Cameron Interstate Pipeline LLC
A SEMPRA ENERGY DEVELOPMENT

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RECEIVED
APR 1 8 2011
BY:

US Department of Transportation
Pipeline Hazardous Materials Safety Administration
8701 South Gessner
Suite 1110
Houston, TX 77074

Re: CPF 4-2011-1003M

Dear Mr. Seeley:

On March 22, 2011 Cameron Interstate Pipeline (CIP) received an electronic copy of your office's Notice of Amendment (NOA) for inspections conducted by your office of the Sempra Pipelines & Storage Integrity Management Plan in April and July of 2010. CIP reviewed the identified inadequacies identified in the NOA and has made the necessary changes to our plan or procedures to address each of the inadequacies identified.

The following information is provided for you to assess the revisions made by CIP.

Inadequacy 1

Applicable Code Language: **§192.921 How is the baseline assessment to be conducted?**

(a) Assessment methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917).

Inadequacy Summary by PHMSA: CIP's relative risk analysis model must develop procedures through the use of known dependable tools for identifying threat factors within each covered segment. CIP's current procedures are insufficient and do not include specific methods or procedures for evaluating and determining specific threat to the pipeline system, and the appropriate assessment method for each of the threats.

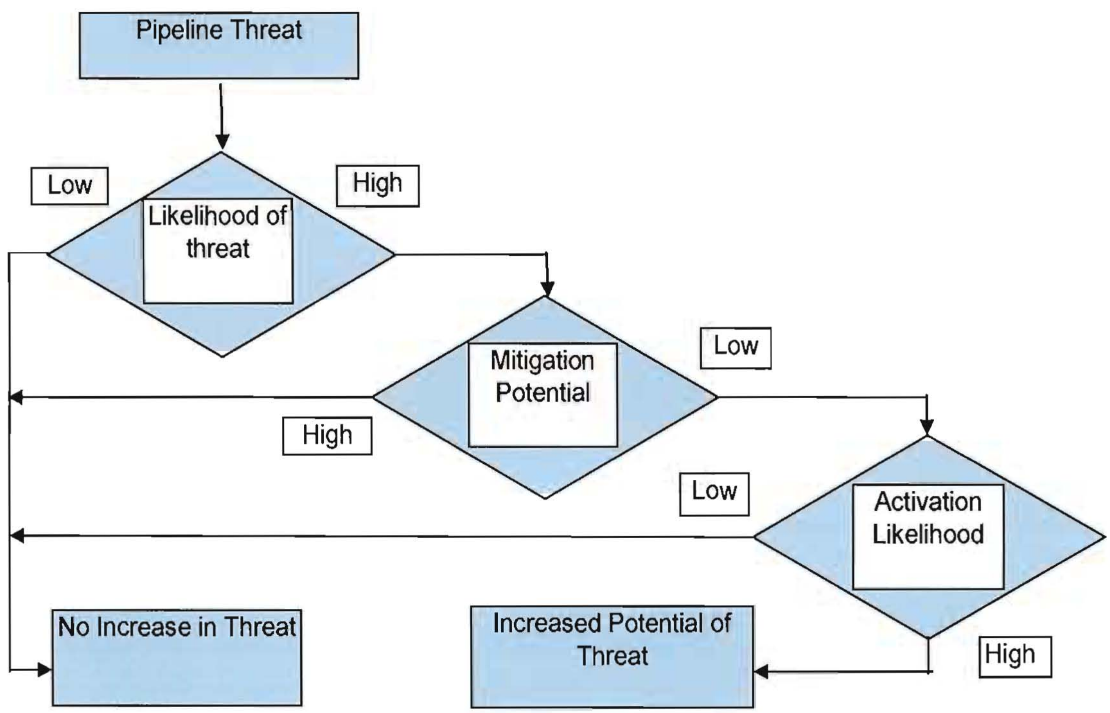
Revised Plan/Procedure Language by CIP:

4.1 Overview

The Company evaluates each of the potential threats that are identified in ASME B31.8S to determine if the associated pipe segments require assessments for the threats. To evaluate potential threats and to determine if the pipeline segment should be assessed the Company utilizes a three step approach. The three steps are outlined below, and the overall process diagram to evaluate the threat is shown in Figure 4.1.

- What is the Likelihood of the threat?
- What measures have been taken to mitigate the threat?
- What factors could activate the threat?

Each of these evaluation steps is utilized in the following sections to help frame a description of each threat on the Company's system. This evaluation process is integrated with the Risk Assessment model results to determine the need to assess for a particular threat.



4.2 Threat Identification

C.01.a. 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]

C.01.b. If the operator 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. [§192.917(a) and ASME B31.8S-2004, Section 2.2]

ASME B318.S defines three major categories of defect types – time dependent, stable, and time independent. These defect types are further subdivided into separate root causes, each of which are considered a potential threat and are evaluated in this program. Each of the defined threats and the Company's approach to those threats are discussed in the following subsections. An important note in the consideration of the threats is the possible interaction between threats where one or more of the threats interact with each other in a section of pipeline that potentially could be a greater risk than one threat alone.

1. Time Dependent
   - External corrosion,
   - Internal corrosion,
   - Stress corrosion cracking;
2. Stable
   - Manufacturing-related defects,
     a. Defective Pipe Seam
     b. Defective Pipe
   - Welding- or fabrication-related defects,
     a. Defective girth weld
     b. Defective fabrication weld
     c. Wrinkle bend or buckle
     d. Stripped threads/broken pipe/coupling failure
   - Equipment
     a. Gasket O-ring failure
     b. Control/Relief equipment malfunction
     c. Seal/Pump packing failure
     d. Miscellaneous
3. Time Independent
   - Third party/mechanical damage
     a. Damage inflicted by first, second, or third parties
     b. Previously damaged pipe
     c. Vandalism
   - Incorrect operations (including human error),
     a. Incorrect operational procedure
   - Weather-related and outside force damage,
     a. Cold weather
     b. Lightning
     c. Heavy rains or floods
     d. Earth movements

In section 4.3 thru section 4.10 of our plan each of the above listed threats are discussed individually describing the data elements required for evaluation of the threat. For each specific threat the data is collected, integrated, and analyzed to evaluate the relative risk of the threat. The relative risk is then factored into the relative risk spreadsheet for determining the overall risk to the HCA segment and prioritization.

Inadequacy 2

Applicable Code Language: **§192.921 (see 1. above)**

(g) Newly installed pipe. An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

Inadequacy Summary by PHMSA: The inspection team noted that CIP does not have and must include a procedural requirement for designating changes for additional pipe segments, facilities, and other covered components in their baseline assessment plan within ten years from the date the affected area was identified as an HCA. CIP has designated its entire pipeline system as an HCA but lacks the means for potential expansion or changes of its pipeline system and the appropriate assessment method for each of the threats.

Revised Plan/Procedure Language by CIP:

3.4.5 New HCA's and Newly Installed Pipe

B.04.a. 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. [§192.905(c)]

If a new HCA is identified or new pipe is installed that is covered, it will be incorporated into the baseline assessment plan, Form 3-2 - Summary BAP, within one year from the date the area or pipe is identified. Assessments for the new HCA or new pipe will be appropriately scheduled and/or completed.

B.04.b. For new HCAs, verify that the operator completes a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified. [§192.921(f)]

For new HCAs, a baseline assessment for the applicable segment(s) will be scheduled on Form 3-2 – Summary BAP and completed within ten (10) years from the date the area is identified.

B.04.c.,d.,e. For newly installed pipe that is covered by this subpart and impacts an HCA, verify that the operator completes a baseline assessment within ten (10) years from the date the pipe is installed. [§192.921(g)]. Verify that threats to these pipeline sections were identified as required under §192.919(a). [§192.921(b)]. 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).

For newly installed pipe that is covered and impacts a HCA, a baseline assessment will be completed within ten (10) years from the date the pipe is installed. This includes the identification of any threats to the pipeline segment as discussed chapter 4 and the selection of the appropriate assessment method is used for the threats identified as discussed in chapter 5. For repairs in an HCA that involve pipe replacement, the following OM Procedures shall be followed to ensure the new pipe is adequately assessed during installation:

- 213 – Leaks, Pipe and Weld Defects & Equipment Damage
- 222 – Pipe Tie-in
- 406 – Weld Inspection and Testing
- 1600 – Strength and Leak Testing

Inadequacy 3

Applicable Code Language: **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

Inadequacy Summary by PHMSA: It is not apparent in CIP's IM program that interactive threats have been addressed. The inspection team did note that CIP adequately describes the major categories of defects found in pipelines but it is not evident that interactive threats have been considered. CIP must develop procedures for identifying interactive threats for developing total risk score and prioritizing P & M measures.

Revised Plan/Procedure Language by CIP:

4.2.1 Interactive Threats

C.01.c. 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].

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered as part of the threat assessment process. Examples of such interaction include:

- Corrosion at a location that also has third party damage.
- Heavy rains in an area with unstable soil properties.
- Gasket failures in an area prone to vandalism.
- Manufacturing defects activated by pressure cycling.

Subject matter experts will address interaction threats and modify the risk evaluation spreadsheet to accommodate the risk interaction.

Inadequacy 4

Applicable Code Language: **§192.915 What knowledge and training must personnel have to carry out an integrity management program?**

(b) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person—

> **(1) Who conducts an integrity assessment allowed under this subpart; or**
> **(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or**
> **(3) Who makes decisions on actions to be taken based on these assessments.**

Inadequacy Summary by PHMSA: CIP's procedures must include qualified personnel for assigned roles and for providing complete, accurate, and objective analysis of identified threats and for describing in more specific terms, personnel roles, and timing for evaluating and implementing risk scores for each HCA.

Revised Plan/Procedure Language by CIP:

1.9 Roles and Responsibilities

The Director of Operations has overall responsibility for the IMP. Table 1.1 lists the overall responsibilities and qualifications for personnel conducting integrity management activities. The responsibilities and qualifications for conducting assessment shall be listed in the assessment procedure using Form QCP-8 – Personnel Qualifications Evaluation Verification.

Position	Responsibilities	Skills & Capabilities	Education, Training & Experience
Vice President of Operations	• Review of the Integrity Management Program • Overall responsibility to assure IMP has adequate funding and staffing to meet regulatory requirements and the elements in the program	• Managerial skills • Communications skills • Understanding of 49 CFR §Part 192 Subpart O • Other skills and capabilities commensurate with the Vice President of Operations position.	• Education, training and experience commensurate with the Vice President of Operations position.
Director of Operations	• Over all program oversight and responsibility • Assures program is in compliance with the Rule and ASME B31.8S • Leads in communication activities • Assigns QC audit personnel to audit ILI processes • Review QC audit findings and approves corrective actions • Provides budget approvals for integrity management issues • Directs the Quality Control activities and notifies the VP - Operations of audit requirements	• Managerial skills • Communications skills • Setting expectations • Understanding of company data sources and structure • In depth understanding of 49 CFR §Part 192 Subpart O • Project management skills including, scheduling, clarifying expectations, tracking and reporting • Understanding of regulatory rules and codes	• Five or more years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O • Detailed understanding of Company organization • Five or more years of pipeline industry experience in the regulatory arena • Demonstrated project management skills including detailed documentation. • Education, training and experience commensurate with the operations manager position.
Plant Superintendent	• Directs data gathering efforts and reviews results • Assures Entry of data into risk model and analyzes and reviews results. • Develops Base Line Assessment Plan by reviewing threat and risk scores and assigning assessment methods • Assures that assessments are conducted in accordance with established procedures. • Facilitates and evaluates the adoption of preventative and mitigative measures • Assembles and monitors performance measures • Assures that integrity of the pipeline is considered before changes are made to pipeline segments or supporting structures • Issues information request letters annually to public agencies requesting information regarding identified sites • Organize and collect feedback from public agencies	• Managerial skills • Communications skills • Setting expectations • Understanding of company data sources and structure • In depth understanding of 49 CFR §Part 192 Subpart O • Project management skills including, scheduling, clarifying expectations, tracking and reporting • Understanding of regulatory rules and codes • Relationship skills to deal with public agencies	• Five or more years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O • Five or more years of pipeline industry experience in the regulatory arena • Demonstrated project management skills including detailed documentation. • Education, training and experience commensurate with the plant superintendent position.
Pipeline Technician	•Performing operating and maintenance activities on the pipeline •Reporting changes on the pipeline that potentially could impact the integrity plan for the pipe segment	• In depth understanding of 49 CFR §Part 192 Subpart O • Communications skills	• Five or more years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O

Position	Responsibilities	Skills & Capabilities	Education, Training & Experience
Administrative Specialist	•Responsible for the development, maintenance, and security of the integrity database including data collection, data integration, quality checks, and risk model analysis. •The Specialist is responsible for all integrity related listings, and overseeing updates to the appropriate listings.	• Working knowledge of company data sources and structure • Database management skills including, scheduling, tracking and reporting	• Working knowledge or specific training in applicable Company data management systems
Integrity Plan Auditor	• Reviews performance measures • Participates in QC audit of ILI processes • Review QC audit findings and verifies corrective actions are completed within the allocated schedule	• In depth understanding of 49 CFR §Part 192 Subpart O • Communications skills • Auditing	• Five or more years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O
Engineer	• Review of the Integrity Management Program • Calculates and verifies PIR calculations • Conducts Hydrostatic Testing • Conducts ILI Pigging • New construction design conforms with IMP rules and regulations • Coordinates initial HCA surveys, drawings, and maps • Assures that assessments are conducted in accordance with established procedures. • Assures that integrity of the pipeline is considered before changes are made to pipeline segments or supporting structures	• Communications skills • Understanding of 49 CFR §Part 192 Subpart O • Technical understanding of structural and remaining life evaluation • Other skills and capabilities commensurate with an engineering position.	• Education, training and experience commensurate with a pipeline engineer. • Five or more years of pipeline experience

Form QCP-8: Personnel Qualifications Evaluation Verification

Position	Identified Person	Education, Training & Experience
Vice President of Operations	John Pirraglia	• 20+ years of pipeline experience • Detailed understanding of Company organization • BA in Engineering and Masters of Business Administration
Director of Operations	Hugh Berglund	• 17+ years of pipeline experience • Working knowledge of in 49 CFR §Part 192 Subpart O • Detailed understanding of Company organization • 17+ years of pipeline industry experience in the regulatory arena • 27+ years of demonstrated project management skills in Department of Army and Pipeline industry. • BA in Computer Science, MA in Management, and Masters of Business Administration
Plant Superintendent	Open Position	•
Pipeline Technician	Darrell Langley	• 23+ years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O • NACE Certified
Engineer	Hernan Machicado	• Understanding of 49 CFR §Part 192 Subpart O • Technical understanding of structural and remaining life evaluation • 25+ years of demonstrated project management skills in Pipeline industry. • Other skills and capabilities commensurate with an engineering position. • BS in Engineering
Engineer	Diane Schattenberg	• Understanding of 49 CFR §Part 192 Subpart O • Technical understanding of structural and remaining life evaluation • 10+ years of demonstrated project management skills in Pipeline industry. • Other skills and capabilities commensurate with an engineering position. • BS in Engineering

Inadequacy 5

Applicable Code Language: **§192.933 What actions must be taken to address integrity issues?**

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs

(d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

Inadequacy Summary by PHMSA: CIP's determination of discovery of an anomalous condition is insufficient and must within a few days identify and assess the total risk according to the IM rule definition of an immediate, 180 day and one year criterion. The threat must be promptly reported and address a prioritized remediation or monitoring schedule.

Revised Plan/Procedure Language by CIP:

6.2 Discovery of Condition

6.2.1 Definition

E.01.a. Verify a definition of discovery is provided. [§192.933(b)]

Discovery of condition used within the context of the IMP is defined as the date when the Company has adequate information about the pipeline condition to make a determination that a condition presents a potential threat to pipeline.

6.2.2 Time Requirements

The Plant Superintendent shall undertake all reasonable efforts to promptly obtain sufficient information regarding the pipeline condition to make a determination, but no later than 180 days after completion of integrity assessments. The 180 day limit should not be the norm and determination should be expedited for conditions that potentially could fall in the category of "immediate" repair. If this time requirement cannot be met, the Plant Superintendent shall follow the instructions in this chapter.

6.2.3 Documentation of Discovery

E.01.b. Verify a requirement exists to document the actual date of discovery. [§192.933(b)]

The discovery date along with other information with which to identify the type and location of the condition will be documented. This date is important as it will the starting point from which all deadlines will be calculated.

6.2.4 Schedule for Evaluation and Remediation Development

E.01.c. Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]

The Company must complete evaluation and remediation of a condition according to a schedule. The schedule will be prioritized by condition category first and further sub-prioritized within a condition category by relative risk and consequence score. Unless a special requirement for remediating certain conditions applies, as described in this chapter, the Company must follow the schedule specified in this chapter. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

6.3.1. Immediate Repair Conditions

E.02.b.1. Verify provisions exist to classify and categorize anomalies meeting the following criteria: Immediate Repair Conditions (Conditions requiring immediate remediation actions)

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 the operator 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;
5. All indications of stress corrosion cracks; 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.

6.3.1.1 Temporary Pressure Reduction

E.02.a. Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. [ï¿½192.933(d)(1)]

Pressure shall be reduced to a minimum safe level determined in accordance with ASME B31G, RSTRENG, KAPA, Pipeline Toolbox , or equivalent computational methods.

-OR-

80% of the operating pressure at the time of discovery.

The reduction in pressure shall occur within 5 days after determination of the immediate condition.

Other response actions shall be evaluated and implemented that ensures the safety of the covered segment.

6.3.2 One Year Repair Conditions

E.02.b.2. Verify provisions exist to classify and categorize anomalies meeting the following criteria: One-Year Conditions (Conditions requiring remediation within one year of discovery).

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.

6.3.3 Monitored Repair Conditions

E.02.b.3. Verify provisions exist to classify and categorize anomalies meeting the following criteria: Monitored Conditions (Conditions which must be monitored until the next assessment).

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,

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.

Inadequacy 6

Applicable Code Language: **§192.933 (see 5. above)**

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

CIP must include a procedure in their IMP manual for the identification and evaluation of anomalous conditions for completing remediation and developing a prioritized schedule in a timely manner. CIP does not describe in their IM manual, the examination or remediation of anomalous conditions or when remediation of a condition must be completed, in acceptable timeframes, as required in the Gas IMP rule.

Revised Plan/Procedure Language by CIP:

6.2.4 Schedule for Evaluation and Remediation Development

E.01.c. Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]

The Company must complete evaluation and remediation of a condition according to a schedule. The schedule will be prioritized by condition category first and further sub-prioritized within a condition category by relative risk and consequence score. Unless a special requirement for remediating certain conditions applies, as described in this chapter, the Company must follow the schedule specified in this chapter. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

6.3.1. Immediate Repair Conditions

E.02.b.1. Verify provisions exist to classify and categorize anomalies meeting the following criteria: Immediate Repair Conditions (Conditions requiring immediate remediation actions)

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 the operator 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;
5. All indications of stress corrosion cracks; 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.

6.3.1.1 Temporary Pressure Reduction

E.02.a. Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. [ï¿½192.933(d)(1)]

Pressure shall be reduced to a minimum safe level determined in accordance with ASME B31G, RSTRENG, KAPA, Pipeline Toolbox , or equivalent computational methods.

-OR-

80% of the operating pressure at the time of discovery.

The reduction in pressure shall occur within 5 days after determination of the immediate condition.

Other response actions shall be evaluated and implemented that ensures the safety of the covered segment.

6.3.2 One Year Repair Conditions

E.02.b.2. Verify provisions exist to classify and categorize anomalies meeting the following criteria: One-Year Conditions (Conditions requiring remediation within one year of discovery).

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.

6.3.3 Monitored Repair Conditions

E.02.b.3. Verify provisions exist to classify and categorize anomalies meeting the following criteria: Monitored Conditions (Conditions which must be monitored until the next assessment).

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.

Inadequacy 7

Applicable Code Language: **§192.933 (see 5. above)**

(d) Special requirements for scheduling remediation.

(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include: ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(3) Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than

NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrates critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

Inadequacy Summary by PHMSA: CIP's pipeline was completed in November 2008 and has not detected anomalies that would be categorized in the field as monitored conditions. CIP must, however, develop a method for addressing the potential of third party or corrosion threats or any other likely threat as part of their planned "monitored" procedures.

Revised Plan/Procedure Language by CIP:

CIP reviews a variety of threats during its annual review. The result of the review is annotated in the risk assessment model. The plan language specific to corrosion and third party threats is below.

4.4.1 Required Data Elements for External Corrosion

The following data elements in Table 4.1 are required for the evaluation of the external corrosion threat. Plant Superintendent shall assure that the data elements are collected, integrated and analyzed to evaluate the external corrosion threat. This activity will be completed through the risk assessment model.

Table 4.1: Required Data Elements for External Corrosion Threat

• Year of installation	• Years without CP	• Wall thickness
• Coating type	• Soil Characteristics	• Diameter
• Coating condition	• Pipe Insp. Reports	• % SMYS
• Years with adequate CP	• MIC Detected	• Past hydro test info.
• Years with questionable CP	• Leak history	

4.4.1.1Likelihood of External Corrosion

External corrosion is a very low likelihood threat on the Company's transmission lines since the transmission lines are relatively new (greater than 1992).

4.4.1.2Mitigative Measures for External Corrosion

The buried transmission lines in the company system have had cathodic protection applied to them since they were in service. The Company takes bi-monthly rectifier readings and annual pipe-to-soil readings

4.4.1.3Activation and Assessment of External Corrosion

The Plant Superintendent will utilize the relative risk scores to determine the schedule of assessments.

4.4.2 Required data elements for the Internal Corrosion Threat

The data elements shown in Table 4.2 are required for the evaluation of the internal corrosion threat. The Plant Superintendent shall assure that the data elements are collected, integrated, and analyzed to evaluate the internal corrosion threat. This activity will be completed through the risk assessment model.

Table 4.2: Required Data Elements for Internal Corrosion Threat

• Liquids analyzed	• Drying Operation Conducted
• Liquid drains present	• Internal Corrosion Detected
• Frequency of drain checks	• Internal MIC or corrosive detected
• History of liquids	• Upstream source of liquids

4.4.2.1Likelihood of Internal Corrosion History

The Company has not identified any internal corrosion since the lines are new. Electrolytes can enter the system upon dehydrator failure or inadequate dewatering after hydrostatic testing. Since the main lines are bi-directional, it is possible, but unlikely, that wet gas could be received from other Transmission pipelines. Internal Corrosion will be considered as a threat.

4.4.2.2Mitigative Measures for Internal Corrosion

The Company has supplier contracts that specify that gas content cannot exceed 7 lbs. of water vapor per MMCF. The company also analyzes its gas quality through sampling. Sweeping of some lines occurs as conditions dictate.

4.4.2.3Activation and Assessment of Internal corrosion

Internal corrosion will be assessed.

4.4.8 Required data elements for TPD Threat

The following data elements listed in Table 4.8 are required for the evaluation of the TPD threat. The Plant Superintendent shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 4.8: Required Data Elements for Third Party Damage Threat

• Vandalism incidents	• Incidences involving previous damage
• Pipe Inspection Reports	• One Call Records
• Leak Reports	• Encroachment Records

4.4.8.1Likelihood of TPD

Third party damage resulting from excavation activity is the most likely threat to the Company system

4.4.8.2Mitigative Measures for TPD

The Company has implemented aggressive programs to prevent, detect, and mitigate TPD on the system. The ROW is inspected in accordance with federal regulations 49 CFR 192.705. The Company participates in the State One Call Systems (811), monitors 3rd party excavations near transmission lines, provides damage prevention/emergency readiness classes and conducts public awareness meetings in accordance with API 1162.

4.4.8.3Activation and Assessment of TPD

Third Party Damage is the greatest threat to Company buried facilities. The Company focus is on the prevention and detection of TPD. Specific assessment for TPD will be initiated from the Patrolling program.

Inadequacy 8

Applicable Code Language: **§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d).

Applicable Code Language: **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

> **(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive 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, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must 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.**

Inadequacy Summary by PHMSA: CIP's pipeline system was constructed and their baseline assessment established with a hydrostatic test November 2008. The inspection team recognized that third party activity is the major threat to the pipeline system at this time. CIP must address a specific periodic for re-evaluation based on this likely pipeline threat.

Revised Plan/Procedure Language by CIP:

3.4.2 Form 3-3 Summary Baseline Assessment Plan

B.02.a. Verify the BAP schedule includes all covered segments not already assessed. [§192.921(a)]

B.02.b. Verify that the BAP schedule prioritizes the covered segments based on potential threats and applicable risk analysis, and that the risk ranking is appropriate. [§192.917(c) and §192.921(b)]

Annually upon completion of the relative risk spreadsheets for all the HCA segments on a transmission line, the plant superintendent or his designee will complete Form 3-3 Summary BAP. The form consists of all the covered segments for the company, the prioritized rank of each covered segment, and the planned assessment date. The Form 3-3 Summary Baseline Assessment Plan shall be printed after completion of threat identification, assessment method selection, and assessment scheduling.

3.4.7 Revising the Baseline Assessment Plan

B.06a. Verify that the operator'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]

As new information becomes available during routine operations and maintenance or during the annual HCA surveys, the new information shall be evaluated to verify the impact on pipeline segments. The baseline assessment plan consisting of the field verification surveys, the relative risk spreadsheets, and Form 3-3 Summary BAP will be modified using the new information and reviewed to determine if the assessment schedule or assessment method requires modification.

(2010)

HCA onseq uence Score	HCA Total Score	Rank of HCA	HCA length Miles	PIR + 25 Ft.	Location Class	Normal Operating Pressure psig	MAOP of Line at HCA psig	% SMYS at MAOP	Threat	Primary Assessment Method	Planned Assessment Date Month-Day--Yr	Required Date Month -Day-Yr	Interval Years	Next Assessment Date Month-Yr
1.8	51.6	1	1.6	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.5	34.4	7	0.8	1140	2	1200	1480	60%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.4	33.2	8	0.4	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.6	36.5	5	1.5	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.5	44.9	2	0.3	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.5	38	3	1.0	1140	3	1200	1480	50%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.5	35.26	6	0.6	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15
1.5	37.74	4	1.4	1140	1	1200	1480	72%	Third Party Damage	ILI	7/08	Within 10 Years of New HCA	7 Years	7/31/15

Inadequacy 9

Applicable Code Language: **§192.913 When may an operator deviate its program from certain requirements of this subpart?**

(a) General. ASME/ANSI B31.8S (incorporated by reference, see §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

Inadequacy Summary by PHMSA: CIP's IMP manual does not include a procedure for developing a performance matrix for demonstrating exceptional performance of their monitoring and mitigative measures and for confirming the overall effectiveness of their IM program. CIP must include in their procedure a method for developing a performance matrix for addressing a request to deviate from re-assessment requirements or CIP must clearly state in their IMP manual that it will not be using this option.

Revised Plan/Procedure Language by CIP:

9.3.2 Exceptional Performance Metrics

The Company is not intending to request a deviation from certain requirements of the rule based on exceptional performance. Additional measures may be tracked but no additional reporting will be made to PHMSA.

If you have any questions, please don't hesitate to contact me at (281)-774-4411.

Sincerely,

Hugh Berglund
Director of Operations