JONES DAY

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September 28, 2007

VIA HAND DELIVERY

Jim Curry, Esq.
Presiding Official
Pipeline and Hazardous Material Safety Administration
1200 New Jersey Ave, S.E.
Washington, D.C. 20590

RE: CenterPoint Energy Gas Transmission Company, CPF 4-2007-1004
Presentation of CEGT Hearing Materials

Dear Mr. Curry:

Thank you for your letter confirming that the informal hearing regarding the March 29, 2007 Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("Notice") issued to CenterPoint Energy Gas Transmission Company ("CEGT") will take place on Thursday, October 11, 2007 at 10:00 A.M. CDT at the PHMSA Southwest Region office. Section 192.211 of the DOT's regulations states that a respondent may submit any relevant information and material at hearing. CEGT has prepared a written response to the Notice along with a set of materials referenced in its written response. CEGT intends to use these materials as the basis for its presentation at the hearing. Enclosed with this letter please find two copies of CEGT's written response to the Notice and the associated materials.

Please call me if you have any questions about these materials or if you need to discuss with CEGT any other matters related to the October 11 hearing.

Sincerely,

Kenneth B. Driver

Enclosure:

cc w/enclosure: Rodrick Seeley, Southwest Region Director
Scott A. Mundy

Integrity Management Program Audit NOPV Response

September 27, 2007

Introduction and Overview

On April 3, 2007, CenterPoint Energy Gas Transmission Company ("CEGT") received a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order ("Notice") issued by the Southwest Region of the Department of Transportation's Office of Pipeline and Hazardous Materials Safety Administration ("PHMSA"). In the Notice, PHMSA stated that, based on its review of CEGT's Integrity Management Program ("IMP") conducted in Shreveport, Louisiana, during the weeks of September 12-16 and November 14-18, 2005, it appears that CEGT has committed probable violations of the IMP provisions of the pipeline safety regulations.

On April 30, 2007, CEGT requested a hearing pursuant to 49 C.F.R. § 190.211(a) (2007) and the Notice's instructions. In addition to requesting a hearing on the Notice's specific findings, CEGT raised two general issues for hearing:

(1) Does PHMSA have the authority to impose civil penalties in connection with an audit conducted in November 2005?

(2) Based on the timing of the CEGT audit and the nature of the proposed findings, did PHMSA select the appropriate remedy for each proposed finding – a finding of violation, accompanied by a compliance order and in five instances a civil penalty?

General Issues

1. <u>PHMSA Lacks The Authority To Impose A Civil Penalty For The Alleged Violations.</u>

The obligation to develop an integrity management program was first imposed on pipelines by the Pipeline Safety Act of 2002 (the "Act"), which was promulgated on December 17, 2002.[1] The Act gave PHMSA the authority to impose a specific remedy to address operators' inadequate compliance with this obligation. At the time PHMSA completed its 2005 audit of CEGT's program, this remedy was limited to requiring operators, after notice and an opportunity for a hearing, to revise their integrity management programs to address any perceived inadequacy or noncompliance.[2] The Act

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1 Pipeline Safety Improvement Act of 2002, Pub. L. No. 107-355, 116 Stat. 2985 (Dec. 17, 2002).

2 *See* 49 U.S.C. § 60109(c)(9)(iii) (2000 and Supp. II). The relevant provision in effect prior to December 29, 2006 stated:

> If the Secretary determines that a risk analysis or integrity management program does not comply with the requirements

was amended by the Pipeline Safety Act of 2006 (the "2006 Act") on December 29, 2006 to give PHMSA the authority to issue notices of probable violations, to impose civil penalties, and to propose compliance orders as remedies for inadequate compliance.[3] The 2006 Act did not provide for retroactive application of this new authority. Therefore, PHMSA does not have the statutory authority to penalize CEGT in connection with an audit covering a period of time which closed more than a year before such penalty authority was granted.

2. Selection of Remedies

CEGT has worked hard to develop and implement an Integrity Management Program that complies with Part 192, Subpart O of the DOT's regulations, and with the engineering standards incorporated by reference in Subpart O. CEGT's IMP reflects a good faith effort by CEGT to comply with PHMSA's IMP requirements and to develop an IMP that ensures the current and ongoing integrity of the CEGT pipeline system.

CEGT does not believe that any element of its IMP warranted the issuance of a Proposed Compliance Order or the issuance of Civil Penalties. As explained below, CEGT's actual practices satisfy Subpart O and the associated engineering standards, and those practices do not endanger public safety.

The audit identified inadequacies in the way CEGT's procedures describe its IMP. In many instances, PHMSA's findings reflect an apparent misunderstanding or miscommunication between PHMSA and CEGT about CEGT's actual IMP practices and the way in which CEGT implemented the IMP. One purpose of this hearing is to provide a further explanation of the way CEGT complies with the regulations – based on information that was available at the time of the audit – in the hope of addressing the issues raised in the Notice.

Even if the explanation provided below is insufficient to fully resolve one of the Notice's proposed findings, the fact remains that those findings relate to the completeness

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> of this subsection or regulations issued as described in paragraph (2), or is inadequate for the safe operation of a pipeline facility, the Secretary shall act under section 60108 (a)(2) to require the operator to revise the risk analysis or integrity management program. *Id.* (Emphasis added).

Section 60108(a)(2), as it existed in 2006, stated: "[i]f the Secretary or a State authority responsible for enforcing standards prescribed under this chapter decides that a plan required under…this subsection is inadequate for safe operation, the Secretary or authority shall require the person to revise the plan," but only after notice and opportunity for a hearing. 49 U.S.C. § 60108(a)(2) (2000).

[3] *See* 49 U.S.C. § 60109(c)(9)(iii) as amended by *Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006*, Pub. L. No. 109-468, 120 Stat. 3486 (Dec. 29, 2006).

of CEGT's processes. This is exactly the type of matter that could be, and should be, addressed through the issuance of a Notice of Amendment ("NOA").

An NOA is designed to improve the completeness of a pipeline's procedures – the exact issue here. PHMSA's explanation of its enforcement program states that "PHMSA inspections, incident investigations, and other oversight activities routinely identify shortcomings in an operator's plans and procedures under PHMSA regulations. In these situations, PHMSA issues a [NOA] letter alleging that the operator's plans and procedures are inadequate and requiring that they be amended."[4]

The timing of this audit also supports addressing the proposed findings through the issuance of an NOA. At the time of the initial site visit, the IM regulations had been in place for only ten (10) months. Those regulations stated that, by December 17, 2004, an operator of a covered pipeline segment must "develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment." 49 C.F.R. § 192.907(a) (2006). In addition,

> the initial integrity management program must consist, at a minimum, of a *framework* that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. *The framework will evolve into a more detailed and comprehensive program*. An operator must make continual improvements to the program.
>
> 49 C.F.R. § 192.907(a) (2006) (emphasis added).

CEGT had such a framework in place at the time of PHMSA's September 2005 site visit.

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[4] *See* http://primis.phmsa.dot.gov/comm/reports/enforce/Actions_opid_0.html. CEGT has been unable to find any detailed public guidelines that explain when PHMSA should issue an NOA rather than a Notice. CEGT believes that PHMSA should publish the criteria it applies when deciding (1) whether to issue a Notice rather than an NOA; and (2) whether to impose a civil penalty in addition to issuing a compliance order. A better understanding of the PHMSA guidelines that address these matters will improve pipeline compliance with the Integrity Management rules. In any event, the criteria PHMSA applies in making these decisions should be discussed at the hearing and PHMSA should identify the criteria it intends to use to evaluate the Notice's proposed findings.

PHMSA did not issue its Notice until March 29, 2007, which is more that 15 months after PHMSA's second site visit. During those 15 months, PHMSA and the pipeline industry continued to apply and learn from the IM rules. CEGT believes that in this audit PHMSA has taken its more detailed and more specific "2007" understanding of the IM rules, and applied that understanding to CEGT's IMP compliance as of Fall 2005.

Specific Issues

1. § 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 (ibr, see §192.7), section 2, which are as follows:
(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.

CenterPoint Energy Gas Transmission (CE) did not identify or evaluate the potential for interactive threats to each covered pipeline segment. The regulation specifically requires that CE identify and evaluate the threats listed in ASME/ANSI B31.8S, section 2, which includes the following:

> ASME B31.8S 2.2 Integrity Threat Classification
> 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. An example of such an interaction is corrosion at a location that also has third party damage.

While CE's procedure PS-03-01-216, "Threat Identification and Risk Assessment," Section 2.2 states that, "The results from the evaluation together with the criteria used to evaluate the significance of this threat or interaction of threats to the covered pipe segment shall be used to prioritize the integrity assessment," there is not a process to ensure the evaluation of interactive threats is accomplished.

<u>NOPV Item 1 -- CenterPoint Response</u>

ASME B31.8S-2001 Managing System Integrity of Gas Pipelines, Section 2.2 Integrity

Threat Classification states:

> *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. An example of such an interaction is corrosion at a location that also has third party damage.*

CEGT identifies and evaluates the potential for interactive threats to each covered pipeline segment using a risk assessment model. To determine the overall failure likelihood score for a segment, the model adds together the individual failure likelihood values determined for each of the nine ASME B31.8S threat categories – external corrosion, internal corrosion, stress corrosion cracking, manufacturing, construction, equipment, third-party damage, incorrect operations, and weather and outside force – in the covered segment. This overall score measures the interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) for a pipeline segment. Therefore, the model considers multiple threats and evaluates the potential for interactive threats.

Example - Line BT-1, Series 1100, Station 403869 to 405621

Threat	Score	Weight
External Corrosion	39.5	15%
Internal Corrosion	43.9	14%
SCC	0	10%
Manufacturing	39.9	14%
Construction	39.4	10%
Equipment	9.0	7%

Third Party Damage	49.6	15%
Weather	45.3	9%
Incorrect Operations	12.0	6%
Weighted Failure Likelihood Score	34.5	

This threat value "weighted score" is used to rank segments by the level of risk, to prioritize assessments, and to determine preventive and mitigative measures. Using the corrosion and third-party damage example in ASME B31.8S, Section 2.2, when two segments of pipe with similar external corrosion values are compared, the segment with the higher third-party damage value will have a higher overall score (assuming scores in the other seven categories remain the same).

CEGT's method of identifying and evaluating interactive threats to a covered segment satisfies the requirements of ASME B31.8S, Section 2.2 . CEGT is not aware of any published standard or regulation beyond B31.8S that explains how to evaluate interactive threats. Attachment 1.1 contains the full text of Section 2.2.

Appendix B in CEGT Procedure PS-03-01-216, Threat Identification and Risk Assessment shows the configuration of the risk model, including the detailed algorithms used to develop risk values for each threat and to determine the interactive nature of threats when more than one threat occurs on a pipeline section at the same time (see Attachment 1.2 Procedure PS-03-01-216 Appendix B). Procedure 216 requires the risk assessment to be performed at least annually.

For these reasons, and as reflected in CEGT's procedure at the time of the audit, CEGT's model appropriately considers the interactive nature of threats.

Proposed Compliance Actions and Proposed Penalty

CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV. CEGT does not believe that a penalty was appropriate in this situation.

2. § 192.917 (see above)

(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment.

CE did not provide specific documentation requirements or documentation to support conclusions to eliminate threats from HCAs in accordance with the minimum requirements specified by each of the relevant sections of ASME B31.8S. At the time of the inspection, CE did not provide the inspection team with any documentation in support of this requirement. The regulations require that threats be identified and that a risk assessment based on those threats be performed according to section 5 of ASME B31.8S.

NOPV Item 2 -- CenterPoint Response

The standard referenced in Section 192.917(c) of the regulations, ASME B31.8S, discusses the elimination of threats in Section 5.10 (see Attachment 2.1) as follows:

> *The integrity plan shall also provide for the elimination of any specific threat from the risk assessment. For a prescriptive integrity management program, the minimum data required and the criteria for risk assessment in order to eliminate a threat from further consideration are specified in Nonmandatory Appendix A.*

CEGT utilizes a relative assessment model, which is a risk assessment approach as described in ASME B31.8S, Section 5.5(b)(2) (See Attachment 2.2), to evaluate the nine categories of threats listed in ASME B31.8S, Section 2.2 (see Attachment 1.1), i.e., external corrosion, internal corrosion, stress corrosion cracking, manufacturing, construction, equipment, third-party damage, incorrect operations, and weather and outside force. CEGT used the guidance provided in ASME B31.8S for prescriptive integrity management plans to develop the data sets used in the risk model to evaluate the nine threat categories.

The risk model contains algorithms that use the data supplied for each covered segment to determine, in sequence, 1) a numerical value for the individual data element within the threat category, 2) a value for the likelihood that an adverse event caused by the particular threat will occur, 3) a value for the combined likelihood that any adverse event will occur, 4) a value for the consequence if an adverse event occurs, and finally 5) a risk score for the segment. The risk scores derived for each segment are relative to other segments in the model; they are not absolute scores.

In running the risk model, CEGT considers and evaluates all nine threat categories on all covered segments. Based on the results of the data evaluation, CEGT identified four threat categories (Stress Corrosion Cracking, Equipment, Manufacturing and Construction) that could be assigned zero values for risk comparison purposes at the time the model was run.

<u>Stress Corrosion Cracking</u>

ASME B31.8S Appendix A3.3 (See Attachment 2.3) states *"[e]ach segment should be assessed for risk for the possible threat of SCC if all the following criteria are present:*

> *(a) operating stress > 60% SMYS*
>
> *(b) operating temperature > 100 degrees F*
>
> *(c) distance from compressor station < or equal to 20 miles*

(d) age > or equal to 10 years

(e) all corrosion coating systems other than fusion-bonded epoxy (FBE)."

SCC assessment is required only if each of these criterion is met. Accordingly, in its risk model, CEGT assigned a SCC threat score of zero to segments that did not meet all of these criterion (with the exception of the temperature criterion). CEGT did not assign a zero risk score based on the temperature criterion in order for the evaluation to cover near-neutral SCC (per NACE RP0204 Stress Corrosion Cracking Direct Assessment Methodology, Section 1.2.2). Therefore, CEGT's evaluation is more conservative than required by ASME B31.8S, Appendix A3.3.

<u>Equipment</u>

Equipment is defined in B31.8S, Appendix A6 (see Attachment 2.4) as pipeline facilities other than pipe and pipe components. Meter/regulator and compressor stations are listed as typical equipment locations. If a covered segment contains no equipment, it is assigned a zero equipment score in the risk model.

<u>Manufacturing and Construction</u>

CEGT relied on the following guidance from PHMSA, as published in its FAQs, in evaluating whether a covered segment could be assigned zero manufacturing or construction threat scores in its risk model:

1. FAQ-219, dated September 16, 2004, states, in part, that *"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."* (See Attachment 2.5 "FAQ #219").
2. FAQ-220, dated January 1, 2005, states, *"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."* (See Attachment 2.6 "FAQ #220").
3. FAQ-231, dated March 9, 2005, which relates to the 5-Year reference pressure for stability of manufacturing and construction defects, states, (1) *"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"*, and (2) *"OPS considers that a hydrostatic test, meeting subpart J requirements, is sufficient to demonstrate that any manufacturing and construction defects will remain stable at the operating pressures related to that test."* (See Attachment 2.7 "FAQ #231").

Based upon these FAQs, CEGT assigned to a covered segment a zero manufacturing threat score or a zero construction threat score if the following conditions were met:

1. The pipeline segment has a record of a Subpart J pressure test in the facilities inventory database, and,

2. There has been no recorded manufacturing or construction leak or failure in the pipe segment defined as a "Series" in the facilities database (generally a continuous length of pipe installed at one time in a single project) which contains the segment being evaluated.

These criteria resulted in a more conservative analysis of manufacturing and construction (M&C) threats than required by the guidance published by PHMSA in its FAQs. First, if a segment did not have a pressure test record, that segment was not assigned a zero score in the risk assessment for M&C defects even though PHMSA's FAQs allow an operator to consider these threats stable without a Subpart J test. Second, even though PHMSA's FAQs allow a segment to be considered stable if there is no history of leaks or failures on the segment being evaluated, CEGT nonethless evaluated the pipe segments that surrounded a segment that had a history of leaks or failures. Conservatively, if a manufacturing or construction related leak was recorded on a surrounding segment, the segment being evaluated was not assigned a zero value.

These criteria are documented in CenterPoint Energy Procedure PS-03-01-216, Appendix B (see Attachment 2.8). Appendix B contains the data filters and the logic used to evaluate threats in the risk model algorithms. Each time CEGT runs the risk assessment model, the latest available data is evaluated for each of the nine threat categories.

Proposed Compliance Actions and Proposed Penalty

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV. CEGT does not believe that a penalty was appropriate in this situation.

3. § 192.917 (see above)

(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 the section and ASME/ANSI B31.8S, Appendix A& 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 §199.935 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. An operator must also have procedures in its integrity management program addressing action it will take to respond to findings from this data integration.

CE does not have a formal procedure or process by which it integrates inspection tool or external corrosion direct assessment data with data related to encroachments or foreign line crossings to define where potential indications of third party damage may exist in covered sections. CE procedures PS-03-01-11-, Gather, Review, and Integrate Data," and section 2.4 of PS-03-01-216, "Threat Identification and Risk Assessment," describe the collection and evaluation of data for risk analysis. However, neither procedure describes requirements for data integration of ILI and ECDA data with data related to encroachments of foreign line crossings prior to any post assessment review. Additionally, the inspection team did not identify any evidence that this data integration had been performed.

<u>NOPV Item 3 -- CenterPoint Response</u>

<u>External Corrosion Direct Assessment (ECDA)</u>

CEGT gathers and utilizes foreign line crossing and encroachment data in the preassessment and indirect inspection steps of CEGT's ECDA. CEGT collects historical records of foreign line crossings and encroachments during preassessment and records this data in the following three areas of the ECDA Data Element Form:

- Section 2.0, Construction Related, Column 2.9 “Proximity to Others”;
- Section 4.0, Corrosion Control, Column 4.10 “Stray Current Sources/Bonds”; and
- Section 5.0, Operation Data, Column 5.4 “3rd Party Damages.”

See Attachment 3.1 “ECDA Preassessment Line ALE” for an example. This ECDA Preassessment document was available at time of audit.

CEGT’s ECDA program considers data regarding indications of foreign line crossings and encroachments found during indirect surveys (recorded in survey field notes) along with tool data. See Attachment 3.2 “ALE Close Interval Survey (CIS) Comments” showing the Platt Pipeline crossing as an example of field notes recorded, and see Attachment 3.3 “ALE Plot 1718+00 to 1780+40” for an example of an ECDA indirect survey data integration sheet. The Platt Pipeline foreign line crossing location is shown plotted on the same sheet as the CIS, DCVG and PCM survey results. Attachments 3.2 and 3.3 were available at time of audit. Encroachment and foreign line crossing data is integrated in both indirect inspection data (comments w/stationing) and direct examination dig sheets where crossings / encroachments are encountered.

Qualified personnel integrate and evaluate preassessment data (which includes foreign line crossing and encroachment information noted above), survey field notes recorded during indirect inspections (which includes foreign line crossing and encroachment data noted above), and indirect survey tool data side-by-side to determine dig locations for direct examination of the pipe.

For example, on Line ALE, CEGT used indirect inspection indications to select a dig site under a road. Direct examination of the pipe under pavement found damage that probably occurred during a recent resurfacing of the road. Photographs of the excavation are shown in Attachments 3.4 and 3.5. CEGT followed up the ECDA work with an Inline Inspection (ILI) assessment of the pipe under pavement. A geometry and MFL assessment with tether-conveyed tools was performed.

Although the data was in fact integrated as a normal part of the ECDA process, the CEGT ECDA procedure did not specifically state that the data from ECDA and foreign line crossings would be integrated. CEGT has revised its procedure to state that the data from ECDA and foreign line crossings/encroachment will be integrated.

Inline Inspection (ILI)

The purpose of integrating foreign line crossing and encroachment data with ILI results is to identify locations on the pipeline with potential for third-party damage. When assessing covered segments using inline inspection tools, CEGT ran a geometry tool in conjunction with a high resolution magnetic flux leakage (MFL) tool in accordance with the company ILI Procedure PS-03-01-244 Section 2.1 requirement to run two tools (see Attachment 3.6). The geometry tool data is integrated with the MFL tool data, and the analysis results are included in the inspection tool final report used to determine dig locations. Attachment 3.7 contains an example of an executive summary from an MFL run describing the dent data incorporated in the report. See Attachment 3.8 for an example of a location where both the MFL tool metal loss indication and the geometry tool dent sizing are integrated. This documentation was available at time of audit.

Running a high resolution geometry tool is a more effective and efficient method of identifying mechanical damage, such as that caused by third parties, than is the correlation of foreign line crossing data with corrosion tool inspection data. The geometry tool provides accurate information on the type, location and extent of the damage, whereas the information gleaned from comparing foreign line crossing data with corrosion tool inspection data is anecdotal and often leads to false positives requiring excavation and examination where no mechanical damage is found. The Dent Study Final Report (TTO Number 10) submitted by Micheal Baker, Jr., Inc, in November, 2004, to the DOT RSPA Office of Pipeline Safety (see Attachment 3.9 “OPS Dent Study Final Report Section 4.5”) discusses the potential benefits of comparing data from different types of ILI tools in Section 4.5 as follows:

> *To conservatively use a metal–loss tool as the sole deformation inspection tool may result in the excavation of deformations that would not otherwise require excavation. Additional information such as deformation depths and the ability to calculate strains may be obtained by running a geometry tool. None of the available geometry tools can identify external metal loss. Consequently, determining if metal loss is present requires excavation for direct examination or*

> *running a metal loss tool. A potential benefit of combining a metal-loss tool with a geometry survey may be the ability to cost effectively screen deformations based on magnitude, strain, and metal-loss. The correlation of the metal-loss tool with the geometry tool could lead to improved selection of deformation for excavation and potentially fewer deformations that require remediation.*

At the time of the audit, although the geometry and MFL tool data were integrated and reports of these results were available, CEGT's procedures did not specifically state that the data from ILI and foreign line crossings and encroachments would be integrated. CEGT has revised its procedures to state that the data from ILI and foreign line crossings and encroachments will be integrated.

<u>Proposed Compliance Actions</u>

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.

4. § 192.917 (e)(1) (see above)

> CE did not integrate ECDA and ILI data with data related to encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," describe how ECDA assessments are to be conducted, to data to be collected, and what documentation needs to be retained. PS-03-01-268, "IMP Quality Assurance', Appendix A requires that the data elements used for ECDA be gathered and integrated. These plans and procedures reference the NASCE RP 0502-2002 ECDA assessment standard but do not reference the need to integrate encroachment and foreign line data as required in §192.917 (e)(1) and §(b) for Preassessments, Indirect Inspections and Direct Examinations undertaken on ECDA for a region or a segment. Three ECDA assessments were reviewed (line ALE, line BT-1, and A-206); and in each case there was no documentation that this data integration was performed.

<u>NOPV Item 4 -- CenterPoint Response</u>

ECDA data integration documentation for Line ALE was provided in response to item 3.

ECDA data integration documentation for BT-1 is provided in Attachments 4.1 through 4.3, and A-206 documentation is provided in Attachments 4.4 through 4.6.

<u>Proposed Compliance Actions and Proposed Penalty</u>

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV. CEGT does not believe that a penalty was appropriate in this situation.

5. § 192.917 (e) (see above)

(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 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, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

CE's Baseline Assessment Plan (BAP) did not consistently specify an assessment method(s) for each covered segment that is appropriate for identifying anomalies associated with specific threats identified for the segment. The rule requires that an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and corrosion seam anomalies. Further, ASME B31.8S states in section A4, "Manufacturing Threat (Pipe Seam and Pipe), A4.4 Integrity Assessment," ". . . pressure testing must be performed to address the seam issue." CE allows for either a Hydrotest or the use of TFI based on their "BAP – Integrity Assessment Selection Guide." However, according to ASME B31.8S, a TFI tool is not an acceptable method of integrity assessment for this threat. CE describes the various assessment methods in PS-03-01-224, "Assessment Methods Selection Process" which references CE's, "BAP – Integrity Assessment Selection Guide." The assessment path on the flow chart in the Guide allows for a hydrotest, pipe replacement, or use of a TFI tool. The ASME B31.8S guidance states that only a hydrotest is appropriate. A pipe replacement is an acceptable approach to eliminate the seam integrity threat, but for those instances where CE does not elect to replace the pipe, only the performance of a hydrotest would satisfy the requirement of the rule and the ASME guidance document.

NOPV Item 5 -- CenterPoint Response

Section 192.917(e)(4) does not always require pressure testing for the pipe identified in ASME B31.8S, Appendices A4.3 and A4.4; it requires an operator to select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies if a seam failure has occurred, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. To address steel pipe seam concerns, ASME B31.8S Appendix A4 (see Attachment 5.1) requires only that, *"when raising the MAOP of a pipeline or when raising the operating pressure above the historical operating pressure (highest pressure recorded in the past 5 years),"* a pressure test be conducted. However, when the MAOP or operating pressure are not being increased in this manner, a pressure test may not be the only option under Section 192.917(e)(4).

CEGT's Baseline Assessment Plan did not specify use of a TFI tool for an integrity assessment on a covered segment where the MAOP has increased or where the operating pressure on a covered segment has increased over the maximum operating pressure experienced during the preceding five years. CEGT has not developed an action plan to use TFI in this situation. At the time of the audit, CEGT had a documented assessment selection guide flow chart for each covered segment, and no segment met the criteria pertaining to pressure increases.

CEGT's assessment selection guide, a process flow chart in use at the time of audit, did contain a mistake permitting a TFI tool run as one option as a response to pressure increases. The TFI tool option was intended as a response to manufacturing defects and was mistakenly included as an option for responding to a pressure increase. See Attachment 5.2 for an example of an assessment selection guide flow chart. The flow chart was developed based on the language of Section 192.917(e). The additional step required to implement ASME B31.8S, Appendix A4 reference was not identified in developing the flow chart. Because CEGT had not undertaken any assessments to address an increase in a line's MAOP or operating pressure, CEGT was not aware of the mistake in the flow chart until the NOPV was received. If CEGT had undertaken an assessment to address an increase in MAOP or operating pressure, CEGT would have recognized and corrected the mistake in the flow chart. This subject was not raised with CEGT during the audit. CEGT believes this issue would have been resolved if it had been raised at audit. The error in the flow chart has been corrected.

Proposed Compliance Actions and Proposed Penalty

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV. CEGT does not believe that a penalty was appropriate in this situation.

6. § 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section in ASME/ANSI B31.8S (ibr, see §192.7), section 6.4, and in NACE RE 0502-2002 (ibr, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination and post-assessment. If the ECDA detects pipeline coating Damage, the operator must also integrate the data from the EDCA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RE 0502-2002, section 3, . . .

CE's plan did not adhere to the requirements of NACE RP 0502-2002, Section 3 by not defining minimum data requirements. CE procedures PS-03-01-232, "External Corrosion Direct Assessment, " PS-03-01-230, "Direct Assessment Plan," and PS8140 "ECDA Data Elements" describe what data elements would be considered to perform and ECDA However, the minimum data elements that are needed to determine if an ECDA can be conducted are not documented as required by NACE RP 0502, Section 3.2.1.1 which states, "The pipeline operator shall define minimum data requirements based on the history and condition of the pipeline segment. In addition, the pipeline operator shall identify data elements that are critical to the success of the ECDA process."

CE's plan did not adhere to the requirements of NACE RP 0502-2002, Section 3 by not documenting conservative assumptions. CE procedures allow conservative assumptions be made where data is not available to address data sufficiency requirements. Three ECDA assessments (completed through the third step, Direct Examination, at the time of the inspection) were reviewed (lines ALE. BT-1, and A-206); and in each case, there of no documentation on the minimum required data, what the basis was for any of the conservative assumptions, and if the ECDA was feasible with the data elements available. CE stated they only have 10 years of data available for integrity management but that additional historic data may be at field locations. Past cathodic protection data is needed to determine if active corrosion is taking place or if corrosion was the result of past inadequate cathodic protection. Under other sections of §192, much of the cathodic protection data should have been retained for the life of the pipeline and this should be available for these ECDA purposes. NACE RP 0502, Section 3.2.4 states, "In the event that the pipeline operator determines that sufficient data for some ECDA regions comprising a segment are not available or cannot be collected to support the Preassessment Step, ECDA shall not be used for those ECDA regions."

CE's plan did not adhere to the requirement of their own procedures and NACE RP 0502-2002, Section 3 by not documenting that a feasibility assessment was undertaken. CE procedures PS-03-01-232 §4.0, "External Corrosion Direct Assessment," PS-03-1-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance, Appendix A require that the feasibility of each ECDA be assessed and documented. In the three ECDAs reviewed by the inspection team (lines BT-1, ALE and A-206) that CE started and completed through the Direct Examination step, there was no documentation that a feasibility assessment was undertaken. Documentation on what was considered during the feasibility review is critical to determine the applicability of the ECDA process to other covered segments and for feedback as required by NACE RP 0502, §192.925 and CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-268, "IMP Quality Assurance', Appendix A.

CE's plan did not adhere to the requirements of their own procedures and NACE RP 0502-2002, Section 3 by not documenting the specific indirect inspection tools chosen and if they were complementary to each other. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A require that the indirect tool selection for each ECDA conducted be verified and documented. In the three ECDAs reviewed by the inspection team (lines BT-1, ALE, and A-206), there was no documentation regarding why the specific indirect inspection tools were chosen and if they were complementary to each other. NACE RP 0502, Section 3.4.1.1 states, "the pipeline operator shall select indirect inspection tools based on their ability to detect corrosion activity and/or coating holidays reliably under the specific pipeline conditions to be encountered." NACE RP 0502, Section 3.4.1.2 states, "The pipe operator should endeavor to select indirect inspection tools that are complementary. That is, the operator should select tools such that the strengths if one tool compensate for the limitations of another'

NOPV Item 6 -- CenterPoint Response

Overview

PHMSA's proposed findings for item 6 refer to NACE RP0502-2002, Section 3, which addresses the application of the preassessment step of ECDA. The PHMSA proposed findings are primarily concerned with the feasibility of ECDA. ECDA feasibility is addressed in the preassessment, indirect inspection and direct examination steps with a final evaluation of effectiveness in the post-assessment step.

ECDA can be declared infeasible in the preassessment step based on (1) specific information about a pipeline segment's condition; or (2) a lack of sufficient information about the segment's history and condition. Even if some of the historical information about a pipeline segment's condition is unavailable or inconclusive, a pipeline operator can decide, as part of the feasibility evaluation, to proceed with ECDA. NACE RP 0502, Section 3.3.1 (see Attachment 6.4, page 11, paragraph 3.3.1) states "the pipeline operator shall integrate and analyze the data collected above to determine whether conditions for which indirect inspection tools cannot be used or that would preclude ECDA application exist". Conversely, unless it is determined that conditions exist for which indirect inspection tools cannot be used or that would otherwise preclude ECDA application, the pipeline operator can decide to proceed with ECDA. Actual feasibility is then confirmed during the indirect inspection and direct examination steps as follows:

- Indirect Inspection Step – Feasibility of ECDA is confirmed by successful execution of two or more surveys using different tools. Information from indirect inspection developed after the identification of initial preassessment data can be incorporated an as update to the preassessment document, thus evidencing continuous improvement. A complementary tool can be used even if it was not identified in the ECDA preassessment step so long as at least two tools are applied. The fact that the complementary tool was not identified in the preassessment does not invalidate ECDA, but it does require a revision/update to the preassessment document. In the event only one tool or no tools can be executed successfully, ECDA is infeasible and another assessment method must be applied.

- Direct Examination Step – Pipeline information from direct examination developed after the identification of initial preassessment data can be incorporated as an update or correction in the preassessment document, thus evidencing continuous improvement during the ECDA process. Required reclassifications of dig priorities based on direct examination findings do not invalidate ECDA so long as the reclassification adequately addresses conditions found in subsequent digs. If conditions from the direct examination conflict with either the initial preassessment or indirect inspection steps, and the discrepancy is material and cannot be reconciled**,** then ECDA is declared infeasible and another assessment method must be applied. Indirect inspection survey indications are classified according to severity criteria and do not directly address percent metal loss. In cases where the magnitude of metal loss is extensive and the number of additional direct examinations (driven by >20% metal loss – NACE RP0502-2002, Section 5.10.2.2.3) required becomes restrictive or unreasonable, or where extensive immediate repairs are required, then ECDA is declared infeasible. In this situation, the options are to (1) select another assessment method, or (2) replace pipe.

Indirect inspection and direct examination are used to true-up the preassessment data. The true-up results in (1) a successful pipeline integrity assessment; (2) improved records and information addressing actual conditions for the pipeline segment; and (3) the capability to address risk ranking more accurately in subsequent updates.

Minimum Data Requirements

CEGT uses an ECDA Data Element Form based on Table 1 of NACE RP0502 to record ECDA preassessment data. There are five categories of data – pipe-related, construction-related, soils/environmental, corrosion control and operational – covering a total of 44 separate data elements. A review of the data element form for Line ALE shows information was recorded directly in the data columns or recorded in the Comments section for all 44 data elements. See Attachment 6.1 “ECDA Data Element Form Line ALE”. The data element form for Line BT-1 shows information was recorded directly in the data columns or recorded in the Comments section for 43 data elements. The 44th data element, 4.7 Coating Condition, is discussed in the Use and Interpretation of Results section on that page. See Attachment 6.2 “ECDA Data Element Form Line BT-1”. The A-206 data element form shows information was recorded directly in the data columns or recorded in the Comments section for all 44 data elements. A portion of column 3.2 Land Use, was filled out. See Attachment 6.3 “ECDA Data Element Form Line A-206”. NACE RP0502, Section 3.2.2 (see Attachment 6.4) includes a statement that “Not all items in Table 1 are necessary for the entire pipeline.”

Although CEGT’s procedures at the time of audit did not include a list of minimum data requirements defining when ECDA was a feasible alternative, the procedures did include the data sets needed to make an ECDA feasibility determination, and that information was taken into account when CEGT selected ECDA as a feasible alternative. CEGT's procedures have been revised to include a list of minimum data requirements defining when ECDA is a feasible alternative.

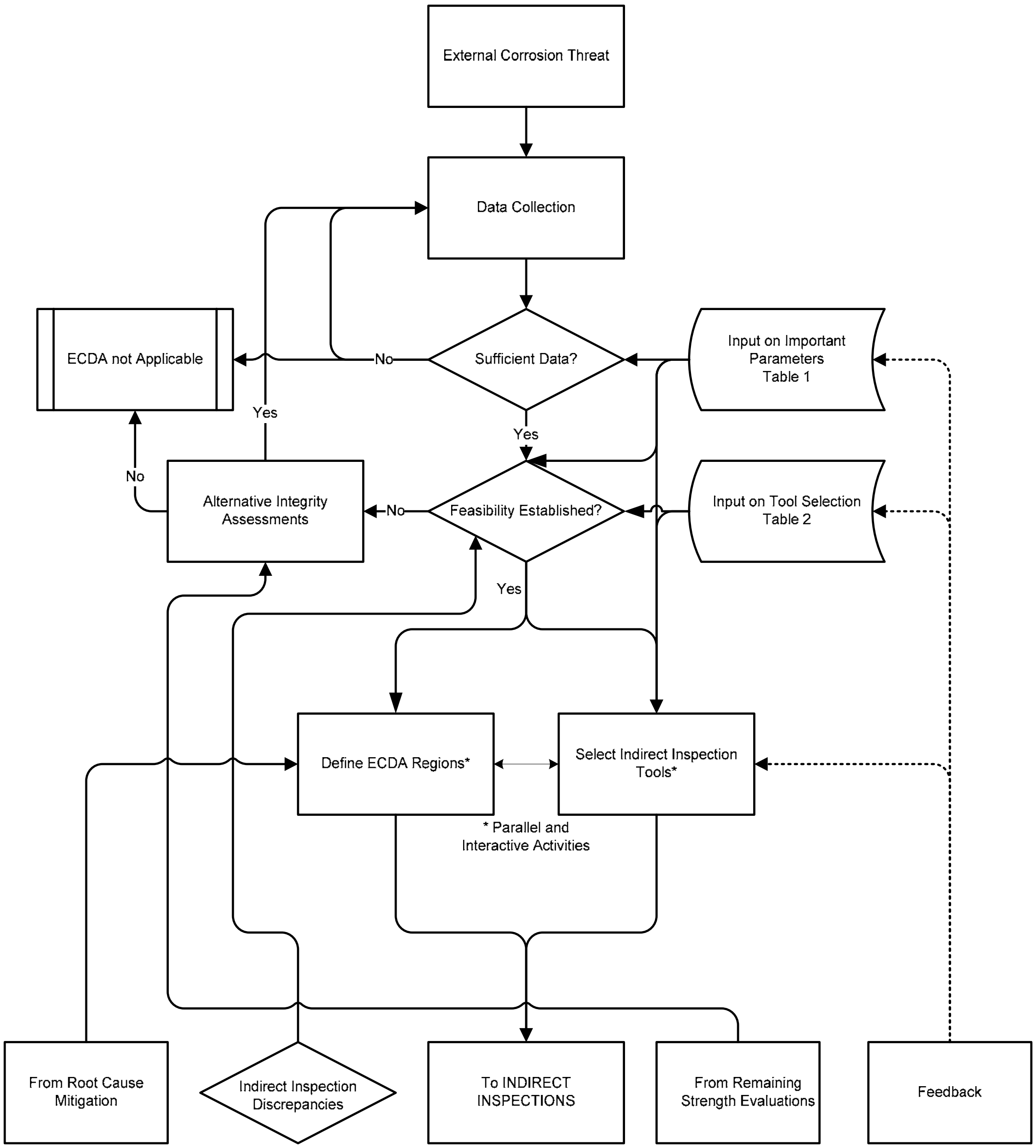
Conservative Assumptions

In response to this proposed finding CEGT has reviewed NACE RP 0502, Section 3.0 (see Attachment 6.4). CEGT has been unable to find any requirement to document conservative assumptions. CEGT ECDA Procedure PS-03-01-232, Section 3.3.4 (see Attachment 6.5) states that conservative defaults may be substituted in the data element form. Conservative defaults were not needed for the three ECDA segments in question because there was information available for the data elements. CEGT's QA Procedure 03-01-268, Appendix A (see Attachment 6.6, bottom of page 7) stated that the person performing a quality assurance audit must "verify conservative assumptions were documented". Because the PHMSA audit was conducted just after the integrity management program requirements went into effect, CEGT had not, at the time of audit, conducted an internal quality assurance audit.

Feasibility

The flow chart below is from CEGT integrity management procedure PS-03-01-232, External Corrosion Direct Assessment, Section 3.0 (see Attachment 6.5, page 3). It is based on the preassessment flow chart in NACE RP0502, Pipeline External Corrosion Direct Assessment Methodology. The flow chart defines the process for the preassessment step of ECDA.

FIGURE 1: Pre-Assessment Step Flowchart



In this process, data collection is followed by an evaluation of the data and a determination of the feasibility of performing ECDA. If ECDA is determined to be feasible, tools are selected and regions are defined.

In the cases of Lines ALE, BT-1 and A-206, data gathered during ECDA preassessment was recorded in the ECDA Data Element Form for each line. See Attachments 6.1 "ECDA Data Element Form Line ALE", 6.2 "ECDA Data Element Form Line BT-1", and 6.3 "ECDA Data Element Form Line A-206". The ECDA Data Element Form is a spreadsheet used by CEGT to record preassessment information. After data was recorded, data analysis and ECDA feasibility evaluation were performed. If ECDA was considered feasible, tools were selected and documented in the data element form. ECDA regions were also defined and documented in the data element form. While the determination that ECDA was feasible was not recorded, the documented tool selection and documented ECDA region definitions show that the evaluation was performed and feasibility determined. Tool selection and region definition documentation for Lines ALE, BT-1 and A-206 is shown in Attachments 6.1, 6.2 and 6.3.

For these reasons, it is clear that CEGT's IMP plan adhered to the requirement of its procedures and NACE RP 0502-2002, Section 3 by documenting that a feasibility assessment was undertaken through the use of the Data Element Form, and through recording tool selection decisions and the definition of ECDA regions. The feasibility of each ECDA was assessed and documented. At the time of audit, documentation existed showing that a feasibility assessment was undertaken for Lines BT-1, ALE and A-206.

CEGT has revised its procedures and forms to directly document the feasibility decision in each of the ECDA steps – preassessment, indirect inspection, direct examination and post assessment.

Complementary Tools

The indirect inspection tools selected for ECDA were documented (see Attachments 6.1, 6.2, 6.3) and are complementary. The ECDA tool selection matrix (PS-03-01-232, Table 2 and NACE RP 0502, Table 2) lists available tools and provides guidance concerning the limitations and applicability of each tool. NACE RP 0502 and CEGT procedure PS-03-01-232 do not require documentation of why particular tools are complementary. Nevertheless, to respond to the audit, CEGT has revised its procedures to include a table indicating which tools are complementary to each other.

Proposed Compliance Actions

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.

7. § 192.925 (b) (see above)

(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 3, the plan's procedures for preassessment must include-

i. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(2) Indirect Examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include –

i. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(b)(3) Direct Examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include –

i. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

CE, in their ECDA plan, did not document the more restrictive criteria, as required by §192.925 when they conducted ECDA for the first time on a covered segment. These more restrictive criteria are for preassessment, indirect inspection, and direct examination steps of the ECDA process. CE did not document for each specific assessment how the more restrictive criteria were applied. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," describe how ECDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. These plans and procedures reference the NACE RP 0502-2002 ECDA assessment standard but do not reference the need to document the more restrictive criteria as required in §192.925(b)(1) subparts (i), (ii) and (iii) for Preassessments, Indirect Inspections and Direct Examinations undertaken on an initial ECDA on a region or segment. Three ECDA assessments were reviewed by the inspection team (line ALE, line BT-1, and A-206), and in each case there was no documentation of the more restrictive criteria for this initial ECDA on these segments.

<u>NOPV Item 7 -- CenterPoint Response</u>

CEGT used more restrictive criteria than required by NACE RP0502 when performing ECDA for the first time on the segments in question. Although the criteria were not specifically identified as being "more restrictive criteria" at the time of the audit, CEGT used and documented such criteria.

Although not available at the time of our audit, FAQ 242 (see Attachment 7.1) identifies examples of more restrictive criteria such as the following:

- Subdividing ECDA regions, which requires additional excavations.
- Requiring a "preassessment meeting" with maintenance crews to "data mine" their experiences of working on the pipeline.
- Using three tools instead of two for part or all of the survey area.

The more restrictive criteria used for the ALE, BT-1, and A-206 ECDA pipeline segments are as follows:

I. Preassessment

A. ECDA segments are defined according to land use and topography. This allows realistic division of a longer pipeline section into manageable sub-parts of covered segments (HCAs). Region definition is unique to a specific ECDA segment. This process results in more direct examinations as compared to defining and examining a lengthy section of pipeline with varying land use and topographical conditions as a single ECDA. (ALE – see Attachments 7.2, 7.3 and 7.4).

   Because CEGT defined two ECDA segments instead of one, CEGT conducted eight digs minimum instead of four. This matches the first FAQ 242 example above.

B. Coordination with local operations personnel for site visits and consultation for validation of conditions. (A-206 – see Attachment 7.5, and BT-1 – see Attachment 7.6).

   The attachments here show information obtained from local CEGT operations personnel consistent with the FAQ 242 example to "data mine" maintenance crew experiences of working on the pipeline.

II. Indirect Inspection

A. Soil resistivity measurements are taken during all ECDA projects. The minimum measurement spacing for soil resistivity testing within an ECDA segment is at the start, one-third distance, two-third distance and ending distance. (ALE – see Attachment 7.7, A-206 – see Attachment 7.8).

This exceeds the requirements of NACE RP0502.

B. Tie physical survey measurements to known aboveground features and take GPS readings to increase confidence in accurately locating defects for future activities (direct examinations). (BT-1 – see Attachment 7.9 and 7.10).

This exceeds the requirements of NACE RP0502.

C. Locate and mark pipeline route with depth-of-cover measurements (location instrumentation) at 100 foot minimum spacing. (BT-1 – see Attachment 7.11 and A-206 – see Attachment 7.12).

This exceeds the requirements of NACE RP0502.

D. Use of a third tool for part of a survey. (ALE – see Attachment 7.4).

Same as the third example item above from FAQ 242.

III. Direct Examination

A. Complete soil chemistry and soil resistivity measurements for all dig sites including validations digs. (ALE – see Attachment 7.14, BT-1 – see Attachment 7.15, and A-206 – see Attachment 7.16).

This exceeds the requirements of NACE RP0502.

The documentation referenced above was available at time of audit.

To better reflect actual practices, CEGT has revised its ECDA procedures to identify the more restrictive criteria CEGT applies when conducting ECDA.

Proposed Compliance Actions and Proposed Penalty

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV. CEGT does not believe that a penalty was appropriate in this situation.

8. § 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) Preassessment. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to –

- **i. All data elements listed in Appendix A2 of ASME/ANSI B31.8S;**

CE's ICDA plan did not adhere to the requirements of their own procedures and Appendix A2 of ASME/ANSI B31.8S. CE Procedures PS-03-01-238, "Dry Gas – Internal Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance', Appendix A require ICDA feasibility be performed in the preassessment step; and no feasibility evaluation results were documented on the ICDA preassessments performed on lines FT-11 and ADT-8 that were completed prior to the inspection. CE did not document the results of the feasibility analysis, and there was not sufficient evidence to conclude that the lines selected for ICDA met the ICDA criteria. CE did not provide sufficient documentation to support the use of ICDA on the lines reviewed. CE did not document the basis for selecting the feasibility criteria for pigging, water upsets, and introduction of sludge In Figure 2, "DG-ICDA Feasibility Filter" of procedure PS-03-01-238, "Dry Gas – Internal Corrosion Direct Assessment," there are several numerical values for some of the feasibility issues, such as "Routine pipeline pigging (more than 3 times per year)," etc. but there is no explanation on where these values come from or how they are to be generated.

Based on a review during the inspection of the data elements for lines FT-11 and ADT-8, the data was of poor quality, and CE did not review the data as required in their procedures. During the review of several ICDA preassessments, data quality was determined to be poor or data was missing. CE procedures PS-03-01-238, "Dry Gas – Internal Corrosion Direct Assessment," PS03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A require that the data elements used for ICDA be gathered. This poor quality data could lead to incorrect critical angles being calculated and to ICDA regions being improperly determined.

<u>NOPV Item 8 -- CenterPoint Response</u>

<u>Feasibility</u>

ICDA feasibility was performed and documented for the pipeline segments in question. Attachment 8.1 shows a feasibility flow chart from the preassessment for Line FT-11 dated March 2005. The flow chart documents that FT-11 met the feasibility criteria. Attachment 8.2 shows a feasibility flow chart for ADT-8 from the March 2005 preassessment. ADT-8 passes the feasibility criteria. Attachment 8.3 shows the ICDA feasibility filter contained in CEGT Procedure PS-03-01-238 Section 3.3.9. All of these documents were available at time of audit, but CEGT believes these documents were not reviewed with the PHMSA auditors.

Numerical values used in Table 2 and Figure 2 in CEGT Procedure 03-01-238 (see Attachment 8.4, pages 12 and 13) were developed as follows:

- "Frequent running of cleaning pigs" is defined as running the pig more than three times in a year. The number was established by company subject matter experts. CEGT is unaware of any industry guidance on this issue.
- A water content above 7 lb/mmscfd was based on the company's FERC gas quality tariff specification.
- "Frequent upsets" is defined as more than one upset per quarter. An upset is excessive water entering the pipeline (see procedure PS-03-01-238, Section 3.3.8). The definition of "frequent" upsets was established by company subject matter experts. CEGT is not aware of any industry guidance on this issue.

Data Quality

CEGT had the necessary data to correctly calculate critical angles and properly determine ICDA regions. This information was available at the time of the audit, but CEGT does not believe it was reviewed with the auditors. The information had also not been transferred from the source documents to the ICDA Data Element Form at the time of audit.

Attachments 8.5 through 8.12 show the source documents used in system analysis for FT-11 and ADT-8 respectively. System analysis is an overall review of the pipeline system to identify inputs, outputs and flow directions in determining initial DG-ICDA regions on the pipeline. Included in Attachments 8.5 and 8.12 are the following:

- A diagram of the pipeline system to identify pipeline inputs (see Attachments 8.5 and 8.6).
- Gate maps with details on input and output facilities showing unidirectional or bidirectional flow that could result in additional DC-ICDA regions (see Attachments 8.7 and 8.8).
- System maps to identify initial DG-ICDA regions (see Attachments 8.9, 8.10, 8.11, and 8.12).

Attachments 8.13 through 8.26 show the source documents used for calculating critical inclination angles for FT-11 and ADT-8 respectively. Integration of system analysis, preassessment data, flow modeling and pipeline elevation profile is used to determine low spots, critical inclination angles and dig locations. These source documents are as follows:

- Preassessment form (see Attachments 8.13 and 8.14).

- Detailed maps / diagrams for pipeline DG-ICDA regions which locate potential low spots in HCAs (see Attachments 8.15 and 8.16).
- Meter station list identifying the input and output meter stations and flow volumes used for flow modeling calculations (see Attachments 8.17 and 8.18).
- Gas analysis used to validate gas quality (see Attachments 8.19 and 8.20).
- Pipeline Elevation Profile using Global Positioning System / Real Time Kinetics (GPS/RTK) sub-centimeter accuracy land elevation profile with depth of cover survey performed concurrently for accurate spatial alignment (see Attachments 8.21 and 8.22). The GPS/RTK survey CEGT performs is the heart of CEGT's ICDA process. CEGT procedure 238, Appendix A (see Attachment 8.23) provides detail on the CEGT GPS/RTK survey requirements as well as other aspects of the ICDA process to determine critical location angle.
- Calculation of critical inclination angle and water hold-up locations (see Attachment 8.24, "Dry Gas – Internal Corrosion Direct Assessment" procedure PS-03-01-238 Section 4.4 "Flow Model Calculations").
- DG-ICDA integration plot showing aerial photography image, ground elevation profile, pipe elevation profile, HCA locations, depth of cover, calculated water hold-up locations, calculated critical inclination angles, graph of inclination angles and pipeline stationing. (see Attachments 8.25 and 8.26).

The attachments show that, at the time of the audit, CEGT had the necessary data quality to correctly calculate critical angles and properly determine ICDA regions. The quality of this data was not "poor."

Proposed Compliance Actions

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.

9. § 192.927 (c) (see above)

(5) Other requirements. The ICDA plan must also include –

ii. provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience:

CE did not document where the more restrictive criteria were used in their ICDA plan, as required by §192.927, and which are required when conducting ICDA for the first time on a covered segment. These more restrictive criteria are for preassessment, indirect inspection, direct examination, and post assessment steps of the ICDA process. CE procedures PS-03-01-238, "Dry Gas – Internal Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A describe how ICDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. These plans and procedures reference the ASME B31.8S for ICDA assessment requirements and §192.927. Although not referenced, the draft NACE RP on Dry-Gas ICDA was also utilized. The CE procedures do not document the more restrictive criteria as required in §192.927(b)(5)(iii) for each of the four steps undertaken on an initial ICDA on a region or a segment. The rule is clear that these criteria must be documented. CE also did not document how the more restrictive criteria were applied in ICDAs for lines FT-11 and ADT-8.

<u>NOPV Item 9 -- CenterPoint Response</u>

At the time of the audit, CEGT used more restrictive criteria than required by Subpart O when performing ICDA for the first time. Although the criteria were not specifically identified as being "more restrictive criteria" at the time of the audit, CEGT used and documented such criteria.

The more restrictive criteria used for the FT-11 and ADT-8 pipeline segments are as follows:

I. Preassessment

A. Coordination with CEGT local operations personnel to consult on validation of conditions. (FT-11 – see Attachment 9.1, and ADT-8 – see Attachment 9.2).

This is similar to the ECDA more restrictive criteria example in FAQ 242 to "data mine" with local maintenance personnel.

II. Indirect Inspection

A. Pipeline Elevation Profile Process: Land surface elevation survey (GPS/RTK) conducted concurrently with depth-of-cover survey (electronic pipe location/depth instrumentation) to produce accurate pipeline elevation profile data. (FT-11 – see Attachment 9.5, and ADT-8 – see Attachment 9.6).

GPS/RTK is sub-centimeter elevation data coupled with measured pipeline depths of cover. FAQ-193 states "operators can use the draft NACE standard (ICDA) as guidance." The draft NACE standard allowed the use of USGS ground elevation data for determination of critical angles and water hold-up locations.

B. Data integration plot of several data items combined on a single page to graphically display the data. The goal is to make evaluation easier and more effective. (FT-11 – see Attachment 9.3 and ADT-8 – see Attachment 9.4).

The data integration plot exceeds the Subpart O requirements.

III. Direct Examination

A. Utilize Long Range Guided Wave Ultrasonic (LR-GWUL) technology as a screening tool to assist in identifying locations for application of in-depth NDT evaluation for evidence of internal corrosion. (FT-11 – see Attachment 9.7, and ADT-8 – see Attachment 9.8).

LR-GWUL screening exceeds the requirements of Subpart O.

To better reflect actual practices, CEGT has revised its ICDA procedures to identify the more restrictive criteria CEGT applies when conducting ICDA.

The Notice seems to require that a pipeline develop four different sets of "more restrictive criteria" – one set for each step of the ICDA process. The Notice states, "[t]hese more restrictive criteria are for preassessment, indirect inspection, direct examination, and post assessment steps of the ICDA process." However, the requirement to establish "more restrictive criteria" applies generally to the ICDA process; it does not necessarily apply at each of the four ICDA steps. Thus, a pipeline has discretion under the regulations to apply "more restrictive criteria" at a single step in the ICDA process, such as the preassessment step, and the pipeline need not apply such criteria at each of the four ICDA steps.

This interpretation of the regulations is supported by comparing the ICDA regulations (Section 192.927) to the ECDA regulations (Section 192.925). Section 192.927 describes the actions that must be taken at each ICDA step in Section 192.927(c)(1) (preassessment), (c)(2) (ICDA region identification), (c)(3) (identification of locations for excavation and direct examination) and (c)(4) (post-assessment evaluation). If PHMSA had intended for a pipeline to apply "more restrictive criteria" to each of these ICDA steps, the requirements would have been placed in these provisions, which are specific to each step. For example, in the ECDA regulation, Section 192.925, the need to apply "more restrictive criteria" is listed as a requirement for three of the four specific ECDA steps. See Sections 192.925(a)(1)(i) (ECDA preassessment), (a)(2)(i) (ECDA indirect examination) and (a)(3)(i) (ECDA direct examination). But the ICDA step-specific regulations do not require the application of "more restrictive criteria."

Rather, in the ICDA regulations, the "more restrictive criteria" requirement is contained in Section 192.927(c)(5) ("other requirements"), which applies to the ICDA process generally, not to each separate step in the ICDA process.

Proposed Compliance Actions

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.

10. §192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(b) General Requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for –
(1) Data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S, Appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified to ASME/ANSI B31.8S, Appendix A3.

CE's SCCDA plan does not require the gathering and evaluating of data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC. CE procedures PS-03-01-240, Stress Corrosion Cracking Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A describe how SCCDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. None of these procedures mandate that CE obtain data on non-covered pipelines that may be susceptible to SCC as required in **§**192.929.

Based on some of the data elements in CE's SCCDA program that were inspected, CE did not review the data as required in their procedures. CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, IMP Quality Assurance", Appendix A require that the data elements used for SCCDA be gathered. During the review of SCCDA preassessment, data quality was determined to be poor or missing. B31.8S, Section A3 3 states, "Where the operator is missing data, conservative assumptions shall be used when performing the risk analysis or alternatively the segment shall be prioritized higher."

CE's IMP does not provide for notification to PHMSA regarding its near-neutral SCC plan. ASME B31.8S, Section A31.1 states, "Near neutral type of SCC similarly would require an inspection and alternative mitigation plan." CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," require CE to notify PHMSA and/or local regulatory authorities if CE Plans to use "Other Technology" as defined in **§**192.921 (a)(4) (and follow the notification procedure in **§**192.949). ASME B31.8S for SCCDA covers only high pH SCC and requires operators to develop a plan for near neutral pH SCC, which CE has done by following the procedure in NACE RP 0204 for near neutral SCC. This recommended practice is not referenced in the rule and thus is considered an "Other Technology". As such, CE must notify PHMSA and/or local regulatory authorities 180 days before proposing to use the technology. CE has not yet used its near neutral pH SCCDA process nor has it notified any regulatory authority.

CE's IMP does not specify the performance of a spike test, per ASME B31.8S, when it has experienced an in-service leak or rupture attributable to SCC. ASME B31.8S, Section A3 4 states, "If the pipeline experiences an in-service leak or rupture, which is attributed to SCC, the particular segment shall be subjected to a hydrostatic test (as described below) within 12 months." CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment, and PS 03-01-230, "Direct Assessment Plan", state that CE can use a pressure test to check for SCC. There is no procedure requirement to perform a spike test following an in-service leak or rupture attributable to SCC. ASME B31.8S specifically mandates that operators use a spike hydrostatic pressure test following an in-service leak or rupture attributable to SCC.

NOPV Item 10 -- CenterPoint Response

Data Gathering and Integration

Section 192.929(b)(1) of the regulation discusses SCC data gathering and integration. At the time of the audit, CEGT O&M Procedures 209 and 504 required the inspection and documentation of pipe conditions when a buried pipeline was exposed. The pipe inspection requirement fits better in the CEGT O&M Manual of Procedures than the Integrity Management Program because the O&M Manual applies to all sites excavated as part of normal operations as well as to integrity assessments. See Attachment 10.1 for O&M procedure 209 and Attachment 10.2 for O&M Procedure 504. The SCCDA procedure in the Integrity Management Program focuses only on how to perform the integrity assessment.

O&M Procedure 209 states that documentation of pipeline inspections is found in the Maintenance Management System, a computer application. CEGT has an instruction manual that provides detailed instructions for completing the required record. See

Attachment 10.3 for the "Pipe Inspection / Atmospheric Corrosion Form Instructions" manual. Data fields on the form include the SCC-related items below:

- Pipe diameter
- Wall thickness
- Grade
- MAOP
- Coating type
- Coating condition
- Pipe-to-soil potential at the pipe
- Pipe-to-soil potential at the surface
- Cathodic protection type
- Type of inspection made
- Condition of external pipe surface
- Type of soil

Data that can be collected in the ditch is recorded in the company's maintenance management computer system. Other information required for SCC under B31.8S A.3.2, such as age of pipe, that is not available in the ditch is found elsewhere in company records. CEGT's procedures at the time of audit did not specifically call for evaluation of data at sites where criteria indicate the potential for SCC. CEGT has revised its Integrity Management procedures to evaluate data related to SCC at all excavation sites where criteria indicate the potential for SCC.

SCCDA Preassessment

Attachment 10.4 is the SCCDA preassessment form completed for an HCA segment on Line ML3 HCA. CEGT believes that this document was reviewed by PHMSA during the audit. This segment had previously been assessed with an MFL tool and a geometry tool. The title of the form is "ECDA Data Element Form" because the Line ML3 assessment was one of the first SCCDA preassessments CEGT performed, and the format of the SCCDA form was carried over from the ECDA assessment form. The title was changed on subsequent SCCDA Data Element forms. The ML3 form is complete, and data are recorded in the columns, remarks, and the "Use and Interpretation of Results" sections.

CEGT performed indirect inspections – CIS, DCVG, PCM – on the entire HCA segment before choosing dig locations, which is not a requirement of NACE RP0204 Stress Corrosion Cracking (SCC) Direct Assessment Methodology. NACE RP0204, Section 5.1.1 (see Attachment 10.5) directs the pipeline operator to "examine pipe at locations chosen after preassessment step." CEGT decided to perform indirect inspections to better integrate data with ILI indications.

The Close Interval Survey (CIS) data is shown in Attachment 10.6. The Pipeline Current Mapper (PCM) survey data is shown in Attachment 10.7. The Direct Current Voltage Gradient (DCVG) survey data is shown in Attachment 10.8. The depth of cover survey is shown in Attachment 10.9. The indirect inspection data integration plot, which brings the survey data together and spatially aligns it on one page, is shown in Attachments 10.10 and 10.11.

MFL tool results were reviewed along with preassessment data and indirect survey results when choosing direct examination locations. The MFL results for the HCA segment are shown in Attachment 10.12.

A summary of the indirect inspection survey results and the dig sites selected for direct examination are shown in Attachment 10.13. The attachment also shows the distance to each dig site from an aboveground reference point. This information is developed as part of the indirect inspection step and allows accurate location of the dig sites.

CEGT performed four digs for SCCDA in the 2,620-foot covered segment. There is no guidance in NACE RP0204 on number of digs to perform for SCCDA.

Attachment 10.14 documents the direct examination that was completed for one of the SCCDA digs in this segment. The documentation includes a cover sheet, Coating Defect Table and the SCCDA section. Magnetic Particle Inspection (MPI) was performed and no indications were found. Attachment 10.16 is a picture of a dig site where MPI is being performed.

Attachment 10.15 documents the direct examination that was completed for an ILI dig on this ML3 segment outside of the HCA. The documentation includes a cover sheet, Coating Defect Table and the SCCDA section. MPI was performed and no indications were found.

At the time of the audit, this data was not missing and was not of "poor quality."

Other Technology Notification

FAQ 223 Data Gathering to support SCCDA, dated March 9, 2005, addresses the following question: "What kind of data must I collect and evaluate to use stress corrosion cracking direct assessment (SCCDA)?" The last paragraph of the FAQ states, "[a]t this time, use of DA for near-neutral SCC is considered 'other technology'. This could change if OPS adopts the new recommended practice, but rulemaking will be required to do so." See Attachment 10.21 "FAQ #223".

This FAQ is inconsistent with the regulations, ASME B31.8S, and other FAQs. Part 192, Subpart O was issued December 15, 2003. The regulation requires a written framework to be in place by December 17, 2004. Section 192.921 of Subpart O lists four assessment methods:

1. Internal inspection tool;
2. Pressure test;
3. Direct assessment "to address threats of external corrosion, internal corrosion and stress corrosion cracking;"
4. Other Technology that an operator demonstrates can provide an understanding of the condition of the pipe that is equivalent to the understanding gained from the use of internal inspection tools, pressure tests or direct assessment.

This regulation supports the conclusion that direct assessment for SCC, which is listed in Section 192.921(a)(3), is not an "Other Technology," which is listed in Section 192.921(a)(4). Section 192.929 is entitled "What are the requirements for using direct assessment for stress corrosion cracking?" If PHMSA had intended that direct assessment for SCC be an "Other Technology," PHMSA would have expressly required such treatment for direct assessment for SCC in Section 192.929.

ASME B31.8S, Section A3.1 (see Attachment 10.18) states, "[n]ear neutral type of SCC similarly would require an inspection and alternative mitigation plan." The phrase "alternative mitigation plan" does not indicate that an "Other Technology" filing would be needed.

FAQ # 46 Acceptable assessment methods, dated 10-2-2004, states "[i]nternal inspection, pressure testing, and direct assessment are acceptable methods to assess pipeline integrity (192.921(a), 192.937(c)). However, the method(s) selected must be appropriate to address the identified threats to the line being assessed. (Thus, for example, direct assessment can only be used where the threats are external or internal corrosion or stress corrosion cracking)". See Attachment 10.17 "FAQ #46".

FAQ # 97 Notifications – types, dated 6-29-2004, states "[t]he notifications required by the rule are . . .. Use of technology other than in-line inspection, Direct Assessment, or pressure testing for conducting assessments". See Attachment 10.19 "FAQ #97".

FAQ # 40 Frequency of Assessments, dated 10-20-2004 and revised 5-3-2006, states "[a]ssessments for all threats must be performed using in-line inspection, pressure testing, direct assessment, or 'other technology' within the maximum intervals specified[.]" See Attachment 10.20 "FAQ #40".

Like the rules themselves, these FAQs lead CEGT to conclude that a pipeline would not need to make an "Other Technology" filing to implement SCCDA. Based on this guidance, and given the apparent conflicts between FAQ #223 and other guidance, CEGT does not believe it is appropriate for this issue to be a NOPV Compliance Order item.

After receiving the NOPV, CEGT submitted an Other Technology Notification to PHMSA on July 18, 2007 to use consensus standard NACE RP0204-2004 "Stress Corrosion Cracking (SCC) Direct Assessment Methodology" for near-neutral SCCDA on segments of CenterPoint's MRT Eastline. CEGT notes that there were no Other Technology Notifications for near-neutral SCCDA on the PHMSA website prior to June 2007.

The proposed finding states "CE procedures PS-03-01-240, 'Stress Corrosion Cracking Direct Assessment,' and PS-03-01-230, 'Direct Assessment Plan,' require CE to notify PHMSA and/or local regulatory authorities if CE Plans to use 'Other Technology' as defined in §192.921 (a)(4) (and follow the notification procedure in §192.949)". CEGT procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," and PS-03-01-230, "Direct Assessment Plan" do not require CEGT to notify PHMSA and/or local regulatory authorities if CEGT plans to use "Other Technology". Other Technology notification is referenced in procedure PS-03-01-264 IMP Communication Plan, Section 2.3 (see Attachment 10.23).

Hydrostatic Testing

ASME B31.8S, Appendix A3.4.b, (see Attachment 10.22) discusses hydrostatic testing for SCC as follows:

> *A3.4.b Hydrostatic Testing for SCC. Hydrostatic testing conditions for SCC mitigation have been developed through industry research to optimize the removal of critical-sized flaws while minimizing growth of subcritical-sized flaws. Recommended hydrostatic test criteria are as follows:*
>
> 1) *high-point test pressure equivalent to a minimum of 100% SMYS*
> 2) *target test pressure shall be maintained for a minimum period of 10 min*
> 3) *upon returning the pipeline to gas service, a flame ionization survey shall be performed (Alternative may be considered for hydrostatic test failure events due to causes other than SCC.)*

ASME B31.8S, Appendix A3.4.b does not use the phrase “spike test.” To avoid any confusion, when developing its procedures, CEGT decided to adopt the same language as used in ASME B31.8S, Appendix A3.4.b. CEGT IMP Procedure PS-03-01-240 Stress Corrosion Cracking (SCC) Direct Assessment states the following concerning hydrostatic (pressure) testing:

7.4.6 Recommended hydrostatic test criteria are:

A. High point test pressure shall be equivalent to a minimum of 100% SMYS

B. Target test pressure shall be maintained for a minimum period of 10 minutes

C. Upon returning the pipeline to gas service, a flame ionization survey shall be performed. (Alternatives may be considered for hydrostatic test failure events due to causes other than SCC).

The issue is not whether CEGT's procedures require a "spike" test. The issue is whether CEGT's procedures comply with ASME B31.8S, Appendix A3.4.b. Because CEGT Procedure PS-03-01-240 Stress Corrosion Cracking Direct Assessment implements the same testing requirement as contained in ASME B31.8S, Appendix A3.4.b, CEGT's procedures use the appropriate test.

Proposed Compliance Actions

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.

11. § 192.935 What additional preventive and mitigative measures must an operator take?

> **Automatic shut-off valve (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the even of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors – swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.**
>
> CE did not follow its procedure requiring that an analysis completed in conjunction with the annual assessment inspection shall result in documentation of results for any feasibility analysis of alternatives, including the installation of ASVs and RCVs. The operator did not provide any documented technical justification either to install or not to install ASVs or RCVs. CE's procedure PS-03-01-258, "Preventive and Mitigative Measures," specifies that the operator shall document all action considered and taken to enhance public safety and/or environmental protection as identified from the risk assessment and/or specific threat factors on each of the HCA pipeline segments. The flow charts provided to the inspection team for preventive and mitigative evaluations did not take into consideration segment specific risk data when determining measures to implement. CE confirmed in discussions that rather than review each segment individually for preventive and mitigative measures that they applied more "global" preventive and mitigative decisions across this system.

<u>NOPV Item 11 -- CenterPoint Response</u>

CEGT performed an analysis on each covered segment to evaluate use of ASVs and RCVs. CEGT documented its analyses in a spreadsheet that contains the analysis and the results for each covered segment. This documentation was available at the time of the audit (see Attachment 11.1 "ASV/RCV Evaluation").

CEGT made a PowerPoint presentation during the audit at the beginning of the Preventive and Mitigative measures review that described the company's approach to

ASV / RCV analysis, including the criteria used. An electronic version was given to the auditors (see Attachment 11.2 "ASV/RCV Presentation").

In performing ASV/RCV analyses, CEGT evaluated each covered segment for preventive and mitigative measures, and considered threats identified through risk analysis. CEGT did not apply global decisions to segments. Each HCA segment was separately evaluated and P&M measures were documented. See Attachment 11.3 for an example of a P&M flow chart in use at the time of audit for an HCA segment.

<u>Proposed Compliance Actions</u>

Although CEGT believes that its procedures satisfied the requirements of the regulations and the applicable engineering standards at the time of the audit, CEGT has revised its procedures going forward to address the concerns identified by PHMSA. CEGT believes that this issue could have been, and should have been, addressed through an NOA rather than an NOPV.