



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 20, 2008

Mr. Allan Schneider
Vice President, Engineering and Operations
Enbridge Midcoast Energy, L.P.
1100 Louisiana
Suite 3300
Houston, TX 77002

CPF 4-2008-1010M

Dear Mr. Schneider:

On February 6 – 10 and February 27 – March 3, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code inspected Enbridge Midcoast Energy, L.P. procedures for Integrity Management in Houston, Texas.

As a result of the inspection, it appears that your written procedures are inadequate to assure safe operation of the pipeline as follows:

1. §192.905(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method for its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.)

Enbridge must amend its HCA identification process and procedures to ensure that they adequately describe how to identify HCAs. The amended HCA identification process must include:

- Individuals responsible for the various aspects of the HCA identification process
- The Criteria of the HCA identification process
- Data/information/resources required to complete the HCA identification
- Quality control measures necessary to ensure that the HCA identification is complete and accurate
- Description of how key elements of the HCA identification are documented
- Techniques to ensure that the limitations and inaccuracies of the system maps used for documenting the pipeline HCA segment locations are appropriately considered
- Steps to include facilities in the HCA identification process
- Information from routine operation and maintenance activities and input from public officials.

2. §192.905(c) Newly-identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

Enbridge must amend its HCA identification process and procedures to adequately describe how to identify newly identified areas as possible high consequence areas. The procedures must adequately describe the requirements to obtain information concerning changing conditions along the pipeline that may require HCA updating and a process for updating the HCA identification that addresses:

- Who owns/is responsible for the various aspects of the HCA update process
- What are the criteria of the update process
- What data/information/resources are required to complete the HCA update (e.g., changes to building use, new identified sites)
- How is the HCA update to be completed
- When or how often is the HCA update to be completed (24 months is too long)
- How are key elements of the HCA update documented
- How is the HCA update documentation maintained
- How are HCA update outputs/results communicated to Compliance and Systems Integrity

3. §192.919(b) Methods. The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity

assessment method an operator uses must be based on the threats identified to the covered segment. (See §192.917.) More than one method may be required to address all the threats to the covered pipeline segment.

§192.921(a)(1) Internal inspection. Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

Enbridge's IMP process and procedures addressing methods selected to assess the integrity of the line pipe must be amended to adequately address the sequence of actions, criteria and methods needed to ensure that the selection process is effective. The process must include detail for the sources of information necessary to perform the selection process and responsibilities within the various organizations for completing and reviewing the assessment selections and ensure that appropriate tool selections are properly defined.

4. §192.919(a) Threats. Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917).

Enbridge must amend its threat identification process and procedures to ensure that assessments on "idle" lines are not being deferred. Enbridge must define "idle" pipe and ensure that their potential threats are being reviewed.

5. §192.919(e) Risk minimization procedure. A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

Enbridge must amend procedures that address safety and environmental risks during the performance of assessments and hydrotest procedures in the company's Safety and Health Manual to ensure that Hydro test procedures address safety precautions (such as those described in Advisory Bulletin ABD-04-01) and that these procedures have a direct link to the IM plan.

6. §192.917(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 (lbr, 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.

Enbridge must amend its Threat identification process and procedures to ensure that there is consideration of interactive threats for each covered pipeline segment. The process must ensure that those decisions on integrity assessment methods are made based on a full evaluation of the threats to each covered segment. The amended procedures must ensure that specific threats for a particular pipeline segment are not eliminated from consideration without adequate justification. Additionally, the amended procedures must ensure that the threat identification flow chart for SCC addresses criteria for near-neutral SCC.

7. §192.917(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

Enbridge must amend its Data gathering and integration process and procedures to ensure the consistent use of the required data such as age, resolution, units of measure, accuracy of location data, quality of data including all steps in the assembly, analysis, and application of data. The amended plan must ensure that the process and procedures describes how required data elements will be consistently obtained and incorporated in risk assessment and threat identification for covered segments. The Data gathering and integration amended procedures must describe how missing data will be treated consistently in the BTS-IMP risk scoring, and the process should trigger additional data collection or analysis in cases where important data are missing. The Data gathering and integration amended procedures must require the integration of encroachment and foreign line crossing location data with ILI or ECDA results to locate areas of potential third party damage.

8. §192.917(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. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

Enbridge must amend its Risk Assessment process and procedures to ensure that they describe how risk results are established and used to prioritize

pipelines/segments for scheduling of integrity assessments and mitigating actions; determine the benefit derived from mitigating actions; determine the most effective mitigative measures for the identified threats; determine the integrity impact from modified inspection intervals; determine the use of or need for alternative inspection methodologies will be incorporated; and facilitate decisions to address risk along a pipeline or within a facility. Additionally, the procedures must adequately address the following:

- The Risk Assessment amended procedures must require that it includes sufficient resolution of pipeline segment size and should consider its potential applicability to leak/incident data on other segments with similar characteristics in order to analyze data as it exists along the pipeline.
- The Risk Assessment amended procedures must ensure that a system-wide re-evaluation shall be performed at least annually.
- The Risk Assessment amended procedures must specifically describe a risk validation process that shall be identified and documented in the integrity management program.

9. §192.917(e)(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 B31.8 S, 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.

Enbridge must amend its threat identification process and procedures to ensure that assessment method(s) for pipe that is susceptible to manufacturing or construction defects (including low frequency electric resistance welded pipe or lap welded pipe) are appropriately selected. The amended process must not limit consideration of leaks due to seam issues to ten years and only to the specific segment under consideration. Pressure history of the entire segment containing the HCA must be considered in the seam determination process. Additionally, the amended procedure must ensure that sufficient data will be documented to make a determination as to the susceptibility of the segments to the LF ERW seam threat.

10. §192.925(b)(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; and

- ii. **The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502-2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.**

Enbridge must amend its ECDA pre-assessment process and procedures to include a definition of minimum data requirements based on the history and condition of the pipeline segment and identify data elements that are critical to the success of the ECDA process. These procedures must define the criteria for conducting the feasibility assessment, the selection of two complementary tools and other tools not listed in the NACE table. Additionally, the procedures must define what more restrictive criteria would be used when conducting ECDA pre-assessment for the first time on a covered segment.

11. §192.925(b)(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;**
- ii. **Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;**
- iii. **Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and**
- iv. **Criteria for scheduling excavation of indications for each urgency level.**

Enbridge must amend its ECDA Indirect Examination process and procedures include a process for adjusting the specified spacing for tool application during different field conditions. The process must adequately compare the results for consistency and compare results with the pre-assessment results and prior history for each ECDA region. Additionally, the procedures must adequately address the following:

- The impact of spatial errors when aligning indirect examination results
- Define a criteria for classifying the severity of each indication
- Integrating ECDA data with encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage
- A process to address pipeline coating indications

- Specifying more restrictive criteria when conducting ECDA In-direct Examination for the first time

12. §192.925(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 -

- Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
- Criteria for deciding what action should be taken if either: (A) corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502-2002), or (B) root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502-2002);.
- Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and
- Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502-2002.

Enbridge must amend its ECDA Direct Examination process and procedures to ensure the ECDA procedures require the performance of an evaluation of the indirect inspection data, the results from the remaining strength calculation, and root cause analysis to evaluate the criteria and assumptions used to categorize the need for repairs and classify the severity of individual indications. Additionally, the procedures must adequately address the following:

- Requirements for a root cause analysis of all significant corrosion activity and evaluations of all other indications that occur in the pipeline segment where similar root cause conditions exist
- Requirements to mitigate or preclude future external corrosion resulting from significant root causes
- A process to reclassify and reprioritize indications in accordance with the provisions specified in NACE RP0502, Section 5.9
- Requirements to consider the use of assessment methods other than ECDA (e.g., ILI or pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage, SCC) discovered during direct examination
- Specifying more restrictive criteria when conducting ECDA Direct Examination for the first time

13. §192.925(b)(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002,

section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

- i. Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and
- ii. Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE RP0502-2002.)

Enbridge must amend its ECDA Post assessment and continuing evaluation process and procedures to provide requirements for determining reassessment intervals in accordance with NACE RP0502. The procedures must provide specific criteria or guidance for performing the post assessment and ensuring feedback at all appropriate opportunities throughout the ECDA process to demonstrate feedback and continuous improvements.

14. §192.927(c)(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. **(c)(1)(iv) *Other data.*** Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

Enbridge must amend its ICDA pre-assessment process and procedures to include requirements to collect some of the data elements and information specified in B31.8S (e.g., pipe inspection reports). The ICDA procedure must contain added specificity regarding the collecting of information where deposits are collected during maintenance pigging operations. Additionally, these procedures must discuss how to use data integration to analyze and evaluate the feasibility of performing ICDA on pipe segments and identification of ICDA regions.

15. §192.927(c)(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further

downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must -

- **(c)(3)(i) Evaluate severity.** Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with **§192.933**;
- **(c)(3)(ii) Additional excavation or assessment method.** As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and
- **(c)(3)(iii) Evaluate system-wide implications.** Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with **§192.933**.

Enbridge must amend its ICDA Identification of locations for excavation and direct examination process and procedures to ensure that the ICDA plan requires a direct examination for internal corrosion using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique of those covered segment locations where internal corrosion is most likely to exist. The procedure must include as a minimum, the following:

- A minimum of two (2) locations within each ICDA region within a covered segment
- At least one location must be the low point (e.g., sags, drips, valves, manifolds, deadlegs, traps) nearest the beginning of the ICDA region
- The second location must be further downstream within a covered segment near the end of the ICDA region
- The severity of the defect be evaluated and remediated per §192.933 requirements. Section 6 of the direct examination procedure (CP-110) contains an erroneous reference with respect to defect repair criteria and must be corrected and the timeliness of repairs must be addressed
- if internal corrosion is found at any location directly examined; the operator will either perform additional excavations or perform additional assessment using an allowed alternative assessment method
- The ICDA plan must require the operator to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found

16. §192.927(c)(4) Post-assessment evaluation and monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes:

- i. **Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and**
- ii. **Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.**
 - **conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or**
 - **assess the covered segment using another integrity assessment method allowed by this subpart.**

Enbridge must amend its ICDA Post-assessment evaluation and monitoring process and procedures to ensure that the ICDA plan requires that the ICDA procedures contain criteria for evaluating the effectiveness of ICDA as an assessment method. Specifically, the procedures must address situations if corrosion is found in areas where the pipeline inclination is greater than the estimated critical inclination, that the operator re-evaluates the critical inclination angle, and additional new areas are selected for direct examination. Additionally, the procedures must adequately address the following:

- The ICDA procedures must require that the reassessment interval determination be carried out within one year of completion of the assessment. These ICDA procedures need to be linked to the reassessment interval criteria contained in the IMP.
- The ICDA procedures must specifically address requirements to continually monitor each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, and periodically drawing off liquids at low points and chemically analyzing them for corrosion products.
- The ICDA plan must incorporate a process to determine the frequency for monitoring and liquid analysis based on all integrity assessments results conducted in accordance with 192 Subpart O and risk factors specific to the covered segment.
- The ICDA procedures must specifically require that if any evidence of corrosion products is found in the covered segment, prompt action must be

taken including, as a minimum: Remediate the conditions the operator finds in accordance with §192.933, and Implement one of the two following required actions: (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.

17. **§192.927(c)(5) Other requirements.** The ICDA plan must also include -
- i. **Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;**
 - 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; and**
 - iii. **Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.**

Enbridge must amend its ICDA plan processes and procedures to ensure that their ICDA plan includes criteria to be applied in making key decisions (e.g., reassessment interval determination, techniques for monitoring internal corrosion, and region identification) in implementing each stage of the ICDA process. Additionally, the plan must include provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment.

18. **§192.933(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.

Enbridge must amend its Discovery of Condition process to ensure that the in-line inspection procedures contain or reference the requirements for "discovery" as they are contained in the IM program document.

19. **§192.933(d)(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 ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991); AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)); 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.**

Enbridge must amend its Immediate Repair Conditions process to ensure that the In-line inspection procedure (PI-104) includes all of the IM rule's immediate repair criteria as they are contained in Section 5 of the IMP.

20. §192.933(d)(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 demonstrate 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.**

Enbridge must amend its Monitored Conditions process and procedures to describe how anomalies that are classified as "monitored conditions" will be recorded and monitored. Additionally, amended procedures must describe how Location Management will schedule and remediate/re-examine anomalies in accordance with Figure 4 of ASME B31.8S.

21. §192.937(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). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

Enbridge must amend its Integrity Evaluation process and procedures to specifically describe how these evaluations will be carried out using assessment results, data integration, risk assessment results, remediation data, and preventive/mitigative action information as required by §192.937(b). Additionally, amended procedures must specify the process for using this information to support determination of assessment intervals, assessment methods, or other integrity decisions and describe how Location Management will conduct these evaluations and apply the results.

22. §192.941(b) External Corrosion. An operator must take one of the following actions to address external corrosion on the low stress covered segment.

- **(b)(1) Cathodically Protected Pipe.** Cathodically Protected Pipe. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- **(b)(2) Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys are Impractical.** Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys are Impractical. If an electrical survey is impractical on the covered segment an operator must -
 - i. Conduct leakage surveys as required by §192.706 at 4-month intervals; and
 - ii. Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

Enbridge must amend its external corrosion procedures for performing low stress reassessments. The procedure must be specific as required by §192.941(b) and it

must link these procedures to those that must be followed by location management when performing the low stress reassessment process.

23. §192.941(c) *Internal Corrosion.* To address the threat of internal corrosion on a covered segment, an operator must -

- 1) Conduct a gas analysis for corrosive agents at least once each calendar year;
- 2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and
- 3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)- (c)(2) with applicable internal corrosion leak records, incident reports, safety- related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

Enbridge must amend its internal corrosion procedures for performing low stress reassessments. The procedure must be specific as required by §192.941(c), and must link these procedures to those that must be followed by location management when performing the low stress reassessment process.

24. §192.939(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

Enbridge must amend its Integrity Evaluation process and procedures for establishing re-assessment intervals for ILI and pressure tests for pipelines operating at or above 30% SMYS in sections 6.2.2.1 and 6.2.2.2 of the Enbridge plan. The amended procedure must clearly reflect the rule requirements that the intervals always are based on a consideration of identified threats, completed assessment results, and the latest risk results. The procedure must also state that the intervals are subject to the maximums in ASME B31.8S, Table 3. The current IM plan implies that Location Management has a choice between these requirements in determining intervals.

25. §192.939(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum

reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following -

Enbridge must amend its Integrity Evaluation process and procedures for establishing re-assessment intervals for ILI and pressure tests for pipelines operating below 30% SMYS in sections 6.2.2.1 and 6.2.2.2 of the Enbridge plan. The amended procedure must clearly reflect the rule requirements that the intervals always are based on a consideration of identified threats, completed assessment results, and the latest risk results. The procedure must also state that the intervals are subject to the maximums in ASME B31.8S, Table 3. The current IM plan implies that Location Management has a choice between these requirements in determining intervals.

26. §192.943(b) *How to apply.* If one of the conditions specified in paragraph (a)(1) or (a)(2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

Enbridge's IMP Section 11.3 must be amended to ensure that it addresses the requirement to send any waiver to affected State regulatory authorities.

27. §192.931 *How may Confirmatory Direct Assessment (CDA) be used?* An operator using the confirmatory direct assessment (CDA) method as allowed in **§192.937** must have a plan that meets the requirements of this section and of **§§192.925 (ECDA)** and **§192.927 (ICDA)**.

Enbridge must amend the re-assessment section of the IM program to ensure that a process and procedures for using Confirmatory Direct Assessment are developed for implementation.

28. §192.935(a) *General Requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See **§192.917.**) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S, Section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel

on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

Enbridge must amend its section 7.2 of the IMP to ensure that evaluations of preventive and mitigative measures specify how these evaluations will use risk assessment results to identify measures and determine where they should be implemented. Additionally, the Enbridge amended IM plan shall specify how both likelihood and consequence will be considered, how the risk results will be used in a cost-benefit analysis, and what decision criteria will be used to determine which measures will be implemented.

29. §192.935(b)(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum-

- i. Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.**
- ii. Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.**
- iii. Participating in one-call systems in locations where covered segments are present.**
- iv. Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B318.S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.**

Enbridge must amend its section 7 of the IMP to clearly specify for pipelines operating below 30% SMYS located in a class 3 or 4 area and either in a high consequence area or not, how they will collect, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.

30. §192.935(b)(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

Enbridge must amend its section 7 of the IMP to clearly specify how Location Management will be implementing the outside force damage requirements.

31. §192.917(e)(5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.

Enbridge must amend its section 7 of the IMP to clearly specify its actions when corrosion is identified on a covered segment. The amended procedure must clearly indicate how the evaluation and remediation criteria will be consistently applied to pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.

32. §192.935(c) Automatic shut-off valves (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 event 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.

Enbridge must amend its IM plan in order to ensure that there is sufficient specificity in the process, based on risk analysis, for evaluating the installation of additional Automatic Shutdown/Remote Control valves.

33. §192.945(a) General. An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must

include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, see §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

Enbridge must amend their IMP Threat-specific performance metrics requirements to ensure that they are consistent with paragraph 192.945(a) and ASME B31.8S. The procedure must require that information must be collected and analyzed on a semi-annual basis as required by the IM rule.

34. §192.947(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

Enbridge must amend its IM process to require documents be developed and maintained to support the many decisions, analyses, and processes that are carried out to support the IM plan. Documents that must be included are those needed to support identification, calculation, amendment, modification, justification, deviation and determination made, as well as actions taken to implement and evaluate program elements.

- 35. §192.909 How can an operator change its integrity management program?**
- **(a) General.** An operator must document any change to its program and the reasons for the change before implementing the change.
 - **(b) Notification.** An operator must notify OPS, in accordance with section §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

Enbridge must amend its Management of Change (MOC) process to ensure that it adequately addresses requirements contained in ASME B31.8S, section 11. The process must ensure that significant changes to the IM program will be reported to PHMSA or State authorities as required by the IM rule. Additionally, changes to the

Integrity Management Program or changes to other operating manuals need to be reviewed by persons that can assess safety impact, assess IM program element impact, and determine if operating system/equipment changes are needed.

36. §192.911 What are the elements of an integrity management program? An operator's initial integrity management program begins with a framework (see CFR: 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S for more detailed information on the listed element.)

- I. A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.**

Enbridge must amend their quality assurance plan to ensure that the responsibilities and authorities under this program shall be clearly and formally defined. Additionally, their quality assurance plan shall ensure that, when they choose to use outside resources to conduct a process that affects quality of the IM program, the operator shall ensure control of such processes and document them within the company's quality assurance plan. The amended plan must show how this process will be implemented.

37. §192.915(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.**

Enbridge must amend their quality assurance plan to ensure that an organized system of tracking training requirements exists. The implementation process should be developed to ensure that all personnel that have IM responsibilities are continuously and adequately trained.

Response to this Notice

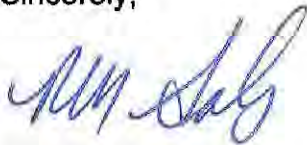
This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C.

552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In your correspondence on this matter, please refer to **CPF 4-2008-1010M** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,



R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*