Verify anomalies meeting the definition of "monitored condition" are evaluated during subsequent assessments
- Verify all required processes in element #5 have been properly documented

Who Should Attend Remediation and Repair:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 3. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 4. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 5. | Andy Anderson | IMP Supervisor | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #5: Remediation and Repair Agenda

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

Frequency of Remediation and Repair Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.

- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve remediation and repair processes and document.
- If required, the IMP 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 and include the "reasons" for any change.

Regulations, Resources, and Procedures Needed to Review Remediation and Repair:

- Element #5 Procedure: Remediation and Repair
- 49 CFR 192.933, 192.949 & 192.913
- FAQs: Remediation
- Gas IMP Protocol Area E With Cross Reference, Remediation
- ASME B31.8S, Gas Integrity Management

| Ref: 49 CFR 192.933, 935 | Updated: Oct 2011 |
|---|---|

Forms and Documents Required For This Review:

- Remediation and Repair Worksheet
- Vendor ILI Reports
- Element #5 Agenda and Action Items
- ASME B31G calculation For Pressure Reduction Justification, If Required
- Technical Justification to Exceed 365 Day Pressure Reduction, If Required
- Remediation Activity Justification When Timelines Can Not Be Met
- Exceptional Performance Justification for Deviation From Remediation Timelines
- OPS Notification When Remediation Schedule Can Not Be Met
- MOC, When Required

Record Keeping for Remediation and Repair:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #5: REMEDIATION AND REPAIR ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #5: Remediation and Repair Agenda

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O1–Record Review for Discovery, Evaluation, and Remediation Scheduling**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity.* | **E.01** | | | | | |
| 1 | Verify a definition of discovery is provided. | **E.01.a** | 5.3 | 933(b) | IMP Leader | 1x | Complete. See remediation procedures & worksheet in Element 5 tab of IMP procedures binder. |
| 2 | Verify a requirement exists to document the actual date of discovery. | **E.01.b** | 5.3 | 933(b) | IMP Leader | 1x | Complete. See remediation procedures & worksheet in Element 5 tab of IMP procedures binder. |
| 3 | Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. | **E.01.c** | 5.3 | 933(c) | IMP Leader | 1x | Complete. See remediation procedures & worksheet in Element 5 tab of IMP procedures binder. |
| 4 | If the company desires to deviate from the timelines for remediation as provided in 192.933 by demonstrating exceptional performance, verify that the requirements of 192.913(b) have been met and the safety of the covered segment is not jeopardized. | **E.01.d** | 5.3 | 933(c)(2) | IMP Leader | 1x | NA, exceptional performance will not be used. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O2– Program Requirements to Identify Anomalies**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Inspect the company's program to verify that provisions exist 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 B31.8S-2004, Section 7 .* | **E.02** | | | | | |
| 5 | Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. | **E.02.a** | 5.4.2 | 933(d)(1) | IMP Leader | 1x | Complete. See remediation procedures & worksheet in Element 5 tab of IMP procedures binder. |

**Element #5: Remediation and Repair: E.O2– Program Requirements to Identify Anomalies (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 6 | Verify provisions exist to classify and categorize anomalies meeting the following criteria: | **E.02.b** | 5.4 | 933(d)(1) | IMP Leader | 1x | |
| | ***Immediate Repair Conditions*** (Conditions requiring immediate remediation actions)<br><br>1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP;<br>2. A dent having any indication of metal loss, cracking, or a stress riser;<br>3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action.<br>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, 7.2.1]<br>5. All indications of stress corrosion cracks; [ASME B31.8S-2004, 7.2.2]; or<br>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, 7.2.3] | **E.02.b (cont.)** | 5.4 | 933(d)(1) | IMP Leader | 1x | Complete.<br>See remediation schedule in Element 5 tab of IMP records binder.<br><br>No ILI immediate repair conditions. |

**Element #5: Remediation and Repair: E.O2– Program Requirements to Identify Anomalies (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 6 (cont.) | Verify provisions exist to classify and categorize anomalies meeting the following criteria: | **E.02.b** | 5.4 | 933(d)(1) | | | |
| | ***One-Year Conditions*** (Conditions requiring remediation within one year of discovery).<br><br>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; [192.933(d)(2)] or,<br>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. [192.933(d)(2)] | **E.02.b (cont.)** | 5.4 | 933(d)(2) | IMP Leader | 1x | Complete.<br>See remediation schedule in Element 5 tab of IMP records binder.<br><br>No ILI one-year repair conditions. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O2– Program Requirements to Identify Anomalies (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 6 (cont.) | Verify provisions exist to classify and categorize anomalies meeting the following criteria: | **E.02.b** | 5.4 | 933(d)(1) | | | |
| | Monitored Conditions (Conditions which must be monitored until the next assessment).<br><br>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; [192.933(d)(3)]<br>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; [192.933(d)(3)]or,<br>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. [192.933(d)(3)] | **E.02.b (cont.)** | 5.4 | 933(d)(2) | IMP Leader | 1x | Complete.<br>See remediation schedule in Element 5 tab of IMP records binder.<br><br>No ILI monitored repair conditions. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O2– Program Requirements to Identify Anomalies (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 7 | Verify provisions exist to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk or integrity assessments for any change in their status that would require remediation. [192.933(d)(3)] | **E.02.c** | 5.4.4 | 933(d)(1) | IMP Leader | 1x | Complete.<br>See remediation schedule in Element 5 tab of IMP records binder. |
| 8 | Verify that program requirements exist to meet the provisions of ASME B31.8S-2004, Section 7, Figure 4 for scheduling and remediating any other threat conditions that do not meet the classification criteria of Protocol E.02.b, above. | **E.02.d** | 5.4.5 | 933(c) | IMP Leader | 1x | Complete.<br>See Element 5 tab of IMP procedures binder. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O3– Operator Response When Timelines for Evaluation & Remediation Not Met**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Verify that provisions exist to respond appropriately when the operator is unable to meet time limits for evaluation and remediation. [192.933(a)].* | **E.03** | | | | | |
| 9 | Verify a requirement exists to take a temporary operating pressure reduction or other action that ensures safety of the covered segment in the event the operator is unable to respond within the timeframes required by 192.933.<br><br>1. Verify a requirement exists to determine the appropriate pressure reduction using ASME B31G, or "RSTRENG", or reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered. [192.933(a)]<br>2. Verify a requirement exists that when a pressure reduction is to exceed 365 days, a documented technical justification is developed that explains the reason for remediation delay and demonstrates continuation of the reduction will not jeopardize pipeline integrity. [§192.933(a)] | **E.03.a** | 5.5 | 933(a) | IMP Leader | 1x | Complete.<br>See remediation procedures & worksheet in Element 5 tab of IMP records binder.<br><br>No pressure reductions required. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation & Repair: E.O3– Oper. Response When Timelines for Evaluation & Remediation Not Met (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 10 | Verify a requirement exists to document the justification, when an evaluation and a remediation activity cannot be completed within established timeframe requirements, that includes the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety. | **E.03.b** | 5.5 | 933(a), 933(c) | IMP Leader | 1x/yr | Complete.<br>See Element 5 tab in IMP procedures binder.<br><br>No late remediations at this time. |
| 11 | Verify a requirement exists to notify CPUC and PHMSA in accordance with §192.949 and the State or local pipeline safety authority, if applicable, when:<br><br>1. the company cannot meet the evaluation and remediation schedule and cannot provide a temporary reduction in operating pressure or other action. [ [§192.933(a)(1) and §192.933(c)], and<br>2. a pressure reduction exceeds 365 days. [§192.933(a)(2)]<br><br>The notification is to include the documented justification under protocols E.03.a and E.03.b. | **E.03.c** | 5.5 | 933(a), 933(c) | IMP Leader | 1x | Complete.<br>See Element 5 tab in IMP procedures binder. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O4–Record Review for Discovery, Repair, and Remediation Activities**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Inspect operator repair and remediation records to verify that remediation activities have been conducted in accordance with program requirements.* | **E.04** | | | | | |
| 12 | Verify a prioritized schedule exists for evaluation and remediation of anomalies identified during assessment or reassessment activities. The prioritized schedule must document which of the criteria specified in 192.933(d) and/or ASME B31.8S-2004 were used as the basis for the schedule. | **E.04.a** | 5.3 | 933(c), 933(d) | IMP Leader | 1x | Complete. See remediation schedule worksheet in Element 5 tab of IMP records binder. |
| 13 | Verify anomaly discovery was documented within 180 days of completion of the assessment or reassessment, or else that compliance with the 180-day period was impracticable. | **E.04.b** | 5.3 | 933(b) | IMP Leader | 1x | Complete. See remediation schedule worksheet in Element 5 tab of IMP records binder. |
| 14 | Verify any remediation activities taken are sufficient to ensure that the anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. | **E.04.c** | 5.3 | 933(a) | IMP Leader | 1x | Complete. See remediation schedule worksheet in Element 5 tab of IMP records binder. |
| 15 | Verify, for any immediate repair anomalies, a temporary pressure reduction is taken by the operator on the pipeline and the reduced pressure is determined in accordance with ASME B31G, or "RSTRENG", or that the reduced pressure does not exceed 80% of the level at the time the condition was discovered. | **E.04.d** | 5.3 | 933(a) | IMP Leader | 1x | Complete. See remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>NO ILI immediate repair items. |

**Element #5: Remediation and Repair: E.O4–Record Review for Discovery, Repair, and Remediation Activities (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 16 | Verify immediate repair conditions have been evaluated and remediated on a schedule established in accordance with the provisions of ASME B31.8S-2004, Section 7. | **E.04.e** | 5.3, 5.4.2 | 933(d)(1) | IMP Leader | 1x/yr | Complete.<br>See remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>No ILI immediate repair items. |
| 17 | Verify any pressure reduction taken has not exceeded 365 days from the date of discovery unless:<br><br>1. a technical justification has been developed that explains the reason for remediation delay and to demonstrates that continuation of the pressure reduction will not jeopardize the integrity of the pipeline, and<br>2. PHMSA and the State pipeline safety authority, if applicable, have been notified in accordance with §192.949. | **E.04.f** | 5.3, 5.4.2 | 933(a) | IMP Leader | 1x/yr | Complete.<br>See remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>No pressure reductions needed. |
| 18 | Verify that remediation activities were completed in accordance with scheduled timeframes. | **E.04.g** | 5.3, 5.4.2 | 933(c), 933(d) | IMP Leader | 1x/yr | Complete.<br>See remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>No remediation required. |

**Ref: 49 CFR 192.933, 935** **Updated: Oct 2011**

**Element #5: Remediation and Repair: E.O4–Record Review for Discovery, Repair, and Remediation Activities (cont.)**

| Agenda Line# | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 19 | Verify that anomalies meeting any of the criteria of 192.933(d)(3) as "monitored conditions" are evaluated during subsequent risk and integrity assessments to identify any change that may require remediation and that any required remediation is scheduled and implemented in accordance with the applicable requirements of 192.933 and ASME B31.8S-2004. | **E.04.h** | 5.3, 5.4.4 | 933(d) | IMP Leader | 1x/yr | Complete.<br>See IMP procedures and remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>None identified during ILI. |
| 20 | Verify any remediation activities that have not been completed in accordance with §192.933 timeframes, and the operator has not provided safety through a temporary pressure reduction:<br><br>1. have technical justifications that include the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety, and<br>2. have been reported to PHMSA and appropriate State or local authorities in accordance with the requirements of §192.933(c) of the rule. [§192.933(c)] | **E.04.i** | 5.5 | 933(a) | IMP Leader | 1x/yr | Complete.<br>See IMP procedures and remediation schedule worksheet in Element 5 tab of IMP records binder.<br><br>None required at this time. |

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #6: Continual Evaluation & Assessments

| Ref: 49 CFR 192.937, 939, 941, 943 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


6.1 Objectives and Purpose
6.2 Definitions Applicable to Element #6
6.3 Periodic Evaluations
6.4 Reassessment Methods
6.5 Low Stress Reassessment
6.6 Reassessment Intervals
6.7 Deviation From Reassessment Intervals
6.8 Waiver From Reassessment Intervals
6.9 Consideration for Environmental & Safety Risks
6.10 Review and Implementation of Element #6
6.11 Source References
6.12 List of Required Ongoing Documentation

Continual Evaluation & Re-Assessment Flowchart


### 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, LGS 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 Periodic Evaluations [192.937(b)]

LGS 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 annually as described in section #6.10 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. LGS 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, LGS 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

Step #1: Conduct periodic evaluation as discussed in this section and section #6.10. [Element #6: record #1]

*Quality of Information*

*Operators should 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*

*LGS 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. 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*

*LGS 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]*

### 6.4 Re-assessment Methods [192.937(c)]

LGS 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 LGS intends to address using this tool(s). The process must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate inspection tool.
2) A pressure test conducted in accordance with subpart J. LGS will 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. Pressure test is appropriate for threats as defined in ASME/ANSI B31.8S, section 6.3.
3) Direct assessment, refer to element #4.
4) Other technology that LGS 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 LGS 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 #4.
6) Low stress assessment method. See section #6.5 below.

The appropriate interval used must be technically justifiable. LGS 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.

### 6.5 Low Stress Re-assessment (< 30% SMYS) [192.941]

LGS does not have low stress HCAs at this time. These procedures will be followed if low stress HCA is incorporated into the LGS IM program.

For pipelines operating at < 30% SMYS, LGS may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, LGS will addresses the requirements described below. LGS will complete a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method.

If used to address external corrosion, LGS 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. LGS 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, LGS 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, LGS 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 LGS will test the fluids removed from each storage field that may affect a covered segment.
3) At least every seven (7) years, LGS 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.

### 6.6 Re-assessment Intervals [192.939]

LGS 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, LGS will follow the requirements described below:

1) When LGS 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 LGS.

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:

   (1) 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

   (2) using the intervals specified for different stress levels of pipeline listed in ASME/ANSI B31.8S, section 5, Table 3. LGS will 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.

4) If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to element #4 for LGS's interval determination.

For pipelines operating below 30% SMYS, LGS 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 LGS 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 LGS will 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.
2) Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to element #4 for evaluating LGS'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.

*Consideration When Prioritizing Segments*

*The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. Risks must be evaluated using a risk assessment that meets ASME/ANSI B31.8S, Section 5, as required by 192.917(c). Section 5.10 of the standard specifically addresses use of risk assessment for prioritizing pipe segments for assessment. [FAQ #28]*

*Explanation of Assessment Intervals*

*Re-assessments must be conducted within the specified number of actual years. For example, a pipe segment assessed on March 23, 2004 must be re-assessed before March 23, 2011, using at least confirmatory direct assessment. This segment would need to be re-assessed using one of the methods specified in the rule before March 23, 2014, March 23, 2019 or March 23, 2024, depending on its operating stress (see192.939). [FAQ #41]*

*Conducting Re-assessment Before Completing All Baseline Assessments*

*All baseline assessments must be completed by December 17, 2012, ten years after the enactment of the Pipeline Safety Improvement Act of 2002. Re-assessment intervals must be established for each covered segment and full reassessment, confirmatory direct assessment, or low-pressure reassessment must be performed within seven years after the baseline assessment for that segment is completed (or less if the operator's risk evaluation determines that a shorter interval is needed to assure pipeline integrity). Thus, some re-assessments will be required before all baseline assessments are completed if operators use the entire ten-year period to perform baseline assessments.*

*For example, a HCA pipeline segment that is assessed (baseline) in 2004 will require re-assessment no later than 2011. [FAQ #42]*

*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. Operators planning 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*

*Operators 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. 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).*

*Operators conducting assessments 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.*

*Operators who use Table 3 test pressures 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. Operators who establish intervals longer than seven years 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]*

### 6.7 Deviation From Re-Assessment Requirements

When LGS elects to deviate from certain requirements listed in §192.913(c), LGS 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 LGS's sector of the pipeline industry for implications both to LGS'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 LGS's performance plan.
8) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

LGS will remediate anomalies identified in the more recent assessment per the requirements of §192.933. LGS will also incorporate the results and lessons learned from the more recent assessment into LGS's data integration and risk assessment.

### 6.8 Waiver from Re-assessment Intervals [192.943]

LGS 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, LGS 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]*

### 6.9 Consideration of Environmental and Safety Risks [192.911(o)]

LGS will addresses requirements for conducting the reassessments in a manner that minimizes environmental and safety risks. LGS will utilize existing DOT pipeline O&M procedures and LGS 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.

### 6.10 Review and Implementation of Element #6

LGS will use the agenda, "Gas IMP Element #6~~8~~, Continual Evaluation and Assessment Agenda and Action Items", for review and implementation of this element. LGS 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]

### 6.11 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 192.937 – 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

**Ref: 49 CFR 192.937, 939, 941, 943** **Updated: Nov 2010**

### 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. | 6.3<br>6.10 | Periodic evaluation using agenda and data integration | IMP Leader | AR | 5 yrs | Co. intranet |
| 2. | 6.8 | Waiver from reassessment interval | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 6.10 | Action item list | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |

Note #1: Frequency is 1x/calendar year not to exceed 18 months.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program – Agenda
## Element #6: Continual Evaluation and Assessment

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

Element #6: Continual Assessment Agenda Objectives:

- Verify the company's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment
- Verify the company followed ASME B31.8S-2001, Section 6 and that the methods selected address all of the threats identified to the covered segments
- Verify the BAP contains a schedule for completing the assessment activities for all covered segments and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule
- Verify if prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of §192.921(a) and that remedial actions have been carried out to address conditions listed in §192.933.
- Verify the company updates the baseline assessment plan for newly identified HCAs and newly installed pipe
- Verify the company addresses requirements for conducting the baseline assessments in a manner that minimizes environmental and safety risks
- Verify the company keeps the BAP up-to-date with respect to newly arising information

Who Should Attend ID of HCAs:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

Frequency of Continual Assessment Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve baseline assessment review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Continual Assessment:

- Element #3 Procedure: Baseline Assessment
- Element #6 Procedure: Continual Evaluation and Assessments
- 49 CFR 192.919, 192.929, 192.937, 939, 941, 943
- ASME section #4, Gathering, Reviewing, and Integrating Data

- ASME section #5, Risk Assessment
- FAQs: Continual Evaluation and Assessment
- Gas IMP Protocol Area B With Cross Reference, Baseline Assessment Plan
- Gas IMP Protocol Area F With Cross Reference, Continual Evaluation and Assessment

Forms and Documents Required For This Review:

- Element #6 Agenda, Action Items, Process Improvement
- Risk Ranking and Risk Assessment Worksheets Including Instructions
- ASME/ANSI B31.8, Appendix A, Threat Process Charts & Prescriptive Management Plans
- Data Gathering Forms and Review Comments Including Any Assumptions (taken from ASME/ANSI B31.8, Table A)
- All applicable O&M forms, reports, inspections, drawings, maps, etc. as required by ASME/ANSI B31.8, Appendix A
- Management of Change Procedures and records
- Assessment data (ILI reports, pressure reports, DA reports, Other reports)
- SME resume/job history
- Validation dig reports and/or other validation record

Record Keeping for Baseline Assessment:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## Attendance List

### Element#6: Continual Evaluation and Assessment

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.01 Periodic Evaluations**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify the operator conducts 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. [§192.917 and §192.937(b)]* | **F.01** | | | | | |
| 6-1 | Verify that periodic evaluations are conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917. The evaluation must consider the following:<br>i. Past and present assessment results<br>ii. Data integration and risk assessment information [§192.917]<br>iii. Decisions about remediation [§192.933]<br>iv. Additional preventive and mitigative actions [§192.935] | **F.01.a** | 6.3 | 937(b), 917 | IMP Leader | 1x/yr | Complete<br>See threat and risk worksheets in Element 2 tab of IMP records binder. |
| 6-2 | Verify that periodic evaluations of data are thorough, complete, and adequate for establishing reassessment methods and schedules | **F.01.b** | 6.3 | 937(b) | | | Complete<br>See threat and risk worksheets in Element 2 tab of IMP records binder and Element Agendas. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.02 Periodic Evaluations (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 6-3 | Verify that an appropriate interval is established for performing required periodic evaluations of threats and pipeline conditions following completion of the baseline assessment. | **F.01.c** | 6.3 | 937(b) | IMP Leader | 1x/yr | Complete<br>See agenda and IMP Procedures in Element 6 tab of IMP procedures binder. |
| 6-4 | Verify that the operator periodically reviews the evaluation results to determine if the new information warrants changes to reassessment intervals and/or methods, and makes changes as appropriate. | **F.01.d** | 6.3 | 937 | IMP Leader | 1x/yr | Complete<br>See agenda and IMP Procedures in Element 6 tab of IMP procedures binder. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.02 Reassessment Methods**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 6-5 | Verify that the approach for establishing the reassessment method is consistent with the requirements in §192.937(c). | **F.02.** | 6.4 | 937(c), 941 | IMP Leader | 1x/yr | Complete<br>See agenda and IMP Procedures in Element 6 tab of IMP procedures binder. |
| 6-6 | Verify that one or more of the following assessment methods (depending on the applicable threats) are specified:<br><br>i. An internal inspection tool(s) capable of detecting corrosion and any other threats that the operator intends to address using this tool(s). The process must follow ASME B31.8S-2004, Section 6.2, in selecting the appropriate inspection tool. [§192.937(c)(1)]<br>ii. A pressure test conducted in accordance with Subpart J. An operator must 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. Pressure test is appropriate for threats as defined in ASME B31.8S-2004, Section 6.3. [§192.937(c)(2)]<br>iii. Direct assessment – refer to Protocol D. [§192.937(c)(3)]<br>iv. Other technology that an operator demonstrates can provide an equivalent | **F.02.a** | 6.4 | | | | Complete<br>See agenda and IMP Procedures in Element 6 tab of IMP procedures binder.<br>See threat analysis worksheet in Element 2 tab of IMP records binder.<br><br>See GE ILI documentation of inspection (6/20/07) |

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| | understanding of the condition of the pipe. If other technology is the method selected, the process should require that the operator notify PHMSA 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 PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [§192.937(c)(4)]<br>v. Confirmatory direct assessment when used on a covered segment that is scheduled for a reassessment period longer than seven years. Refer to Protocol G. [§192.937(c)(5)]<br>vi. If the operator is using "low stress reassessment" method, evaluate the process using Protocol F.03. | | | | | | |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.03 Low Stress Reassessment**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | For pipelines operating at < 30% SMYS, the operator may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, verify that the operator addresses the following requirements [§192.941]: | **F.03** | | | | | NA Pipeline operates at 49% SMYS |
| 6-7 | Verify that the operator completes a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method. [§192.941(a)] | **F.03.a** | 6.5 | 192.941(a) | IMP Leader | 1x/yr | NA Pipeline operates at 49% SMYS |
| 6-8 | If used to address external corrosion, verify that the operator has incorporated the following:<br><br>i. If the pipe is cathodically protected, electrical surveys (i.e., indirect examination tool/method) must be performed at least every 7 years. The operator must 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. [§192.941(b)(1)] | **F.03.b** | 6.5 | 192.941(b)(1) | IMP Leader | 1x/yr | NA Pipeline operates at 49% SMYS |

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| | ii. If the pipe is unprotected or cathodically protected where electrical surveys are impractical, the operator must 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. [§192.941(b)(1)] | | | | | | |
| 6-9 | If used to address internal corrosion, verify that the operator has incorporated all of the following:<br><br>i. Gas analysis for corrosive agents must be performed at least once each calendar year.<br>i. Periodic testing of fluids removed from the segment must be conducted. At least once each calendar year the operator must test the fluids removed from each storage field that may affect a covered segment.<br>i. At least every seven (7) years, the operator must integrate data from the analysis and testing required by c.i and c.ii above with applicable internal corrosion leak records, incident reports, and test records, and define and implement appropriate remediation actions. | | 6.5 | 192.941(c)(1)<br>192.941(c)(2)<br>192.941(c)(3) | | | NA Pipeline operates at 49% SMYS |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.04 Reassessment Intervals**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S-2004. [§192.937(a), §192.939(a), §192.939(b), §192.913(c), and ASME B31.8S-2004, Section 5, Table 3]* | **F.04** | | | | | |
| 6-10 | Verify that the operator reassesses covered segments on which a baseline assessment was conducted during the baseline period specified in subpart 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the reassessment evaluation (refer to Protocol F.01) indicates an earlier reassessment. [§192.937(a)] | **F.04.a** | 6.6 | | IMP Leader | 1x/yr | Complete,<br>SEE BAP worksheet in Element 2 tab of IMP records binder.<br><br>Re-assessment is scheduled on a 5 year interval. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.04 Reassessment Intervals (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 6-11 | For pipelines operating at or above 30% SMYS, verify that the operator meets the following requirements:<br>1) If the operator establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment (refer to Protocol G) must be performed at intervals not to exceed seven (7) years followed by a reassessment at the interval established by the operator (refer below). [§192.939(a)]<br>2) Unless a deviation is permitted under §192.913(c), the maximum reassessment interval shall not exceed the values listed in the §192.939(b) table. [§192.937(a)]<br>3) If the reassessment method is a pressure test, ILI, or other equivalent technology, the interval must be based on either: (1) 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 (2) using the intervals specified for different stress levels of pipeline listed in ASME B31.8S-2004, Section 5, Table 3. An operator must 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. [§192.939(a)(1)]<br>4) If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator's interval determination. | **F.04.b** | 6.6 | | IMP Leader | 1x/yr | Re-assessment is scheduled on a 5 year interval. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.04 Reassessment Intervals (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 6-12 | For pipelines operating < 30% SMYS, verify that the operator selects one of the following reassessment approaches:<br>1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in §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 operator must 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. An operator must 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.[§192.939(b)(1)]<br>2) Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to Protocol D for evaluating the operator's interval determination. [§192.939(b)(2), §192.939(b)(3) and §192.939(b)(4)]<br>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) – §192.939(b)(3) by year 20 of the interval. | **F.04.c** | 6.6 | | | | NA<br><br>Pipeline operates above 30% SMYS |

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| | [§192.939(b)(4)]<br>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 §192.939(b)(3) by year 20 of the interval. [§192.939(b)(5)] | | | | | | |
| 6-13 | Verify that a covered segment on which a prior assessment was credited as a baseline assessment under subpart §192.921(e) is required to be reassessed by no later than December 17, 2009. [§192.937(a)] | | 6.6 | | | | NA<br><br>Baseline assessment June 20th 2007 |
| 6-14 | Verify that reassessment intervals are appropriate and that adequate documentation and technical bases support the intervals selected. | | 6.6 | | | | Complete,<br>See BAP worksheet in Element 2 tab of IMP records binder.<br><br>Reassessment scheduled on a 5 year interval. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.05 Deviation From Reassessment Requirements**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *If the operator elects to deviate from certain requirements listed in §192.913(c), verify that the operator uses a performance based approach that satisfies the requirements for exceptional performance as follows: [§192.913 and ASME B31.8S-2004]* | **F.05** | 6.7 | | | | |
| 6-15 | Verify that the operator has a performance based integrity management program that meets or exceeds the performance-based requirements of ASME B31.8S-2004 and includes, at a minimum, the following elements: [§192.913(a)]<br><br>i. A comprehensive process for risk analysis;<br>ii. All risk factor data used to support the program;<br>iii. A comprehensive data integration process;<br>iv. A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;<br>v. A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program; | **F.05.a** | 2.4 & RA | 905(c) | IMP Leader | 1x/yr | NA<br><br>Performance-based program not used at this time. |

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| | vi. 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 (Refer to Protocol I);<br>vii. Semi-annual performance measures beyond those required in §192.943 that are part of the operator's performance plan. [See §192.911(i)] Refer to Protocol I.<br>viii. An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments. | | | | | | |
| 6-16 | Verify that the operator has completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach and is able to demonstrate that each assessment effectively addressed the identified threats on the covered segments. [§192.913(b)(2)(i)] | **F.05.b** | 2.4 & RA | | | | NA<br><br>Performance-based program not used at this time. |
| 6-17 | Verify the operator has remediated anomalies identified in the more recent assessment per the requirements of §192.933. [§192.913(b)(2)(ii)] | **F.05.c** | 2.4 & RA | | | | NA<br><br>Performance-based program not used at this time. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.05 Deviation From Reassessment Requirements**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| 6-18 | Verify the operator has incorporated the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. [§192.913(b)(2)(ii)] | **F.05.d** | 6.7 | 921(g) | IMP Leader | 1x/yr | Complete<br>See Threat Analysis worksheet in Element 2 tab of IMP records binder. |
| 6-19 | Verify that deviations are allowed only for the timeframe for reassessment as provided in §192.939 except that reassessment by some method allowed by Subpart O (e.g., confirmatory direct assessment) must be completed at intervals not to exceed seven (7) years. [§192.913(c)(1)] | **F.05.e** | 6.7 | 919(a), 921(b) | IMP Leader | 1x/yr | See Element 6 tab of IMP procedures binder. |

**Ref: 49 CFR 192.917, 921, 933, & ASME B31.8S, section #6** **Updated: Oct 2011**

**Element #6: Continual Evaluation and Assessment - F.06 Waiver From Reassessment Intervals**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the operator's program requires that it apply for a waiver, should it become necessary, from the required reassessment interval. The waiver request must demonstrate that the waiver is justified as specified in the rule. Such a waiver request may only be made in the following limited situations: [§192.943]* | **F.05.e** | 6.8 | 919(e), 911(o) | IMP Leader | 1x/yr | NA |
| 6-20 | Lack of internal inspection tools. [§192.943(a)(1)] | **F.06.a** | 6.8 | | | | NA |
| 6-21 | Cannot maintain local product supply. [§192.943(a)(2)] | | 6.8 | | | | NA |
| 6-22 | 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, an operator must apply for the waiver as soon as the need for waiver becomes known). [§192.943(b)] | | 6.8 | | | | NA |

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #7: Confirmatory Direct Assessment

| Ref: 49 CFR 192.937(c)(5), 931 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


7.1 Summary of CDA Requirements
7.2 CDA General
7.3 Related Documents

Continual Re-evaluation and Assessment Flowchart


### 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

LGS **will not use** 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 LGS 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.

LGS'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.

LGS'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 LGS discovers any defect requiring remediation prior to the next scheduled assessment, LGS 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, LGS will reduce pressure consistent with §192.933 until LGS 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

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #8: Preventive and Mitigative Measures

| Ref: 49 CFR 192.935 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


8.1 Objectives and Purpose
8.2 Definitions Applicable to Element #8
8.3 General Requirements & ID of Additional Measures
8.4 Enhancements to Damage Prevention
8.5 Automatic Shutoff Valves or Remote Control Valves
8.6 Replacing Pipe Segments with Pipe of Heavier Wall
8.7 Additional Training on Response Procedures
8.8 Conducting Drills with Local Emergency Responders
8.9 Additional Inspection and Maintenance Programs
8.10 Pipelines Operating Below 30% SYMS
8.11 Plastic Transmission Pipeline
8.12 Outside Force Damage
8.13 Corrosion
8.14 Review and Implementation of Element #8
8.15 Source References
8.16 List of Required Ongoing Documentation

Appendix 8A: Corrosion Control Adequacy Test Flow Chart
Appendix 8B: Process Flow Chart


### 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, LGS has developed these preventative and mitigative measures procedures to assist in this effort.

### 8.2 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 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.



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### 8.3 General Requirements and ID of Additional Measures [192.935(a)]

LGS has a process in place to identify additional measures 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 IMP element #2. Mitigative measures are shown on the LGS risk analysis and mitigative review worksheet.

The additional measures evaluated by LGS 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

A systematic, documented decision-making process will be used to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. 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 IMP element #2 and LGS risk analysis.

### 8.4 Enhancements to Damage Prevention (TPD) [192.935(b)(1), 192.935(e)(1)]

LGS 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 qualified personnel for work LGS 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



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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 LGS finds physical evidence of encroachment involving excavation that LGS did not monitor near a covered segment, LGS 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). LGS 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), LGS will implement these enhancements to the damage prevention program.

*Step #1: Conduct and Complete Enhancements to Damage Prevention Program as Listed in section #8.4 above*

Note, when LGS has a covered segment operating below 30% SMYS and for plastic transmission pipelines, LGS will implement a subset of these enhancements. See element #8.5 below.

### 8.5 Automatic Shut-Off Valves or Remote Control Valves [192.935(c)]

LGS 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. LGS will use a 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 were 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



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~~Consideration for installing computerized monitoring and leak detection systems or improving existing systems will also be part of the review.~~

*Step #2: Conduct Automatic Shutoff Review Using Risk Analysis Format*

**8.6** Replacing Pipe Segments with Pipe of Heavier Wall Thickness

Consideration for replacing pipe segments with pipe of heavier wall thickness will part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS risk analysis.

**8.7** Providing Additional Training to Personnel on Response Procedures

Consideration for providing additional training to personnel on response procedures will part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS risk analysis.

**8.8** Conducting Drills with Local Emergency Responders

Consideration for conducting drills with local emergency responders will part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS risk analysis.

**8.9** Implementing Additional Inspection and Maintenance Programs

Consideration for implementing additional inspection and maintenance programs will part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS risk analysis.

Other preventive or mitigative measures not specifically referenced by the rule that LGS will consider include the following:

- 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

These additional preventive and mitigative measures are also included the LGS risk analysis as described in element #2.



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### 8.10 Pipeline Operating Below 30% SMYS [192.935(d)]

LGS will implement the following preventive and mitigative requirements for pipelines operating below 30% SMYS:

1) LGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if LGS 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) LGS'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, LGS will implement the following minimum requirements:

1) LGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if LGS 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) LGS'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) LGS 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]



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*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) |
| Unodorized | 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) |
| Unodorized | Quarterly (706(b)) | Quarterly (935(d)) | Quarterly (935(d)) |

### 8.11 Plastic Transmission Pipeline [192.935(e)]

LGS does not have plastic transmission pipeline in an HCA segment at this time. If LGS has plastic transmission pipelines in the future, LGS will implement the following applicable third party damage requirements to covered segments:
[Element #8: Record #14]

1) LGS's processes for damage prevention program enhancements will include requirements for the use of qualified personnel if LGS 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) LGS'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 LGS finds physical evidence of encroachment involving excavation that LGS did not monitor near a covered segment, LGS 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). LGS must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.



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*Step #4: Implement Preventive & Mitigative Measures for Plastic Transmission, if Applicable*

### 8.12 Outside Force Damage Preventive & Mitigative Measures [192.935(b)(2)]

LGS will address threats due to outside force (e.g., earth movement, floods, and unstable suspension bridge). If LGS 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, LGS 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 part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS 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, LGS 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*

### 8.13 Corrosion Preventive and Mitigative Measures [192.917(e)(5)]

LGS will take required actions to address corrosion threats. If LGS makes a determination that corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line, LGS 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 LGS'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 LGS finds corrosion metal loss resulting in a Pf <1.1 times MAOP. [FAQ #135]



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Implicit in this requirement is that LGS'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.

~~See Appendix 8A, Corrosion Control Adequacy Test Flow Chart for assistance in corrosion review.~~

Consideration for corrosion will be part of the risk analysis that includes mitigative measures. See IMP element #2 and LGS risk analysis.

*Step #6: Implement Additional Corrosion Preventive and Mitigative Measures, if Appropriate*

### 8.14 Review and Implementation of Element #8

LGS will use the agenda, "Gas IMP Element #8, Preventive and Mitigative Measures Agenda and Action Items", for review and implementation of this element. LGS 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]



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### 8.15 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




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**Ref: 49 CFR 192.935** **Updated: Nov 2010**

### 8.16 List of Required Ongoing Documentation for Element #8

| Rec. #: | Sect. #: | Description of Required Documentation: | Respon. Person | Freq. & Deadline | Record Retention Period | Record Location |
|---|---|---|---|---|---|---|
| 1. | 8.4 | OQ Records for Personnel Marking and Locating | IMP Leader | AR | 5 yrs | Co. intranet |
| 2. | 8.4 | Central Database for TPD | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 8.4 | One Call System Records | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 4. | 8.4 | Monitoring Excavation (Exposed Pipe Reports) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 5. | 8.4 | Excavation When Encroachment Without Monitoring | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 6. | 8.4 | Above Ground Surveys (CIS, DCVG, etc.) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 7. | 8.5 | Auto Shutoff Review Using Risk Analysis Approach | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 8. | 8.10 | OQ Records for Personnel Marking and Locating (< 30% S~~Y~~MYS) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 9. | 8.10 | One Call Records (<30% S~~Y~~MYS) | IMP Leader | 1x/yr[1] | Life of pipeline | Co. intranet |
| 10. | 8.10 | Monitoring Excavation - Exposed Pipe Reports (<30% SMY~~YM~~S) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 11. | 8.10 | Bi-Monthly Patrols for Excavations Near the Pipeline (<30% SMY~~M~~S) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 12. | 8.10 | Follow Up Investigation When Indications of Unreported Construction Activity (<30% SMYS) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 13. | 8.10 | 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. | 8.11 | Plastic Pipe Additional Surveys, if Applicable | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 15. | 8.12 | 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.

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### 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. | 8.13 | Corrosion Evaluation | IMP Leader | AR | 5 yrs | Co. intranet |
| 17. | 8.13 | Schedule for Remediating Corrosion on Similar Segments | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 18. | 8.13 | Corrosion Root Cause Analysis | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 19. | 8.13 | Corrosion Surveys to Determine Extent of Damage (CIS, DCVG, etc.) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 20. | 8.14 | Element #8 agenda | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 21. | 8.14 | Element #8 action items | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |



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# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #8: Preventive and Mitigative Measures Agenda

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

Objectives for Mitigative Measures:

- Verify processes are in place to identify additional measures, verify these processes are based on identified threats, and verify the additional measures cover the appropriate spectrum of alternatives (shut-off valves, heavier wall pipe, etc.)
- Verify additional measures have been reviewed and considered for third party damage
- Verify additional measures have been reviewed and considered for pipeline operating less than 30% SMYS
- Verify additional measures have been reviewed and considered for plastic transmission pipeline
- Verify additional measures have been reviewed and considered for plastic transmission pipeline
- Verify additional measures have been reviewed and considered for outside force damage
- Verify additional measures have been reviewed and considered for corrosion
- Verify the company has a process for reviewing automatic shutoff valves
- Verify all required processes in element #8 have been properly documented

Who Should Attend Mitigative Measures:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

Frequency of Mitigative Measures Review:

- This agenda and these actions items should be conducted once per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve preventive and mitigative review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Mitigative Measures:

- Element #8 Procedure: Preventive and Mitigative Measures
- 49 CFR 192.935, 192.917(e)(1)

| Ref: 49 CFR 192.935, 917(e)(1) | Updated: Oct 2011 |
|---|---|

- FAQs: Preventive and Mitigative Measures
- Gas IMP Protocol Area H With Cross Reference, Preventive and Mitigative Measures
- ASME B31.8S, Gas Integrity Management

Forms and Documents Required For This Review:

- Preventive and Mitigative Review Worksheet
- Element #8 Agenda and Action Items
- IMP central database or map
- Root cause analysis, If Any
- Exposed pipe reports
- CP surveys and CP close interval survey
- TPD Follow-up Investigation Reports, If Any
- Patrols and Leak Surveys
- Risk Analysis for Auto Shut-off Review
- MOC, When Required

Record Keeping for Remediation and Repair:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #8: PREVENTIVE AND MITIGATIVE MEASURES ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #8: Preventive and Mitigative Measures Agenda

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O1– General Requirements (Identification of Additional Measures)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that a process is in place to identify additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. | **H.01** | | | | | |
| 8-1 | Verify that the process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by 192.917. [Note: Protocol H.08 addresses the implementation decision process for additional preventive and mitigative measures.] | **H.01.a** | 8.3 | 917, 935(a) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheet in Element 2 tab of IMP records binder. |
| 8-2 | Verify that additional measures evaluated cover a spectrum of alternatives such as, but not limited to:<br>▪ Installing Automatic Shut-off Valves or Remote Control Valves<br>▪ Installing computerized monitoring and leak detection systems<br>▪ Replacing pipe segments with pipe of heavier wall thickness<br>▪ Providing additional training to personnel on response procedures<br>▪ Conducting drills with local emergency responders<br>▪ Implementing additional inspection and maintenance programs | **H.01.b** | 8.3 | 935(a) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheet in Element 2 tab of IMP records binder. See automatic shut-off valve assessment in Element 8 tab of IMP records binder. |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O2– Third Party Damage**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the following preventive and mitigative requirements regarding threats due to third party damage have been addressed: | | | | | | |
| 8-3 | Verify implementation of enhancements to the 192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that the enhanced measures include, at a minimum: [Note: As noted in Protocol H.03 and Protocol H.04, a subset of these enhancements are required for pipelines operating below 30% SMYS and for plastic transmission pipelines. | **H.02.a** | 8.4 | 935(b)(1) | IMP Leader | 1x/yr | Complete<br>LGS conducts O&M tasks and OQ tasks. OQ and O&M program in place has been subject to PHMSA audits conducted by CPUC. |
| | 1) Using qualified personnel (see Protocol L.02 - 192.915(c)) 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. | | | | | | Complete.<br>LGS conducts O&M tasks and OQ tasks. OQ and O&M program in place has been subject to PHMSA audits conducted by CPUC. |
| | 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. | | | | | | In Progress.<br>In process of loading data into integration Maps by BPL Integrity Management Department. |

**Element #8: Preventive and Mitigative Measures: H.O2– Third Party Damage (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 8-3 (cont.) | 3) Participating in one-call systems in locations where covered segments are present. | | | | | | Complete. LGS is in California USA North One call system. |
| | 4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel.<br><br>1. 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 RP0502-2002 must be conducted.<br>A. 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 ASME B31.8S-2004, Section 7.5 and □192.933. | | | | | | LGS conducts O&M tasks and OQ tasks. OQ and O&M program in place has been subject to PHMSA audits conducted by CPUC.<br><br>O&M procedures require monitoring if pipeline is exposed for any reason. |

**Element #8: Preventive and Mitigative Measures: H.O2– Third Party Damage (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 8-4 | If the threat of third party damage is identified by results of the §192.917(b) (Protocol C.02) and ASME B31.8S-2004, Appendix A7 data integration processes, verify that comprehensive additional preventive measures are implemented. [§192.917(e)(1)]<br><br>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)]<br><br>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.<br><br>3) Participating in one-call systems in locations where covered segments are present.<br><br>4) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. | **H.02.b** | 8.4 | 935(b)(1) | IMP Leader | 1x/yr | 1) LGS conducts O&M tasks and OQ tasks. OQ and O&M program in place has been subject to PHMSA audits conducted by CPUC.<br><br>O&M procedures require monitoring if pipeline is exposed for any reason.<br><br>2) Pipeline Integrity Department data integration alignment sheets under development<br><br>3) LGS is in California USA North One call system.<br><br>4) LGS conducts O&M tasks. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8-4 (cont.) | 5) When there is physical evidence of encroachment involving excavation that the company did not monitor near a covered segment, 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)]<br><br>6) If an above ground survey is conducted, the company will 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)] | | | | | | 5) No encroachments<br><br>6) NA |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O3– Pipelines Operating Below 30% SMYS**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the following preventive and mitigative requirements for pipelines operating below 30% SMYS have been addressed: | **H.03** | | 935(d) | | | |
| 8-5 | For pipelines operating below 30% SMYS located in a high consequence area: | **H.03.a** | 8.4 | 935(d) | IMP Leader | 1x/yr | NA, line operates at above 30% SYMS. |
| | 1) Verify that the company's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - 192.915(c)) 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. | | | | | | NA, line operates at above 30% SYMS. |
| | 2) Verify that the company's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. | | | | | | NA, line operates at above 30% SYMS |
| | 3) Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by 192.705.<br>1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. | | | | | | NA, line operates at above 30% SYMS |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O3– Pipelines Operating Below 30% SMYS (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 8-6 | For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area: | **H.03.b** | 8.4 | 935(d) | IMP Leader | 1x/yr | |
| | 1) Verify that the company's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - 192.915(c)) 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. | | | | | | NA, line operates at above 30% SYMS |
| | 2) Verify that the company's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. | | | | | | NA, line operates at above 30% SYMS |
| | 3) Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by 192.705.<br>1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. | | | | | | NA, line operates at above 30% SYMS |
| | 4) Verify that the company performs semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). | | | | | | NA, line operates at above 30% SYMS |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O4– Plastic Transmission Pipe**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | For plastic transmission pipelines, verify that applicable third party damage requirements have been applied to covered segments of the pipeline. | **H.04** | | | | | |
| 8-6 | Verify that the company's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - 192.915(c)) 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. | **H.04.a** | 8.6 | 935(e) | IMP Leader | 1x | NA, there is no plastic pipe on these HCA segments at this time. |
| 8-8 | Verify that the company's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. | **H.04.b** | 8.6 | 935(e) | IMP Leader | 1x | NA, there is no plastic pipe on these HCA segments at this time. |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O4– Plastic Transmission Pipe (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 8-9 | Verify that the excavations on covered segments are monitored by pipeline personnel.<br><br>1) When there is physical evidence of encroachment involving excavation that the company 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 RP0502-2002 must be conducted.<br><br>1. 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 ASME B31.8S-2004, Section 7.5 and 192.933. | **H.04.c** | 8.6 | 935(e) | IMP Leader | 1x | NA, there is no plastic pipe on these HCA segments at this time. |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O5– Outside Force Damage**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the company adequately addresses threats due to outside force (e.g., earth movement, floods, unstable suspension bridge). | **H.05** | | | | | |
| 8-10 | If the company makes a determination that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment (e.g., via Protocol C.01 activities), verify that measures have been taken 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. | **H.05.a** | 8.7 | 935(b)(2) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheet in Element 2 tab of IMP records binder. |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O6– Corrosion**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the company takes required actions to address corrosion threats. | **H.06** | | | | | |
| 8-11 | Verify that the company makes a determination of whether or not corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in 192.933).<br><br>If such corrosion is identified, then verify that:<br><br>The corrosion is evaluated and remediated, as necessary, for all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. A schedule is established for evaluating and remediating, as necessary, the similar segments consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair. | **H.06.a** | 8.7 | 933, 917(e)(5) | IMP Leader | 1x/yr | Complete.<br><br>See 2007 Farwest CIS report |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O7– Automatic Shutoff Valves or Remote Control Valves**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the company has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. | **H.07** | | | | | |
| 8-12 | Verify that an adequate risk analysis-based process is used to determine if an automatic shut-off valve or remote control valve should be added.<br><br>Verify that, as a minimum, the following factors were considered:<br><br>▪ Swiftness of leak detection and pipe shutdown capabilities<br>▪ Type of gas being transported<br>▪ Operating pressure<br>▪ Rate of potential release<br>▪ Pipeline profile<br>▪ Potential for ignition<br>▪ Location of nearest response personnel | **H.07.a** | 8.9 | 935(c) | IMP Leader | 1x/yr | Complete<br><br>Remote shut off valve is installed at PG&E Line 401 connection, upstream of the HCA locations, and a remote shut off valve is installed at the compressor station downstream.<br><br>Considering additional remote shut-off valves at Hwy 12 and Woodbridge Rd valve sites. |

**Ref: 49 CFR 192.935, 917(e)(1)** **Updated: Oct 2011**

**Element #8: Preventive and Mitigative Measures: H.O8– General Requirements (Implementation of Additional Measures)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the company has identified and implemented (or scheduled) 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: | **H.08** | | | | | |
| 8-13 | Verify that a systematic, documented decision-making process is in place to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. | **H.08.a** | 8.10 | 935(a) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheets and agendas in Element 2 tab and Element 8 tab of IMP records binder. |
| 8-14 | Verify that the decision-making process considers both the likelihood and consequences of pipeline failures. | **H.08.b** | 8.10 | 935(a) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheets and agendas in Element 2 tab and Element 8 tab of IMP records binder. |
| 8-15 | Verify that additional measures are identified and documented and have actually been implemented, or scheduled for implementation. | **H.08.c** | 8.10 | 935(a) | IMP Leader | 1x/yr | Complete. See BAP and RA worksheets in Element 2 tab and Element 8 tab of IMP records binder and action item list. |

# Lodi Gas Storage
# Integrity Management Plan
## Element #9: Performance Measures

| Ref: 49 CFR 192.945 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


9.1 Summary of Performance Measure Requirements
9.2 Objective and Purpose of Performance Measures
9.3 Performance Measures Submittal to OPS
9.4 General Requirements & ID of Additional Measures
9.5 Performance Measures if Conducting ECDA
9.6 Characteristics of Performance Measures
9.7 Exceptional Performance Measures
9.8 Review and Implementation of Element #9
9.9 Source References
9.10 List of Required Ongoing Documentation


### 9.1 Summary of Requirements for Performance Measures [192.945]

LGS must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective is effective in assessing and evaluation the integrity of each pipeline segment and in protecting the high consequence areas.

### 9.2 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, LGS will develop performance measures to determine IMP effectiveness. Effective performance measures will guide LGS by focusing resources to provide for effective preventative maintenance.

### 9.3 Performance Measures Submittal to OPS
[§192.945(a) and ASME B31.8S, §12(b)(5)]

*Step #1: Semi-Annual Submittal to OPS on Four Performance Measures*
**This whole section (9.3) needs to be updated per the revisions to 49 CFR 191.17 published in the November 2010 federal register.**

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LGS will conduct performance measurement semi-annually (completed through June 30th and December 31st of each year) for each of the following: [ASME B31.8S, §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

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- Number of leaks, failures and incidents (classified by cause).

The four overall performance measures of ASME B31.8S, § 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]
LGS 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.

LGS 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, LGS can mail or fax the reports to PHMSA.

| | |
|---|---|
| PHMSA Fax number: | (202) 366–7128 |
| PHMSA mailing address: | Information Resources Manager<br>Office of Pipeline Safety<br>Pipeline and Hazardous Materials Safety Administration (PHMSA)<br>U.S. Department of Transportation<br>400 Seventh Street SW, Room 7128<br>Washington, DC 20590 |

LGS will submit the semi-annual report for each state in which LGS has jurisdictional gas transmission pipelines. If LGS pipeline operations change so that there are no longer any HCAs, LGS will continue to submit performance metrics semi-annually. This is so LGS can continue looking for new HCAs. LGS will review information such as population growth or land use changes that could result in new HCAs.

### 9.4 General Requirements & ID of Additional Performance Measures
[§192.945(a) and ASME B31.8S, §12(b)(5) and appendix A]

*Step #2: Determine Which of the ASME B31.8S, Appendix A Threats Apply to the LGS Pipelines*

In addition to the four performance measures already discussed in section #9.2 above, LGS will also determine which of the ASME B31.8S Appendix A threats apply. LGS will use these identified threats for measuring integrity management program effectiveness. [Element #9: Record #2]



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# Lodi Gas Storage
# Integrity Management Plan
## Element #9: Performance Measures

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*Step #3: Review Additional Threats Semi-Annually:* LGS will review threat specific measures semi-annually. A list of these threat specific measures are 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<br>(b) Number of repair actions taken due to in-line inspection results, immediate and scheduled<br>(c) Number of repair actions taken due to direct assessment results, immediate and scheduled<br>(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<br>(b) Number of repair actions taken due to in-line inspection results, immediate and scheduled<br>(c) Number of repair actions taken due to direct assessment results, immediate and scheduled<br>(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<br>(b) Number of repair or replacements die to SCC<br>(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<br>(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<br>(b) Number of girth welds/couplings reinforced/removed<br>(c) Number of wrinkle bends removed<br>(d) Number of wrinkle bend inspections<br>(e) Number of fabrication welds repaired/removed |
| Equipment ASME B31.8S-2004, Appendix A, Section A6.8 | (a) Number of regulator valve failures<br>(b) Number of relief valve failures<br>(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<br>(b) Number of leaks or failures caused by previously damaged pipe<br>(c) Number of leaks or failures caused by vandalism<br>(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<br>(b) Number of audits/reviews conducted<br>(c) Number of findings per audit/review classified by severity<br>(d) Number of changes to procedures due to audit/reviews |



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# Lodi Gas Storage
# Integrity Management Plan
## Element #9: Performance Measures

| Ref: 49 CFR 192.945 | Updated: Nov 2010 |
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| | |
|---|---|
| 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<br>(b) Number of repair, replacement, or relocation actions due to weather related or outside force threats |

The following pipeline O&M procedures, completed reports, and surveys will be gathered and reviewed for performance measures, includinge 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]



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*Step #4: Review IM Program for Potential Additional Threats*

LGS 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 plans 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. Is there a form for this? This should be added to the agenda and not be a separate record. [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. This is the same standard in which this performance measure is specified. LGS will apply the definitions in the ASME standard when reporting their performance measures. [FAQ #136]

Timing for Determination of Performance Measures

LGS 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

LGS 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 LGS, in the postulated situation, uses the prior assessment as the baseline for the new HCA



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segment, then the associated mileage can be included in the next semi-annual performance measure submittal. If LGS elects not to treat the prior assessment as its baseline, then the mileage shall not be reported. [FAQ #186]

PHMSA Website for Performance Measure Reporting

OPS will develop an on-line form for submitting this information. The form will be available on the OPS web site (http://ops.dot.gov). The same information can be submitted by mail or facsimile, in accordance with 192.951, but OPS would prefer to receive performance measures via the web site. [FAQ #194]

Performance Measures for Submittal

Section 192.945 was revised by the rule correction published in the *Federal Register* on April 6, 2004 (69 FR 18228). As revised, the rule requires semi-annual submission of only the four overall measures. In additions to LGS implementing performance-based programs, under 192.913, LGS is required to submit the additional performance measures they define for their programs in addition to the Section 9.4 measures. [FAQ #209]

## 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 LGS uses direct assessment to assess the external corrosion threat, LGS shall define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

## 9.6 Characteristics of Performance Measures Characteristics
[§192.945(a) and ASME B31.8S, 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 LGS performance measures worksheet.



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Process or Activity Measures: Process or activity measures can be used to evaluate prevention or mitigation activities. These measures determine how well LGS 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, Table 8.

### 9.7 Exceptional Performance Measures

When LGS chooses to demonstrate exceptional performance in order to deviate from certain requirements of the rule, LGS 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 LGS'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

LGS will use the agenda, "Gas IMP Element #9, Performance Measures Agenda and Action Items", for review and implementation of this element. LGS 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



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- 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 a 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




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# Lodi Gas Storage
# Integrity Management Plan
## Element #9: Performance Measures

**Ref: 49 CFR 192.945** **Updated: Nov 2010**

### 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 | ~~IMP Leader~~OM | 1x/yr[1] | 5 yrs | Co. intranet |
| 5. | 9.4 | Reporting of Safety Related Conditions, O&M #1.02 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 6. | 9.4 | Investigation of Failures and Accidents, O&M #1.03 | OM~~/IMP Leader~~ | 1x/yr[1] | Life of Pipe | Co. intranet |
| 7. | 9.4 | Annual Reports, O&M #1.04 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 8. | 9.4 | Class Location Survey Report, O&M #4.01 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 9. | 9.4 | Continuing Surveillance Report, O&M #5.01 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 10. | 9.4 | Gas Leak Survey Reports, O&M #5.02 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 11. | 9.4 | Pipeline Patrol Reports, O&M #5.03 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 12. | 9.4 | Internal and External Examination of Buried Pipe (exposed pipe reports) O&M #6.04 | OM~~/IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 13. | 9.4 | Pipeline Repair Procedures and Reports, O&M #9.01 | OM~~/IMP Leader~~ | 1x/yr[1] | Life of Pipe | Co. intranet |
| 14. | 9.4 | Conversion of Service, O&M #12.02 | OM~~/IMP~~ | 1x/yr[1] | 5 yrs | Co. intranet |



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| | | | ~~Leader~~ | | | |
| 15. | 9.4 | Abandonment or Inactivation of Facilities, O&M #13.01 | OM~~IMP Leader~~ | 1x/yr[1] | 5 yrs | Co. intranet |
| 16. | 9.4 | Pressure Testing and Reports, O&M #15.01 | OM~~IMP Leader~~ | 1x/yr[1] | Life of Pipe | Co. intranet |
| 17. | 9.4 | Visual Inspection and NDT Testing and Reports, O&M #15.02 | OM~~IMP Leader~~ | 1x/yr[1] | Life of Pipe | Co. intranet |
| 18. | 9.4 | Control Room Management Incident Review, PSOM #17.11 | IMP Leader | 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.

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# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #9: Performance Measures Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Objectives for Performance Measures:

- Verify the four required minimum PHMSA measurements are tracked and reported to OPS semiannually
- Verify additional measures are in place, tracked and reviewed for potential mitigation activities
- Verify requirements are meet when the company chooses to use exceptional performance
- Verify all the appropriate records are completed and maintained for the life of the pipeline
- Verify Management of Change (MOC) has been implemented according to MOC requirements
- Verify all required processes in element #9 have been properly documented

Who Should Attend Performance Measures:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Frequency of Performance Measures Review:

- This agenda and these actions items should be conducted twice per calendar year, not to exceed 18 months
- Semi-annual reporting to PHMSA is due by February 28 and August 31

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve Performance Measures process and document.

Regulations, Resources, and Procedures Needed to Review Performance Measures:

- Element #9 Procedure: Performance Measures
- 49 CFR 192.945, 192.947, 192.909
- FAQs: Performance Measures
- Gas IMP Protocol Area I With Cross Reference, Performance Measures

Forms and Documents Required For This Review:

- Performance Measures Review Worksheet
- Element #9 Agenda and Action Items
- PHMSA Semi-annual Online Report
- MOC, When Required

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #9: Performance Measures Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Record Keeping for Performance Measures:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #9: PERFORMANCE MEASURES ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #9: Performance Measures Agenda

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #9: Performance Measures: I.O1– General Performance Measures**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Inspect the operator's program to verify that, as a minimum, provisions exist for measuring integrity management program effectiveness in accordance with the four elements of ASME B31.8S-2004, Section 9.4 and each identified threat in ASME B31.8S-2004, Appendix A. [§192.945(a) and ASME B31.8S-2004, Section 12(b)(5)]* | **I.01** | | | | | |
| 9-1 | Verify that performance is measured semi-annually (completed through June 30th and December 31st of each year) for each of the following: [ASME B31.8S-2004, Section 9.4]<br>▪ Number of miles of pipeline inspected versus program requirements<br>▪ Number of immediate repairs completed as a result of the integrity management inspection program<br>▪ Number of scheduled repairs completed as a result of the integrity management program<br>▪ Number of leaks, failures and incidents (classified by cause). | **I.01.a** | 9.2 | 945(a) | IMP Leader | 1x/yr | Complete.<br>See copies of Gas IMP reports and performance measures worksheet in Element 9 tab of IMP records binder.<br>Note: *The bi-annual Gas Integrity Management filing for the period ending 12/31/2010 which would normally be due on 2/28th under the ASME B31.8s format is discontinued. The Calendar Year 2010 Gas Transmission & Gathering Systems Annual Report due August 15, 2011 will begin IMP reporting annually on the new annual report form.* |
| 9-2 | Verify that performance is measured semi-annually in accordance with the threat-specific metrics of ASME B31.8S-2004, Appendix A (See ASME B31.8S-2004, Table 9 for a summary listing). | **I.01.b** | 9.2 | 945(a) | IMP Leader | 1x | Complete.<br>See copies of Gas IMP reports and performance measures worksheet in Element 9 tab of IMP records binder. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #9: Performance Measures Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

**Element #9: Performance Measures: I.O2– General Performance Measures Records Verification**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Inspect company records to verify:* | **I.02** | | | | | |
| 9-3 | The four overall performance measures of ASME B31.8S-2004, Section 9.4 have been submitted to PHMSA on a semi-annual basis in accordance with 192.951. Note: Initial report by August 31, 2004, semi-annual reports by February 28th (or 29th) and August 31st of each year thereafter. | **I.02.a** | 9.2 | 945(a) | IMP Leader | 1x/yr | Complete. See copies of Gas IMP reports and performance measures worksheet in Element 9 tab of IMP records binder. |

# Lodi Gas Storage
# Integrity Management Plan
## Element #10: Record Keeping

| Ref: 49 CFR 192.947 | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


10.1 Objective and Purpose of Record Keeping
10.2 Minimum Records to be Maintained by LGS
10.3 Review and Implementation of Element #10
10.4 Source References and Documents
10.5 List of Required Ongoing Documentation


### 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, LGS has developed these record keeping procedures to assist in this effort.

### 10.2 Minimum Records to be maintained by LGS [192.947]

LGS 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



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# Lodi Gas Storage
# Integrity Management Plan
## Element #10: Record Keeping

| Ref: 49 CFR 192.947 | Updated: Nov 2010 |
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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 LGS 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~~in~~ properly completed (i.e., no missing signatures or dates) when necessary to demonstrate compliance with the rule. For document management, LGS IM program records will be maintained on the LGS intranet unless otherwise noted in the procedure and/or element agenda.

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 #10.3 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 LGS 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

LGS 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]



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Management Level for Certification

OPS expect that LGS will exercise appropriate controls to ensure that their IM programs, and the procedures by which its elements are implemented, are approved for use. The level of management official responsible for that approval is up to LGS, but shall be at a level sufficient to assure compliance. The LGS "Team Charter" as described in element #12, Quality Assurance defines the appropriate level of LGS management responsible for approval. [FAQ #189]

### 10.3 Review and Implementation of Element #10

LGS will use the agenda, "Gas IMP Element #10 & #11, Records and MOC Agenda and Action Items", for review and implementation of this element. LGS 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]

*Step #1: Using element #10 #11 agenda, verify all appropriate IM program documentation is completed and available for PHSMA review.*



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### 10.4 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




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# Lodi Gas Storage
# Integrity Management Plan
## Element #10: Record Keeping

**Ref: 49 CFR 192.947** **Updated: Nov 2010**

### 10.5 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.
Note #2: Frequency is semi-annually completed through June 30th and December 31st of each year.



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# Lodi Gas Storage
# Integrity Management Plan
## Element #10: Record Keeping

**Ref: 49 CFR 192.947** **Updated: Nov 2010**

~~List of Required Ongoing Documentation for Element #1 (from section #1.10)~~

| ~~Rec. #:~~ | ~~Sect. #:~~ | ~~Description of Required Documentation:~~ | ~~Respon. Person~~ | ~~Freq. & Deadline~~ | ~~Record Retention Period~~ | ~~Record Location~~ |
|---|---|---|---|---|---|---|
| ~~1.~~ | ~~1.1~~ | ~~Jurisdictional determination~~ | ~~IMP Leader~~ | ~~AR~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~2.~~ | ~~1.3~~ | ~~Gas IMP List of HCAs with PIR calculation~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~3.~~ | ~~1.3~~ | ~~Form #1-1A (HCA Identification Survey Method #1)~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~4.~~ | ~~1.3~~ | ~~Form #1-1B (HCA Identification Survey Method #2)~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~5.~~ | ~~1.3~~ | ~~Form #1-1C (HCA Identified Site Survey)~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~6.~~ | ~~1.3~~ | ~~Form #1-1D (Change in Operation Affecting HCA)~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~7.~~ | ~~1.3~~ | ~~GPS instrument manufacturer's technical info on accuracy~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~8.~~ | ~~1.3~~ | ~~Aerial photography or survey maps~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~9.~~ | ~~1.3~~ | ~~As-built drawing alignment sheets~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~Life of pipeline~~ | ~~Co. intranet~~ |
| ~~10.~~ | ~~1.3~~ | ~~Public Officials/Em. Officials Identified Site Survey Letter~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~11.~~ | ~~1.4~~ | ~~Annual Reports, O&M #1.04~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~12.~~ | ~~1.4~~ | ~~Onshore Gas Gathering Determination, O&M #4.02~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~13.~~ | ~~1.4~~ | ~~Continuing Surveillance, O&M #5.01~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~14.~~ | ~~1.4~~ | ~~Pipeline Patrols, O&M #5.03~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~15.~~ | ~~1.4~~ | ~~Maximum Allowable Operating Pressure, O&M #8,01~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~16.~~ | ~~1.4~~ | ~~Pipeline Uprating, O&M #12.01~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~17.~~ | ~~1.4~~ | ~~Conversion of Service, O&M #12.02~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~18.~~ | ~~1.5~~ | ~~Notification to OPS for change in HCA method~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~19.~~ | ~~1.6~~ | ~~Gas IMP record of revisions~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |
| ~~20.~~ | ~~1.7~~ | ~~Element #1 agenda~~ | ~~IMP Leader~~ | ~~1x/yr[1]~~ | ~~5 yrs~~ | ~~Co. intranet~~ |

~~Note #1: Frequency is 1x/calendar year not to exceed 18 months.~~



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# Lodi Gas Storage
# Integrity Management Plan
## Element #11: Management of Change (MOC)

| Ref: 49 CFR 192.909 | Updated: Nov 2011 |
|---|---|

**Contents of this Element:**


11.1 Summary of MOC Requirements
11.2 Objectives and Purpose of MOC
11.3 Definitions Applicable to Element #11
11.4 Documentation and Notification of Change
11.5 Agency Notification Requirements
11.6 Attributes of the MOC Process
11.7 Review and Implementation of Element #11
11.8 Source References
11.9 List of Required Ongoing Documentation


### 11.1 Summary of MOC Requirements [192.909]

LGS has a management of change (MOC) process to address reasons for change, notification of the change, and documentation of the change to the gas integrity management program.

### 11.2 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, LGS will use MOC process to track ~~how, what, why, when, and where~~ significant changes ~~are made to~~to the IM program.

### 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

LGS will use existing MOC procedures to document changes to the integrity management program. Notification will also be performed in accordance with existing MOC procedures. LGS will ensure the reasons for program changes have been documented prior to implementation of the change(s).

It is not the intent of LGS 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 LGS MOC procedures determine if a change would require documentation under the MOC process.
[Element #11: Record #1]

*Step #2: MOC Documentation*

If answer to step #1 is yes, then document MOC process using LGS 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

Examples of changes that would not be considered significant and would not require notification are:

- Addition of new HCA segments
- 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

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 LGS 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 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 shall 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 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 LGS 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

LGS 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

LGS 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. LGS will update the risk assessment process and outputs to include changes to applicable data.

Deadline for Implementing MOC

Operators' management of change process shall be implemented as soon as there is a program whose change needs to be managed. If an operator 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 operators 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

LGS will use the agenda, "Gas IMP Element #10 & #11, Records and MOC Agenda and Action Items", for review and implementation of this element. LGS 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: Nov 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.

# Integrity Management Plan
## Natural Gas Pipelines
## Element #12: Quality Assurance

| Ref: 49 CFR 192.911(l) | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


12.1 Objectives and Purpose of QA
12.2 Summary of Quality Assurance Requirements
12.3 Definitions Applicable to Element #12
12.4 General Program Requirements
12.5 IM Program Documentation
12.6 Responsibilities and Authorities
12.7 Program Review, Corrective Action, and Monitoring
12.8 Personnel Qualification and Training Requirements
12.9 Qualification of Personnel Reviewing Integrity Data
12.10 IM Program Internal Audits
12.11 Invoking Non-Mandatory Statements in Standards
12.12 Quality Assurance Key Responsibilities Chart
12.13 Review and Implementation of Element #12
12.14 Source References
12.15 List of Required Ongoing Documentation


### 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, LGS has developed these quality assurance procedures to assist in this effort.

### 12.2 Summary of Requirements for Quality Assurance [192.911(l)]

LGS 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.

### 12.3 Definitions Applicable to Element #12

**Quality assurance** is a process that describes how LGS 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)]

LGS 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
- Responsibilities and authorities under the IM program will be clearly and formally defined
- Results of the IM program will be reviewed at predetermined intervals and include recommendations for improvements
- Personnel qualification requirements must be identified for anyone who is involved in the IM program
- Monitoring of the IM program to ensure that it is being implemented according to the written procedures
- Periodic internal audits of the IM program
- Corrective actions to improve the IM program

When LGS chooses to use outside resources to conduct any process that affects the quality of the integrity management program, LGS will ensure the quality of such processes and document them within the quality program.

### 12.5 IM Program Documentation

IM program documentation requirements are listed at the end of each IM procedure, duplicated at the end of each agenda, and summarized in IM element #10 Record Keeping procedures.

### 12.6 IM Program Responsibilities and Authorities

The LGS Team Charter defines general team member roles and responsibilities. [Element #12: Record #1] The required documentation section at the end of each procedure defines who is responsible for completing specific tasks including documentation. The LGS 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.

*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 and the 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 #6~~2~~]

The LGS corrective action process shall include 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

LGS will verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. LGS integrity management program supervisory personnel will have the appropriate training or experience for their assigned responsibilities. Records shall be maintained by LGS for any training or qualification used for the integrity management program. [Element #12: Record #2~~3~~, #3~~4~~]

*Step #3: Document LGS and Contractor Qualifications*

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, §12(b)(4)]

As part of the review process, LGS 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 and training requirements and records are documented in the IM program records binder/files. IM program tasks that are also operator qualification (OQ) covered tasks are defined in the LGS 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 LGS 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.

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 LGS chooses to use outside resources to conduct any process that affects the quality of the integrity management program, LGS will ensure the quality of such processes and document them within the quality program.

### ~~12.8 (cont.) 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 Silicon Valley Power (LGS) gas transmission pipeline This supports LGS 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:**~~ | ~~John Roukema~~<br>~~City of Santa Clara, Director of Electric Utilities~~ |
| ~~**IMP TEAM LEADER:**~~ | ~~Andy Bradfield~~<br>~~Pipeline Consultant~~<br>~~Compliance Services Inc~~ |
| ~~**OTHER IMP TEAM MEMBERS:**~~ | ~~Orville Plum~~<br>~~LGS – Acting Sr. Elec. Div. Mgr – Engineering & Generation~~<br><br>~~Steve Hance~~<br>~~LGS – Electrical Division Supervisor and Planner~~<br>~~Damon Beck~~<br>~~LGS – EHS Advisor~~<br>~~Richard Tucker~~<br>~~DBTS, VP – Pipeline Maintenance & Repair Contractor~~<br>~~Brien Vierra~~<br>~~FJ Technologies, Inc. – Engineering Consultant~~ |

### ~~GIMT Qualification Requirements (cont.)~~

| | |
|---|---|
| ~~**IMP TEAM MANAGEMENT SUPPORT/SPONSOR:**~~ | ~~John Roukema~~<br>~~City of Santa Clara, Director of Electric Utilities~~ |
| ~~**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**~~ | ~~Orville Plum~~<br>~~LGS – Acting Sr. Elec. Div. Mgr – Engineering & Generation~~ |
| ~~**Qualification Requirements:**~~ | ~~1. General understanding of DOT integrity management regulations, risk analysis process, and need for mitigative measures to reduce pipeline integrity risks~~<br>~~2. General understanding of risk assessment methodologies~~ |

| | |
|---|---|
| ~~**IMP Team Assistant Supervisor and Planner**~~ | ~~Steve Hance~~<br>~~LGS – Electrical Division Supervisor and Planner~~ |
| ~~**Qualification Requirements:**~~ | ~~1. General understanding of DOT integrity management regulations, risk analysis process, and need for mitigative measures to reduce pipeline integrity risks~~<br>~~2. General understanding of risk assessment methodologies~~ |

| | |
|---|---|
| ~~**IMP TEAM LEADER:**~~ | ~~Andy Bradfield~~<br>~~Pipeline Consultant~~<br>~~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~~<br>~~2A. Minimum 5 years of pipeline/facility operation, maintenance experience in a supervisory or manager capacity with strong technical background; or~~<br>~~2B. Minimum 5 years of DOT pipeline compliance experience; and~~<br>~~3. Experience or certification in Process Hazard Analysis methodologies or other risk assessment techniques experience.~~ |

~~**GIMT Qualification Requirements (cont.)**~~

| | |
|---|---|
| ~~**IMP TEAM MEMBER #1:**~~ | ~~Damon Beck~~<br>~~LGS – EHS Advisor~~ |
| ~~**Qualification Requirements:**~~ | ~~1. General understanding of DOT IMP regulations and OPS IMP protocols, and~~<br>~~2. Minimum 5 years of experience in safety and/or environmental compliance~~ |
| ~~**IMP TEAM MEMBER #2:**~~ | ~~Richard Tucker~~<br>~~DBTS, VP – Pipeline Maintenance & Repair Contractor~~ |
| ~~**Qualification Requirements:**~~ | ~~1. Completion of all job applicable OQ training modules; and~~<br>~~2. Minimum 5 years of experience with pipeline/facility operations and maintenance; and~~<br>~~3. Knowledge of DOT O&M, OQ, and IMP regulations applicable to the pipeline facility.~~ |
| ~~**IMP TEAM MEMBER #3:**~~ | ~~Brien Vierra~~<br>~~FJ Technologies, Inc. – Engineering Consultant~~ |
| ~~**Qualification Requirements:**~~ | ~~1. Understanding of DOT IMP regulations and OPS IMP protocols, and~~<br>~~2. Minimum 5 years of experience with pipeline operations, maintenance, and engineering~~<br>~~3. Bachelors degree in engineering or science with at least 5 years of pipeline/facility operation, maintenance, or construction experience; or~~ |

~~**Other Consultants and Contractors**~~

| | |
|---|---|
| ~~**IMP TEAM MEMBER #5:**~~ | ~~Bill Golden~~<br>~~Far West Corrosion – NACE Corrosion Tech~~ |
| ~~**Qualification Requirements:**~~ | ~~1. Understanding of DOT corrosion regulations, and~~<br>~~2. Minimum 5 years of experience with corrosion, and~~<br>~~3. NACE Corrosion Technician~~ |

### 12.9 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 LGS's Integrity Management Plan will result in data that must be analyzed by personnel qualified to do so. 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, LGS will rely on its ILI vendors to provide the expertise required for data analysis. LGS will only contract with reputable in-line inspection vendors with at least three years of proven experience 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 API #1163 and ASNT ILI-PQ, level II.

LGS 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, 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 LGS employee who has been qualified to LGS's Operator Qualification Program. A LGS engineer, consulting engineer, or California State Fire Marshall (CSFM) certified testing LGS shall certify the hydrostatic test.

**Direct Assessment**

Direct Assessment methodologies that may be employed in the determination of the LGS pipeline integrity shall be conducted by reputable vendors with proven experience in applying the methodology. LGS 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.

### 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 LGS integrity management program audit results. [Element #12: Record #4~~5~~]

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*

LGS 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 LGS 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 LGS management of change procedures.

### 12.11 Invoking Non-Mandatory Statements in Standards ASME [B31.8S,§11(a)(8) & §12.2(b)(4)]

LGS will use non-mandatory requirements (e.g., "should" statements) from industry standards or other documents invoked by Subpart O (e.g., ASME B31.8S-2001 and NACE RP0502-2002) by one of the following approaches: [§192.7(a)]

1) LGS will incorporate the non-mandatory standard into the LGS's plan and implement as recommended in the standard; or
2) LGS will use an equivalent alternative method for accomplishing the same objective and will justify and implement the equivalent alternative method; or
3 LGS will document the justification including the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O.

LGS will use approach number one 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]

### 12.12 Gas IMP
### Quality Assurance Key Responsibilities Chart

Company Management:
- Accountable for all IM program elements
- Provide guidance, approval, support, and funding to implement all elements
- Review key documents as outlined in the team charter
- Sign team charter

IMP Coordinator:
- Accountable for implementation and oversight of all IM program elements
- Conduct review IM program procedures annually including recommendations and tracking of corrective action status
- Lead HCA segment specific IM program reviews with appropriate IMP team members. Review to include recommendations and corrective actions
- Conduct internal audits of whole program once per three years
- Communicate all program reviews to appropriate IMP team members and company management

Pipeline/Facility Supervisor:
- Accountable for implementation oversight of all IM program elements within their facility
- Assist IMP Coordinator with annual reviews and internal audits
- Communicate IM program R&Rs to pipeline operators

SMEs:
- Provide recommendations for program improvement in their area of expertise
- Participate in annual reviews when requested

Pipeline Operators:
- Provide recommendations for program improvement in their HCA segment area
- Participate in annual reviews when requested

### 12.13 Review and Implementation of Element #12

LGS will use the agenda, "Gas IMP Element #12, Quality Assurance Agenda and Action Items", for review and implementation of this element. LGS 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 #5~~6~~]

- 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 #6]

### 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: Nov 2010**

### 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~~2. | 12.8 | LGS IMP Team Qualification Records | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| ~~4~~3. | 12.8 | Contractor Qualification Records | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| ~~5~~4. | 12.10 | IM Program Audits | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| ~~6~~5. | 12.13 | Element #1 agenda | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| ~~7~~6. | 12.13 | 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.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #10, #11: Records and MOC Agenda

| **Ref: 49 CFR 192.945** | **Updated: Oct 2011** |
|---|---|

Objectives for Records and MOC:

- Verify that the appropriate records are maintained for the useful life of the pipeline
- Verify that changes to the integrity management program have been handled in accordance with regulation §192.909
- Verify that the integrity management program meets the requirements of ASME B31.8S-2004, Section 11 for a management of change process
- Verify Management of Change (MOC) has been implemented according to MOC requirements
- Verify all required processes in element #10 and #11 have been properly documented

Who Should Attend Records and MOC:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Frequency of Records and MOC Review:

- This agenda and these actions items should be conducted twice per calendar year, not to exceed 18 months
- Semi-annual reporting to PHMSA is due by February 28 and August 31

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve Records and MOC review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Records and MOC:

- Element #10 Procedure: Record Keeping
- Element #11 Procedure: MOC
- 49 CFR 192.945, 192.947, 192.909
- FAQs: Record Keeping and MOCs
- Gas IMP Protocol Area J With Cross Reference, Record Keeping
- Gas IMP Protocol Area K With Cross Reference, Management of Change

Forms and Documents Required For This Review:

- Element #10, #11 Agenda and Action Items
- PHMSA Semi-annual Online Report
- MOC, When Required

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #10, #11: Records and MOC Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Record Keeping for Records and MOC:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #10, #11: RECORDS and MOC ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #10: Record Keeping: J.O1– Records to be Maintained by the Operator**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the following records, as a minimum, are maintained for the useful life of the pipeline: [192.947, ASME B31.8S-2004, Section 12.1 and ASME B31.8S-2004, Section 12.2(b)(1)] | **J.01** | | | | | |
| 10-1 | A written integrity management program<br>1) Threat identification and risk assessment documentation per 192.917 [192.947(b)]<br>2) A written baseline assessment plan per 192.919 [192.947(c)]<br>3) 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 [192.947(d)]<br>4) Training program documentation and training records per 192.915 [192.947(e)]<br>5) Remediation schedule and technical basis documentation per 192.933 [192.947(f)]<br>6) Direct assessment plan documentation per 192.923 through 192.929 [192.947(g)]<br>7) Confirmatory assessment documentation per 192.931 [192.947(h)]<br>8) Documentation of Notifications to PHMSA or State/Local Regulatory Agencies. [192.947(i)] | **J.01.a** | 10.1 | 947(a) | IMP Leader | 1x/yr | Complete. |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #11: Management of Change (MOC): K.O1– Documentation and Notification of Changes to the IM Program**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that changes to the integrity management program have been handled in accordance with 192.909 of the rule. | **K.01** | | | | | |
| 11-1 | Verify that the reasons for program changes have been documented prior to implementation of the change(s). [192.909(a)] | **K.01.a** | 11.3 | 909(a) | IMP Leader | 1x/yr | NA, no program changes for 2011 |
| 11-2 | Verify that for significant changes to the program, program implementation, or schedules, OPS or the State or local pipeline safety authority, if applicable, has been notified within 30 days after the operator has adopted the change. [192.909(b)] | **K.01.b** | 11.3 | 909(b) | IMP Leader | 1x/yr | NA, no significant changes to date. |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #11: Management of Change (MOC): K.O2– Attributes of the Change Process**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that the integrity management program meets the requirements of ASME B31.8S-2004, Section 11 for a management of change process. [192.911(k)] | **K.02** | | | | | |
| 11-3 | Verify the existence of procedures that consider impacts of changes to pipeline systems and their integrity. [ASME B31.8S-2004, Section 11(a)] | **K.02.a** | 11.4 | 911(k) | IMP Leader | 1x/yr | Complete. See LGS MOC procedures. |
| 11-4 | Verify change procedures address technical, physical, procedural, and organizational changes. [ASME B31.8S-2004, Section 11(a)] | **K.02.b** | 11.4 | 911(k) | IMP Leader | 1x/yr | Complete. See LGS MOC procedures. |

**Element #11: Management of Change (MOC): K.O2– Attributes of the Change Process (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 11-5 | Verify the following are provided for by the change procedures: [ASME B31.8S-2004, Section 11(a)]<br><br>1. Reason for change<br>2. Authority for approving changes<br>3. Analysis of implications<br>4. Acquisition of required work permits<br>5. Documentation<br>6. Communication of the change to affected parties<br>7. Time limitations<br>8. Qualification of staff | **K.02.c** | 11.4 | 911(k) | IMP Leader | 1x/yr | Complete.<br>See MOC procedures and form in Element 11 tab of IMP records binder. |
| 11-6 | Verify that integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. [ASME B31.8S-2004, Section 11(b)] | **K.02.d** | 11.4 | 911(k) | IMP Leader | 1x/yr | Complete.<br>See MOC procedures and form in Element 11 tab of IMP records binder. |
| 11-7 | Verify that equipment or system changes have been identified and reviewed before implementation. [ASME B31.8S-2004, Section 11(d)] | **K.02.e** | 11.4 | 911(k) | IMP Leader | 1x/yr | Complete.<br>See MOC procedures and form in Element 11 tab of IMP records binder. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #12: Quality Assurance Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Objectives for Quality Assurance:

- Verify there is a quality assurance process that defines responsibilities and authorities
- Verify that personnel involved in the integrity management program are qualified for their assigned responsibilities
- Verify that 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) are addressed
- Verify all the appropriate records are completed and maintained for the life of the pipeline
- Verify Management of Change (MOC) has been implemented according to MOC requirements
- Verify all required processes in element #12 have been properly documented

Who Should Attend Quality Assurance:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Frequency of Performance Measures, Records, and MOC Review:

- This agenda and these actions items should be conducted twice per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve Quality Assurance review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

Regulations, Resources, and Procedures Needed to Review Quality Assurance:

- Element #12 Procedure: Quality Assurance
- 49 CFR 192.911, 192.915, 192.7
- FAQs: Quality Assurance
- Gas IMP Protocol Area L With Cross Reference, Quality Assurance

Forms and Documents Required For This Review:

- Quality Assurance Roles and Responsibilities Worksheet
- Quality Assurance Training Requirements, Training Plan, and Training/Qualification Records
- Element #12 Agenda and Action Items
- MOC, When Required

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #12: Quality Assurance Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

Record Keeping for Quality Assurance:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #12: QUALITY ASSURANCE ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #12: Quality Assurance Agenda

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #12: Quality Assurance: L.O1– Program Requirements for the Quality Assurance Process**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that a quality assurance process exists that meets the requirements of ASME B31.8S-2004, Section 12. [192.911(l)] | **L.01** | | | | | |
| 12-1 | Verify that responsibilities and authorities for the integrity management program have been formally defined. [ASME B31.8S-2004, Section 12.2(b)(2)] | **L.01.a** | 12.5, 12.7 | 911(l) | IMP Leader | 1x/yr | Complete. See IMP procedures and agendas. |
| 12-2 | Verify that reviews of the integrity management program and the quality assurance program have been specified to be performed on regular intervals, making recommendations for improvement. [ASME B31.8S-2004, Section 12.2(b)(3)] | **L.01.b** | 12.5, 12.7 | 911(l) | IMP Leader | 1x/yr | Complete. See QA procedures in Element 12 tab of IMP procedures binder and all agendas. |
| 12-3 | Verify that corrective actions to improve the integrity management program and the quality assurance process have been documented and are monitored for effectiveness. [ASME B31.8S-2004, Section 12.2(b)(7)] | **L.01.c** | 12.5, 12.7 | 911(l) | IMP Leader | 1x/yr | Complete. See action item list. |
| 12-4 | Verify that when a company chooses to use outside resources to conduct any process that affects the quality of the integrity management program, the company ensures the quality of such processes and documents them within the quality program. [ASME B31.8S-2004, Section 12.2(c)] | **L.01.d** | 12.5, 12.7 | 911(l) | IMP Leader | 1x/yr | Complete. See QA procedures in Element 12 tab of IMP procedures binder and all agendas. |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #12: Quality Assurance: L.O2– Personnel Qualification and Training Requirements**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. [192.911(l), 192.915 and ASME B31.8S-2004, Section 12(b)(4)] | **L.02** | | | | | |
| 12-5 | Verify that the Integrity Management Program requires supervisory personnel to have the appropriate training or experience for their assigned responsibilities. [192.915(a)] | **L.02.a** | 12.5, 12.7 | 911(l), 915(a) | IMP Leader | 1x/yr | Pending, see action items. |
| 12-6 | Verify the qualification of personnel that carry out assessments and who evaluate assessment results. [192.915(b)] | **L.02.b** | 12.5, 12.7 | 911(l), 915(b) | IMP Leader | 1x/yr | NA. No ILI in 2011. |
| 12-7 | Verify the qualification of personnel who participate in implementing preventive and mitigative measures including: [192.915(c)]<br><br>1. Personnel who mark and locate buried structures.<br>2. Personnel who directly supervise excavation work.<br>3. Other personnel who participate in implementing preventive and mitigative measures as appropriate. [ASME B31.8S-2004, Section 12.2(b)(4)] | **L.02.c** | 12.5, 12.7 | 911(l), 915(c) | IMP Leader | 1x/yr | Complete.<br><br>LGS Employee's have been qualified using approved OQ training programs. |

**Element #12: Quality Assurance: L.O2– Personnel Qualification and Training Requirements (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 12-8 | Verify that the personnel who execute the activities within the integrity management program are competent and properly trained in accordance with the quality control plan. [ASME B31.8S-2004, Section 11(a)(8) and ASME B31.8S-2004, Section 12.2(b)(4)] | **L.02.d** | 12.5, 12.7 | 911(l), 915(c) | IMP Leader | 1x/yr | Complete. See IMP Element #12 records binder. |

**Element #12: Quality Assurance: L.O3– Invoking Non-Mandatory Statements in the Standards**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that 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) are addressed by one of the following approaches: [192.7(a)] | **L.03** | | | | | |
| 12-9 | Incorporated into the operator's plan and implemented as recommended in the standard; or | **L.03.a** | 12.10 | 7(a) | IMP Leader | 1x/yr | Complete, see IMP procedure #12.10. |
| 12-10 | An equivalent alternative method for accomplishing the same objective is justified and implemented; or | **L.03.b** | 12.10 | 7(a) | IMP Leader | 1x/yr | Complete, see IMP procedure #12.10. |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #12: Quality Assurance: L.O3– Invoking Non-Mandatory Statements in the Standards (cont.)**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| 12-11 | A documented justification is included in the plan that demonstrates the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O. | **L.03.c** | 12.10 | 7(a) | IMP Leader | 1x/yr | Complete, see IMP procedure #12.10. |

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #13: Communication Plan

| Ref: 49 CFR 192.911(m) | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


13.1 Summary of Communication Plan Requirements
13.2 Objective and Purpose
13.3 Internal Communication Requirements
13.4 External Communication Requirements
13.5 Addressing OPS and State Safety Concerns
13.6 Review and Implementation of Element #13
13.7 Source References
13.8 List of Required Ongoing Documentation


### 13.1 Summary of Requirements for Communication Plan [192.911(m)]

LGS will have a communication plan that includes the elements of ASME/ANSI B31.8S-2004, section 10. The communication plan will include the following procedures and communicated periodically:

- Addressing safety concerns raised by the OPS or state authority with jurisdictional authority
- Keeping LGS employees informed of appropriate integrity issues
- Making the public aware of its integrity management efforts and results

### 13.2 Objective and Purpose for 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, LGS will use these communication procedures to assist in this effort.

### 13.3 Internal Communication Requirements

LGS internal communications is aimed at building program support and to inform all appropriate LGS personnel in the progress and problems of the program.

Communication to IM Program Management Sponsor

To build support from LGS 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

*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 on an annual basi~~e~~s 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 LGS mgmt [Element #13: Record #7]

Communication to IM Program Team Members and LGS Personnel

LGS will communicate the progress and problems to IM program team members and other LGS 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 LGS 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 LGS's system and their integrity management efforts. These communications will take place periodically, usually at an annual interval during LGS safety meetings.

### 13.4 External Communication Requirements

This procedure establishes the minimum communication requirements in order to keep appropriate LGS the public informed about their integrity management efforts. External communication information will be communicated as part of the LGS existing "Public Awareness Procedures (O&M #3.03).

LGS integrity management communication plan will meet the requirements of ASME/ANSI B31.8S-2004, 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]

*Step #3: Conduct External Communications to Target Audiences*

Frequency for external communication is described in LGS O&M procedure #3.03, Public Awareness procedures.

### 13.5 Addressing OPS and State Safety Concerns

LGS's communication plan will include provisions to address safety concerns raised by OPS and State or local pipeline safety authorities, as applicable. Specifically, this means when PHMSA or the jurisdictional state agency issues corrective actions, LGS 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, LGS will submit the company's risk analysis or integrity management program to OPS 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.

### 13.6 Review and Implementation of Element #13

LGS will use the agenda, "Gas IMP Element #13, #14, & #15, Communication Plan, Agency Notification, and Environmental and Safety Agenda and Action Items", for review and implementation of this element. LGS will conduct this element #13, #14, and #15 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, Agency Notification, and Environmental Safety 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, #14, and #15 review [Element #13: Record #~~0~~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. OPS Gas IMP Protocols for Small Operators, Protocol Section #M,
   Communications Plan, July 2008

5. OPS Frequently Asked Questions (FAQs): #184

6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #8
   Communications Plan

**Ref: 49 CFR 192.911(m)** **Updated: Nov 2010**

### 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 LGS 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 LGS 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 |
| 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.

# Lodi Gas Storage
# Gas Integrity Management Plan
## Element #14: Agency Notification, Inspections, & Documentation

| Ref: 49 CFR 192.911(n) | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


14.1 Summary of Requirements for Submittal of Program Documents
14.2 Objectives and Purpose
14.3 Agency Notification Requirements
14.4 Agency Inspection
14.5 Enforcement and Consistency in Application
14.6 State Requirements
14.7 Review and Implementation of Element #14
14.8 Source Documents
14.9 List of Ongoing Documentation


### 14.1 Summary of Requirements for Submittal of Program Documents

LGS~~T~~ will submit, upon request, the company's risk analysis or integrity management program to:

1) OPS and,
2) State or local pipeline safety authorities, as applicable.

### 14.2 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, LGS has developed these agency notification and agency inspection procedures to assist in this effort.

### 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*

If notification required as described below, submit the information using one of the methods listed below: [Element #14: Record #1]

- 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
- Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.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 LGS 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). LGS 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 LGS 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 LGS will be unable to meet required remediation schedules must be submitted as soon as it is determined that the schedule cannot be met.

OPS 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 OPS objects to the proposed alternative approach. [FAQ #98]

Information Requirements for a Notification

Notifications must provide enough information for OPS 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. OPS 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. LGS 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 OPS 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 LGS 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

OPS 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, OPS 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 #2]

Notification of Changes to Assessment Schedule

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]

### 14.4 Agency Inspections

Advance Scheduling of OPS Inspections

OPS will schedule all integrity management inspections as far in advance as possible. OPS will coordinate the inspections with the companies to identify mutually agreed upon dates whenever possible. [FAQ #93]

Availability of OPS 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

OPS 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 OPS files. OPS 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. OPS 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 OPS 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. OPS 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]

Part 192 Appendix E Must Statements

Appendices to Part 192 are guidance and do not contain requirements. Where "must" is used to provide guidance for what an operator must do to comply with a requirement in the body of Subpart O, then that action may be required as a result of the language in the rule body. Compliance with the Appendices is not required solely because of the use of "must" statements. [FAQ #114]

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". OPS expects that an operator will implement all activities included in the operator's program. OPS encourages operators to undertake additional activities beyond those required by regulation. However, OPS 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

Submitting Performance Measures to States

The rule requires that an operator "notify" OPS (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 OPS and to states. Section 192.945 requires that performance measures be submitted to OPS. OPS 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. LGS shall consult with state pipeline safety authorities regarding the application of state laws. [FAQ #206]

### 14.7 Review and Implementation of Element #14

The Company will use the attached agenda, "Gas IMP Element #13, #14, #15 Communications Plan, Agency Notification, and Environmental and Safety Risk Agenda and Action Items", for implementation of this element. LGS 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 #3]

- 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 #14: Record #4]

### 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. OPS Gas Integrity Management Protocols, Protocol Area #N, Submittal of Program Documents, January 2008

5. OPS Frequently Asked Questions (FAQs): Notification & Regulatory Inspections

6. OPS 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

### 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 | OPS notification | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 2. | 14.3 | Waiver | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 3. | 11.4 | 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 |
| 4. | 11.7 | 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.

# Lodi Gas Storage
# Integrity Management Plan
## Element #15: Minimization of Environmental & Safety Risk

| Ref: 49 CFR 192.911(o) | Updated: Nov 2010 |
|---|---|

**Contents of this Element:**


15.1 Consideration of Environmental and Safety Risks
15.2 Implementation of Element #15
15.3 Source References
15.4 List of Required Ongoing Documentation


### 15.1 Consideration of Environmental and Safety Risks [192.911(o)]

LGS will address requirements for conducting the baseline assessment and reassessments in a manner that minimizes environmental and safety risks. LGS will utilize existing DOT pipeline O&M procedures and LGS 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 LGS 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 ~~E~~HSE procedures to address these issues are listed below: [Element #15: Record #1]

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

### 15.2 Implementation of Element #15

LGS will use the attached agenda, "Gas IMP Element #13, #14, #15 Communications Plan, Agency Notification, and Environmental and Safety Risk Agenda and Action Items", for implementation of this element. LGS will conduct this element #13, #14, and #15 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 #15: Record #2]

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, Agency Notification, and Environmental Safety 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, #14, and #15 review [Element #15: Record #3]

### 15.3 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, Protocol Area #B-5, Consideration of Environmental and Safety Risks, January 2008

5. OPS Frequently Asked Questions (FAQs): #184

6. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, section #8 Communications Plan

7. LGS Safety Procedures

### 15.4 List of Required Ongoing Documentation for Element #15

| Rec. #: | Sect. #: | Description of Required Documentation: | Respon. Person | Freq. & Deadline | Record Retention Period | Record Location |
|---|---|---|---|---|---|---|
| 1. | 15.1 | LGS Safety Documents (Hot work permits, safety work permits, etc.) | IMP Leader | 1x/yr[1] | 5 yrs | Co. intranet |
| 2. | 15.2 | 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 |
| 3. | 15.2 | 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.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #13, #14, #15: Communication Plan, Agency Notification, and Environmental & Safety Risk Agenda

| **Ref: 49 CFR 192.945** | **Updated: Oct 2011** |
|---|---|

Objectives for Communication Plan, Agency Notification, and E&S Risk:

- Verify that an integrity management communication plan exists that meets the requirements of ASME B31.8S-2004, Section 10
- Verify that provisions exist to address safety concerns raised by PHMSA and/or state agency
- Verify that the company includes provisions in its program to submit, upon request, the company's risk analysis or integrity management program to PHMSA, State, or local pipeline safety authorities, as applicable.
- Verify all the appropriate records are completed and maintained for the life of the pipeline
- Verify Management of Change (MOC) has been implemented according to MOC requirements
- Verify all required processes in element #13, #14, #15 have been properly documented

Who Should Attend Communication Plan, Agency Notification, and E&S Risk:

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 1. | Greg Clark | IMP Leader (LGS) | Compliance Manager | Lodi Gas Storage, LLC | Mandatory |
| 2. | Andy Anderson | IMP Operations | Operations Manager, Operations | Lodi Gas Storage, LLC | Mandatory |
| 3. | Eric Kuykendall | IMP Maintenance | Operations Manager, Maintenance | Lodi Gas Storage, LLC | Mandatory |
| 4. | Andy Bradfield | IMP Advisor | Compliance Consultant | Compliance Services Inc | Mandatory |
| 5. | Robert Russell | IMP Management | VP, Operations | Lodi Gas Storage, LLC | Optional |
| 6. | Mark Shook | IMP Corrosion Control | Group Leader, Pipeline Integrity | Buckeye Partners, L.P. | Optional |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #13, #14, #15: Communication Plan, Agency Notification, and Environmental & Safety Risk Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

| # | Name: | Function: | Title: | Company: | Attendance Requirements |
|---|---|---|---|---|---|
| 7. | John Reinbold | Management – Regulatory Compliance | Group Leader, Regulatory Compliance | Buckeye Partners, L.P. | Optional |
| 8. | Susan Chwistek | IMP Advisor | Compliance Consultant | GTS Engineering | Optional |

Frequency of Communication Plan, Agency Notification, and E&S Risk Review:

- This agenda and these actions items should be conducted twice per calendar year, not to exceed 18 months

How This Activity is to be Completed:

- With the appropriate personnel in attendance as shown on this agenda, the IMP Leader shall review the meeting objectives and have personnel sign the attendance roster.
- The IMP Leader shall ensure all the required resources (procedures, regulations, forms, etc.) as shown on this agenda are available during the meeting.
- The IMP Leader shall lead the meeting using the agenda checklist and make comments for each checklist item. If an item does not apply the IMP Leader shall note with a “NA/not applicable” and state the reason it does not apply.
- The IMP Leader shall collect appropriate records and file as shown on this agenda unless otherwise noted.
- The IMP Leader shall summarize the meeting notes and actions.
- The IMP Leader shall ask for input and feedback on how to improve Communication Plan, Agency Notification, and E&S Risk review processes and document.
- If required, the IMP 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 and include the “reasons” for any change.

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #13, #14, #15: Communication Plan, Agency Notification, and Environmental & Safety Risk Agenda

| **Ref: 49 CFR 192.945** | **Updated: Oct 2011** |
|---|---|

Regulations, Resources, and Procedures Needed to Review Communication Plan, Agency Notification, and E&S Risk:

- Element #13 Procedure: Communication Plan
- Element #14 Procedure: Agency Documentation
- Element #15 Procedure: Environmental and Safety Risk
- 49 CFR 192.911
- FAQs: Communication Plan, Agency Notification, E&S Risk
- Gas IMP Protocol Area M With Cross Reference, Communications Plan
- Gas IMP Protocol Area N With Cross Reference, Submittal of Program Documents

Forms and Documents Required For This Review:

- Communication Plan
- Agency Notification Records
- Element #13, #14, #15 Agenda and Action Items
- MOC, When Required

Record Keeping for Communication Plan, Agency Notification, and E&S Risk:

- Maintain all records and forms required to complete this meeting for the life of the pipeline.
- Records will be maintained in the Gas IMP Records and Data binder or at a different location as noted in the Gas IMP Records and Data binder.

## ELEMENT #13, #14, #15: Communication Plan, Agency Notification, and E&S Risk ATTENDANCE LIST

**Meeting Date:** **October 10-12, 2011**

**Meeting Location:** **Lodi, Ca.**

| | Print Name | *Signature* | IMP Function |
|---|---|---|---|
| 1 | Greg Clark | | IMP Leader (LGS) |
| 2 | Andy Anderson | | IMP Operations |
| 3 | Eric Kuykendall | | IMP Maintenance |
| 4 | Andy Bradfield | | IMP Advisor |
| 5 | Robert Russell | | IMP Management |
| 6 | Mark Shook | | IMP Corrosion Control |
| 7 | John Reinbold | | Management – Regulatory Compliance |
| 8 | Susan Chwistek | | IMP Advisor |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #13, #14, #15: Communication Plan, Agency Notification, and Environmental & Safety Risk Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

**Element #13: Communications Plan: M.O1– External and Internal Communication Requirements**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that an integrity management communication plan exists that meets the requirements of ASME B31.8S-2004, Section 10. [192.911(m)] | **M.01** | | | | | |
| 13-1 | Verify that the company has submitted its API-1162 external communications plan to the PHMSA clearinghouse for approval. | **M.01.a** | 13.2 | 911(m) | IMP Leader | 1x/yr | Complete. |
| 13-2 | Verify provisions for company internal organizational communication exist to establish understanding of and support for the integrity management program. [ASME B31.8S-2004, Section 10.3] | **M.01.b** | 13.2 | 911(m) | IMP Leader | 1x/yr | Complete. |

# LODI GAS STORAGE, LLC
# Gas Integrity Management Program
## Element #13, #14, #15: Communication Plan, Agency Notification, and Environmental & Safety Risk Agenda

| Ref: 49 CFR 192.945 | Updated: Oct 2011 |
|---|---|

**Element #13: Communications Plan: M.O2– Addressing Safety Concerns**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | Verify that provisions exist to address safety concerns raised by: | **M.02** | | | | | |
| 13-3 | PHMSA and State or local pipeline safety authorities (when a covered segment is located in a State where PHMSA has an interstate agent agreement). [192.911(m)(1) and 192.911(m)(2)]. | **M.02.a** | 13.3 | 911(m) | IMP Leader | 1x/yr | Complete. See Element 13 tab in IMP procedures binder. |

**Element #14: Submittal of Program Documents: N.O2– IM Program Document Submittal**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who is Respon. | Freq. | Comments/Status and Record Type: |
|---|---|---|---|---|---|---|---|
| | *Verify that the operator includes provisions in its program to submit, upon request, the operator's risk analysis or integrity management program to: [192.911(n)]* | **N.01** | | | | | |
| 14-1 | OPS and State or local pipeline safety authorities, as applicable. [192.911(n)] | **N.01.a** | 14.2 | 911(n) | IMP Leader | 1x/yr | N/A, no documents requested at this time. |

**Ref: 49 CFR 192.945** **Updated: Oct 2011**

**Element #3: Baseline Assessment – B.05 Consideration of Environmental and Safety Risk**

| # | Description: | Protocol # | IMP Section # | 192 Reg. # | Who | Freq. | Comments/Status: |
|---|---|---|---|---|---|---|---|
| | *Verify that the operator addresses requirements for conducting the integrity assessments (baseline and reassessment) in a manner that minimizes environmental and safety risks. [§192.919(e) and §192.911(o)]* | **B.05** | 3.17, 15.1 | 919(e), 911(o) | IMP Leader | 1x/yr | Complete. |
| 15-1 | Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of gas) during assessments. [§192.919(e) and §192.911(o)] | **B.05.a** | 3.17, 15.1 | 919(e), 911(o) | IMP Leader | 1x/yr | Complete.<br>See LGS O&M procedures and company safety procedures.<br><br>See Element 3 and Element 15 tabs in IMP procedures binder. |