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Southern Star Central Gas Pipeline, Inc.
3800 Frederica Street, Suite 200
P.O. Box 20010
Owensboro, Kentucky 42304-0010
Phone 270/852-5000

Subject: Response to PHMSA Notice of Amendment
CPF 4-2007-1012M

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

September 18, 2007

Dear Mr. Seeley:

Southern Star Central Gas Pipeline, Inc. (SSCGP) received the Notice of Amendment (NOA) dated August 20 on August 24, 2007. The NOA resulted from the inspection of the company's integrity management procedures performed in Owensboro, KY during September of 2006. In response to the NOA, SSCGP concurs with the findings of the PHMSA representatives who inspected our integrity management procedures.

At the time of the inspection, SSCGP was converting to a new pipeline risk assessment model. The conversion began in August, 2005 and concluded in July of 2007. Many of the identified NOA issues resulted from their dependence on the risk model's completion.

The new risk model, American Innovations IMP Version 6.4, has now been installed, populated, reviewed, and generated output. PHMSA has been notified of this change and acknowledged the notification (#118) on July 13, 2007. The PHMSA acknowledgement is provided in the attached NOA response. Placing the new risk model in service allows SSCGP to proceed with addressing many of the issues documented in the NOA.

SSCGP responses to PHMSA's identified issues are summarized below and completely documented in the attached NOA response document.

1A. Plan to address inspection issue submitted in SSCGP's NOA response document.
1B. Modification submitted and deemed adequate by PHMSA.
2.–3. Plan to address inspection issue submitted in SSCGP's NOA response document.
4. Modification submitted and deemed adequate by PHMSA.
5. Modification completed by SSCGP and submitted in SSCGP's NOA response document.
6.– 7. Plan to address inspection issue submitted in SSCGP's NOA response document.
8.–12. Modification submitted and deemed adequate by PHMSA.
13.-15. Plan to address inspection issue submitted in SSCGP's NOA response document.

In addition, SSCGP shall continue to provide monthly progress reports to keep PHMSA informed of the completion status of its submitted completion plans. Please contact Mark Elliott at (270) 852-4421 should you require clarification or additional information on the SSCGP NOA Response or the aforementioned monthly progress reports.

Sincerely,

Mr. Robert S. Bahnick,
Senior Vice President, Operations and Technical Support

Attachment

Southern Star Central Gas Pipeline

Response to PHMSA Notice of Amendment

CPF 4-2007-1012M

The numbered appendices of this Notice of Amendment (NOA) response provide amended procedures and documents to demonstrate compliance with an NOA issue. Each appendix is labeled to coincide with the issue number of Mr. R. M. Seeley's NOA correspondence dated August 20, 2007. For example, the documentation to address Issue 3B of the NOA would be located in Appendix 3B. The PHMSA risk model change acknowledgement is provided in Appendix X. The official NOA letter from Mr. Seeley along with SSCGP receipt documentation will be provided in Appendix Y and the Gantt Chart which graphically illustrates SSCGP's projected schedule for amending all its documents and procedures consistent with the NOA will be found in Appendix Z. Appendices X, Y and Z are located at the end of the document, but in front of the numbered appendices which contain Southern Star Central Gas Pipeline, Inc. (SSCGP) submissions for NOA resolution.

Each item below provides the protocol covering the PHMSA issue followed by the specific issue description provided by PHMSA which requires amendment.

1. **§192.905 How does an operator identify a high consequence area?**
   (b)(1) Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

   SSCGP must revise its IM plan and procedures to:

   A. *Ensure the integration of information from routine operations and maintenance activities (e.g., identification of new structures/change in facility use along the right-of-way) into the HCA identification process.*

   09/11/2007 Performed O&M Manual Review and approved.
   10/01/2007 Implement procedure and form changes in updated O&M Manual.

   B. *Detail its process by which local public officials are contacted for information regarding identified sites and specify the periodicity with which officials should be contacted.*

   Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

2. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

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

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

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

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

(4) Human error.

SSCGP must revise its procedures to include guidance on how subject matter experts (SMEs) identify and address potential interacting threats.

12/31/2007	Define different interacting threats and methods for assessment.
02/29/2008	Complete final draft of procedures.
03/31/2008	Approve and implement the required procedures.

3. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

(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.

SSCGP must revise its procedures to:

A. Ensure the verification that individual data elements are brought together and analyzed in their context. Integrated data should provide improved confidence with respect determining the relevance of specific threats and can support an improved analysis of overall risk (e.g., depth of cover, land use).

12/31/2007	Identify data to be integrated for each threat and for interacting threats.
04/30/2008	Evaluate and select mechanisms for data integration and analysis.
06/30/2008	Develop procedure for data integration.
08/29/2008	Approve and implement the required procedure.

B. Ensure provisions exist to collect data identifying if a pipeline line segment includes flash-welded pipe.

Updated procedures and forms addressing these issues are provided in Appendix 3B. References to EFW pipe are highlighted in yellow. These documents have completed the management of change process and are implemented in the SSCGP Integrity Management Plan as of September 14, 2007.

C. ***Ensure procedures adequately address how data for conditions unique to each pipeline is gathered and evaluated for both covered and similar non-covered segments.***

07/31/2008	Develop scope for procedures (dependent upon completion of 4/30/2008 milestone in 3A.).
10/31/2008	Identify data gathering and evaluation methods for each data gathering item above.
12/31/2008	Develop procedures.
02/27/2009	Approve and implement procedures.

D. ***Ensure procedures address how suspect, missing, or unknown information will be addressed in the risk analysis process and include requirements for how and when suspect, missing, or unknown data elements will be collected and managed.***

03/31/2008	Identify data gathering items and suspect data issues and methods of data collection and validation.
04/30/2008	Document how data will be evaluated in the risk model.
06/30/2008	Develop procedures.
09/30/2008	Approve and implement procedures.

E. ***Ensure procedures address the timing for incorporation of new data and requirements to ensure the most current information is available prior to running the risk analysis program.***

12/31/2007	Identify data elements that need to be collected and updated in the databases that provide input data to the risk model.
03/31/2008	Identify data paths from generation point to database.
06/30/2008	Determine timelines for data to complete identified path into database and date maximums for database population.
08/29/2008	Develop procedures.
12/31/2008	Approve and implement procedures.

4. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
   (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.

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

5. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
   (e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
   (3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.
   (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
   (ii) MAOP increases; or
   (iii) The stresses leading to cyclic fatigue increase.
   (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 noncovered 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.

SSCGP must revise its IM plan to specify that segments with low-frequency ERW or lap welded pipe or that have manufacturing defects where operational changes could have made them unstable be treated as high-risk segments.

Updated procedures and forms addressing these issues are provided in Appendix 5. References to higher prioritization for ERW or lap welded pipe are highlighted. These documents have completed the management of change process and are implemented in the SSCGP Integrity Management Plan as of September 14, 2007.

6. **§192.921 How is the baseline assessment to be conducted?**

   (b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

   (d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

SSCGP must modify the process to require the development of its baseline assessment plan prior to December 17, 2007 in order to ensure that the 50% completion deadline will be met.

09/14/2007	Approved documentation of Baseline Assessment Plan process.
12/17/2007	Complete "white paper" discussing Baseline Assessment Plan changes.
12/17/2007	Complete Summary report illustrating compliance with 50% completion deadline.

7. **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 (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, 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 ECDA 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).

SSCGP must revise its procedures to ensure references to O&M procedures are provided at the appropriate locations in the ECDA process in order to provide the appropriate guidance for consistent application of the process.

10/31/2007	Review and modify all ECDA documents and procedures in the SSCGP Integrity Management Plan to verify references to O&M procedures are accurate and complete. Generate a complete list of modifications to submit to PHMSA.
11/30/2007	Approve and implement modifications to identified documents and procedures if changes required.

8. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(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; 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.

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

9. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(b) ***see above***

(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—

(iii) 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

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

10. §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.

(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;

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

11. §192.933 What actions must be taken to address integrity issues?

(a) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 (``RSTRENG"; ibr, see §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

12. §192.933 What actions must be taken to address integrity issues?

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

Per page 7 of the PHMSA NOA in Appendix Y, SSCGP provided finalized documentation via e-mail to PHMSA on July 5, 2007. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on this item.

13. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(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 (incorporated by reference, see §192.7), 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.

SSCGP needs to revise its procedures to ensure:

A. P&M measures reference all of the requirements in ASME B31.8S, evaluate all threats, and evaluate the adequacy of measures already being implemented along with applying the procedures to all relevant threats in each covered segment.

09/14/2007	Approved and implemented procedures for evaluation of all threats. Updated procedures and forms addressing these issues are provided in Appendix 13A. These documents have completed the management of change process and are implemented in the SSCGP Integrity Management Plan as of September 14, 2007. Additional documents regarding 13A will be submitted as indicated below.
04/30/2008	Develop methodology for evaluating the effectiveness of P&M measures.
06/30/2008	Develop required documents and procedures.
08/29/2008	Approve and implement required documents and procedures.

B. An adequate documented decision-making process exists to decide which P&M measures are to be implemented that involves input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control.

Updated procedures and forms addressing these issues are provided in Appendix 13B. These documents have completed the management of change process and are implemented in the SSCGP Integrity Management Plan as of September 14, 2007.

C. The evaluation of both the likelihood and the consequences of a pipeline failure with regard to additional P&M measures. Based on the information reviewed during the inspection, it appears that this concern will be addressed through implementing the new risk model.

04/30/2008	Documentation of risk model scoring and impact upon likelihood and consequences of a pipeline failure for potential P&M measures.
05/30/2008	Develop final draft of procedures to perform this evaluation for reconciliation of real-world events to the risk model.
08/29/2008	Approve and implement documents and procedures for evaluation and reconciliation.

D. The ongoing implementation of P&M measures for all HCAs.

11/30/2007	Issue HCA P&M measure identification forms with data sheet.
02/29/2008	Receive all completed HCA P&M measure identification forms.
03/31/2008	Determine data gathering and database population methods for all P&M measures.
05/30/2008	Develop data gathering and database population procedures for all P&M measures.
05/30/2008	Review and approve all HCA P&M measure identification forms with data sheet.
06/30/2008	Schedule and begin implementation of P&M measures.
06/30/2008	Approve and implement data gathering and database population procedures for all P&M measures.

14. §192.935 What additional preventive and mitigative measures must an operator tak to protect the high consequence area?

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operato determines, based on a risk analysis, that an ASV or RCV would be an efficient mean of adding protection to a high consequence area in the event of a gas release, a 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 pip shutdown capabilities, the type of gas being transported, operating pressure, the rat of potential release, pipeline profile, the potential for ignition, and location of neares response personnel.

SSCGP must revise its procedures to ensure decisions and technical justification for not installing additional automatic or remote-acting valves are documented.

09/28/2007	Get questionnaires out to SMEs.
12/31/2007	Receive completed information from SMEs.
02/29/2008	Input information in EN Engineering evaluation model.
03/31/2008	Complete ASV/RCV Report Preliminary Draft.
05/30/2008	SSCGP review ASV/RCV Preliminary Draft.
06/30/2008	Complete ASV/RCV Report.
07/31/2008	Generate action plan associated with ASV/RCV project.

15. §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

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

SSCGP must revise its procedures to ensure the following:

A. Continual evaluation and assessments in the SSCGP process must specify all of the required elements and sufficient guidance must be provided for consistent application of the process.

1/31/2008	Identify continual evaluation or improvement examples for key program elements.
3/31/2008	Document continual evaluation or improvement examples for key program elements in the Integrity Management Program.
4/30/2008	Approve and implement documented examples.

B. The periodic evaluations per the SSCGP procedure (2 years) must be revised to reflect the need to update important information on a continual basis.

11/30/2007	Achieve agreement on time frame for getting new information into the appropriate databases and subsequently into the risk model for evaluation.
02/29/2008	Submit proposed procedures.
04/30/2008	Approve final draft of impacted procedures.
05/30/2008	Approve and Implement procedures.

Appendix X

PHMSA Risk Model Acknowledgment

CPF 4-2007-1012M

Elliott, Mark

From: Gas IM Notification Service [clearinghouse@cycla.com]
Sent: Friday, July 13, 2007 8:23 AM
To: clearinghouse@cycla.com
Cc: Elliott, Mark; Etheridge, Warren A
Subject: Gas IM Notification Status Change: #118, Acknowledged

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Event...........: Gas IM Notification Status Change New Status.......: ACKNOWLEDGED
Previous Status..: Under Review

Notification #...: 118
Operator.........: Southern Star Central Gas Pipeline, Inc.
Operator ID......: 31711
Notification Type: Program
Operator Email...: Mark.D.Elliott@SSCGP.com,Warren.A.Etheridge@SSCGP.com
Data Entry Time..: 07/13/2007 06:23 AM
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OPERATOR SUMMARY

This notification shall advise PHMSA that Southern Star Central Gas Pipeline, Inc. is implementing a more advanced and appropriate risk model to address the requirements of Title 49, Part 192, Subpart O (Integrity Rule).

RESPONSE BASIS

PHMSA has received your notification of a change to your IM program.
This information will be incorporated into PHMSA inspection planning.

NOTICE

This PHMSA database is supported by Cycla, a contractor to PHMSA. All content contained herein, submitals, and responses to submitals are reviewed by PHMSA personnel and approved for appropriate action.

Appendix Y

PHMSA Notice of Amendment Dated August 20, 2007
And
Proof of Receipt

CPF 4-2007-1012M

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

August 20, 2007

Robert S. Bahnick
Senior VP of Operations and Technical Services
Southern Star Central Gas Pipeline
4700 Highway 56
Owensboro, KY 42301

CPF 4-2007-1012M

Dear Mr. Bahnick:

During the weeks of September 11-14 and 25-28, 2006, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Southern Star Central Gas Pipeline (SSCGP) your integrity management procedures in Owensboro, Kentucky.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within SSCGP's plans or procedures, as described below:

1. **§192.905 How does an operator identify a high consequence area?**
   (b)(1) Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

SCCGP must revise its IM plan and procedures to:

A. Ensure the integration of information from routine operations and maintenance activities (e.g., identification of new structures/change in facility use along the right of way) into the HCA identification process.
B. Detail its process by which local public officials are contacted for information regarding identified sites and specify the periodicity with which officials should be contacted.

2. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

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

   (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
   (2) Static or resident threats, such as fabrication or construction defects;
   (3) Time independent threats such as third party damage and outside force damage; and
   (4) Human error.

SSCGP must revise its procedures to include guidance on how subject matter experts (SMEs) identify and address potential interacting threats.

3. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

   (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.

SSCGP must revise its procedures to:

A. Ensure the verification that individual data elements are brought together and analyzed in their context. Integrated data should provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk (e.g., depth of cover, land use).
B. Ensure provisions exist to collect data identifying if a pipeline line segment includes flash-welded pipe.
C. Ensure procedures adequately address how data for conditions unique to each pipeline is gathered and evaluated for both covered and similar non-covered segments.
D. Ensure procedures address how suspect, missing, or unknown information will be addressed in the risk analysis process and include requirements for how and when suspect, missing, or unknown data elements will be collected and managed.
E. Ensure procedures address the timing for incorporation of new data and requirements to ensure the most current information is available prior to running the risk analysis program.

4. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

   (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.

SSCGP must revise its procedures to ensure there is a documented basis for the 1000 foot segmentation used for risk analysis.

5. **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**

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

   (3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

   (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

   (ii) MAOP increases; or

   (iii) The stresses leading to cyclic fatigue increase.

   (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 noncovered 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.

SSCGP must revise its IM plan to specify that segments with low-frequency ERW or lap welded pipe or that have manufacturing defects where operational changes could have made them unstable be treated as high-risk segments.

6. **§192.921 How is the baseline assessment to be conducted?**

   (b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

   (d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

SSCGP's must modify the process to require the development of its baseline assessment plan prior to December 17, 2007 in order to ensure that the 50% completion deadline will be met.

7. **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 (incorporated by reference, see § 192.7), section 6.4, and in NACE RP 0502-2002 (incorporated by reference, 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 ECDA 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).

SSCGP must revise its procedures to ensure references to O & M procedures are provided at the appropriate locations in the ECDA process in order to provide the appropriate guidance for consistent application of the process.

8. **§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**

   (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; 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.

SSCGP must revise its procedures to:

A. Provide additional guidance and documentation in order to assure consistent results of the feasibility assessment in the pre-assessment step of the ECDA process.

B. Provide justification for the spacing of some indirect inspection tool readings that do not meet industry standards or NACE requirements (e.g., acceptability of 30 ft. spacing in paved locations).
C. Provide better documentation of the more restrictive criteria required on initial ECDA assessments in the pre-assessment, indirect inspections, and direct examination steps.

9. **§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?**

   (b) ***see above***

   (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—

      (iii) 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

SSCGP must revise its procedure to ensure adequate internal communications exist on changes in the ECDA plan are documented in the SSCGP ECDA process.

10. **§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.

    (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;

SSCGP must revise its procedures to ensure requirements defining the criteria for making decisions regarding the selection of ICDA regions and determining the feasibility of the ICDA assessment provide sufficient guidance for consistent application of the process.

11. **§192.933 What actions must be taken to address integrity issues?**

    (a) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 (''RSTRENG"; ibr, see §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in

operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

SSCGP must revise its procedures to ensure that upon discovery of an immediate repair condition, that pressure is reduced as required and remediation is accomplished in a prompt manner.

12. **§192.933 What actions must be taken to address integrity issues?**
    (b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

SSCGP must revise its procedures to ensure IMP procedures require that the date of discovery for an anomaly be documented.

13. **§192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?**
    (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 (incorporated by reference, see §192.7), 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.

SSCGP needs to revise its procedures to ensure:

A. P & M measures reference all of the requirements in ASME B31.BS, evaluate all threats, and evaluate the adequacy of measures already being implemented along with applying the procedures to all relevant threats in each covered segment
B. An adequate documented decision-making process exists to decide which P&M measures are to be implemented that involves input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control.
C. The evaluation of both the likelihood and the consequences of a pipeline failure with regard to additional P & M measures. Based on the information reviewed during the inspection, it appears that this concern will be addressed through implementing the new risk model.
D. The ongoing implementation of P&M measures for all HCAs.

14. §192.935 What additional preventive and mitigative measures must an operator take to protect the high consequence area?

(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.

SSCGP must revise its procedures to ensure decisions and technical justification for not installing additional automatic or remote acting valves are documented.

15. §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

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

SSCGP must revise its procedures to ensure the following:

A. Continual evaluation and assessments in the SSCGP process must specify all of the required elements and sufficient guidance must be provided for consistent application of the process.
B. The periodic evaluations per the SSCGP procedure (i.e., 2 years) must be revised to reflect the need to update important information on a continual basis.

In regard to Items 1.B, 4, 8, 9, 10, 11, and 12 listed above, SSCGP provided finalized documentation via email to PHMSA on July 5, 2007 of various changes made to the IMP. After considering the material provided, PHMSA deemed the modifications adequate, and no further action is required on these items in response to this Notice.

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 [number of days] 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 correspondence concerning this matter, please refer to **CPF 4-2007-1012M** 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*

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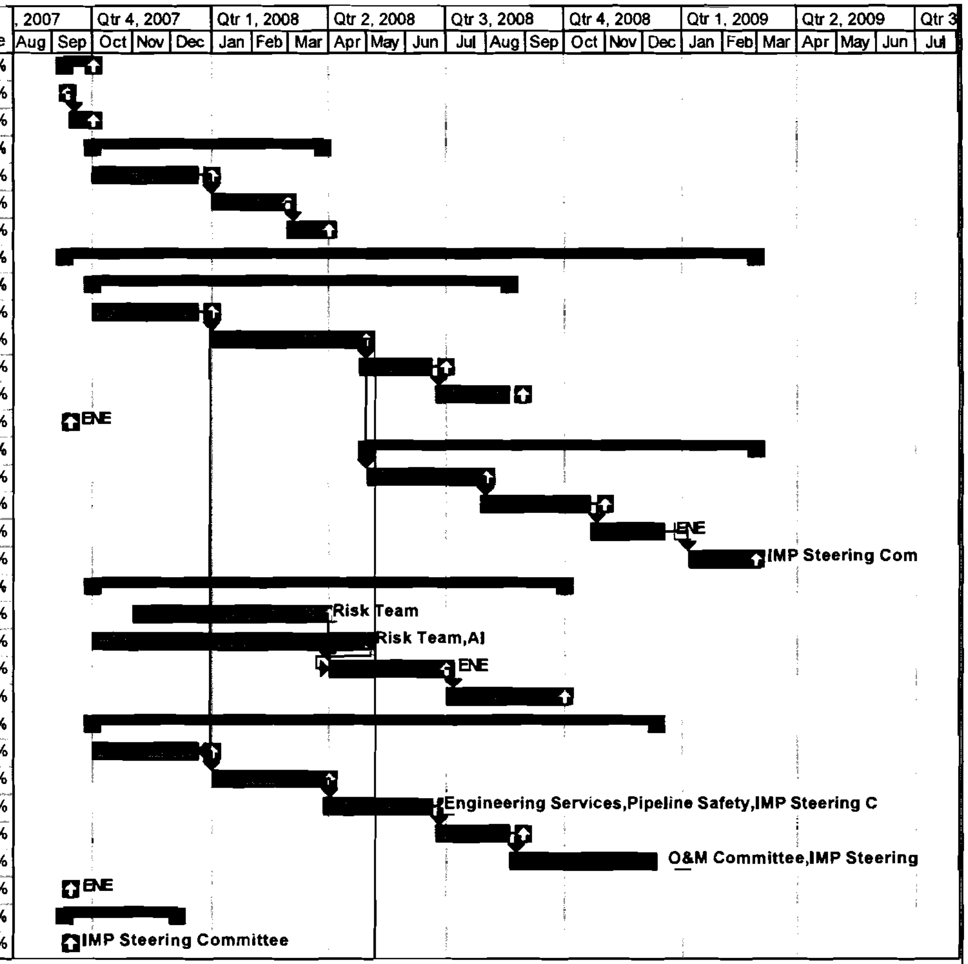
Appendix Z

Gantt Chart
Illustrating SSCGP Completion Timeline for NOA Issues

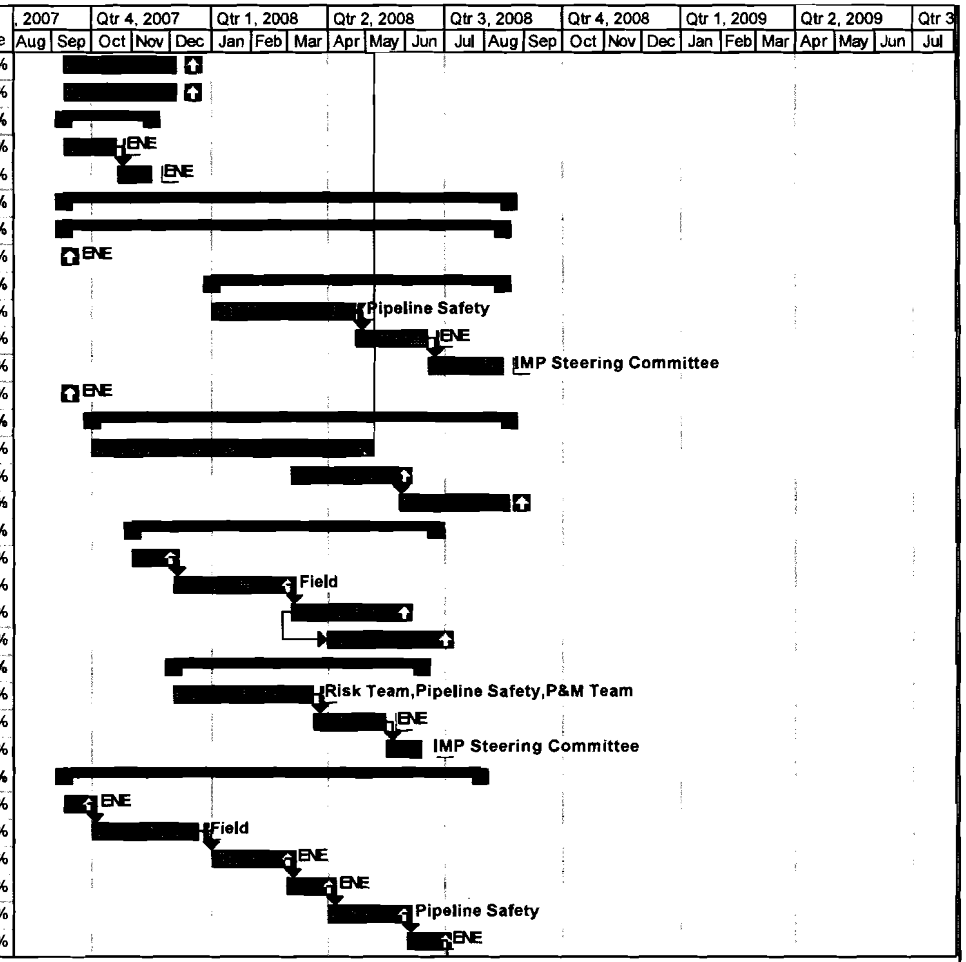
CPF 4-2007-1012M

ID		Task Name	Deadline	% Complete
1		**1 - Revise O&M procedure**	**Mon 10/1/07**	**14%**
2	✓	O&M Manual review & approval	Tue 9/11/07	100%
3		Implement O&M procedure change	Mon 10/1/07	0%
4		**2 - Interacting Threats**	**NA**	**0%**
5		Define	Mon 12/31/07	0%
6		Develop procedure	Fri 2/29/08	0%
7		Approve / implement procedure	Mon 3/31/08	0%
8		**3 - Data Gathering & Integration**	**NA**	**0%**
9		**3A - Data Integration procedures**	**NA**	**0%**
10		Identify data for threats	Mon 12/31/07	0%
11		Determine integration & analysis mechanisms	Wed 4/30/08	0%
12		Develop procedure	Mon 6/30/08	0%
13		Approve / implement procedure	Fri 8/29/08	0%
14	✓	**3B - EFW data**	Fri 9/14/07	100%
15		**3C - Unique conditions**	**NA**	**0%**
16		Develop scope for identifying unique conditions	Thu 7/31/08	0%
17		Identify data gathering items & methods	Fri 10/31/08	0%
18		Develop procedure	Wed 12/31/08	0%
19		Approve / implement procedure	Fri 2/27/09	0%
20		**3D - Suspect, Missing, Unknown data**	**NA**	**0%**
21		Identify data issues & collection methods	Mon 3/31/08	0%
22		Document how data evaluated in risk model	Wed 4/30/08	0%
23		Develop procedures	Mon 6/30/08	0%
24		Approve / implement procedures	Tue 9/30/08	0%
25		**3E - Timing to Incorporate New Data**	**NA**	**0%**
26		Identify data issues	Mon 12/31/07	0%
27		Identify data paths	Mon 3/31/08	0%
28		Determine timelines	Mon 6/30/08	0%
29		Develop procedures	Fri 8/29/08	0%
30		Approve / implement procedures	Wed 12/31/08	0%
31	✓	**5 - Low-frequency ERW & Lap welded pipe**	Fri 9/14/07	100%
32		**6 - Baseline Assessment Plan**	**NA**	**4%**
33	✓	Approve BAP process documentation (2004-2007)	Fri 9/14/07	100%



Project: NOA gantt chart3~328 Date: Mon 9/17/07	Task	Progress	Summary	External Tasks	Deadline
	Split	Milestone	Project Summary	External Milestone	

ID		Task Name	Deadline	% Complete
34		White paper explanations of 2004-2007 plan	Mon 12/17/07	0%
35		Summary report showing 50% completion	Mon 12/17/07	0%
36		**7 - ECDA / O&M references**	**NA**	**0%**
37		Review ECDA changes, create & submit list to PHMSA	Wed 10/31/07	0%
38		Approve / implement any additional modifications if necessary	Fri 11/30/07	0%
39		**13 - Preventive & Mitigative Measures**	**NA**	**1%**
40		**13A - Evaluate all threats & adequacy of measures**	**NA**	**3%**
41	✓	Approve / implement procedures to evaluate P&Ms for all threats	Fri 9/14/07	100%
42		**Evaluate effectiveness of P&Ms**	**NA**	**0%**
43		Develop methodology	Wed 4/30/08	0%
44		Develop procedure	Mon 6/30/08	0%
45		Approve / implement procedure	Fri 8/29/08	0%
46	✓	**13B - Decision-making process**	Fri 9/14/07	100%
47		**13C - Likelihood & Consequence of Failure**	**NA**	**0%**
48		Document risk model impact of P&Ms	Wed 4/30/08	0%
49		Develop procedure to reconcile field results vs. risk	Fri 5/30/08	0%
50		Approve / implement procedure	Fri 8/29/08	0%
51		**13D - Implement P&Ms**	**NA**	**0%**
52		Issue P&M forms to field	Fri 11/30/07	0%
53		Complete P&M forms	Fri 2/29/08	0%
54		Review / approve P&M forms	Fri 5/30/08	0%
55		Implement / schedule P&M measures	Mon 6/30/08	0%
56		**Record Keeping**	**NA**	**0%**
57		Determine data gathering & database population methods	Mon 3/31/08	0%
58		Develop procedure / documentation	Fri 5/30/08	0%
59		Approve / implement procedure	Mon 6/30/08	0%
60		**14 - ASV / RCV Study**	**NA**	**0%**
61		Issue RCV questionnaires to field	Fri 9/28/07	0%
62		Complete RCV questionnaires	Mon 12/31/07	0%
63		Input data & run evaluation model	Fri 2/29/08	0%
64		Preliminary Report	Mon 3/31/08	0%
65		Review preliminary report	Fri 5/30/08	0%
66		Final Report	Mon 6/30/08	0%

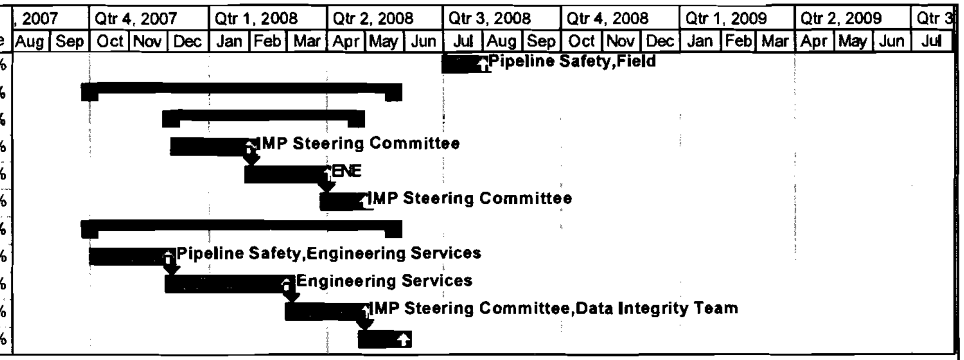


Project: NOA gantt chart3~328
Date: Mon 9/17/07

Task	Progress	Summary	External Tasks
Split	Milestone	Project Summary	External Milestone

Deadline

ID		Task Name	Deadline	% Complete
67		Generate action plan & include technical justification	Thu 7/31/08	0%
68		**15 - Continual Evaluation**	**NA**	**0%**
69		**15A - Guidance for consistent application**	**NA**	**0%**
70		Determine continual improvement examples for key elements	Thu 1/31/08	0%
71		Document examples	Mon 3/31/08	0%
72		Approve / implement documentation	Wed 4/30/08	0%
73		**15B - Continual updates**	**NA**	**0%**
74		Agree on timeframe for incorporating new information	Fri 11/30/07	0%
75		Submit proposed procedures	Fri 2/29/08	0%
76		Finalize proposed procedures	Wed 4/30/08	0%
77		Approve / implement procedures	Fri 5/30/08	0%



Project: NOA gantt chart3~328 Date: Mon 9/17/07	Task		Progress		Summary		External Tasks		Deadline
	Split		Milestone		Project Summary		External Milestone		

Appendix 3B

Amended Documents Per
Notice of Amendment

Collection of Electric Flash Welded (EFW) Pipe Data

CPF 4-2007-1012M

RISK ASSESSMENT AND THREAT IDENTIFICATION
(§192.917)

1.0 INTRODUCTION

SSCGP has developed the following plan pertaining to threat identification per 49 CFR Part 192 Subpart O. This document details the general procedure for assessing risk and identifying threats for the covered pipeline segments.

Per Part 192 and ASME B31.8S one or a combination of the following approaches are acceptable methods of risk assessment:

- Subject Matter Experts (SMEs)
- Relative Assessment Models
- Scenario-Based Models
- Probabilistic Models

The objective of the SSCGP risk assessment initiative is to evaluate risk likelihood and consequences to allow prioritization for assessments, repairs, and P&M measures and to ensure integrity of the SSCGP pipeline system. Through a more accurate evaluation of risk likelihood and consequences, SSCGP can more effectively manage risk and apply resources. Section 4.0 of this document details the risk assessment program (RAP); Section 5.0 discusses the threat determination process; Section 6.0 outlines the validation process for both risk scores and threat analysis.

Element 3 of the SSCGP Integrity Management Plan also includes several related documents. The first, entitled Risk Assessment Program Development, details the history, current status, and planned improvements to the Risk Assessment Program used in determining and prioritizing risk threats. The second, entitled Data Integrity, details the data collection and validation efforts related to SSCGP's Integrity Management Program.

The Baseline Assessment Plan results directly from the threat identification process. The SSCGP SME chooses the appropriate method of integrity assessment based upon the identified threats. Selection of the assessment type and scheduling result from the type of threat, the severity, and consequences of a failure as do the selection of P&M measures. More than one assessment method may be necessary to address all of the identified threats.

2.0 RELATED FORMS AND PROCEDURES

The Threat Identification element includes the following procedures and forms:

- *IMP.E3.RAP.01 "Import / Export of Risk Data"*
- *IMP.E3.THR.01 "Threat Analysis and Justification"*
- *SSCGP-IMP-0302 "Integrity Management Pipeline Threat Analysis"*

This document also references the following related procedures and forms:

- *IMP.E2.ASMT.06 "Finding Corrosion in an HCA"*
- *IMP.E8.PREV.03 "Identifying and Implementing Preventive and Mitigative Measures"*
- *SSCGP-IMP-1100 "Management of Change"*

- *SSCGP-IMP-1200 "Integrity Management Statement of Qualifications"*

3.0 DATA MANAGEMENT

Part 192 Subpart O §192.917 requires an operator to identify and evaluate all potential threats in each High Consequence Area (HCA). An operator must consider all the threats listed in ASME / ANSI B31.8S section 2 as well as any additional threats. At a minimum, SSCGP must gather and evaluate the data sets specified in ASME / ANSI B31.8S Appendix A. ASME / ANSI B31.8S section 4 also provides requirements for data collection. For more detailed information on data collection and integration, refer to Element 3 "Data Integrity" in the Integrity Management Plan.

3.1 Data Collection

SSCGP retains pipeline design and construction information and collects data during routine operations and maintenance procedures that are relevant to risk assessment and threat identification. In general, information is primarily stored in the O&E database or the Pipeline Compliance System (PCS) database.

3.2 Data Integration

Risk assessment is performed through a combination of a relative risk assessment program (RAP) and analysis by SSCGP Subject Matter Experts (SMEs), further discussed in section 4.0. The majority of the information used in the RAP is bridged directly from the O&E and PCS databases as outlined in procedure IMP.E3.RAP.01, current revision, "Import / Export of Risk Data".

3.3 Updating the Risk Assessment Program with New Information

New information pertaining to the SSCGP pipeline system is collected and documented on a continual basis, as discussed in the Data Integrity document within the Integrity Management Plan. Data is then imported to the American Innovations IMP risk assessment database according to procedure IMP.E3.RAP.01, latest revision, "Import / Export of Risk Data". Pipeline Integrity personnel recalculate the risk scores twice each year in accordance with the procedure.

4.0 RISK ASSESSMENT

The RAP is a relative risk model that incorporates construction data, operating data and pipeline survey data to determine a quantitative estimate of failure probabilities and failure consequences along the pipeline. The RAP calculates, based on available data, Risk of Failure and other scores for both HCA and non-HCA segments along the SSCGP pipeline. Additionally, the RAP determines annual wall loss due to time dependent threats and from this calculates the theoretical available pipe wall thickness for the segment.

4.1 Dynamic Segmenting

The RAP segments each line such that a boundary exists at each location where any data changes. In other words, it dynamically segments on all input data. Therefore, each pipeline segment is composed of numerous sub-segments of varying lengths. Since some data input changes in each sub-segment, the sub-segments frequently vary in their calculated values of ROF and POF.

4.1.1 Probability of Failure (POF)

The RAP calculates threat-specific and overall Probability of Failure (POF) scores for each dynamic segment. These scores reflect the likelihood of a failure occurring on that segment. The following threats generate a POF score:

- Time Dependent threats
- Third-Party Damage
- Weather & Outside Force
- Incorrect Operations

POF scores are calculated on a scale of 0 to 1, with 1 being the most severe.

4.1.1.1 Time Dependent Threats

The RAP determines a theoretical mils/year wall loss due to the following time-dependent threats:

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking (SCC)
- Fatigue

The RAP calculates overall available wall thickness as:

$$\textit{Available Wall} = x - (y \times z)$$

Where:

x = Last known wall thickness
y = Elapsed time since last wall thickness reading (years)
z = Sum of theoretical wall loss due to time dependent threats (mils/year)

If actual inspection data is not available for a pipe segment, then the last known wall thickness is equal to the nominal wall thickness.

4.1.1.2 Time Independent Threats

For time independent threats such as Third-Party Damage, Weather and Outside Force, Incorrect Operations, or Equipment threats, the RAP calculates the number of failures per mile per year based on data from the Integrity Event table in the O&E database. This information is used in determining POF scores for each segment.

4.1.2 Consequence of Failure (COF)

The RAP calculates a Consequence of Failure (COF) score for each dynamic segment. This score reflects the impact of a potential failure and is based on factors including, but not limited to, Class location, PIR distance, and potential for secondary failure. COF scores are calculated on a scale of 0 to 10, with 10 being the most severe.

4.1.3 Risk of Failure (ROF)

Risk of Failure (ROF) is defined as the product of probability and consequence of failure. That is,

$$ROF = POF \times COF$$

ROF scores are calculated on a scale of 0 to 10, with 10 being the most severe.

4.2 Collapsed Data

The segmented data described in Section 4.1 is combined – or collapsed – into larger, more meaningful segments in order to obtain output for an entire HCA or non-HCA segment. These output values are exported from the RAP, retained in the O&E database, and used in the validation process described in Section 6.0.

4.2.1 Risk Scores

The RAP calculates both a weighted average ROF score and a maximum ROF score for each HCA. Weighted average scores are weighted based on comparative lengths of each segment within the HCA. Maximum values are the highest for any segment within the HCA. POF and COF scores are collapsed and weighted similarly.

4.2.2 Available Wall

The minimum available pipe wall is reported for each HCA equal to the smallest available wall thickness for any segment within the HCA. *Note:* Because available wall is based on a theoretical mpy wall loss therefore it is possible for the RAP to calculate a minimum available wall of zero (0.0") inches.

5.0 THREAT SCREENING

In addition to being a relative risk model, the IMP software also screens for the following threats based on construction data, operating data and pipeline survey data:

Table 1 - Threats Addressed by Risk Model

Threat[1]	*Abbreviation*	*Description*
External Corrosion	EC	Assumed a threat for all segments.
Internal Corrosion	IC	Assumed a threat for all segments.
Third-Party Damage	TPD	Assumed a threat for all segments. Pertains to third-party inflicted damage, vandalism incidents and pipe previously subject to third-party damage.
Manufacturing	MFG	Addresses manufacturing threats, particularly those associated with pipe seam (e.g. EFW or low-frequency ERW pipe). Also includes defective pipe.
Construction	CONS	Addresses welding and fabrication, particularly threats related to pipe girth welds, fabrication welds, wrinkle bends, stripped threads, broken pipe and couplings.
Weather & Outside Force	WOF	Includes earth movements, heavy rains / floods, cold weather and lightning.
Stress Corrosion Cracking	SCC	High-pH and Near-Neutral SCC threats are screened separately.
Incorrect Operations	IO	Pertains to having incorrect operating / maintenance procedures as well as the failure of personnel to follow operating / maintenance procedures. Also considered "human error".
Equipment	EQ	Addresses threats associated with pipeline facilities such as meter, regulator and compressor stations. Specific equipment includes gaskets, o-rings, control valves, relief valves and seal / pump packing.

[1] According to GRI – 04/0178 "Effects of Pressure Cyles on Gas Pipelines, fatigue is not considered a threat for natural gas pipelines; therefore the Threat Screener was not set up to address Fatigue as a separate threat category.

5.1 Threat Screening Criteria

Appendix 0306 "Threat Screening Criteria" models the threat screening decision-tree developed by SSCGP and incorporated into the RAP model. Subject Matter Experts may override the RAP's threat identification results as described in procedure IMP.E3.THR.01, latest revision.

A brief synopsis of threat criteria is provided in the Table below.

Table 2 – Examples of Threat Screening Criteria

Threat	*Abbrev.*	*Factors Considered*
External Corrosion	EC	Present for all pipeline segments[2]
Internal Corrosion	IC	
Third-Party Damage	TPD	
Manufacturing	MFG	Factors including, but not limited to: seam type (low-frequency ERW, EFW), material, manufacture date, joint type, girth weld method
Construction	CONS	Factors including, but not limited to: weld procedures, joint inspection, weld method, questionable reinforcements, manufacturer inspections, interacting outside forces, bend radius, joint type, joint bend method
Weather & Outside Force	WOF	Factors including, but not limited to: frost heave, lightning, ice, erosion/scour, flood, seismic potential, blasting activity, dead loads, liquefaction, frost depth
Stress Corrosion Cracking, High-pH	SCC	All five of the required criteria must be present: • Operating stress > 60% SMYS • Operating temperature > 100°F • Distance from compressor station ≤ 20 miles • Age ≥ 10 years • Corrosion coating systems other than fusion bonded epoxy (FBE)
Stress Corrosion Cracking, Near-Neutral	SCC	All three of the required criteria must be present: • Operating stress > 60% SMYS • Age ≥ 10 years • Corrosion coating systems other than fusion-bonded epoxy (FBE)
Incorrect Operations	IO	Procedures – quality, coverage, use, periodic review Training – quality, coverage Audit results Incidents
Equipment	EQ	Regulator/Relief performance Set Point drift history Incidents Threat mechanisms

5.1.1 Constant Threats

SSCGP considers External Corrosion, Internal Corrosion, and Third-Party Damage threats to exist for all pipeline segments. The risk model attempts to estimate the severity of the threat and the effectiveness of P&M measures.

[2] Not included in Appendix 0306. Refer to section 5.1.1 of this document.

5.2 Threat Screener Results

5.2.1 Collapsed Data

The RAP collapses threat screener output data into manageable segment sizes rather than reporting separate results for each discrete point along the pipeline. For threat results, the line is broken into a separate segment whenever one of these conditions is met:

- Change in HCA status (HCA begin and end points)
- Change in Manufacturing threat status
- Change in Construction threat status
- Change in SCC threat status

For all other threats, the most severe case within the HCA is applied to the entire HCA segment. This approach was taken in order to limit the number of segments to a manageable number while retaining the ability to differentiate segments that may require different assessment methods[3].

5.2.2 Output

Threat Screener output labels each of the threats as one of the following:

- *Present:* This threat is known to exist for the HCA.
- *Possible:* Threat may exist. Additional data collection may be required. Refer to IMP.E3.THR.01.
- *Stable:* Threat is stable due to pressure test and stable operating history (only available for Manufacturing or Construction Threats). Refer to IMP.E3.THR.01.
- *Assessed:* A baseline assessment has already been performed for threat.
- *Not Indicated:* Criteria required for a threat to exist are not met.

Other categories may be created in order to flag missing or unknown data or otherwise assist in data validation efforts.

5.2.2.1 Present versus Possible Threats

The table below summarizes the difference between a Present versus Possible threat for each threat category. Refer to Appendix 0306 "Threat Screening Criteria" for more information.

[3] Specific requirements for assessing Manufacturing, Construction, and SCC threats are discussed in Element 2 of the Integrity Management Program.

Table 3 Present vs. Possible Threats

Threat	*Threat Present*	*Threat Possible*
MFG	MFG threat due to pipe seam	MFG threat not related to pipe seam
CONS	Weld/joint procedures = none or unknown Weld/joint procedures = poor or none along with high possibility of Outside Force High possibility of wrinkle bend, buckle, or coupling along with high possibility of Outside Force	Weld/joint procedures = poor or none along with moderate possibility of Outside Force Weld/joint procedures = fair, unknown, or null along with high possibility of Outside Force High possibility of wrinkle bend, buckle, or coupling along with moderate possibility of Outside Force Moderate possibility of wrinkle bend, buckle, or coupling along with high possibility of Outside Force
WOF	WOF threat present due to known data.	WOF threat due to unknown or null data. These may be eliminated by gathering additional missing data.
SCC	SCC anomalies or cracking found.	Meets SCC threat criteria but no known anomalies or cracking found.
IO	Procedures/training is fair or null Audit results = fair or not performed Incorrect operation within the last year	No procedures or training Audit results = poor or unknown Incorrect operation > 1 year ago
EQ	Known history of equipment failures	Equipment failure history unknown

5.3 Baseline Assessment Planning based on Identified Threats

5.3.1 2004 to 2007 Assessments

For assessments performed in 2004 through 2007, threats were evaluated using the old RAP and earlier versions of procedures and forms. Refer to historical records for more information. Based on preliminary results and analysis of the new RAP, portions of the 2007 Baseline Assessment Plan were modified .

5.3.2 2008 to 2012 Assessments

Upon implementation of the new RAP, satisfactory validation of the algorithm, and generation of new risk scores, SSCGP shall execute its threat identification process per Procedure IMP.E3.THR.01, latest revision for baseline assessments scheduled in 2008 through 2012 and subsequently revised the Baseline Assessment Plan for these years. The Baseline Assessment Plan details the threats identified for each HCA segment.

6.0 RISK AND THREAT VALIDATION

SSCGP uses the RAP as a first tier determination of threats for the covered pipeline segments. Subject Matter Experts then validate threats, HCA Priority, and risk scores generated by the RAP using form SSCGP-IMP-0302. This form allows for a consistent and documented validation method. This process is further detailed in procedure IMP.E3.THR.01, current revision "Threat Analysis and Justification".

6.1.1 Subject Matter Experts

SMEs are SSCGP employees who work on the pipelines and are frequently involved in pipeline activities. Therefore, they are knowledgeable with the daily environment in which the pipeline operates and the past operating history. The Manager Safety and Technical Training maintains form SSCGP-IMP-1200 "Integrity Management Statement of Qualifications" summarizing the qualifications of each SME.

6.1.2 Pre-2008 Assessments Validation Process

Originally form SSCGP-IMP-0302 was used in conjunction with the old Bass-Trigon 5.8 Risk Model. In cases where the old RAP did not adequately address a specific threat, the SME further analyzed the threat using this form. The form and related procedure IMP.E3.THR.01 were revised as part of the new RAP implementation.

7.0 PLASTIC TRANSMISSION LINES

SSCGP currently does not have any plastic transmission pipeline contained in a HCA. If a HCA is identified in the future that contains plastic transmission pipeline, the Project Manager Pipeline Integrity Management or designee will assess the threats for the covered segment as well as consider any threats unique to plastic pipe.

8.0 QUALITY ASSURANCE

Quality assurance is inherent to the threat identification process. The RAP determines risk scores and identifies threats using criteria determined by SSCGP personnel. In addition, SMEs further evaluate the threat on form SSCGP-IMP-0302. If the SME refutes the outcome of the RAP, the SME justifies why he or she does not agree on this form. Refer to procedure IMP.E3.THR.01, latest revision.

9.0 MANAGEMENT OF CHANGE

Because Threat Identification is an ongoing process, it is expected that minor changes will be required to the Threat Analysis and supporting documents from year to year.

SSCGP Procedure IMP.E3.THR.01 "Threat Analysis and Justification" outlines the types of changes that require completion of form SSCGP-IMP-1100 "Management of Change." These include, but are not limited to:

- Change that results in identification of a new threat.
- Change that results in the elimination of a previously identified threat.

Threat Analysis and Justification

DOT – 49 CFR 192 SUBPART O

Key Words: Threat, Risk of Failure (ROF), Risk Assessment Program (RAP)

1.0 PURPOSE

1.1 Identify active threats for High Consequence Areas based on Risk Assessment Program (RAP) results. Review and validate risk scores and the Threat Screener based on Subject Matter Expert and Pipeline Integrity judgment.

2.0 TASK OVERVIEW

- General
- Provide Risk Assessment Output
- SME Review
- Identify Stable Threats
- Pipeline Compliance Review

3.0 GENERAL

3.1 The RAP provides overall risk scores, some threat specific scores and a threat screener.

3.1.1 Threat screener evaluates whether SCC (both high pH and near-neutral), Manufacturing, Construction, Weather and Outside Force, Incorrect Operations and Equipment threats are Present, Possible, Stable, Assessed or Not Indicated.

3.1.2 The risk model calculates threat-specific scores for Time Dependent (EC, IC, SCC, and Cyclic Fatigue), Third Party, Outside Force and Incorrect Operation threats.

3.1.3 SSCGP always considers External Corrosion, Internal Corrosion, and Third Party Damage as threats for all HCAs.

3.2 For purposes of threat analysis and justification, the SME is the District Manager in whose district the HCA is located.

3.2.1 SMEs are encouraged to discuss HCA threats with other Operations personnel.

4.0 PROVIDE RISK ASSESSMENT OUTPUT

4.1 **Responsibility:** Project Manager Pipeline Safety, Subject Matter Expert or designee

4.1.1 Provide the SME with Risk Assessment Program (RAP) results for HCAs to be assessed in Section 1 of Form SSCGP-IMP-0302.

5.0 SME REVIEW

5.1 **Responsibility:** District Manager / Subject Matter Expert

5.1.1 Complete Form SSCGP-IMP-0302 for each HCA using risk and threat data from the report provided by Pipeline Compliance. Verify data inputs using SME's knowledge and explain any disagreements in the space provided.

5.1.1.1 Data inputs affecting the Risk Model output are listed for each section.

5.1.1.2 Pipe data inputs may be reviewed in the Facility Maintenance application of the O&E database.

5.1.1.3 See section 6.0 "Identify Stable Threats" below if a Manufacturing or Construction threat is identified as *Stable*.

5.1.2 Review section 10 of Form SSCGP-IMP-0302 and explain any disagreements with HCA Priority in the space provided.

5.1.3 Complete section 11 (Sign-Off) on Form SSCGP-IMP-0302.

5.1.4 Send completed forms SSCGP-IMP-0302 to Project Manager Pipeline Safety.

6.0 IDENTIFY STABLE THREATS

6.1 **Responsibility:** District Manager / Subject Matter Expert

6.1.1 If Construction or Manufacturing threats are identified as stable in Section 1 of Form SSCGP-IMP-0302, determine whether the RAP result is correct.

6.1.2 Determine whether a pressure test has been performed on the HCA segment(s) that met the requirements of 49 CFR 192 Subpart J.

6.1.3 If a pressure test has not been performed on the segment(s), determine the maximum operating pressure in the five (5) years preceding identification of the HCA.

6.1.4 Determine whether the MAOP has increased since the pressure test or HCA identification.

6.1.5 Determine whether the MAOP has been exceeded since the last pressure test.

6.1.6 Determine whether stresses leading to cyclic fatigue have increased since the pressure test or HCA identification.

6.1.7 The threat may be considered stable if a pressure test <u>has</u> been performed and since that time neither the MAOP nor stresses leading to cyclic fatigue have increased <u>and</u> the MAOP has not been exceeded.

6.1.8 The threat may be considered stable if a pressure test has not been performed but neither the MAOP nor stresses leading to cyclic fatigue have increased and operating pressure has not exceeded the maximum operating pressure achieved in the five (5) years preceding HCA identification.

6.1.9 A Manufacturing or Construction threat considered stable does not require an Integrity Assessment (pressure test) to assess that particular threat.

6.1.10 If a previously identified stable threat no longer meets these conditions, complete form SSCGP-IMP-1100.

7.0 PIPELINE COMPLIANCE REVIEW

7.1 **Responsibility:** Pipeline Safety Engineer or designee

7.1.1 Update the RAP Output in the O&E database according to SME responses if applicable.

7.1.2 Consider the SME's disagreements, if any, with the Risk Assessment Program's scores or data inputs.

7.1.2.1 Review the components of the RAP threat score for that segment.

7.1.2.2 Discuss the risk assessment with the SME, District Manager, Project Manager Pipeline Safety or other personnel as necessary.

7.1.3 Determine whether the RAP threat screener and scores are legitimate or whether the SME's justification is sufficiently supported by the data.

7.1.4 Determine whether the RAP algorithm should be modified based on the results of this analysis.

7.1.4.1 Algorithm changes should be based on the collective threat analysis results for the pipeline system, not on a single HCA.

7.1.5 Document response and supporting information to SME's disagreement in the space provided.

7.2 **Responsibility:** Project Manager Pipeline Safety or designee

7.2.1 Review Form SSCGP-IMP-0302 and document final determination and supporting information for that decision in the space provided for Pipeline Compliance Review.

7.2.1.1 If the threat analysis results in the elimination of a previously identified threat or identification of a new threat, complete form SSCGP-IMP-1100.

7.2.1.2 If the threat analysis warrants rescheduling of the assessment, complete form SSCGP-IMP-1100.

7.2.1.3 If the threat analysis warrants modifying the RAP algorithm, complete form SSCGP-IMP-1100.

7.2.2 Notify District Manager of decision and complete section 10 (Sign Off) on Form SSCGP-IMP-0302.

7.2.3 File and retain copies of all forms SSCGP-IMP-0302 per IMP Record Keeping procedures.

7.3 **Responsibility:** Pipeline Safety Data Analyst

7.3.1 Upload SSCGP-IMP-0302 forms into Report Tracking database.

7.3.2 Update O & E database with changes.

7.3.2.1 Database changes include but are not limited to pipeline segment data, HCA priority ranking, and identified threat data.

NOTE:

Changes to the Risk Score for a HCA will be incorporated into the RAP during the next scheduled evaluation.

Definitions and Abbreviations:

Available Pipe Wall	Also referred to as Available Wall. Calculated remaining wall thickness = known wall thickness - mpy wall loss × time
COF	Consequence of Failure. Reported as a weighted average or maximum for the HCA for each individual threat or for the combined overall threats. Reported on a scale of 0-1.
CONS	Construction threat
CONS Threat Possible	Moderate WOF • With poor or no weld/joint procedure. • With high possibility of wrinkle bend, buckle, or coupling. High WOF • With fair, unknown, or null weld joint procedures. • With moderate possibility of wrinkle bend, buckle or coupling.
Consequence of Failure	COF
Construction Threat	CONS
EC	External Corrosion
EC Threat Possible	Unknown equipment failure history.
EQ	Equipment threat
Equipment Threat	EQ
HCA Priority	A function within the RAP that ranks HCA assessment scheduling priority based on conditions determined by SSCGP. Refer to Element 3 "Baseline Assessment Plan Development" for more information.
IC	Internal Corrosion
Incorrect Operations Threat	IO
IO	Incorrect Operations threat
IO Threat Possible	No procedures/training, poor or unknown audit results, OR incorrect operation within last year.
Manufacturing Threat	MFG
MFG	Manufacturing threat
MFG Threat Possible	MFG threat not related to the pipe seam.
Minimum Available Pipe Wall	See Available Pipe Wall.
mpy	mils per year
POF	Probability of Failure. Reported as a weighted average or maximum for the HCA for each individual threat or for the combined overall threats. Reported on a scale of 1-10.
Probability of Failure	*POF*
RAP	Risk Assessment Program. General term for the overall program that calculates risk scores and also screens threats for each segment. Official software title is "IMP ????"
Risk Algorithm	A function wihtinwithin t he RAP that calculates Risk Scores based on known features and data for each segment of the pipeline. The algorithm includeEncompasses hundreds of variables and formulas covering an assortment of factors.
Risk of Failure	*ROF*
Risk Scores	General term for ROF, POF, and COF scores calculated by the RAP. May also refer to mpy and available wall values calculated by the RAP.

ROF	Risk of Failure. POF × COF. Reported as a weighted average or maximum for the HCA for each individual threat or for the combined overall threats. Reported on a scale of 1-10.
SCC	Stress Corrosion Cracking. Two types are High-pH and Near Neutral.
SMYS	% Specified Minimum Yield Stress. MAOP/SMYS.
Stable Threat	Indicates the threat is present but can be considered stable based on operating history and other conditions. Applies only to Manufacturing and Construction threats.
Stress Corrosion Cracking	*SCC*
SCC Threat Possible	Meets criteria but no known anomalies or cracking found.
Threat Assessed	Indicates the threat is present but a baseline assessment addressing the threat has already been perfomed.
Threat Not Indicated	Based on known data, conditions required for this threat are not present.
Threat Possible	Based on known data it is unclear whether the threat is present. Treated as if the threat is present unless prove otherwise.
Threat Present	Based on known data, this threat is present.
Threat Screener	A function within the RAP that determines threats based on predetermined conditions set by SSCGP.
Threat Stable	Indicates the threat is present but can be considered stable based on operating history and other conditions. Applies only to Manufacturing and Construction threats.
Time Dependent Threats	Combination of external corrosion, internal corrosion, SCC, and cyclic fatigue. All of these threats act over time.
Weather and Outside Force Threat	WOF. May also be referred to as Weather/Geotechnical
WOF	Weather and Outside Force threat
WOF Threat Possible	WOF threat due to unknown or null data. These may be eliminated by gathering additional missing data.

INTEGRITY MANAGEMENT PIPELINE THREAT ANALYSIS

District

SECTION 1 - HCAs (Location / Priority / Risk Scores Identified Threats)

Line:

Begin Series / Station Number: /

End Series / Station Number: /

HCA Length:

HCA Earliest Identified Year:

HCA Priority [10.1]:

Numbers in brackets on field headings indicate the corresponding question number on the main body of the IMP-0302 form.

	Max	Wt Avg	Min
ROF {Risk of Failure}:			
POF {Probability of Failure}:			
COF {Consequence of Failure}:			
POF Time Dependent [2.1]:			
External Corrosion (metal loss rate in mils/yr) [2.2]:			
Internal Corrosion (metal loss rate in mils/yr) [2.5]:			
SCC (metal loss rate in mils/yr) [2.8]:			
Cyclic Fatigue (metal loss rate in mils/yr) [2.11]:			
Available Pipe Wall (mils) [2.14]:			
POF Third-Party Damage [3.1]:			
POF Weather & Outside Force [5.1]:			
POF Incorrect Operations [8.1]:			

Guidelines of what are considered low, medium, and high scores for some of the various risk scores (based on system wide results):

	Low	Medium	High
ROF Max	0.9372	1.3440	4.6440
ROF Wt Avg	0.8202	1.0500	2.7640
COF Wt Avg	6.2030	6.9500	7.8970
POF Max	0.1356	0.1883	0.6593
POF Wt Avg	0.1202	0.1485	0.3949
External Corrosion (mils/yr)	2	4	8
Internal Corrosion (mils/yr)	0.5	1.5	2.5

Begin Series	Begin Station Number	End Series	End Station Number	SCC High pH Threat [4.1]	SCC Near Neutral Threat [4.1]	Weather & Outside Force Threat [5.1]	Manufacturing Threat [6.1]	Construction Threat [7.1]	Incorrect Operations Threat [8.1]	Equipment Threat [9.1]

*** SSCGP always considers External Corrosion, Internal Corrosion, and Third Party Damage as Threats for all line segments.

SECTION 2 - ANALYSIS OF TIME DEPENDENT THREATS

Yes No

2.1 **Does the SME agree with Time Dependent POF scores?** ☐ ☐

External Corrosion

2.2 **Does the SME agree with the mpy?** ☐ ☐

If disagree, verify data inputs for items 2.3.1-2.3.4 and justify reason for disagreeing with risk model in the space below.

2.3.1 External corrosion history
2.3.2 Age of pipe
2.3.3 Coating type and condition
2.3.4 CP (cathodic protection) variables

Pipeline Compliance Review:

Yes No

2.4 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)* ☐ ☐

Internal Corrosion

Yes No

2.5 **Does the SME agree with the mpy?** ☐ ☐

If disagree, verify data inputs for items 2.6.1-2.6.4 and justify reason for disagreeing with risk model in the space below.

2.6.1 Internal corrosion history
2.6.2 Age of Pipe
2.6.3 Internal coating (Y/N)
2.6.4 Internal Corrosion monitoring variables

Pipeline Compliance Review:

Yes No

2.7 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)* ☐ ☐

SCC

Yes No

2.8 **Does the SME agree with the mpy?** ☐ ☐

If disagree, verify data inputs for items 2.9.1-2.9.4 and justify reason for disagreeing with risk model in the space below.
NOTE: Refer to Section 4 for SCC threat questions.

2.9.1 Operating stress level (% SMYS)
- MAOP - 100% SMYS value

2.9.2 Age of pipe
2.9.3 Coating type (i.e. FBE vs. all other)
2.9.4 Age of pipe

Pipeline Compliance Review:

Yes No

2.10 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)* ☐ ☐

Cyclic Fatigue

Yes No

2.11 **Does the SME agree with the mpy?** ☐ ☐

If disagree, verify data inputs for items 2.12.1-2.12.3 and justify reason for disagreeing with risk model in the space below.

2.12.1 Crossing Types (ie. Railroads, highways)
2.12.2 Pressure Fluctuation
2.12.3 External loading conditions

Pipeline Compliance Review:

	Yes	No
2.13 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

Available Wall

	Yes	No
2.14 **Does the SME agree with the minimum available wall?**	☐	☐

If disagree, verify data inputs for items 2.15.1-2.15.2 and justify reason for disagreeing with risk model in the space below.
NOTE: *A zero available wall is not uncommon for older pipe depending on mpy and most recent inpsection date. Agreeing with this question does not mean the SME agrees that there is no physical pipe wall left in the ground.*

2.15.1 Installation date
2.15.2 Last inspection or assessment wall thickness
- ILI assessment
- Pressure test assessment
- UT measurement (applies only to specific location tested)

Pipeline Compliance Review:

	Yes	No
2.16 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 3 - ANALYSIS OF THIRD-PARTY DAMAGE THREAT

	Yes	No
3.1 **Does the SME agree with POF scores?**	☐	☐

If disagree, verify data inputs for items 3.2.1-3.2.5 and justify reason for disagreeing with risk model in the space below.

3.2.1 Third-Party Damage history
3.2.2 Age of Pipe
3.2.3 Depth of Cover
3.2.4 Facilty security
3.2.5 Land use, construction activity, and XXX variables

Pipeline Compliance Review:

	Yes	No
3.3 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 4 - ANALYSIS OF THE STRESS CORROSION CRACKING THREAT

	Yes	No
4.1 **Does Threat Screener identify High pH SCC &/or Near-Neutral SCC as a threat?**	☐	☐
4.2 **Does the SME agree with Threat Screener?**	☐	☐

If disagree, verify data inputs for items 4.3.1-4.3.6 and justify reason for disagreeing with risk model in the space below.
NOTE: Refer to Section 2 for SCC mpy questions.

4.3.1 Known SCC indications or failures
- Pipe Condition = SCC present
- Pressure Test failure due to SCC
- ILI or Visual Inspection anomalies attributed to SCC

4.3.2 Operating stress level (% SMYS)
- MAOP
- 100% SMYS value

4.3.3 Age of pipe
4.3.4 Coating type (i.e. FBE vs. all other)
4.3.5 Product temperature
4.3.6 Distrance from compressor station (i.e. greater than or less than 20 miles)

	Yes	No
4.4 **Based on SME review, is High pH SCC a threat?**	☐	☐
4.5 **Based on SME review, is Near Neutral SCC a threat?**	☐	☐

Pipeline Compliance Review:

	Yes	No
4.6 **Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)*	☐	☐
4.7 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 5 - ANALYSIS OF THE OUTSIDE FORCE THREAT

If "yes" to questions 6.4 to 6.13, select the correct option and explain on line given.

5.1 **Does blast activity occur?** Yes ☐ No ☐

- ☐ *High:* One or more times a year?
- ☐ *Medium:* Less than once a year to once in ten years?
- ☐ *Low:* Less than once in ten years?

5.2 **Does the pipe traverse unstable slopes?** Yes ☐ No ☐

- ☐ *High*
- ☐ *Medium*
- ☐ *Low*

5.3 **Is there potential for soil liquefaction** Yes ☐ No ☐

- ☐ *High* probability
- ☐ *Moderate* probability
- ☐ *Low* probability

5.4 **Does experience loading due to ice build-up?** Yes ☐ No ☐

- ☐ *High:* Continuous ice loading?
- ☐ *Moderate:* One day per year?
- ☐ *Low:* Less than one day per year?

5.5 **Is there potential for erosion/scour at river, creek, ditch, ravine crossings or other areas of the segment?** Yes ☐ No ☐

- ☐ *High:* for rivers
- ☐ *Medium:* creek, ditch, ravine crossings
- ☐ *Low:* others

5.6 **Is there potential for a flood event to remove soil from around the pipeline?** Yes ☐ No ☐

- ☐ *High*
- ☐ *Medium*
- ☐ *Low*

5.7 **Is the pipe located in sand, silt or clay?** Yes ☐ No ☐

Other: ____________

5.8 **Is the Depth of Cover over the pipe between 0 to 36 inches?** Yes ☐ No ☐

5.9 **Does the segment become exposed?** Yes ☐ No ☐

5.10 **Does the segment experience loads that were *not* intended in design?** Yes ☐ No ☐

☐ *Live*

- ____ *High*
- ____ *Medium*
- ____ *Low*
- ____ *None, they were intended in design*

☐ *Dead*

- ____ *High*
- ____ *Medium*
- ____ *Low*
- ____ *None, they were intended in design*

5.11 **Does the SME agree with Threat Screener and POF scores?** Yes ☐ No ☐

If disagree, verify data inputs for items 5.13.1- 5.13.3 and justify reason for disagreeing with risk model in the space below.

5.12.1 Crossing types
5.12.2 Weather Forces variables
5.12.3 Movement Forces variables
- Extreme Surface Loads
- Earthquake Fault Zone
- Subsidence Area

Pipeline Compliance Review:

5.13 **Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)* Yes ☐ No ☐

5.14 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)* ☐ ☐

SECTION 6 - ANALYSIS OF THE MANUFACTURING THREAT

		Yes	No
6.1	**Does the SME agree with Threat Screener?** *If disagree, verify data inputs for items 6.2.1-6.2.8 and justify reason for disagreeing with risk model in the space below. Otherwise, skip to question 5.3*	☐	☐

6.2.1 Is the pipe material and age correct?
- Cast iron vs. steel
- Pipe older than 1952

6.2.2 Is the seam type correct?

6.2.3 Is the girth weld joint type correct?
- Couplings
- Aceylene girth welds

6.2.4 Is failure and incident history correct?
- History of seam failure
- Lamination, hard spot, or hard HAZ
- MFG defects found by ILI, DA, or visual inspection
- Prior failure due to MFG defect
- History of low temperature brittle failure

6.2.5 Is the pipe material and age correct?
- Cast iron vs. steel
- Age of pipeline (greater than or less than 50 years)

6.2.6 Is the seam type correct?

6.2.7 Is the girth weld joint type correct?
- Couplings
- Aceylene girth welds

Stable Threats

		Yes	No
6.3	**Does the Threat Screener identify Manufacturing (MFG) as a stable threat?** *If "no", skip to question 5.6*	☐	☐
6.4	Has the MAOP increased since the last Subpart J pressure test?	☐	☐
6.5	Has the operating pressure increased above the MAOP <u>or</u> above the highest operating pressure experienced within 5 years prior to HCA identification (for any reason, including abnormal operation) since the last pressure test? *If "yes" to either question 5.4 or 5.5, threat is not stable.*	☐	☐

<u>Pipeline Compliance Review:</u>

		Yes	No
6.6	**Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)*	☐	☐
6.7	**Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 7 - ANALYSIS OF THE CONSTRUCTION THREAT

		Yes	No
7.1	**Does the SME agree with Threat Screener?** *If disagree, verify data inputs for items 6.2.1-6.2.6 and justify reason for disagreeing with risk model in the space below. Otherwise, skip to question 6.3*	☐	☐

7.2.1 Pipe material and age
- Cast iron vs. steel
- Pipe older than 1952

7.2.2 Weld type

7.2.3 Joint type
- Couplings
- Aceylene girth welds

7.2.4 Bend method

7.2.5 Construction variables
- Welding procedure used
- Construction inspection
- Manufacturer inspection (pressure test, NDT, visual)
- Joint inspection
- Required reinforcement performed

7.2.6 If wrinkle bends are present, verify the following. If no wrinkle bends, skip to next question.
- Wrinkle bend max. temperature
- Non-standard/wrinkle bend radius
- Non-standard/wrinkle bend degree angle

Stable Threats

		Yes	No
7.3	**Does the Threat Screener identify Construction (CONS) as a stable threat?** *If "no", skip to question 6.9*	☐	☐
7.4	Has the MAOP increased since the last Subpart J pressure test?	☐	☐
7.5	Has the operating pressure increased above the MAOP <u>or</u> above the highest operating pressure experienced within 5 years prior to HCA identification (for any reason, including abnormal operation) since the last pressure test? *If "yes" to either question 6.4 or 6.5, threat is not stable.*	☐	☐

<u>Pipeline Compliance Review:</u>

		Yes	No
7.6	**Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)*	☐	☐
7.7	**Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 8 - ANALYSIS OF THE INCORRECT OPERATIONS THREAT

[illegible]

	Yes	No
8.1 **Does the SME agree with Threat Screener and POF scores?**	☐	☐

If disagree, verify date inputs for items 8.2.1-8.2.2 and justify reason for disagreeing with risk model in the space below.

8.2.1 Audit finding variable
- Failure to follow procedures
- Incorrect operating procedures

8.2.2 Incident age
- Leaks or failures attributed to incorrect operations

Pipeline Compliance Review:

	Yes	No
8.3 **Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)*	☐	☐
8.4 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 9 - ANALYSIS OF THE EQUIPMENT THREAT

[illegible]

	Yes	No
9.1 **Does the SME agree with Threat Screener?**	☐	☐

If disagree, verify data inputs for items 9.2.1-9.2.2 and justify reason for disagreeing with risk model in the space below.

9.2.1 History of Problems variables
- Gasket
- O-Ring
- Regulator/Relief Performance
- Setpoint Drift
- Seal/Packing

9.2.2 Incident Age

Pipeline Compliance Review:

	Yes	No
9.3 **Manual override of Threat result in O&E database required?** *(If "Yes", explain in space below.)*	☐	☐
9.4 **Data or alogirthm changes required?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 10 - HCA PRIORITY

	Yes	No
10.1 **Does the SME agree with the HCA Priority?** *(If "No", explain below.)*	☐	☐

Pipeline Compliance Review:

	Yes	No
10.2 **Were any changes made to HCA Priority?** *(Describe changes or explain why changes not required in space below.)*	☐	☐

SECTION 11 - SIGN-OFF

Subject Matter Expert
Review by: ______________________________ Date: ______________

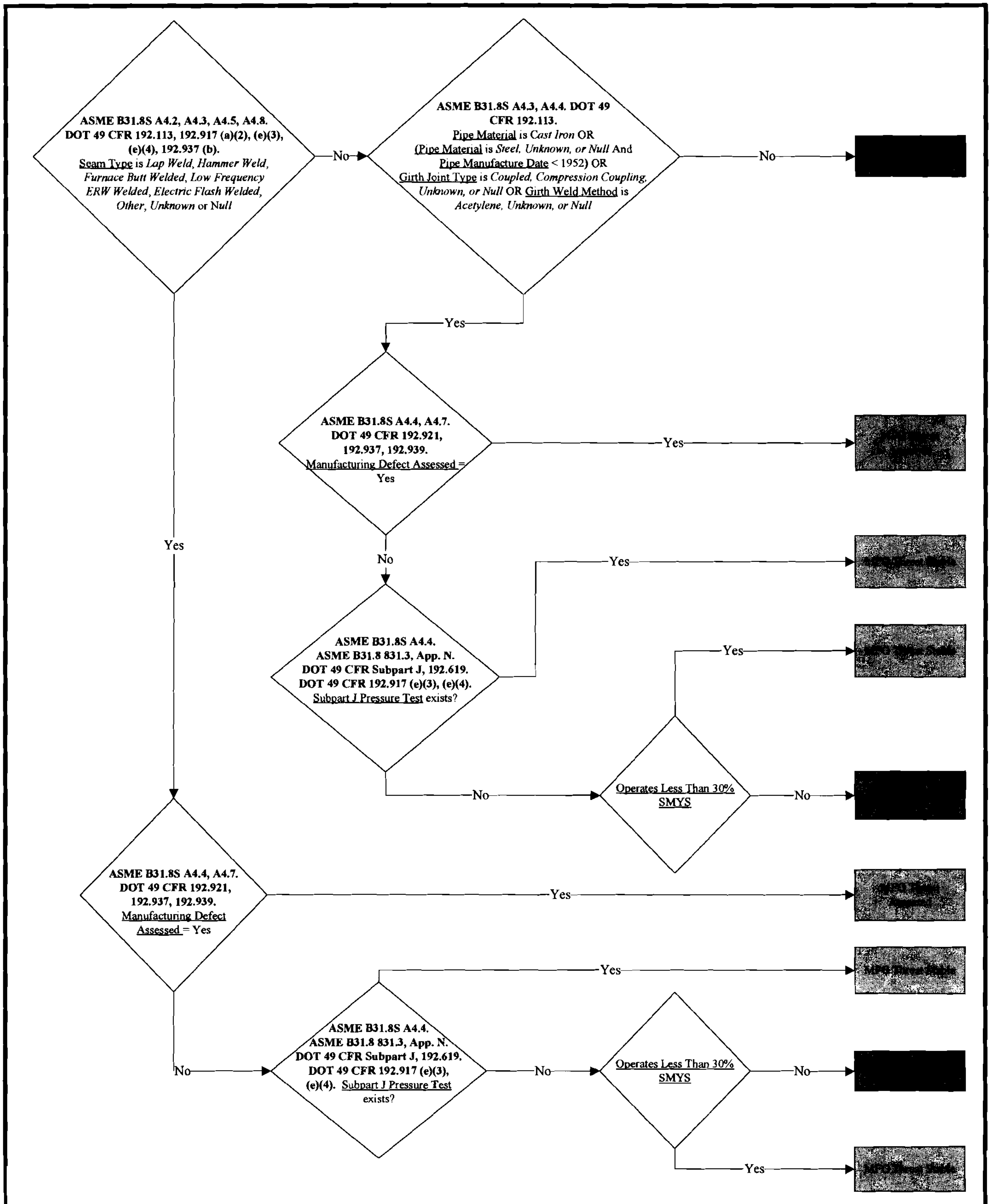
Pipeline Compliance
Review by: ______________________________ Date: ______________

THREAT IDENTIFICATION
APPENDIX 0306 – THREAT SCREENING CRITERIA

1.0 INTRODUCTION

The RAP Threat Screening tool identifies threats for each HCA (adjacent HCAs) based on criteria established by SSCGP in conjunction with American Innovations, the software developer. The IMP Steering Committee and Project Manager Pipeline Integrity Management appointed individuals to an Algorithm Team which was responsible for both the risk score algorithm and threat screening function.

American Innovations provided documentation of the Threat Screening tool in the form of the flowcharts provided on the following pages.

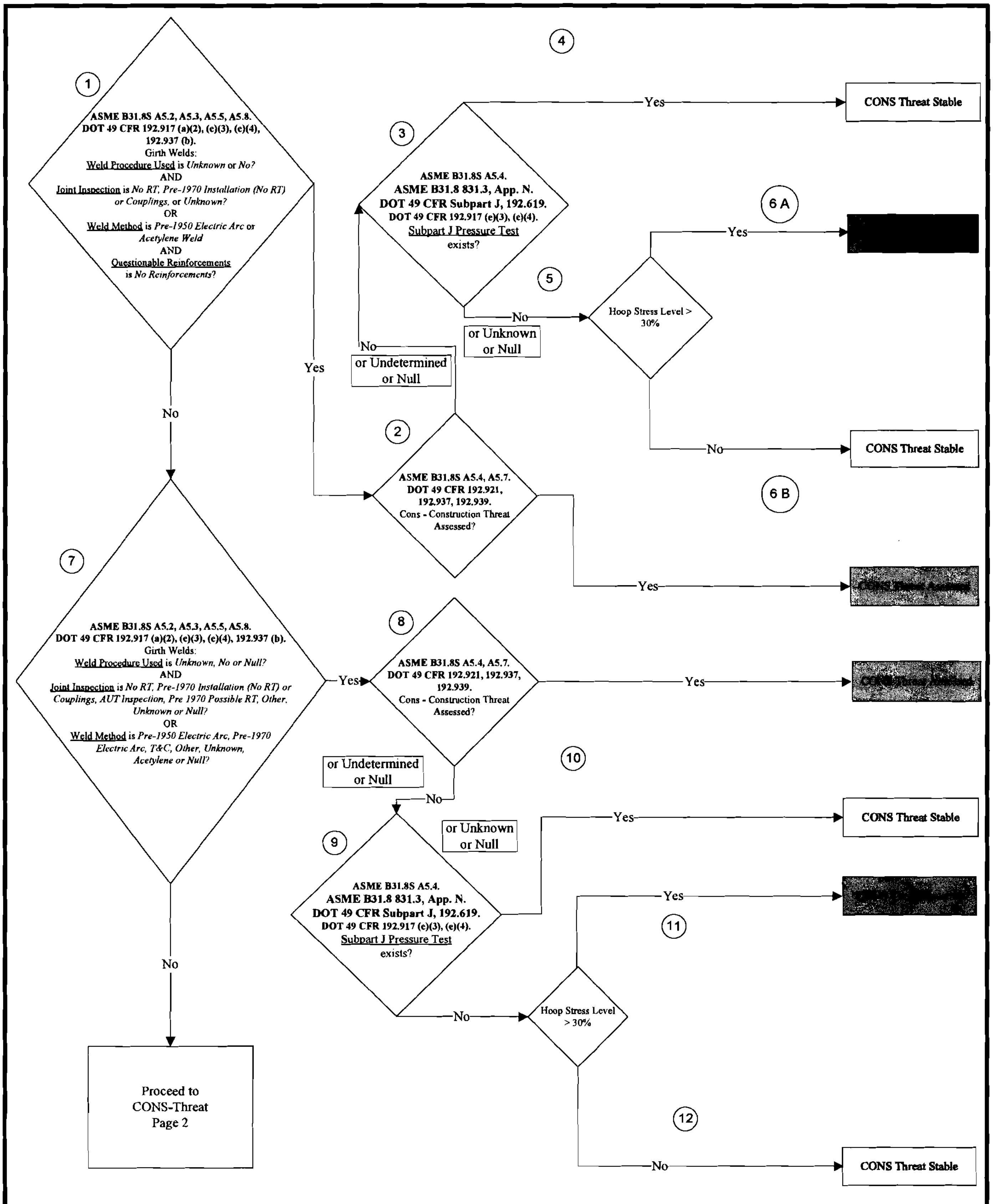


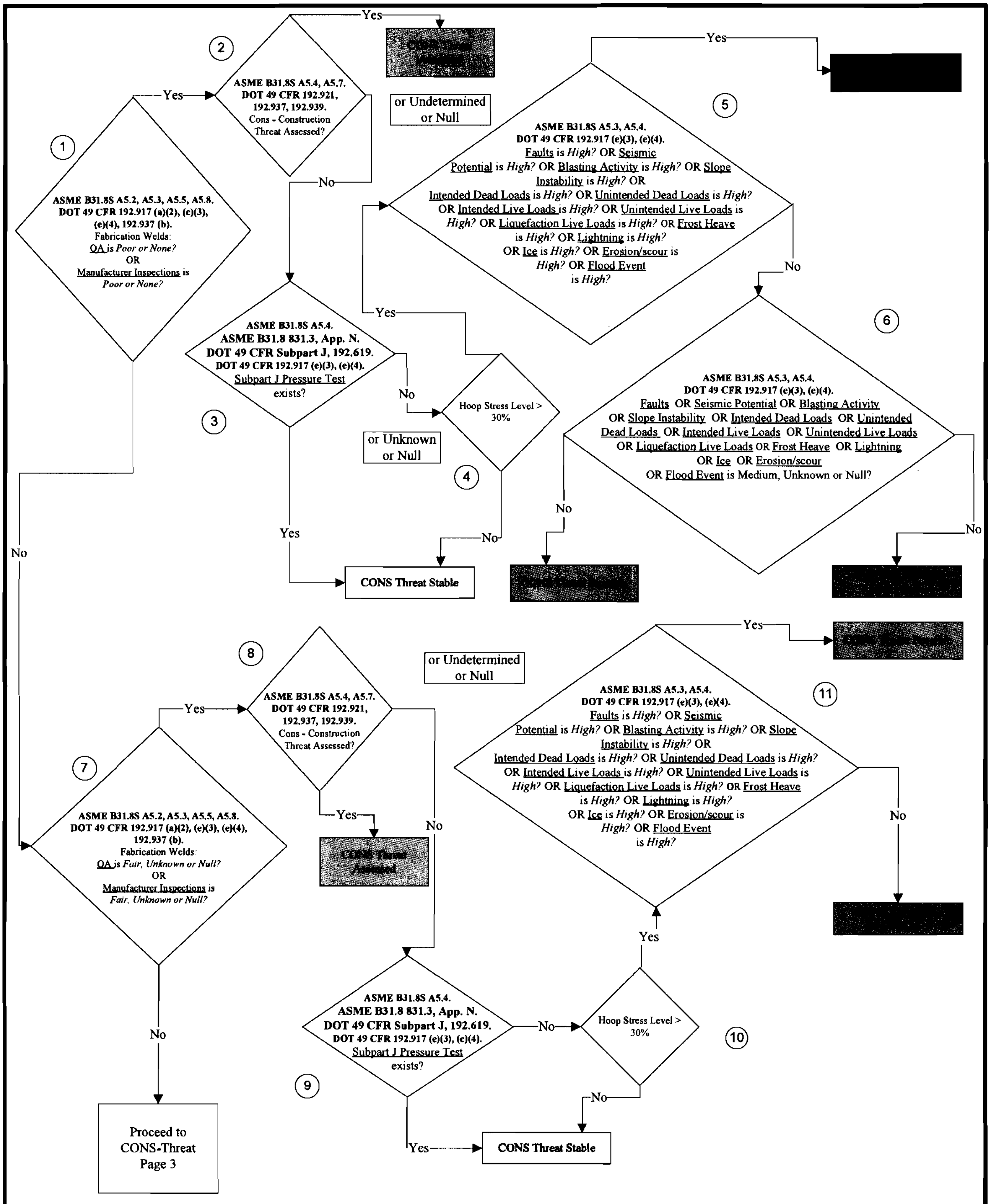
AMERICAN INNOVATIONS
7810 South Shaffer Parkway, Suite 150
Littleton, Colorado 80127

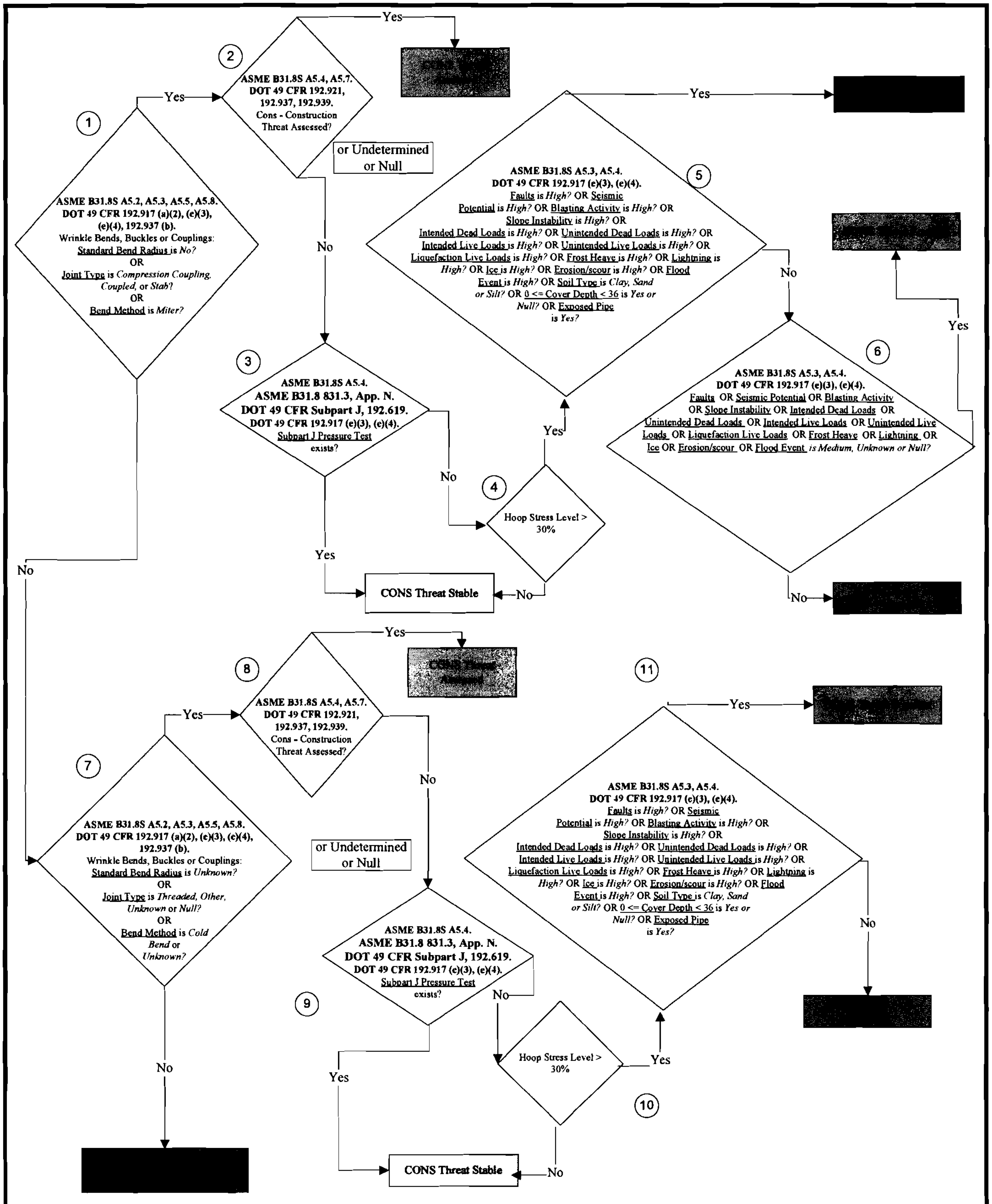
MFG Threat Evaluation

Revision Date: 5/23/2007

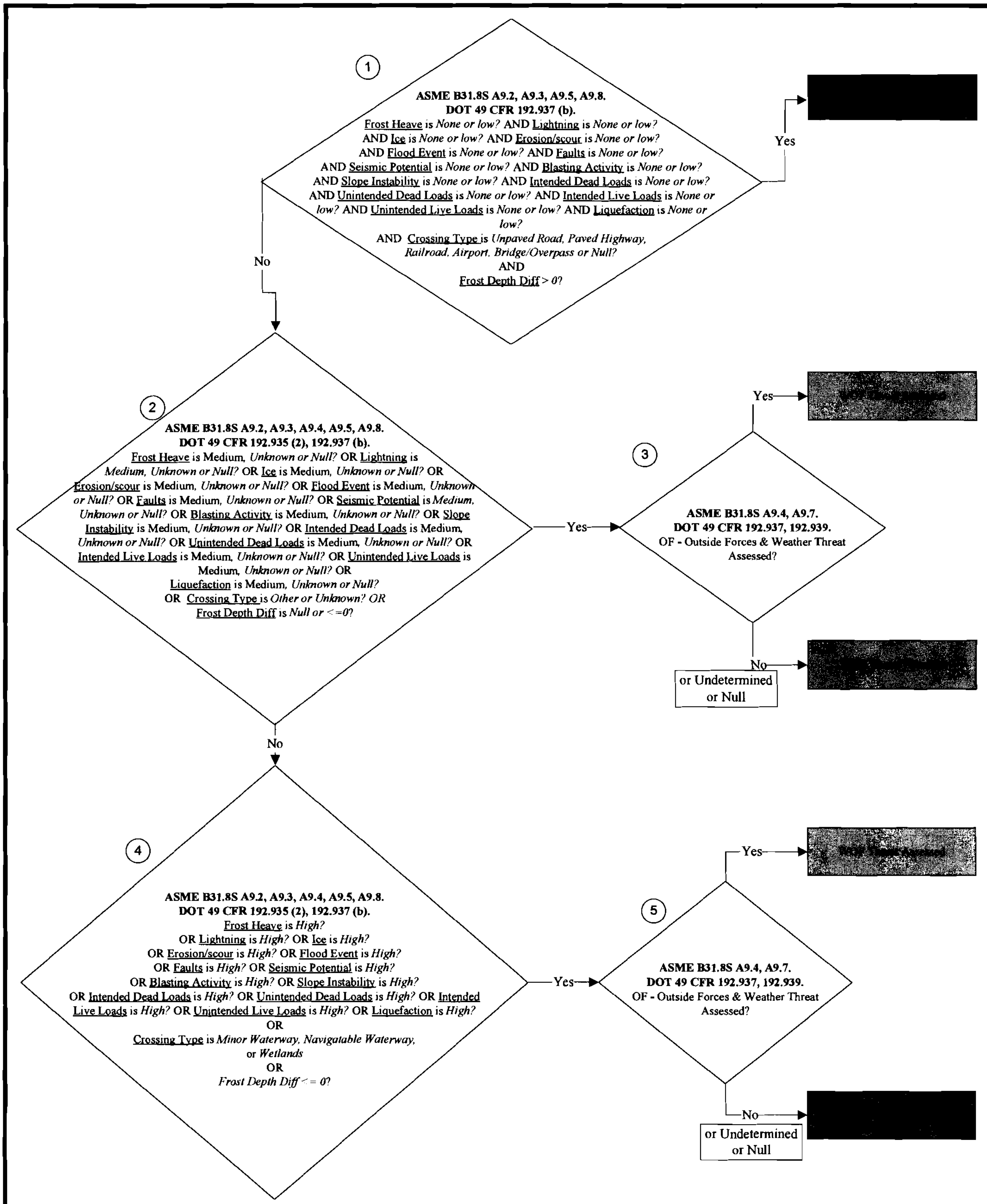
SOUTHERN STAR CENTRAL GAS PIPELINE

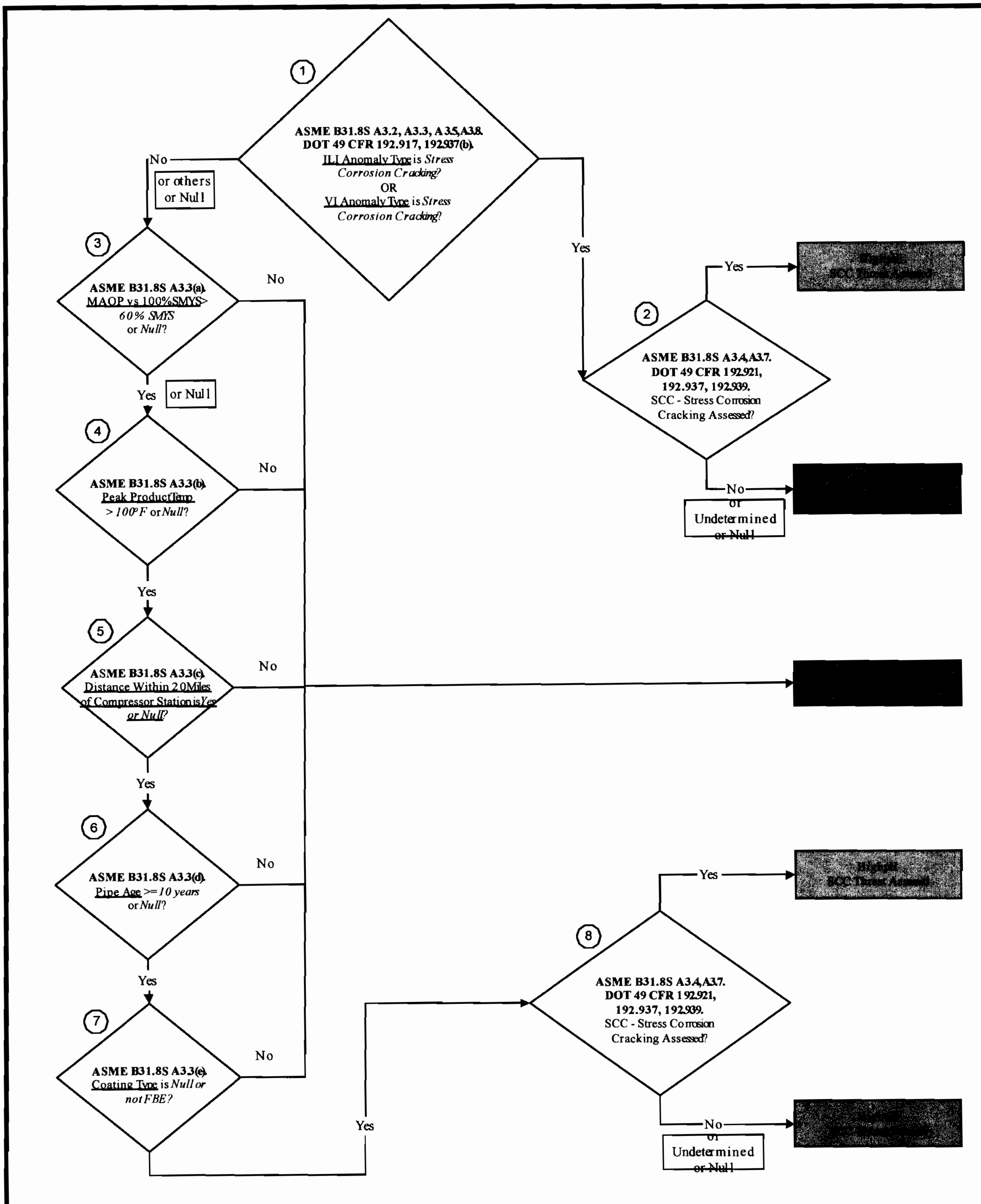

1
ASME B31.8S A5.2, A5.3, A5.5, A5.8.
DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b).
Girth Welds:
Weld Procedure Used is Unknown or No?
AND
Joint Inspection is No RT, Pre-1970 Installation (No RT) or Couplings, or Unknown?
OR
Weld Method is Pre-1950 Electric Arc or Acetylene Weld
AND
Questionable Reinforcements is No Reinforcements?
Yes
No
2
ASME B31.8S A5.4, A5.7.
DOT 49 CFR 192.921, 192.937, 192.939.
Cons - Construction Threat Assessed?
No
or Undetermined or Null
Yes
3
ASME B31.8S A5.4.
ASME B31.8 831.3, App. N.
DOT 49 CFR Subpart J, 192.619.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Subpart J Pressure Test exists?
4
Yes
CONS Threat Stable
No
or Unknown or Null
5
Hoop Stress Level > 30%
6 A
Yes
No
CONS Threat Stable
6 B
7
ASME B31.8S A5.2, A5.3, A5.5, A5.8.
DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b).
Girth Welds:
Weld Procedure Used is Unknown, No or Null?
AND
Joint Inspection is No RT, Pre-1970 Installation (No RT) or Couplings, AUT Inspection, Pre 1970 Possible RT, Other, Unknown or Null?
OR
Weld Method is Pre-1950 Electric Arc, Pre-1970 Electric Arc, T&C, Other, Unknown, Acetylene or Null?
Yes
No
Proceed to CONS-Threat Page 2
8
ASME B31.8S A5.4, A5.7.
DOT 49 CFR 192.921, 192.937, 192.939.
Cons - Construction Threat Assessed?
Yes
No
or Undetermined or Null
9
ASME B31.8S A5.4.
ASME B31.8 831.3, App. N.
DOT 49 CFR Subpart J, 192.619.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Subpart J Pressure Test exists?
10
Yes
CONS Threat Stable
or Unknown or Null
No
Hoop Stress Level > 30%
11
Yes
12
No
CONS Threat Stable


1
ASME B31.8S A5.2, A5.3, A5.5, A5.8. DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b). Fabrication Welds: QA is Poor or None? OR Manufacturer Inspections is Poor or None?
Yes
No
2
ASME B31.8S A5.4, A5.7. DOT 49 CFR 192.921, 192.937, 192.939. Cons - Construction Threat Assessed?
Yes
No
or Undetermined or Null
3
ASME B31.8S A5.4. ASME B31.8 831.3, App. N. DOT 49 CFR Subpart J, 192.619. DOT 49 CFR 192.917 (e)(3), (e)(4). Subpart J Pressure Test exists?
Yes
No
CONS Threat Stable
4
Hoop Stress Level > 30%
or Unknown or Null
Yes
No
5
ASME B31.8S A5.3, A5.4. DOT 49 CFR 192.917 (e)(3), (e)(4). Faults is High? OR Seismic Potential is High? OR Blasting Activity is High? OR Slope Instability is High? OR Intended Dead Loads is High? OR Unintended Dead Loads is High? OR Intended Live Loads is High? OR Unintended Live Loads is High? OR Liquefaction Live Loads is High? OR Frost Heave is High? OR Lightning is High? OR Ice is High? OR Erosion/scour is High? OR Flood Event is High?
Yes
No
6
ASME B31.8S A5.3, A5.4. DOT 49 CFR 192.917 (e)(3), (e)(4). Faults OR Seismic Potential OR Blasting Activity OR Slope Instability OR Intended Dead Loads OR Unintended Dead Loads OR Intended Live Loads OR Unintended Live Loads OR Liquefaction Live Loads OR Frost Heave OR Lightning OR Ice OR Erosion/scour OR Flood Event is Medium, Unknown or Null?
No
No
7
ASME B31.8S A5.2, A5.3, A5.5, A5.8. DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b). Fabrication Welds: QA is Fair, Unknown or Null? OR Manufacturer Inspections is Fair, Unknown or Null?
Yes
No
Proceed to CONS-Threat Page 3
8
ASME B31.8S A5.4, A5.7. DOT 49 CFR 192.921, 192.937, 192.939. Cons - Construction Threat Assessed?
or Undetermined or Null
Yes
No
CONS Threat Assessed
9
ASME B31.8S A5.4. ASME B31.8 831.3, App. N. DOT 49 CFR Subpart J, 192.619. DOT 49 CFR 192.917 (e)(3), (e)(4). Subpart J Pressure Test exists?
No
Yes
CONS Threat Stable
10
Hoop Stress Level > 30%
Yes
No
11
ASME B31.8S A5.3, A5.4. DOT 49 CFR 192.917 (e)(3), (e)(4). Faults is High? OR Seismic Potential is High? OR Blasting Activity is High? OR Slope Instability is High? OR Intended Dead Loads is High? OR Unintended Dead Loads is High? OR Intended Live Loads is High? OR Unintended Live Loads is High? OR Liquefaction Live Loads is High? OR Frost Heave is High? OR Lightning is High? OR Ice is High? OR Erosion/scour is High? OR Flood Event is High?
Yes
No

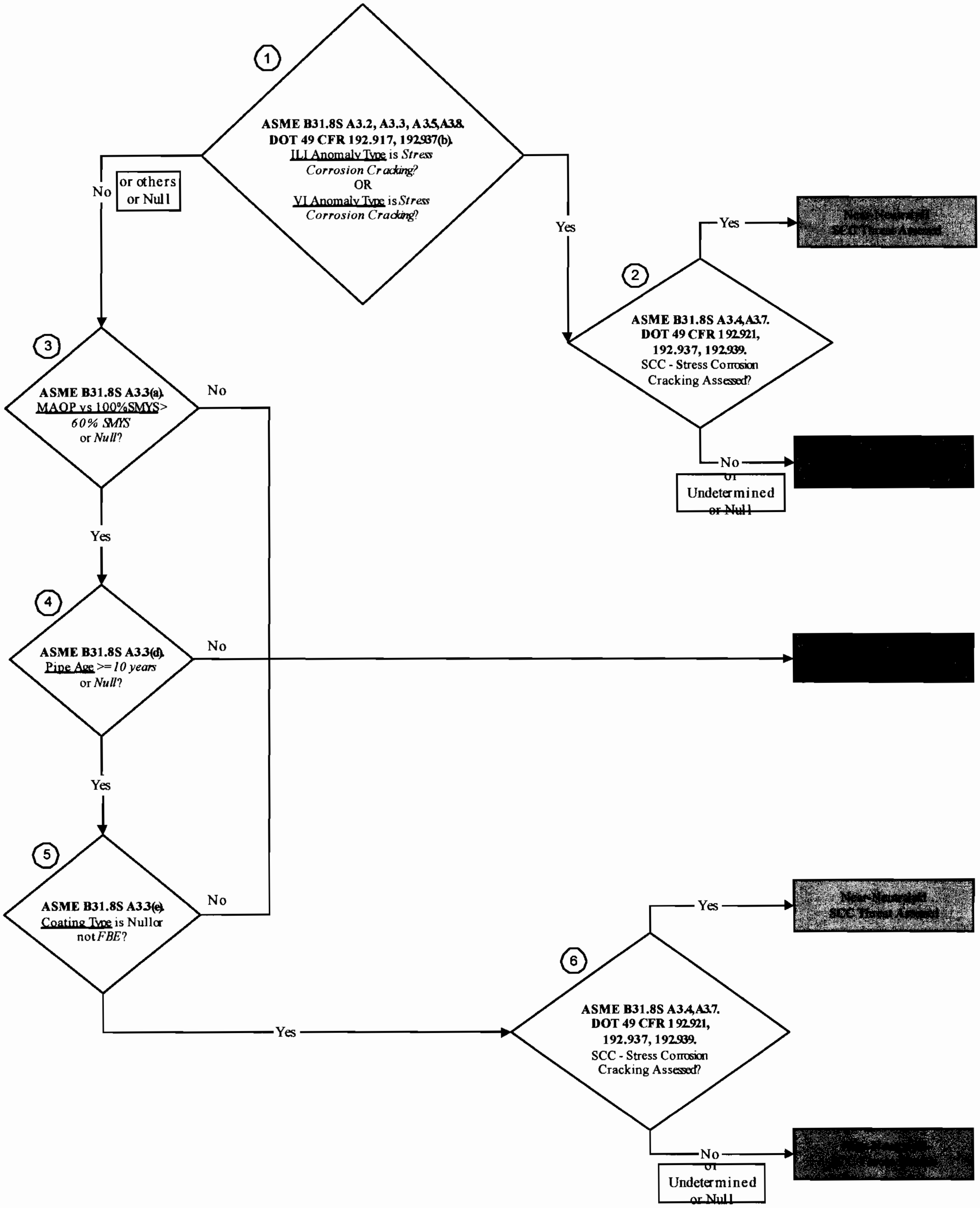


1
ASME B31.8S A5.2, A5.3, A5.5, A5.8.
DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b).
Wrinkle Bends, Buckles or Couplings:
Standard Bend Radius is No?
OR
Joint Type is Compression Coupling, Coupled, or Stab?
OR
Bend Method is Miter?
Yes
No
2
ASME B31.8S A5.4, A5.7.
DOT 49 CFR 192.921, 192.937, 192.939.
Cons - Construction Threat Assessed?
Yes
or Undetermined or Null
No
3
ASME B31.8S A5.4.
ASME B31.8 831.3, App. N.
DOT 49 CFR Subpart J, 192.619.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Subpart J Pressure Test exists?
Yes
No
4
Hoop Stress Level > 30%
Yes
No
CONS Threat Stable
5
ASME B31.8S A5.3, A5.4.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Faults is High? OR Seismic Potential is High? OR Blasting Activity is High? OR Slope Instability is High? OR Intended Dead Loads is High? OR Unintended Dead Loads is High? OR Intended Live Loads is High? OR Unintended Live Loads is High? OR Liquefaction Live Loads is High? OR Frost Heave is High? OR Lightning is High? OR Ice is High? OR Erosion/scour is High? OR Flood Event is High? OR Soil Type is Clay, Sand or Silt? OR 0 <= Cover Depth < 36 is Yes or Null? OR Exposed Pipe is Yes?
Yes
[redacted]
No
6
ASME B31.8S A5.3, A5.4.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Faults OR Seismic Potential OR Blasting Activity OR Slope Instability OR Intended Dead Loads OR Unintended Dead Loads OR Intended Live Loads OR Unintended Live Loads OR Liquefaction Live Loads OR Frost Heave OR Lightning OR Ice OR Erosion/scour OR Flood Event is Medium, Unknown or Null?
Yes
No
[redacted]
7
ASME B31.8S A5.2, A5.3, A5.5, A5.8.
DOT 49 CFR 192.917 (a)(2), (e)(3), (e)(4), 192.937 (b).
Wrinkle Bends, Buckles or Couplings:
Standard Bend Radius is Unknown?
OR
Joint Type is Threaded, Other, Unknown or Null?
OR
Bend Method is Cold Bend or Unknown?
Yes
No
[redacted]
8
ASME B31.8S A5.4, A5.7.
DOT 49 CFR 192.921, 192.937, 192.939.
Cons - Construction Threat Assessed?
Yes
CONS Threat Assessed
or Undetermined or Null
No
9
ASME B31.8S A5.4.
ASME B31.8 831.3, App. N.
DOT 49 CFR Subpart J, 192.619.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Subpart J Pressure Test exists?
No
Yes
10
Hoop Stress Level > 30%
Yes
No
CONS Threat Stable
11
ASME B31.8S A5.3, A5.4.
DOT 49 CFR 192.917 (e)(3), (e)(4).
Faults is High? OR Seismic Potential is High? OR Blasting Activity is High? OR Slope Instability is High? OR Intended Dead Loads is High? OR Unintended Dead Loads is High? OR Intended Live Loads is High? OR Unintended Live Loads is High? OR Liquefaction Live Loads is High? OR Frost Heave is High? OR Lightning is High? OR Ice is High? OR Erosion/scour is High? OR Flood Event is High? OR Soil Type is Clay, Sand or Silt? OR 0 <= Cover Depth < 36 is Yes or Null? OR Exposed Pipe is Yes?
Yes
No
[redacted]


1
ASME B31.8S A9.2, A9.3, A9.5, A9.8.
DOT 49 CFR 192.937 (b).
Frost Heave is None or low? AND Lightning is None or low?
AND Ice is None or low? AND Erosion/scour is None or low?
AND Flood Event is None or low? AND Faults is None or low?
AND Seismic Potential is None or low? AND Blasting Activity is None or low?
AND Slope Instability is None or low? AND Intended Dead Loads is None or low?
AND Unintended Dead Loads is None or low? AND Intended Live Loads is None or low? AND Unintended Live Loads is None or low? AND Liquefaction is None or low?
AND Crossing Type is Unpaved Road, Paved Highway, Railroad, Airport, Bridge/Overpass or Null?
AND
Frost Depth Diff > 0?
Yes
[redacted]
No
2
ASME B31.8S A9.2, A9.3, A9.4, A9.5, A9.8.
DOT 49 CFR 192.935 (2), 192.937 (b).
Frost Heave is Medium, Unknown or Null? OR Lightning is Medium, Unknown or Null? OR Ice is Medium, Unknown or Null? OR Erosion/scour is Medium, Unknown or Null? OR Flood Event is Medium, Unknown or Null? OR Faults is Medium, Unknown or Null? OR Seismic Potential is Medium, Unknown or Null? OR Blasting Activity is Medium, Unknown or Null? OR Slope Instability is Medium, Unknown or Null? OR Intended Dead Loads is Medium, Unknown or Null? OR Unintended Dead Loads is Medium, Unknown or Null? OR Intended Live Loads is Medium, Unknown or Null? OR Unintended Live Loads is Medium, Unknown or Null? OR
Liquefaction is Medium, Unknown or Null?
OR Crossing Type is Other or Unknown? OR
Frost Depth Diff is Null or <=0?
Yes
3
ASME B31.8S A9.4, A9.7.
DOT 49 CFR 192.937, 192.939.
OF - Outside Forces & Weather Threat Assessed?
Yes
No
or Undetermined or Null
No
4
ASME B31.8S A9.2, A9.3, A9.4, A9.5, A9.8.
DOT 49 CFR 192.935 (2), 192.937 (b).
Frost Heave is High?
OR Lightning is High? OR Ice is High?
OR Erosion/scour is High? OR Flood Event is High?
OR Faults is High? OR Seismic Potential is High?
OR Blasting Activity is High? OR Slope Instability is High?
OR Intended Dead Loads is High? OR Unintended Dead Loads is High? OR Intended Live Loads is High? OR Unintended Live Loads is High? OR Liquefaction is High?
OR
Crossing Type is Minor Waterway, Navigatable Waterway, or Wetlands
OR
Frost Depth Diff <= 0?
Yes
5
ASME B31.8S A9.4, A9.7.
DOT 49 CFR 192.937, 192.939.
OF - Outside Forces & Weather Threat Assessed?
Yes
No
or Undetermined or Null
[redacted]



AMERICAN INNOVATIONS 7810 South Shaffer Parkway, Suite 150 Littleton, Colorado 80127	**High pH SCC Threat Evaluation** Revision Date: 6/2/2007	SOUTHERN STAR CENTRAL GAS PIPELINE

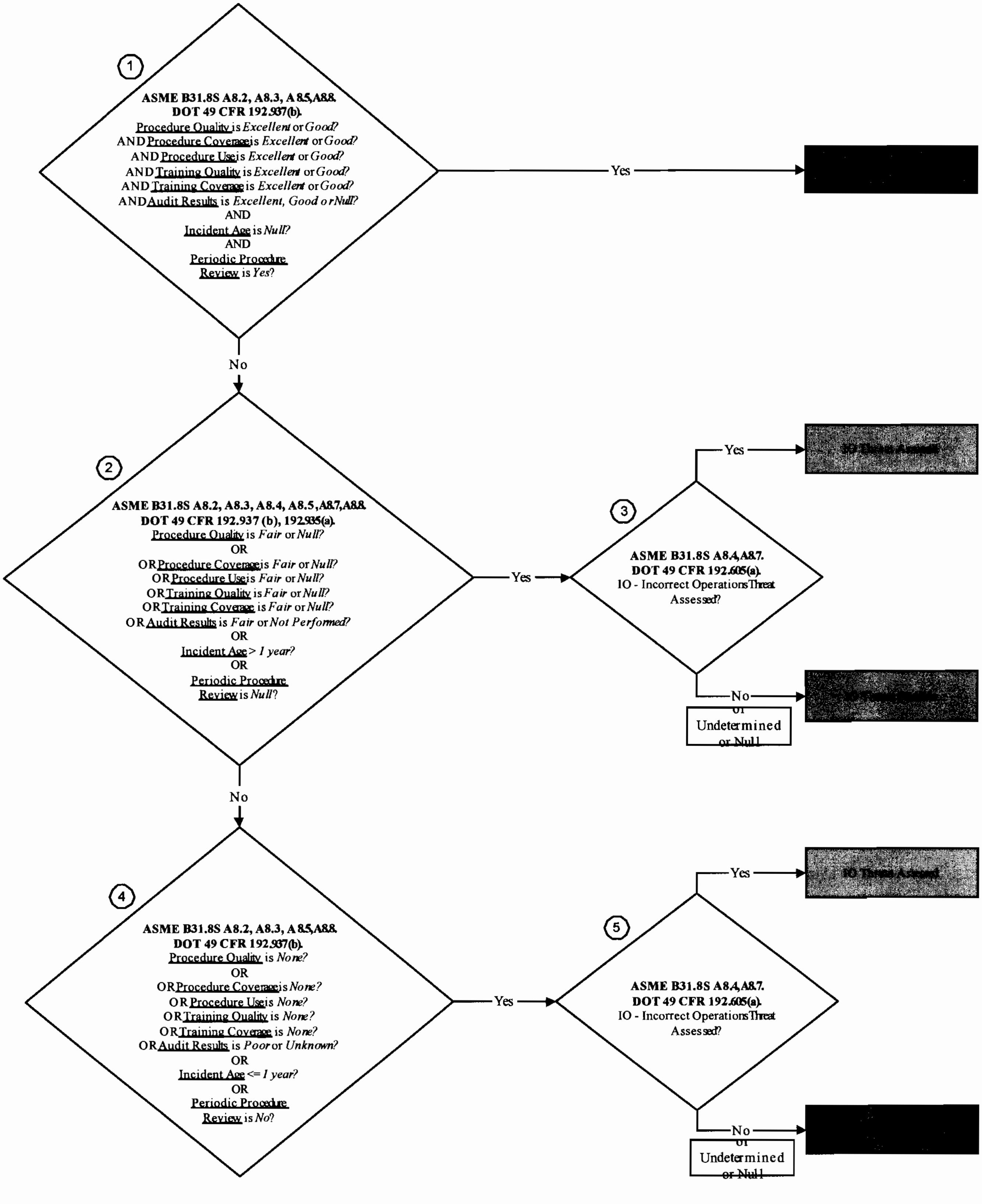


AMERICAN INNOVATIONS
7810 South Shaffer Parkway, Suite 150
Littleton, Colorado 80127

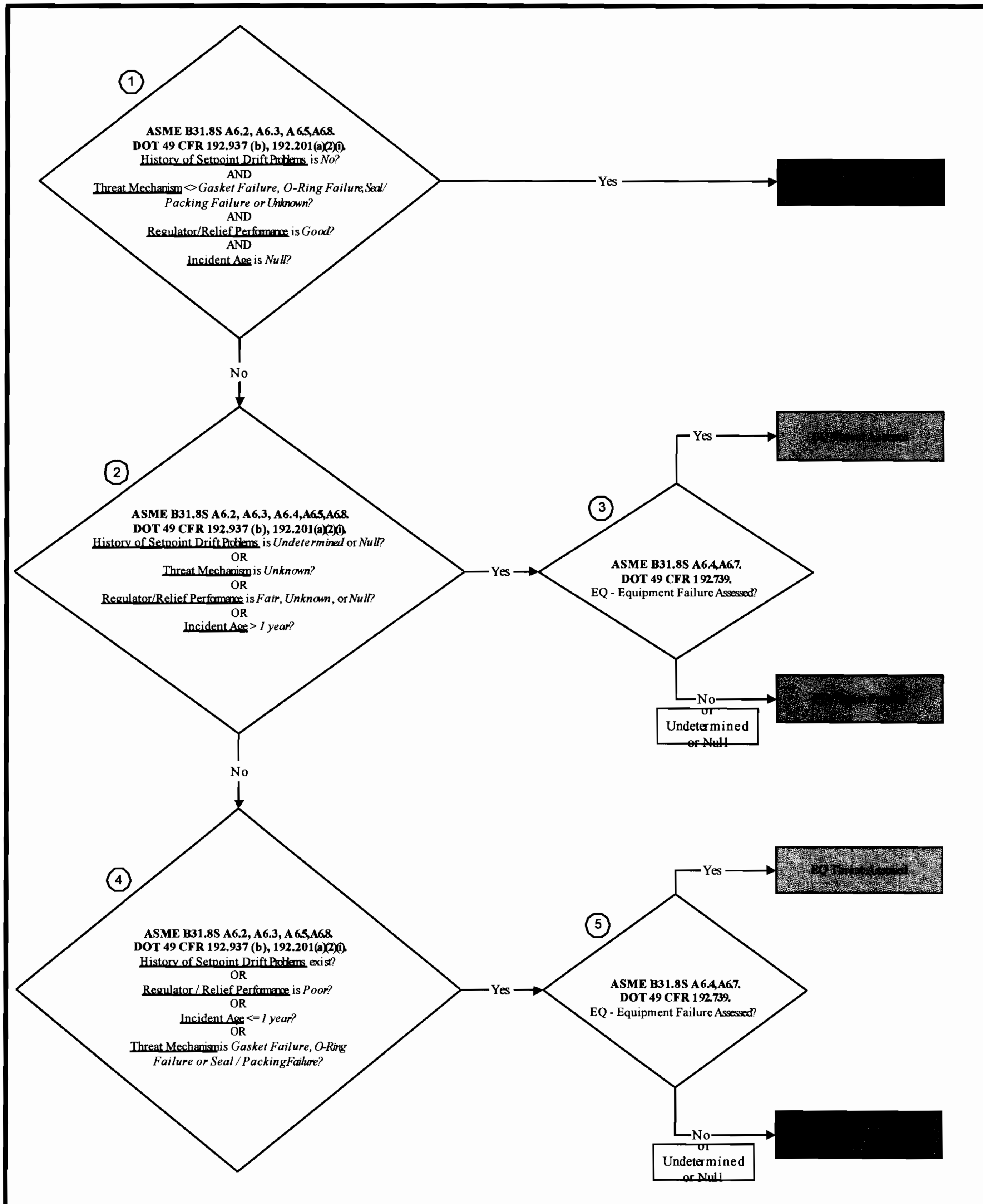
Near Neutral pH SCC Threat Evaluation

Revision Date: 5/23/2007

SOUTHERN STAR CENTRAL GAS PIPELINE



AMERICAN INNOVATIONS 7810 South Shaffer Parkway, Suite 150 Littleton, Colorado 80127	**IO Threat-Human Error Evaluation** Revision Date: 5/23/2007	SOUTHERN STAR CENTRAL GAS PIPELINE


1
ASME B31.8S A6.2, A6.3, A 6.5, A6.8.
DOT 49 CFR 192.937 (b), 192.201(a)(2)(i).
History of Setpoint Drift Problems is No?
AND
Threat Mechanism <> Gasket Failure, O-Ring Failure, Seal/ Packing Failure or Unknown?
AND
Regulator/Relief Performance is Good?
AND
Incident Age is Null?
Yes
[redacted]
No
2
ASME B31.8S A6.2, A6.3, A6.4, A6.5, A6.8.
DOT 49 CFR 192.937 (b), 192.201(a)(2)(i).
History of Setpoint Drift Problems is Undetermined or Null?
OR
Threat Mechanism is Unknown?
OR
Regulator/Relief Performance is Fair, Unknown, or Null?
OR
Incident Age > 1 year?
Yes
3
ASME B31.8S A6.4, A6.7.
DOT 49 CFR 192.739.
EQ - Equipment Failure Assessed?
Yes
EQ Threat Assessed
No or Undetermined or Null
No
4
ASME B31.8S A6.2, A6.3, A 6.5, A6.8.
DOT 49 CFR 192.937 (b), 192.201(a)(2)(i).
History of Setpoint Drift Problems exist?
OR
Regulator / Relief Performance is Poor?
OR
Incident Age <= 1 year?
OR
Threat Mechanism is Gasket Failure, O-Ring Failure or Seal / Packing Failure?
Yes
5
ASME B31.8S A6.4, A6.7.
DOT 49 CFR 192.739.
EQ - Equipment Failure Assessed?
Yes
EQ Threat Assessed
No or Undetermined or Null
[redacted]

Appendix 5

Amended Documents Per
Notice of Amendment

Prioritization of Unstable Manufacturing Defects as High-Risk Segments

CPF 4-2007-1012

BASELINE ASSESSMENT PLAN DEVELOPMENT
(§192.919, §192.921)

1.0 INTRODUCTION

SSCGP has developed a Baseline Assessment Plan. This document details the development and background for the Baseline Assessment Plan. Two related Integrity Management documents are also contained in the Baseline Assessment section of the SSCGP Integrity Management Plan:

- Baseline Assessment Plan
    - Documents identified threats and assessment scope and methods for covered pipeline segments
    - Generated from the O&E database Assessment Scheduling module and Risk Program Results
- Performing Integrity Assessments
    - Documents procedures, data validation, record keeping and quality assurance for integrity assessments

2.0 RELATED PROCEDURES AND FORMS

The Baseline Assessment Plan element includes the following procedures and forms:

- *Baseline Assessment Plan*
- *IMP.E2.BAP.01 "Determining Integrity Assessment Methods"*
- *IMP.E2.BAP.02 "Incorporating Newly Identified HCAs into the Baseline Assessment Plan"*
- *IMP.E2.BAP.03 "Scheduling Assessments"*
- *IMP.E2.BAP.04 "Retiring / Reducing HCAs in the Baseline Plan and Assessment Schedule "*

This document also references the following related documents, procedures and forms:

- *IMP.E2.ASMT.05 "Integrating ILI Data with Encroachment Data"*
- *IMP.E2.ASMT.06 "Finding Corrosion in an HCA"*
- *IMP.E3.THR.01 "Threat Analysis Justification"*
- *IMP.E8.PREV.03 "Identifying and Implementing Preventive and Mitigative Measures"*
- *IMP.E11.MOC.01 "Management of Change – Preparing and Submitting a Change Request"*
- *IMP.E13.COM.02 "Providing Notification to PHMSA"*
- *SSCGP-IMP-1100 "Changes to the IMP and Pipeline System Approval Form"*

3.0 BASELINE ASSESSMENT PLAN DOCUMENTATION

The Baseline Assessment Plan is documented in the "Assessment Plan Report" which is generated out of the O&E database based on information input into the Assessment Scheduling module.

Specific details for each individual assessment are included in the corresponding Integrity Assessment documentation. This documentation such Integrity Assessment Life Cycle Documents SSCGP-IMP-0200 or SSCGP-IMP-0202 are stored in the Assessment Scheduling module of the O&E database. These forms are used to document changes in the planned assessment and to guide in execution of the assessment.

3.1 December 17, 2007 and December 17, 2012 Deadlines

Per Part 192 Subpart O and Procedure IMP.E2.BAP.03, latest revision, "Scheduling Assessments" SSCGP will perform a baseline integrity assessment on at least 50% of the covered pipeline segments by December 17, 2007. The highest risk segments will be considered first for assessment; the remaining covered segments will be assessed by December 17, 2012.

SSCGP is taking a proactive approach to the integrity assessments and has scheduled to assess more footage than what is required by December 17, 2007 deadline. The IMP Steering Committee prioritized and scheduled the baseline assessments such that more than 50% of the covered segments will be assessed by December 17, 2007. This approach will allow SSCGP to still meet the 50% by December 17, 2007 requirement in the event that availability of a tool, failure to reach an agreement with an end-user, or other issue beyond the control of SSCGP delays the execution of an integrity assessment. Other business issues also require SSCGP to assess High Consequence Area footage ahead of schedule. Business issues such as customer increases in service or reroutes of existing lines make the delay of baseline integrity assessments and integrity reassessments justifiable from both SSCGP and its customer's perspective. Excess footage must be assessed to make such a delay possible.

3.2 Assessments Prior to December 17, 2002

Based upon the determination of 2004 HCAs, SSCGP will not use any assessments conducted prior to December 17, 2002 as a baseline assessment. However, SSCGP reserves the right to receive credit for any such assessments in the future at the discretion of the Project Manger Pipeline Integrity Management and IMP Steering Committee. Requirements for using assessments before December 17, 2002 would be detailed at that time.

4.0 PRIORITIZATION OF 2004-2007 BASELINE ASSESSMENTS

4.1 2004 Assessments

When SSCGP began developing the risk assessment model for integrity management, the Office of Pipeline Safety (now PHMSA) had not made the final determination on how to define a High Consequence Area. SSCGP decided at that time to consider each Class 3 area as an HCA. Pipeline Safety then segmented the pipeline system for the risk model database by this defined HCA and determined risk scores for HCA segments.

The Risk Assessment Program (RAP) generated a Risk of Failure (ROF) score for each segment. The HCAs were ranked based upon their ROF scores. Lines containing HCAs with the highest ROF were considered first for baseline assessment.

Selection of the lines to be assessed in 2004 was based upon the Risk of Failure scores as determined by the RAP and what SSCGP believed could reasonably be completed by the end of the year. Furthermore, SSCGP strives to minimize customer inconveniences and disruptions by assessing lines with lesser risk scores along with the higher-risk HCA when performing integrity assessments so that additional disruptions are not required. Combining high and low-risk HCA assessments also reduces costs for the operator that would otherwise eventually result in higher costs for the SSCGP customer. Scheduling of the initial integrity assessment was based on the HCA with the highest risk in the test segment.

Baseline assessments for 2004 were already being executed at the time the decision to revised the RAP and algorithm was made. These assessments were completed as designed and scheduled.

4.2 2005 to 2007 Assessments

SSCGP scheduled integrity assessments for 2005 to 2007 based upon ROF scores determined by the original risk algorithm using the 1000-foot segmentation and comparison criteria as outlined in Element 3 "Risk Assessment Program Development". As a result of modifications, there was a slight change in the risk ranking; however, in most cases the ROF for the lines assessed in 2004 still fell within the top 10% using the new algorithm and comparison criteria.

The Steering Committee considered the highest risk HCA segments (excluding HCAs assessed in 2004) for assessment by December 17, 2007. The top-tier was considered for 2005; the next tier, 2006; the third tier, 2007. In some cases the assessment of a lower risk HCA was included with the assessment of a higher risk HCA in order to capitalize on the efficiencies of performing these assessments together.

Additionally, Project Manager Pipeline Integrity Management reviewed leaks that occurred over the past ten (10) years in existing HCAs and the circumstances under which they occurred. Project Manager Pipeline Integrity Management and the IMP Steering Committee evaluated these circumstances and in some cases assigned a higher priority to certain segments than indicated by the ROF score alone. Regardless, more than 50% of the HCA segments (by footage) are scheduled for baseline assessment before December 17, 2007. Note: This schedule was based upon the known HCA footage in 2004.

5.0 PRIORITIZATION OF BASELINE ASSESSMENTS AFTER 2007

Assessments scheduled for years 2008 through 2012 are based on the results of the new Risk Assessment Program algorithm as well as other considerations. Procedure IMP.E2.BAP.03, latest revision, "Schedule Assessments" details the process for prioritizing and scheduling assessments.

Refer to Element 3 "Risk Assessment Program Development" for more information on the RAP software's capabilities. Refer to Element 3 "Risk Assessment and Threat Identification" for specific information on risk scores and threat screening results.

5.1 HCA Priority Ranking

The RAP prioritizes each HCA segment according to the following criteria developed by SSCGP. Maximum and weighted average ROF and POF scores are used to categorize the HCA as Priority 1 through 6 as shown in Table 1 below. Each HCA is placed in the highest priority group for which it qualifies.

Table 1 Single-HCA Priority Codes

Priority Code	***Criteria***	***Justification***
1	Weighted Average Overall ROF > 6.0	Indicates high potential risk for the HCA as a whole
2	Manufacturing Threat Present	Indicates a manufacturing threat due to pipe seam such as low-frequency ERW or EFW is present.
3	Maximum Overall ROF > 7.5	Indicates high potential risk for a sub-segment within the HCA
4	Weighted Average Overall POF > 0.70	Indicates high probability of failure for the HCA as a whole
5	Maximum Overall POF > 0.8	Indicates high probability of failure for a sub-segment within the HCA
6	All other HCAs	

5.1.1 Priority 1 – Average Risk of Failure

This indicates a high potential risk for the HCA as a whole. Since Risk of Failure (ROF) scores range from 1 to 10, a weighted average score greater than 6.0 indicates risk greater than the midpoint.

5.1.2 Priority 2 – Manufacturing / Pipe Seam Threats

Typically the existence of pipe with manufacturing threats (i.e. low-frequency ERW, EFW, lap-weld, etc.) will drive the overall ROF score higher; therefore, Priority 2 represents lower scoring HCAs with manufacturing threats. SSCGP decided not to rank manufacturing threats as Priority 1 since a significant portion of its system contains ERW pipe. By prioritizing in the order shown, SSCGP is able to screen HCAs more finely while still ensuring that Manufacturing threats are treated as high priority in accordance with §192.917(e).

5.1.3 Priority 3 – Maximum Risk of Failure

This indicated a high potential risk for a sub-segment within the HCA. A slightly higher cutoff value was selected for category 2 than 1 because presumably HCAs with ROF scores significantly higher than 7.5 for extended lengths will result in a high average score. These segments are ranked lower than those with known Manufacturing pipe seam threats.

5.1.4 Priority 4 – Average Probability of Failure

This indicates high probability of failure for the HCA as a whole. A POF score of 0.70 indicates a theoretical seventy percent (70%) probability of failure. This level addresses HCA's with a high Probability of Failure (POF) score.

5.1.5 Priority 5 – Maximum Probability of Failure

This indicates high probability of failure for a sub-segment within the HCA. A POF score of 0.80 indicates a theoretical eighty percent (80%) probability of failure on the segment. This level addresses small sub-segments with HCA's that have a high POF.

5.1.6 Priority 6 – All Other HCAs

Any HCA not meeting the criteria for Priorities 1 though 5 listed above are considered Priority 6. Within this category, HCAs are prioritized in descending order of Overall Weighted Average Risk of Failure (ROF) score.

5.2 Assessment Priority / Aggregate Risk

When a planned integrity assessment encompasses multiple HCAs, an aggregate risk for the entire assessment must be determined. SSCGP has decided to prioritize Assessments as shown in Table 2 below.

Table 2 Multiple-HCA Assessment Priority

Priority	*Criteria*
1	Contains any HCA ranked Priority 1
2	Contains any HCA ranked Priority 2
3	Contains any HCA ranked Priority 3
4	Contains any HCA ranked Priority 4
5	Contains any HCA ranked Priority 5
6	All other ranked according to Baseline Assessment Score

5.2.1 Baseline Assessment Score

The Baseline Assessment Score used to differentiate between assessments in the same category is determined in two steps.

$$HCA\ Score = \frac{HCA\ length}{average\ HCA\ length} \times (weighted\ \ average\ ROF)^2$$

$$Baseline\ Assessment\ Score = HCA\ Score_1 + HCA\ Score_2 + HCA\ Score_3 + \ldots.$$

In this way, some consideration is given to the relative length of each HCA within the assessment segment but yet short HCAs with high ROF scores are weighted more heavily. This minimizes the likelihood that a short segment with a very high Risk of Failure will be completely overshadowed by larger but lower risk HCAs.

5.3 Other Considerations

SSCGP strives to minimize customer inconveniences and disruptions by assessing lines with lesser risk scores along with the higher-risk HCA when performing integrity assessments so that additional disruptions are not required. Combining high and low-risk HCA assessments also reduces costs for the operator that would otherwise eventually result in higher costs for the SSCGP customer.

Schedule adjustments based on these types of considerations are not contrary to the HCA prioritization process. Priority rankings are determined and used as a tool for scheduling baseline assessments but are not the only source of information.

5.4 2008 to 2012 Completion of Framework Status

As part of continual improvement of the SSCGP Integrity Management Program, SSCGP made significant modifications to the RAP database, software and algorithm. SSCGP anticipated having the software conversion completed, a new algorithm developed and new risk scores generated by September 30, 2007. Therefore, identified threats will change once modifications are complete and the new algorithm is run. As a result, for the lines scheduled for assessment in 2008 to 2012 – the lower risk HCA segments – threats will be identified by the original RAP, but were not validated and reviewed by Subject Matter Experts after implementation of the new RAP in 2007.

SSCGP also recognized that choosing an assessment method and developing the details of the assessment may not be the best use of resources while the new RAP was under development. Therefore, SSCGP decided to document the 2008 to 2012 assessments as a framework in order to allow resources to focus on other aspects of IMP development and execution as well as the improvements to the RAP database and algorithm. Beginning with the validation of risk and threat results, SSCGP will initially focus efforts on completing a documented Baseline Assessment Plan for 2008, then for the remainder of the baseline assessments.

6.0 NEWLY IDENTIFIED HIGH CONSEQUENCE AREAS

Once a new HCA is identified, it is added to the Integrity Management Program per Procedure IMP.E2.BAP.02 "Incorporating Newly Identified HCAs into the Baseline Assessment Plan". The new HCA is incorporated into the Baseline Assessment Plan within one (1) year of identification. A baseline integrity assessment is performed within ten (10) years of identification.

In some cases, a newly identified HCA may be combined with or added to an adjacent HCA for the purpose of efficiently performing the required assessments. However, the combined HCA is placed in the assessment schedule such that no portion of the total covered segment experiences an assessment interval longer than allowed by regulation CFR 192 Subpart O.

6.1 Elimination of HCAs

As conditions around the pipeline change some High Consequence Areas may be reduced in size or eliminated entirely. Refer to Procedure IMP.E2.BAP.04, latest revision, "Retiring / Reducing HCAs in the Baseline Plan and Assessment Schedule" for more information.

7.0 ASSESSMENT METHOD SELECTION AND JUSTIFICATION

Procedure IMP.E2.BAP.01 "Determining Integrity Assessment Methods" details the process used to select assessment methods based on threat applicability and feasibility.

7.1 In-Line Inspection

By using a high-resolution MFL tool as well as a caliper tool for the In-Line Inspection (ILI), SSCGP will obtain significantly greater detail of metal loss due to external or internal corrosion than by using a pressure test. The combination of these two tool runs provides a thorough indication of metal loss anomalies that may fall short of failure during a pressure test.

ILI is appropriate for addressing metal loss due to both external and internal corrosion threats. In addition it can identify dents and gouges caused by third-party damage that might not have caused a pressure test failure. Third-party damage is particularly addressed by integrating known encroachment and crossing data against the ILI findings. An anomaly discovered at or near a known encroachment has significant probability of being due to third-party damage, particularly if a dent or gouge is located on the top half of the pipe. SSCGP evaluates the ILI report and classifies any anomaly as an Immediate Condition, One-Year, Scheduled, or Monitored Condition per Procedures IMP.E5.REM.00, IMP.E5.REM.01, IMP.E5.REM.03, and IMP.E5.REM.02, latest revisions. In this way, any accelerated corrosion due to the interaction with dents or gouges from Third-Party Damage, Manufacturing, or Construction threats will be addressed.

In-Line Inspection is a desirable option because the detailed inspection results provide useful data for assessing the condition of the pipeline. ILI is not appropriate, however, for all lines. Those with active manufacturing or construction threats ideally require a pressure test; however transverse flux (TFI) inspection tools can be effective for assessing pipeline seam integrity. Lines without ILI pig launching or receiving facilities would require modification and construction, which may be cost-prohibitive. Lines that do not meet minimum geometry and flow conditions required for successful tool runs cannot be assessed via In-Line Inspection.

7.1.1 Caliper / Geometry / DeformationTool

Caliper tools – also known as deformation or geometry tools – are primarily used for detecting damage to the line that involves deformation of the pipe cross section. This damage is often the result of third-party damage, construction damage, dents caused by pipe settling onto rocks, wrinkles, or buckles. Caliper tools range in complexity from single-channel gaging pigs to multi-channel caliper pigs. SSCGP utilizes multi-channel (high-resolution) equipment that provides detailed results, including deformation sizing. Unless stated otherwise in the appropriate subparagraph describing an assessment, SSCGP uses a combination of caliper and MFL tool runs to assess its pipe.

Per NACE Standard RP0102-2002, caliper tools are generally used for detection and sizing of the following anomalies:

- Dents & Sharp Dents
- Wrinkle bends
- Buckles
- Gouges
- Bends
- Ovalities

7.1.2 Magnetic Flux Leakage (MFL) Tool – High Resolution

MFL tools are well suited to detect metal loss although sizing accuracy is somewhat limited for irregular geometries such as what might be found with a dent. A high-resolution MFL tool was selected for its ability to detect defects other than metal loss. Unless stated otherwise in the appropriate subparagraph describing an assessment, SSCGP uses a combination of caliper and MFL tool runs to assess its pipe.

Per NACE Standard RP0102-2002, high-resolution MFL tools are generally used for detection and sizing of the following anomalies:

- Metal loss due to External Corrosion
- Metal loss due to Internal Corrosion
- Circumferential cracking
- Gouges
- Dents, sharp dents, wrinkle bends (sizing not reliable)

Additionally, high-resolution MFL tools can detect:

- Circumferential position of buckles
- Previous repairs with steel sleeves, patches, or ferrous markers
- Laminations / Inclusions (limited detection)
- Mill-related anomalies (limited detection)

7.1.3 Transverse Flux Inspection (TFI) Tool

Although SSCGP primarily uses a combination of caliper and high-resolution MFL tools in its In-Line Inspections, it recognizes that for some applications, a transverse MFL – also known as TFI – tool may be required. TFI tools have different capabilities and would be particularly useful where cracks or crack-like defects or selective seam corrosion issues are likely. Use of this tool type will be noted in the Baseline Assessment Plan when necessary.

Per NACE Standard RP0102-2002, high-resolution transverse MFL tools are generally used for detection and sizing of the following anomalies:

- Metal loss due to External Corrosion
- Metal loss due to Internal Corrosion
- Narrow axial External Corrosion
- Axial cracks & crack-like defects
    - SCC*
    - Fatigue cracks
    - Longitudinal seam weld imperfections
    - Incomplete fusion
    - Toe cracks
- Gouges
- Dents, sharp dents, and wrinkle bends (sizing not reliable)

**Note:* SCC cannot be detected until crack openings grow beyond 0.1 mm; therefore, even transverse MFL tools are not reliable for early detection of SCC.

Additionally, transverse MFL tools can detect:

- Circumferential position of buckles
- Previous repairs with steel sleeves, patches, or ferrous markers
- Laminations / Inclusions (limited detection)
- Mill-related anomalies (limited detection)

7.1.4 Inertial Mapping Unit (IMU)

SSCGP reserves the right to use ILI mapping tools in combination with one or more other tools in its Integrity Assessments.

Per NACE Standard RP0102-2002, mapping tools provide pipeline coordinates and can be used for detection and sizing of the following anomalies:

- Bends
- Ovalities
- Dents, sharp dents, and wrinkle bends (sizing not reliable)

7.1.5 Electro Magnetic Acoustic Transducer (EMAT) Tool

EMAT technology has been adapted for use in natural gas pipelines for crack detection applications. SSCGP reserves the right to employ EMAT tools in situations where cracks or crack-like defects are a particular concern. Use of this tool type will be noted in the Baseline Assessment Plan when necessary.

EMAT tools are capable of detecting the following anomalies:

- SCC colonies
- Sub-critical Stress Corrosion Cracking
- Longitudinal cracking
- Long seam cracks

7.2 Pressure Test

Pressure testing has historically proven effectiveness, widespread use, and flexibility for addressing a large number of threats – including external and internal corrosion, stress corrosion cracking, manufacturing and construction per ASME B31.8S, Section 6.3.

Pressure testing is the only assessment method that addresses manufacturing and construction threats per ASME B31.8S. Therefore, any HCAs with manufacturing or construction threats to be assessed (*i.e.*, those that could not be considered stable) require a Subpart J pressure test. HCAs with active manufacturing or construction threats ideally require a pressure test; however transverse flux (TFI) inspection tools can be effective for assessing pipeline seam integrity.

Unless required due to manufacturing or construction threats, pressure testing may not be the first choice for assessment methodology. Pressure tests can involve a significant amount of coordination and it is not always possible to maintain an alternate gas supply to all customers during the test.

7.3 Direct Assessment

Direct Assessment methods integrate known physical characteristics, operating history, inspection results, and examination results to determine the pipeline integrity. Separate and distinct processes are involved in each of the three types of Direct Assessment – External Corrosion, Internal Corrosion, and Stress Corrosion Cracking.

7.3.1 External Corrosion Direct Assessment (ECDA)

ECDA is a prescriptive process that is used to identify and address external corrosion activity on a pipeline. Furthermore, by integrating encroachment and foreign line crossing data with the indirect inspection data, SSCGP can evaluate for the threat of potential residual third-party damage. Although not specifically used to assess Stress Corrosion Cracking (SCC) and threats related to mechanical damage, evidence of mechanical damage and SCC may be found during an ECDA direct examination.

Although ECDA can only be used to assess the threat of external corrosion (and third-party damage when integrated with foreign line and encroachment data), ECDA is able to provide a thorough assessment of the threat by looking at many aspects of external corrosion including the level of cathodic protection and coating condition on a pipeline.

7.3.2 Internal Corrosion Direct Assessment (ICDA)

ICDA is a process that assesses the threat of internal corrosion and applies to pipeline segments transporting nominally dry natural gas. Indirect Inspection is used to identify areas of highest likelihood for internal corrosion. Direct Examination is then used to determine whether evidence of internal corrosion is present at these likely locations, extend beyond these locations, or is not present. ICDA can only be used to assess the threat of internal corrosion; it is often performed in conjunction with ECDA.

7.3.3 Stress Corrosion Cracking Direct Assessment (SCCDA)
SCCDA addresses the threat for Stress Corrosion Cracking. SSCGP's SCCDA procedures shall be completed prior to implementing this assessment method. The SCCDA method is appropriate due to the lack of SCC occurrences on SSCGP's pipeline and its typically low operating stress levels. Indications of SCC found during an SCCDA would warrant detailed analysis, potentially including a crack detection In-Line Inspection tool or a spike pressure test.

7.4 Threats Not Addressed by Assessment

Not every threat can or should be addressed using one of the three primary assessment methods – Pressure Test, ILI, or Direct Assessment. Rather, these threats are addressed through ongoing preventative and mitigative measures. These threats add the corresponding methods are as follows:

7.4.1 Incorrect Operation
The Incorrect Operation (IO) threat will be assessed through annual reviews to verify:

- Operating and maintenance procedures are current and correct
- Personnel and contractors are following procedures
- Personnel and contractors are appropriately qualified to perform their job function

7.4.2 Weather and Outside Force
In order to address the Weather and Outside Force (WOF) threat, evaluations continue to be conducted per SSCGP O&M policies and procedures. During routine surveillance activities, personnel look for indications of outside forces including indications of ground movement, indications of lightning strikes to pipeline appurtenances and soil erosion due to heavy rains or floods.

Specific surveillance activities vary from line to line, but applicable SSCGP O&M procedures may include:

- 70.58.01, latest edition "Identifying and Evaluation Land Movement"
- 70.60.01, latest edition "Performing Fixed Wing Aerial Patrols"
- 70.10.01, latest edition "Performing Transmission Line Patrols"
- 70.06.01, latest edition "Practicing Continuing Surveillance"
- 70.11.00, latest edition "Performing Transmission Line Leak Surveys"

7.4.3 Third-Party Damage
In addition to utilizing assessment data integrated with encroachment and foreign line crossing data per Procedures IMP.E2.ASMT.05 "Ingtegrating ILI Data with Encroachment Data" and IMP.E4.ECDA.06 "Aligning Indirect Inspeciton Data with Encroachment Data", Third-Party Damage threats are addressed through continuing patrols and leak surveys conducted per SSCGP policies and procedures.

7.4.4 Equipment Threat

In order to assess the Equipment (EQ) threat, SSCGP continues to conduct inspections and maintenance activities per the requirements of the SSCGP O&M Manual. Specific activities vary from facility to facility, but applicable O&M procedures include those related to equipment maintenance and testing found in the following sections of the SSCGP O&M Manual:

- Corrosion (20)
- Electrical and Automation (30)
- Measurement (60)
- Pipeline (70)

8.0 CRITERIA FOR ADDRESSING PARTICULAR THREATS

SSCGP developed its Baseline Assessment Plan in accordance with Part 192 Subpart O §192.917, which identifies specific responses for particular threats. These responses are detailed in the subparagraphs below.

8.1 Third-Party Damage

SSCGP considers Third-Party Damage threat to exist for all pipeline segments. Third-Party Damage includes vandalism incidents as well as previously damaged pipe. Third-Party Damage also covers mechanical damage due to not only third parties, but by SSCGP personnel or contractors.

Refer to Procedure IMP.E8.PREV.03, latest edition, for information regarding preventive and mitigative measures.

If an internal inspection tool is used as the method of baseline assessment, SSCGP personnel integrate encroachment and foreign crossing data for each HCA with the assessment data in accordance with Procedure IMP.E2.ASMT.05 "Integrating ILI Data with Encroachment Data". Likewise, if External Corrosion Direct Assessment (ECDA) is used, the data is integrated with encroachment and foreign crossing information.

8.2 Cyclic Fatigue

Cyclic Fatigue is not identified as a distinct threat category by the RAP. However, it is a component within the RAP which may interact with manufacturing or construction threats.

Metallurgical fatigue due to internal pressure variations historically is not an issue for natural gas pipelines and cyclic fatigue has not been an issue anywhere on the SSCGP pipeline system. Because fatigue due to internal pressure cycling is not considered a threat for the SSCGP pipeline system, the SMEs do not consider this mechanism in their analysis.

8.3 Manufacturing and Construction

Once a pressure test has been successfully completed and any required repairs are made, any potential remaining manufacturing and construction defects are considered stable defects that no longer present a threat to the integrity of the covered segment. Procedure IMP.E3.THR.01 details the criteria for determining stable manufacturing or construction threats.

8.4 ERW Pipe

Low-frequency electric resistance weld (ERW) pipe and electric flash weld (EFW) pipe are considered Manufacturing threats. Low-frequency ERW pipe was made by a variety of mills up through the 1970s. EFW pipe was manufactured by A.O. Smith. Additionally, pipe with a joint factor less than 1.0 such as lap-welded or butt welded pipe are considered manufacturing threats. The specific criteria for addressing Manufacturing threats outlined in Section 8.3 apply.

8.5 Corrosion

Procedure IMP.E2.ASMT.06, latest revision, "Finding Corrosion in an HCA" addresses the requirements for corrosion found in a covered segment.

9.0 QUALITY ASSURANCE

The IMP Steering Committee has taken quality assurance measures while developing the Baseline Assessment Plan. These measures have been incorporated through frequent interaction between District Managers, Subject Matter Experts and Project Manager Pipeline Integrity Management. During this interaction, particular threats were discussed, the appropriate method of integrity assessment was discussed and in some cases data was validated.

10.0 MANAGEMENT OF CHANGE

The SSCGP Baseline Assessment Plan is a dynamic document and is subject to modification as new information pertaining to the pipeline system become available including the identification of new threats or the identification of new HCAs.

10.1 Weather, Permitting, Vendor, Customer Delays

SSCGP anticipates there may be certain factors beyond their control that may affect the integrity assessment schedule. Inclement weather may cause scheduling difficulties / delays and may hinder the progress of a baseline assessment. Permitting delays, difficulties scheduling a contractor or failure to reach an agreement with an end-user may also affect the start date of an integrity assessment. Any such hindrances in the execution of an integrity assessment will be documented; however, they will not require notification to PHMSA or a State jurisdictional authority.

10.2 Changes to the Integrity Assessment Method

Changes to the Baseline Assessment method may be made by Project Manager Pipeline Integrity Management, Operations and Technical support. The process may change for several reasons, including:

- Inconclusive or unacceptable results from a direct examination.
- Direct examination or pipeline repair may indicate a threat that was previously unaccounted for and that the current method of baseline assessment is unsuitable to evaluate.
- The change of pipeline conditions or operations that make an assessment method no longer executable.
- The availability of a more effective or cost effective method of assessment.

Required changes to the integrity assessment process are documented on Form SSCGP-IMP-1100 per procedure IMP.E11.MOC.01.

10.3 Changes to the Baseline Assessment Plan Document

It is the responsibility of Project Manager Pipeline Integrity Management to monitor the Baseline Assessment Plan and verify its accuracy. District Managers bear responsibility for the information regarding any integrity assessments occurring in their area and requesting any required changes to the Baseline Assessment Plan document. The Baseline Assessment Plan is a dynamic document and will be reviewed on an annual basis. Changes within the BAP typically result from other situations documented on Form SSCGP-IMP-1100 per the IMP Management of Change Element.

Old versions of the Baseline Assessment Plan will be archived and maintained for the useful life of the pipeline system.

11.0 NOTIFICATIONS TO PHMSA AND STATE JURISDICTIONAL AUTHORITIES

If SSCGP decides to conduct an integrity assessment by using "Other Technology", Project Manager Pipeline Integrity Management will notify the Pipeline and Hazardous Materials Safety Administration (PHMSA) 180 days prior to conducting the assessment per procedure IMP.E13.COM.02.

If the covered segment is located in a state where PHMSA has an interstate agreement or where an intrastate pipeline is regulated by the State, that regulating agency will also be notified.

Scheduling Assessments

DOT – 49 CFR 192 SUBPART O

Key Words: Assessment, Reassessment

1.0 PURPOSE

1.1 To prioritize and schedule baseline assessments.

1.2 To add an assessment to the Assessment Schedule module of the O&E Database.

1.3 To update an assessment status and attach documentation in the O&E Database.

1.4 To schedule reassessments in the Assessment Schedule module of the O&E Database.

2.0 TASK OVERVIEW

- Prioritize and Schedule Baseline Assessments
- Add an Assessment
- Update Assessment Status
- Complete Post-Assessment Documentation
- Schedule a Reassessment

3.0 PRIORITIZE AND SCHEDULE BASELINE ASSESSMENTS

3.1 **Responsibility:** Project Manager Pipeline Safety or designee

3.1.1 Review the HCA segments to determine what covered segment or segments can and should be evaluated for integrity using the same assessment.

3.1.2 For each planned assessment, determine the HCA priority as assigned by the Risk Assessment Program. Priority levels are designed to address lines with a high Risk of Failure (ROF) first, then lines with Manufacturing threats, followed by lines with a high Probability of Failure (POF).

- Priority 1 – Weighted Average Overall ROF > 6.0
- Priority 2 – Manufacturing Threat Present
- Priority 3 – Maximum Overall ROF > 7.5
- Priority 4 – Weighted Average Overall POF > 0.7
- Priority 5 – Maximum Overall POF > 0.8
- Priority 6 – All other

3.1.2.1 For assessments covering multiple HCAs, the assessment priority is equal to the highest priority for any HCA in the assessment.

3.1.3 Determine the overall Baseline Assessment Score (BAS) for each assessment.

3.1.3.1 For assessments covering a single HCA, use the weighted average Overall Risk of Failure (ROF) score.

3.1.3.2 For assessments covering multiple HCAs, determine the aggregate risk using the following two-step process:

$$\textit{HCA Score} = (\textit{HCA length} / \textit{average HCA length}) \times (\textit{weighted average overall ROF})^2$$

$$\textit{Baseline Assessment Score} = ?\ \textit{HCA Score}_1 + \textit{HCA Score}_2 + \ldots\ \textit{HCA Score}_n.$$

3.1.4 Rank assessments within each priority from largest to smallest Baseline Assessment Score.

3.1.5 Create a preliminary baseline assessment schedule by scheduling assessments in order of priority.

3.1.6 Confer with Gas Control, Engineering Services, and Operations personnel in revising and finalizing the assessment schedule.

3.1.6.1 Consider resource constraints such as the following when scheduling assessments:

- Equipment and/or facilities
- Personnel and/or service provider availability
- Financial considerations
- Customer supply requirements
- Operations requirements (e.g. pressures and flow rates)

3.1.6.2 If line modifications such as installation of launcher/receiver facilities or valve replacement are necessary prior to assessment, schedule the assessment accordingly.

3.1.6.3 Consider whether two or more assessments should be performed in conjunction with one another. For example, schedule a baseline assessment on a newly identified HCA to coincide with a reassessment on that same line.

3.1.7 Ensure that all integrity assessment deadlines are met:

- 50% baseline assessment of originally identified HCAs by December 17, 2007
- 100% baseline assessment of originally identified HCAs by December 17, 2012
- Newly identified HCAs assessed within 10 years of certification

4.0 ADD AN ASSESSMENT

4.1 **Responsibility:** Project Manager Pipeline Safety or designee

4.1.1 Insert a new record into the Assessment Schedule module.

4.1.1.1 Enter assessment year.

4.1.1.2 Enter assessment purpose:

- "Baseline Assessment"
- "Assessment Due to Result on Similar Pipe"

4.1.1.3 Enter assessment method:

- "Abandon/Remove/Relocate/Sale"
- "External Direct Assessment" – ECDA
- "In-Line Inspection" – ILI
- "Internal Direct Assessment" – ICDA
- "Pressure Test" – hydrostatic pressure test (Subpart J compliant)
- "Stress Corrosion Cracking" – SCCDA

Note:

Assessment methods available in the Integrity Event table drop down menus are subject to change. The list above is provided as examples.

4.1.1.4 Enter responsible district.

4.1.2 Save the record.

4.1.2.1 The database assigns an assessment tracking number.

4.1.2.2 Enter an assessment description.

4.1.2.3 Enter location range information including line name, beginning and ending series and stationing.

Note:

Series and station should reflect the boundaries of the assessment. The database automatically determines HCA segments within the assessment boundaries.

If multiple assessment methods are required, schedule separate assessments and flag the one with shorter HCA footage to not include its footage in the overall performance metrics.

4.1.2.4 Complete any other known fields.

5.0 UPDATE ASSESSMENT STATUS

5.1 **Responsibility:** Project Manager Pipeline Safety or designee

5.1.1 As various stages of the assessment process are completed, review and update the Assessment Schedule status field.

- "Scheduled" –inspection or testing has not yet begun
- "In Progress" –inspection or testing in progress
- "Completed" – pressure test completed, ILI tool removed from line, or last direct examination in a Direct Assessment is completed
- "Closed" – all field work completed (including any required validation digs) and all required documentation submitted and reviewed
- "Out of Compliance" – reassessments past their compliance due date
- "Void" – a previously scheduled assessment that is no longer necessary

6.0 COMPLETE POST-ASSESSMENT DOCUMENTATION

6.1 **Responsibility:** Project Manager Pipeline Safety or designee

6.1.1 Attach completed Life Cycle Assessment form SSCGP-IMP-0200 or SSCGP-IMP-0202 if a Pressure Test or In-Line Inspection was performed.

6.1.2 Upon completion of a Pressure Test assessment, enter the minimum test pressure achieved (per form SSCGP-0110) and Test Pressure/MAOP ratio.

6.1.3 Upon completion of an In-Line Inspection post-assessment data analysis, enter the predicted failure pressure (determined per Procedure IMP.E6.EVAL.01) and Predicted Failure Pressure/MAOP ratio.

6.1.4 Update Assessed Threats fields.

6.1.5 Attach any supporting documentation such as photographs in the Assessment Schedule module.

6.1.6 Ensure that all reports related to the assessment (including, but not limited to SSCGP-0105, SSCGP-0110, SSCGP-0092) are stored in the Report Tracking module and cross-reference the assessment tracking number.

7.0 SCHEDULE A REASSESSMENT

7.1 **Responsibility:** Project Manager Pipeline Safety or designee

7.1.1 Once an assessment has been completed and a reassessment interval has been established per Procedure IMP.E6.EVAL.01 "Determining Reassessment Intervals", schedule the required reassessment(s).

7.1.1.1 Record the reassessment purpose as "Scheduled Reassessment."

7.1.1.2 Record the reassessment method.

- "Abandon/Remove/Relocate/Sale"
- "External Direct Assessment" – ECDA
- "In-Line Inspection" – ILI
- "Internal Direct Assessment" – ICDA
- "Pressure Test" – hydrostatic pressure test (Subpart J compliant)
- "Stress Corrosion Cracking" – SCCDA

7.1.1.3 Record the year in which the reassessment will take place. This year cannot exceed the Out of Compliance date.

7.1.1.4 Set an Out of Compliance date no later than the completion date of the assessment plus the reassessment interval.

7.1.2 If the reassessment interval is more than 7 years, the database will prompt for an interim reassessment method to take place in year 7.

- "External Confirmatory Direct Assessment" – External CDA
- "Internal Confirmatory Direct Assessment" – Internal CDA
- "Low Stress Reassessment" – low stress reassessments only apply to segments operating below 30% SMYS.

7.2 **Responsibility:** District Manager

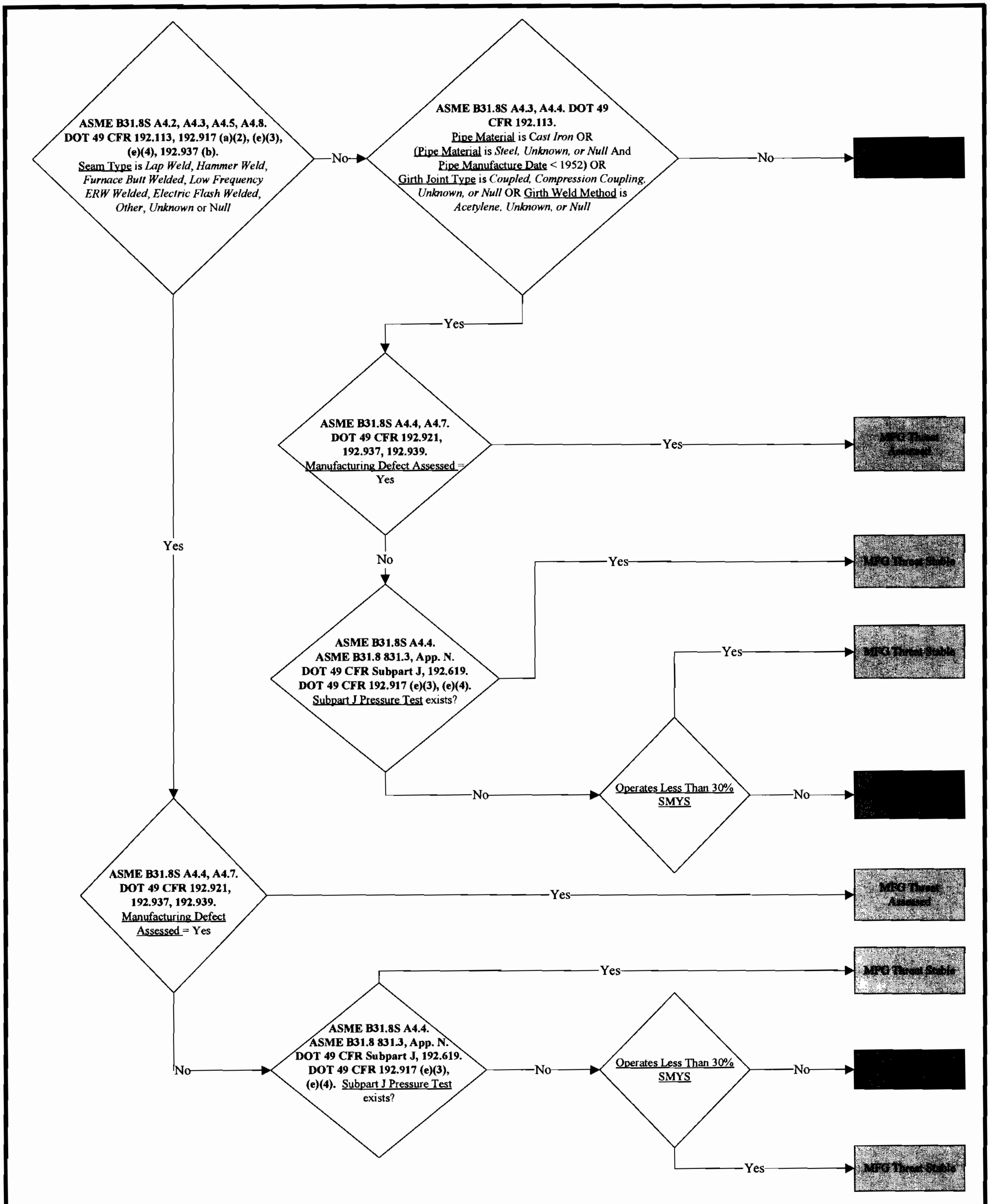
7.2.1 Review the Assessment Schedule in the O&E database and use the data for both short-term and long-term planning.

THREAT IDENTIFICATION
APPENDIX 0306 – THREAT SCREENING CRITERIA

1.0 INTRODUCTION

The RAP Threat Screening tool identifies threats for each HCA (adjacent HCAs) based on criteria established by SSCGP in conjunction with American Innovations, the software developer. The IMP Steering Committee and Project Manager Pipeline Integrity Management appointed individuals to an Algorithm Team which was responsible for both the risk score algorithm and threat screening function.

American Innovations provided documentation of the Threat Screening tool in the form of the flowcharts provided on the following pages.



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MFG Threat Evaluation

Revision Date: 5/23/2007

SOUTHERN STAR CENTRAL GAS PIPELINE

Appendix 13A and 13B

Amended Documents Per
Notice of Amendment

Preventive and Mitigative Measure Identification
Form and Procedure

CPF 4-2007-1012

PREVENTIVE AND MITIGATIVE MEASURES
(§192.935)

1.0 INTRODUCTION

Southern Star Central Gas Pipeline (SSCGP) implements Preventive and Mitigative (P&M) measures to prevent a pipeline failure, to mitigate the consequences of a pipeline failure in a High Consequence Area (HCA) and to enhance the safety of the public.

2.0 RELATED PROCEDURES AND FORMS

SSCGP has many existing policies and procedures that address P&M measures in the O&M Manual. O&M Policies and Procedures related to the Preventive and Mitigative Measures are listed in Appendix 0801: Repair, Prevention, and Detection Policies.

Specific Integrity Management procedures referenced in the Preventive and Mitigative Measures Element include:

- *IMP.E8.PREV.01 "Finding Physical Evidence of Encroachment Involving Excavation"*
- *IMP.E8.PREV.02 "Monitoring Excavations in the Right-of-Way"*
- *IMP.E8.PREV.03 "Identifying and Implementing Preventive and Mitigative Measures"*
- *IMP.E8.PREV.04 "Managing the Encroachment Program"*
- *70.07.01, latest edition, "Establishing a Damage Prevention Program"*
- *70.07.03, latest edition, "Collecting Information on Excavation Damage"*
- *70.11.01, latest edition, "Leakage Surveys of Transmission Lines"*

The following forms are specifically referenced in the Preventive and Mitigative Measures Integrity Management Element:

- *SSCGP-IMP-0800 "Physical Evidence of Encroachment Involving Excavation"*
- *SSCGP-IMP-0801 "Preventive and Mitigative Measures"*
- *SSCGP-0092 "Pipeline Inspection and Repair Report"*
- *SSCGP-0151 "SSCGP Encroachment / Foreign Line Crossing Form"*

3.0 THIRD-PARTY DAMAGE

Part 192 §192.935 lists specific P&M measures that must be implemented for covered pipeline segments in order to mitigate the risk of third-party damage, as detailed in the subparagraphs below. These measures are:

- Use of qualified personnel
- Participation in a One-Call Program
- Monitoring of excavations in the rights-of-way
- Follow-up evaluation for evidence of unmonitored excavation activity
- Central database for excavation damage

3.1 Operator Qualified Personnel

SSCGP uses Operator Qualified personnel to conduct specific pipeline tasks. These pipeline tasks include, but are not limited to:

- Pipeline marking
- Pipeline locating
- Supervision of known excavation work

Refer to the SSCGP Operator Qualification Program for complete details on the use of Operator Qualified personnel, as well as a complete list of Covered Tasks.

The SSCGP Operator Qualification Program applies to covered and non-covered pipeline segments.

3.2 One-Call Program

SSCGP participates in a One-Call Program as described in O&M Procedure 70.07.01, latest edition, "Establishing a Damage Prevention Program". Participation in One-Call applies to covered and non-covered pipeline segments.

3.3 Encroachments

3.3.1 Encroachment Program

SSCGP has an encroachment program that applies to covered pipeline segments. The program includes the following:

- Review of encroachment requests
- Monitoring status of encroachments
- Maintaining awareness about encroachments

Operations personnel utilize form SSCGP-0151 "SSCGP Encroachment / Foreign Line Crossing Form" to document encroachment requests. Refer to procedure IMP.E8.PREV.04 "Managing the Encroachment Program" for additional information.

3.3.2 Monitoring Excavations

Operator Qualified personnel monitor excavations conducted on covered pipeline segments as indicated in Procedure IMP.E8.PREV.02 "Monitoring Excavations in the Right-of-Way". This procedure applies to HCA segments as well as pipeline segments located in a Class 3 or Class 4 locations (not in an HCA).

Operations personnel complete form SSCGP-0151 "SSCGP Encroachment / Foreign Line Crossing Form" to document monitoring the encroachment. If an SSCGP pipeline is exposed during excavation activities, personnel also complete form SSCGP-0092 "Pipeline Inspection and Repair Report".

3.3.3 Unmonitored Excavation Activity

If personnel find evidence of excavation that was not monitored near a covered pipeline segment or in a Class 3 or Class 4 Location, the area is evaluated per procedure IMP.E8.PREV.01 "Physical Evidence of Encroachment Involving Excavation." Per this procedure, SSCGP may either excavate the area near the encroachment or perform an indirect inspection such as Direct Current Voltage Gradient (DCVG). Operations personnel document the unmonitored encroachment as well as follow-up activities on form SSCGP-IMP-0800 “Physical Evidence of Encroachment Involving Excavation”.

3.3.4 Central Database for Excavation Damage

If Operations personnel witness or discover excavation damage in a covered or non-covered segment, personnel perform a root-cause analysis, per procedure 10.18.01, latest edition “Investigation of the Root Cause of Accidents, Failures or Other Pipeline Events”. The results of this root-cause analysis are then used to identify additional P&M measures for implementation in HCA segments.

Note: excavation damage includes coating damage as well as mechanical damage to the pipe (i.e. dents, gouges).

Refer to procedure 70.07.03, latest edition, “Collecting Information on Excavation Damage” for additional details.

4.0 OUTSIDE FORCE DAMAGE

If Outside Force damage is identified as a threat on a HCA segment, Part 192 §192.935 mandates that additional measures to address the threat be implemented. Outside Forces include earth movement, floods and lightning. Additional measures, specific to the threat, do not need to be implemented if the threat is not identified.

If SSCGP identifies the Outside Force threat for a covered pipeline segment, Subject Matter Experts will evaluate measures to minimize damage to the pipeline or mitigate the consequences of the outside force per procedure IMP.E8.PREV.03, latest revision, “Identifying and Implementing Preventive and Mitigative Measures”.

5.0 AUTOMATIC SHUT-OFF VALVES AND REMOTE CONTROL VALVES

Under certain conditions, an automatic shut-off valve (ASV) or remote control valve (RCV) may be an appropriate measure to protect an HCA in the event of a gas release. SSCGP Subject Matter Experts or designated resources will base the evaluation on the following factors:

- Swiftness of leak detection and pipe shutdown capabilities
- Type of gas being transported
- Operating pressure
- Rate of potential release
- Pipeline profile
- Potential for ignition
- Location of nearest response personnel

6.0 IDENTIFYING AND IMPLEMENTING PREVENTIVE AND MITIGATIVE MEASURES

In addition to P&M measures required by §192.935 to address the threats of Third-Party Damage and Outside Forces, SSCGP implements additional P&M measures for the covered pipeline segments. These P&M measures are beyond those already required by Part 192.

Per procedure IMP.E8.PREV.03, latest revision, "Identifying and Implementing Preventive and Mitigative Measures", Subject Matter Experts review identified threats for the covered pipeline segments and identify P&M measures. Measures selected for implementation are documented on form SSCGP-IMP-0801 "Preventive and Mitigative Measures".

Appendix 0801 lists existing procedures for repair, prevention and detection measures. If SSCGP decides to implement a P&M measure for which there is no existing procedure, SSCGP will document the procedure prior to implementation.

7.0 PIPELINES OPERATING BELOW 30% SMYS

Subpart O has additional requirements for pipelines operating below 30% SMYS, as detailed in the subparagraphs below.

7.1 Located in an HCA

For pipelines that operate below 30% SMYS and are located in an HCA, Subpart O requires additional Preventive and Mitigative Measures. SSCGP employs the following P&M measures for these covered pipeline segments.

- Use of qualified personnel
- Participation in a One-Call system
- Monitoring of excavations in the rights-of-way
- Follow-up evaluation for evidence of unmonitored excavation activity
- Central database for excavation damage

Refer to section 3.0 of this document for additional details on these measures.

7.2 Locatedin Class 3 and Class 4 Location Outside of an HCA

7.2.1 General Requirements

For pipelines operating below 30% SMYS located in a Class 3 or Class 4 location but outside of an HCA, Subpart O requires additional Preventive and Mitigative measures. SSCGP employs the following Preventive and Mitigative measures for all Class 3 and Class 4 locations regardless of operating stress level or HCA status:

- Use qualified personnel
- Participate in a One-Call Program
- Monitor Excavations near the pipeline

Refer to section 3.0 of this document for additional details on these measures.

7.2.2 Leak Survey

In addition to the requirements above, Part 192 requires additional leak surveys for pipelines operating below 30% SMYS and located in a Class 3 or Class 4 location, but not in an HCA, as follows:

- Non-cathodically protected pipelines
  - 4 times a calendar year at intervals not to exceed 4 1/2 months

- Cathodically protected pipe where electrical surveys are not practical
    - 4 times a calendar year at intervals not to exceed 4 1/2 months

SSCGP maintains a list of pipeline segments where additional leak surveys are required. This list is reviewed and updated once every three (3) years by the Senior Technical Specialist.

SSCGP Operations or contracted personnel perform leak surveys on cathodically protected lines per Pipeline Policy 70.01.00, latest edition, "Leakage Surveys of Transmission Lines" and Pipeline Procedure 70.11.01, latest edition, "Performing Transmission Line Leak Surveys."

8.0 PLASTIC TRANSMISSION LINES

To date, SSCGP has not identified any plastic transmission lines located within a High Consequence Area (HCA). If SSCGP does identify plastic transmission lines located in an HCA, the following P&M measures will apply:

- Use of qualified personnel
- Participation in a One-Call Program
- Monitor Excavations in the rights-of-way

Identifying and Implementing Preventive and Mitigative Measures

DOT - 49 CFR §192.935

Key Words: HCA, Preventive and Mitigative Measure, P&M

1.0 PURPOSE

1.1 To establish a standardized approach for identifying Preventive and Mitigative (P&M) measures for covered pipeline segments.

1.1.1 A P&M measure is an action, beyond that already required by Part 192, to prevent a pipeline failure, mitigate the consequences of a pipeline failure and / or enhance public safety.

1.1.2 Certain activities performed by SSCGP as routine O&M procedures may meet the definition of a P&M measure. SSCGP must evaluate what, if any, P&M measures beyond Part 192 are already implemented and their adequacy.

NOTE:

Examples of Preventive and Mitigative measures that SSCGP may already be implementing include, but are not limited to:

- *One-Call system*
- *Aerial patrols*
- *Foot patrols beyond the frequency required by Part 192*

1.2 To establish a standardized approach for implementing and documenting Preventive and Mitigative (P&M) measures for covered pipeline segments.

2.0 TASK OVERVIEW

- Identification of Preventive and Mitigative Measures
- Selecting Measures in Response to Active Corrosion
- Implementing Measures
- Continual Evaluation

3.0 IDENTIFICATION OF PREVENTIVE AND MITIGATIVE MEASURES

3.1 **Responsibility:** District Manager or designee

3.1.1 Complete Section 1 and 2 of form SSCGP-IMP-0801 "Preventive & Mitigative Measures" for each line containing a High Consequence Area (HCA).

3.1.1.1 Multiple HCAs on a given line can be documented on a single form if similar conditions and P&M measures exist.

3.1.1.2 Obtain guidance from Project Manager Pipeline Integrity Management when determining whether multiple HCAs should be grouped on a single form.

3.1.2 Complete Sections 3 through 12 on form SSCGP-IMP-0801 "Preventive and Mitigative Measures" by selecting P&M measures that are sufficiently effective in preventing a pipeline failure and / or mitigating the consequences of a failure.

3.1.2.1 Sources including, but not limited to, the following may be used to determine threats and risk factors:

- Subject Matter Experts
- RAP risk results table (risk scores & identified threats)
- SSCGP-IMP-0302 "Threat Identification" forms
- Baseline Assessment Plan
- O&E database

3.1.2.2 Confer with Operations, Corrosion Control, Engineering, Technical Services, Gas Control, Pipeline Safety or other departments as necessary to determine P&M measures.

3.1.2.3 Consider the following factors when identifying potential P&M measures:

- Pipeline characteristics
- Inspection history
- Results of recent integrity assessments
- Operating history including any leaks or failures
- Root-cause analyses of any excavation damage (procedure 70.07.03 "Collecting Information on Excavation Damage")
- Pipeline access
- Resource allocation

NOTE:

Examples to consider include, but are not limited to:

- *Has new evidence of active corrosion been detected since the P&M measure was implemented?*
- *Did incidents of third-party damage decrease as a result of additional pipeline markers?*
- *Did public education impact the number of non-monitored excavations?*

3.1.3 If more information is needed to decide on the most effective P&M measure for a given HCA, request the Pipeline Safety Engineer perform "what-if" scenarios in the Risk Assessment program to evaluate the effect of implementing a particular P&M measure on both the likelihood of failure and consequence of failure as well as on the risk score.

3.1.4 Use the space provided below each section to justify decisions and provide a detailed description of the P&M measure whenever "Other" is selected.

3.1.4.1 Table 1: Preventive and Mitigative Measures by Threat provided at the end of this procedure may be used as guidance when selecting "Other" measures.

3.2 **Responsibility:** Pipeline Safety Engineer or designee

3.2.1 Provide Risk Assessment Program data to District Mangers or Pipeline Safety personnel upon request. (See step 3.1.3 above.)

3.2.2 Provide "what-if scenario" Risk Assessment program results showing the impact of a proposed P&M measure upon request. (See step 3.1.3 above.)

3.2.2.1 Show the effect on each of the following:

- Likelihood of failure
- Consequence of failure
- Overall risk

3.3 **Responsibility**: District Manager or designee

3.3.1 Record a planned implementation date on Form SSCGP-IMP-0801.

3.3.2 Sign and date section 2 of the form and send to Project Manager Pipeline Integrity Management.

3.3.3 Upload form SSCGP-IMP-0801 to Report Tracking.

3.4 **Responsibility**: Project Manager Pipeline Integrity Management or designee

3.4.1 Review and approve form SSCGP-IMP-0801.

3.4.1.1 Request changes if necessary.

3.4.2 Maintain a copy of the form SSCGP-IMP-0801 "Preventive & Mitigative Measures" for the life of the pipeline.

4.0 IMPLEMENTING MEASURES

4.1 **Responsibility:** District Manager or designee

4.1.1 Notify affected personnel of any newly determined P&M measures.

4.1.1.1 Complete a Management of Change form SSCGP-IMP-1100 to document the new measure if sufficient detail cannot be provided on form SSCGP-IMP-0801 or if the measure requires additional approvals (e.g. relocations, new equipment installations).

4.1.1.2 A new type of P&M measure – one that SSCGP has not used before – must be documented on a Management of Change form SSCGP-IMP-1100.

4.1.1.3 Easily described, non-complicated measures such as an increase in inspection frequency may be documented on form SSCGP-IMP-0801 without a Management of Change form.

4.1.2 For measures affecting an ongoing inspection or maintenance activity, update the Maintenance Management System (MMS) to reflect the revised frequency.

4.1.3 Upload any pertinent forms into Report Tracking upon completion of the P&M activity.

4.2 **Responsibility:** CP technician or designee

4.2.1 Update Pipeline Compliance System (PCS) to reflect equipment installation, survey results, or other data as necessary.

5.0 SELECTING MEASURES IN RESPONSE TO ACTIVE CORROSION

5.1 **Responsibility:** District Manager or designee

5.1.1 If active corrosion is identified and a Preventive or Mitigative Measure must be selected in accordance with procedure IMP.E2.ASMT.06 "Finding Corrosion in an HCA", review applicable P&M measures for External and/or Internal corrosion.

5.1.2 Select a P&M measure that will prevent or mitigate the effects of the Root Cause identified corrosion.

5.1.2.1 Select a P&M measure for any similar segments that were identified during the Root Cause analysis.

6.0 CONTINUAL EVALUATION

6.1 **Responsibility:** Project Manager Pipeline Integrity Management or designee

6.1.1 On an annual basis, verify that P&M measures planned for the year were implemented and appropriate documentation received by Pipeline Safety.

6.1.1.1 Review existing P&M measures by holding a meeting with Subject Matter Experts and discussing any issues that occurred they may be addressed by increasing the effectiveness of current P&M measures or the implementation of new measures.

6.1.2 Ensure P&M measures are reflected in the Risk Assessment Program.

6.1.3 Evaluate the effect of P&M measures on risk scores for the pipeline system.

6.2 **Responsibility**: District Manager or Designee

6.2.1 Review existing Preventive and Mitigative measures at least every two (2) years.

6.2.2 Generate a new form to reflect P&M measures currently in place regardless whether HCA data has changed. Update the review date as necessary.

6.2.2.1 Document and implement any new P&M measures according to sections 3.0 and 4.0 of this procedure.

TABLE 1: PREVENTIVE AND MITIGATIVE MEASURES BY THREAT

The following table is adapted from ASME B31.8S, Table 4 "Acceptable Threat Prevention and Repair Methods" and is provided for reference. Applicable preventive and mitigative methods are also listed for each threat on form SSCGP-IMP-0801 "Preventive & Mitigative Measures".

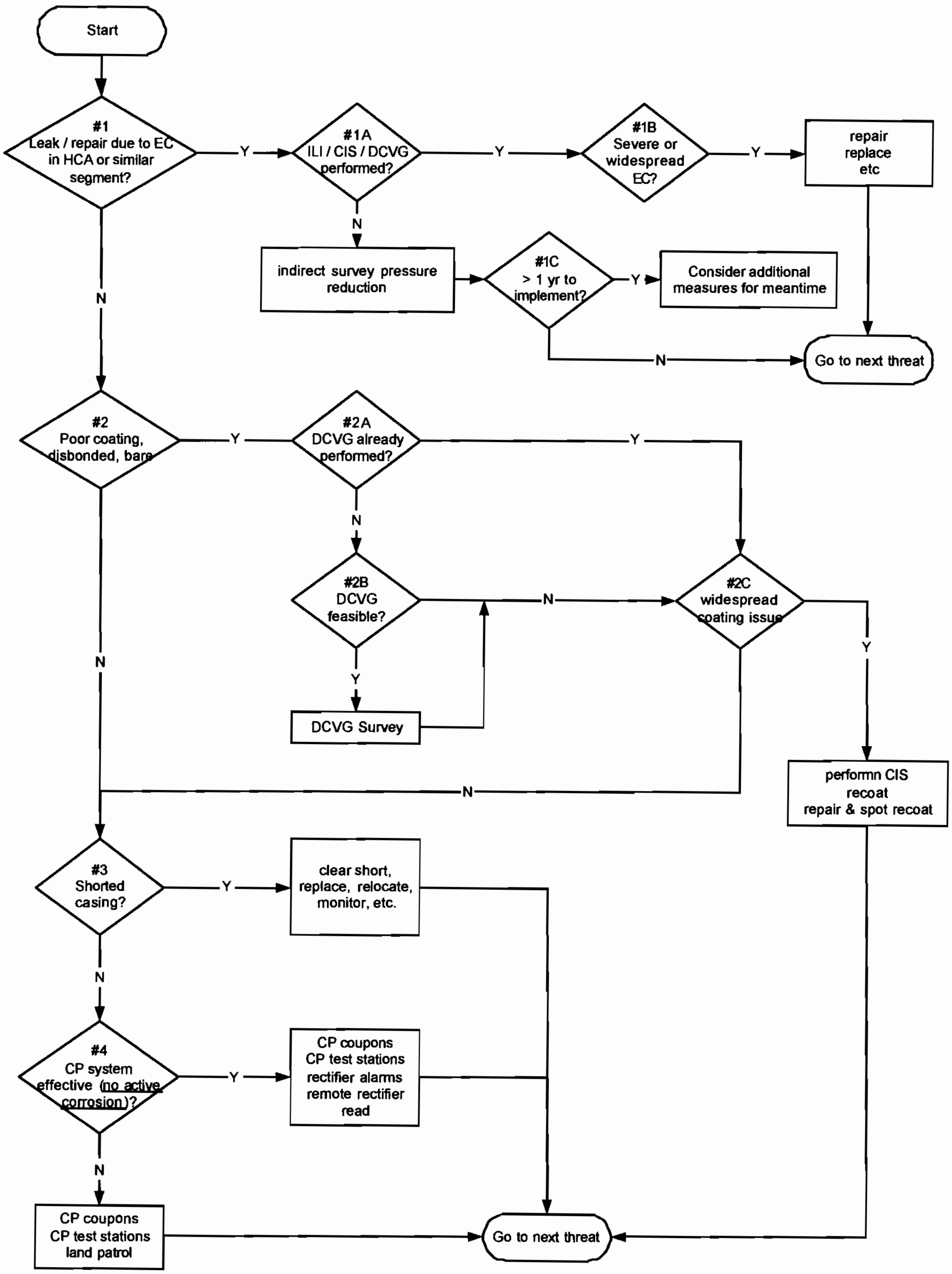
	Corrosion		SCC	Third-Party Damage			Manufacture		Construction				Equipment				Incorrect Ops	Weather Related / Outside Force			
	External	Internal	SCC	Immediate Failure	Previous Damage	Vandalism	Defective Pipe Seam	Defective Pipe	Defective Girth Weld	Defective Fabrication Weld	Coupling Failure	Wrinkle Bend / Buckle	Gasket / O-ring	Stripped Thread / Broken Pipe	Control / Relief Equipt. Malfunction	Seal / Pump Packing Failure	Company Procedures	Cold Weather	Lightning	Heavy Rains / Flood	Earth Movement
Monitor / maintain cathodic protection	X		X																		
Increased wall thickness	X	X		X	X	X															X
Leakage control measures	X	X			X	X					X		X	X	X	X					
Rehabilitation	X	X	X		X						X	X									X
Coating repair	X		X																		
O&M procedures	X	X	X		X	X					X	X	X	X	X	X	X	X	X	X	X
Design Specifications[1]	X	X	X						X		X	X	X	X	X	X					X
Material Specifications							X	X		X			X	X	X	X					
Internal cleaning		X																			
Reduce moisture		X																			
Biocide / inhibitor		X																			
Aerial Patrol				X	X	X					X							X	X	X	X
Foot Patrol	X			X	X	X					X							X	X	X	X
One-Call system				X	X	X															
Public education				X																	
Increase marker frequency				X	X																
External Protection				X	X	X															X
Maintain ROW				X	X																X
Warning tape mesh				X	X																
Line relocation				X		X												X		X	X
Increase cover depth				X		X						X									
Pre-service hydrostatic test					X		X	X	X	X	X	X									
Construction Inspection			X		X			X	X	X	X	X	X	X	X	X					
Manufacturer Inspection					X		X	X		X					X	X					
Transportation Inspection					X		X	X													
Visual / mechanical inspection[2]									X				X	X	X	X		X			
Reduce external stress			X								X	X		X							X
Reduce operating temperature			X										X			X					
Compliance audit																	X				
Operator Training																	X				
Strain monitoring																				X	X
Pig-GPS[3] / strain measurement																		X		X	X
Stabilization of the soil																		X			
Install heat tracing																		X			
Install thermal protection																		X			

[1] In accordance with ASME B31.8 code
[2] Refers to equipment inspections
[3] In-Line Inspection pig taking GPS coordinates of line

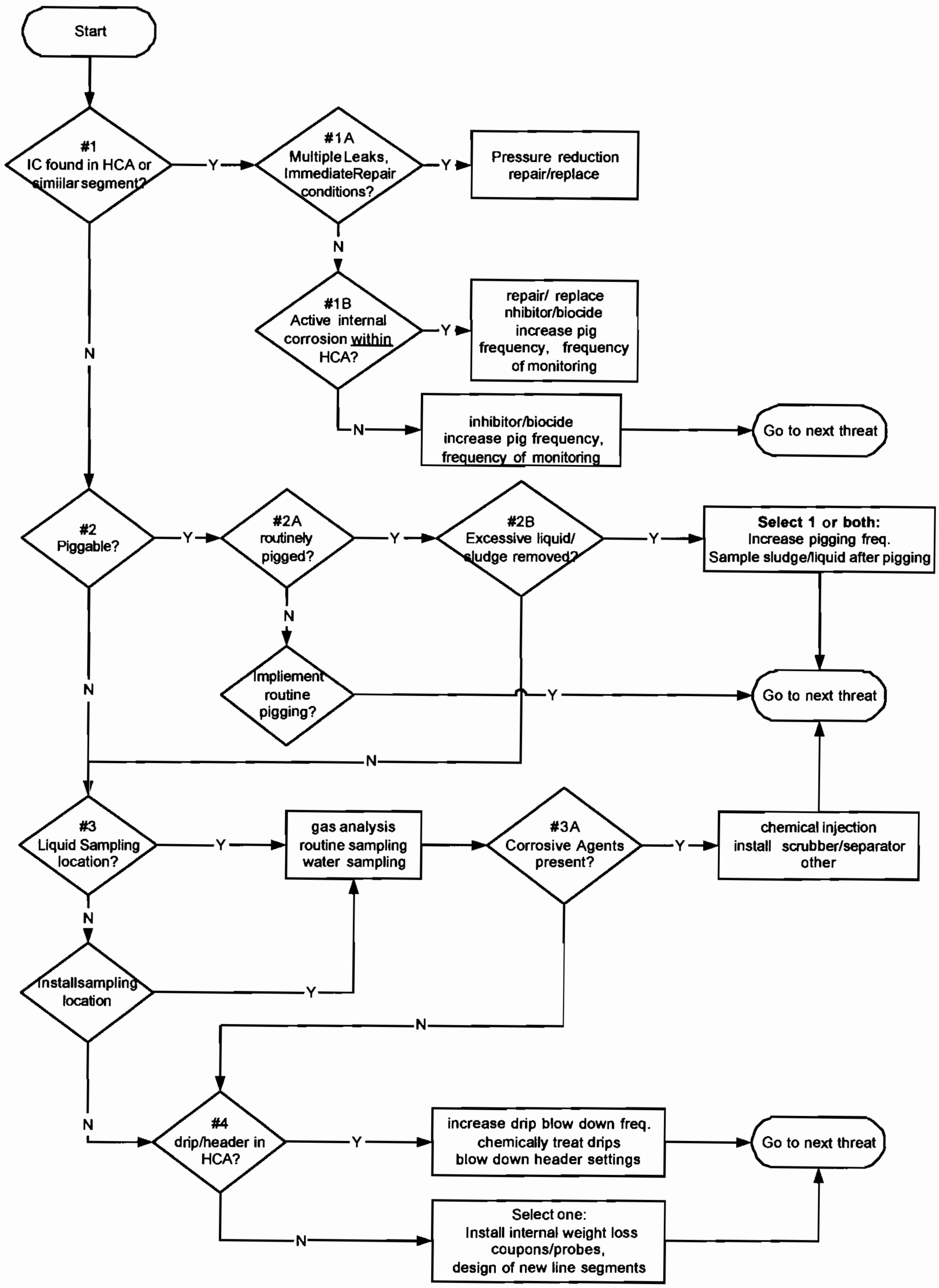
ATTACHMENT

The following flow chart depicts the process for completing form SSCGP-IMP-0801.

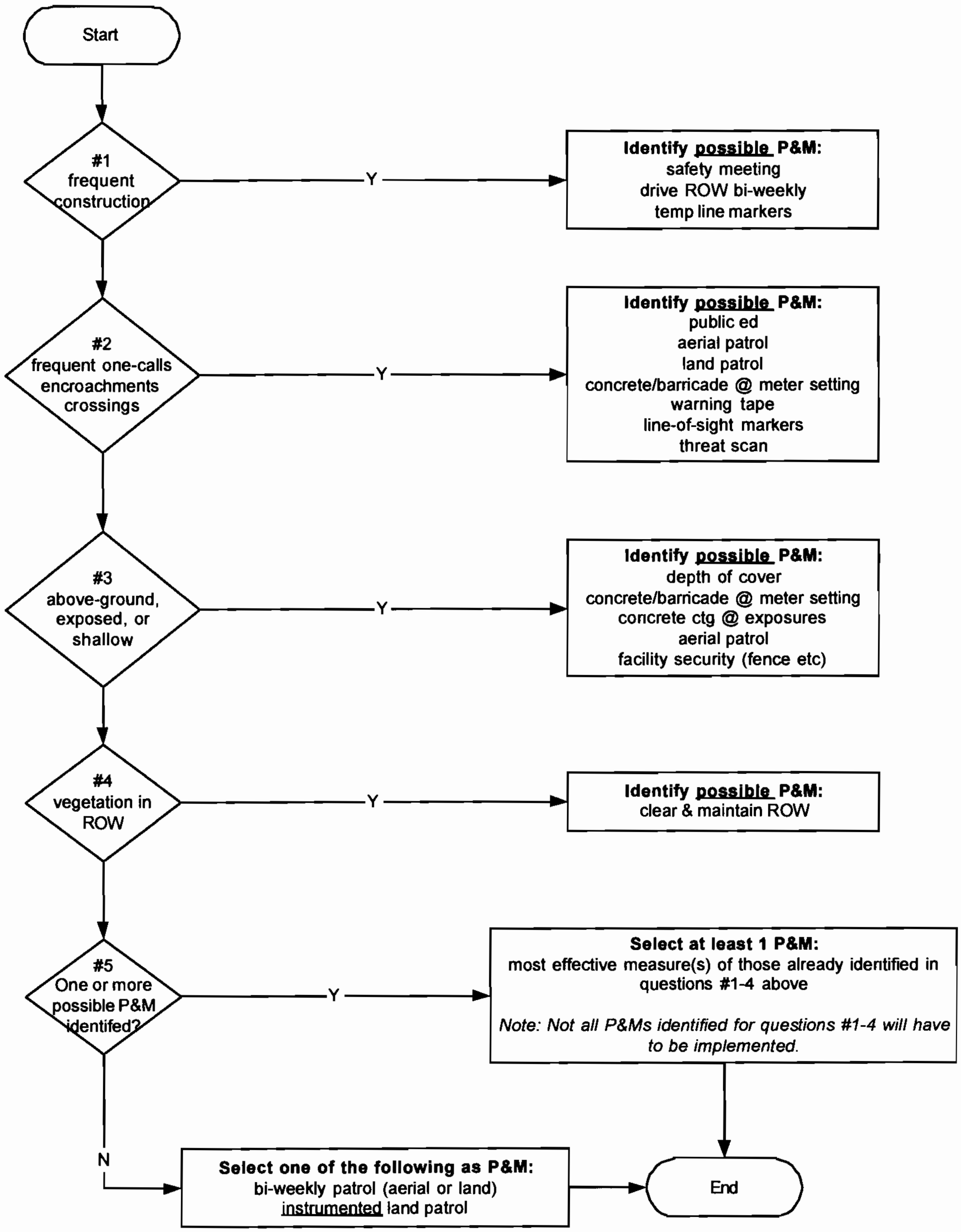
External Corrosion



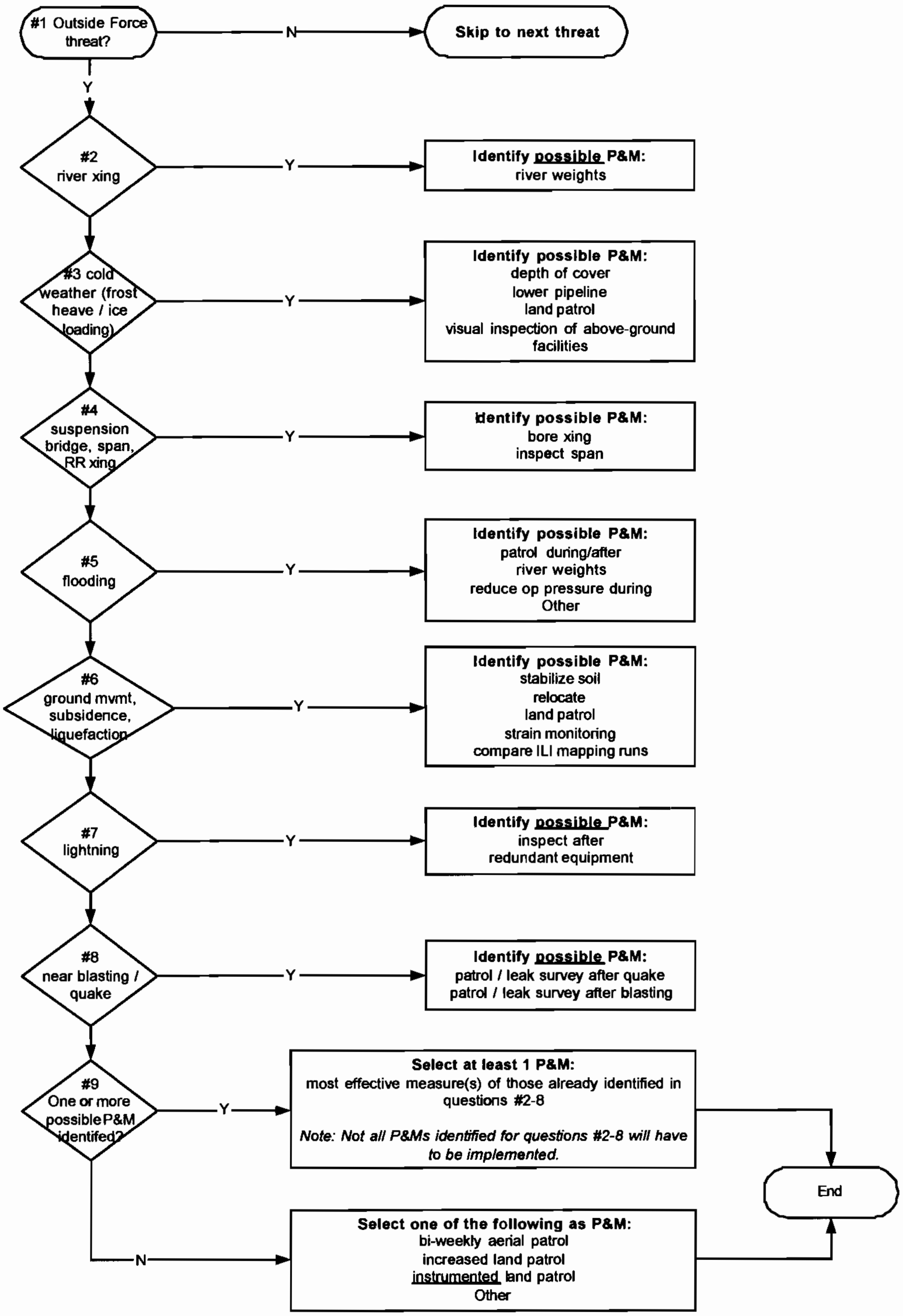
Internal Corrosion



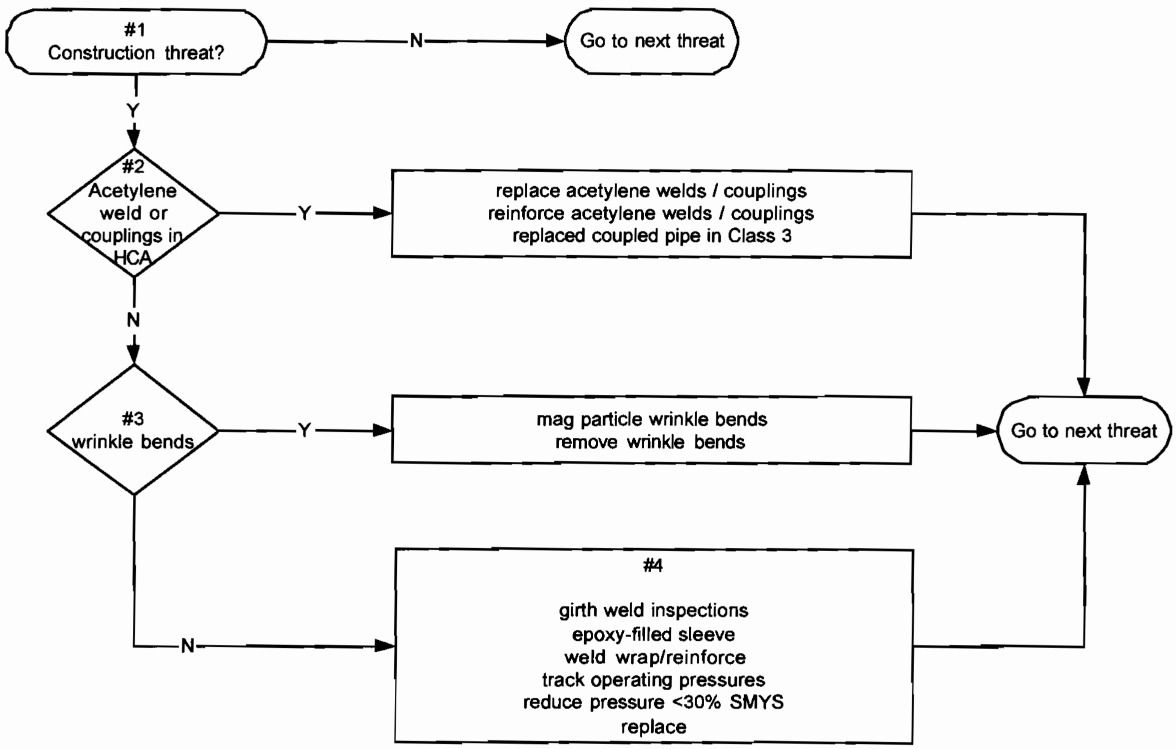
Third-Party Damage



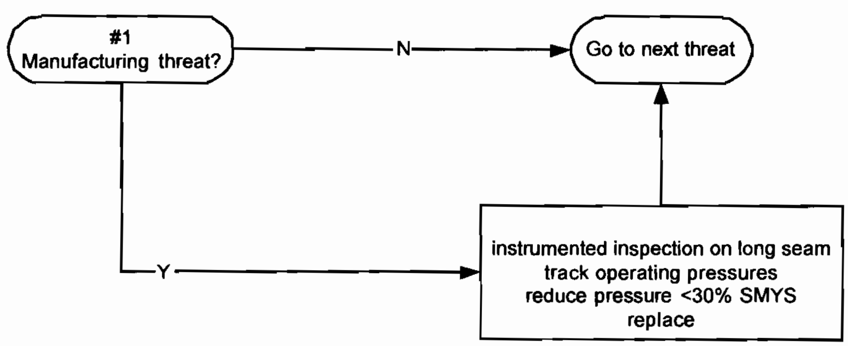
Weather-Related / Outside Force



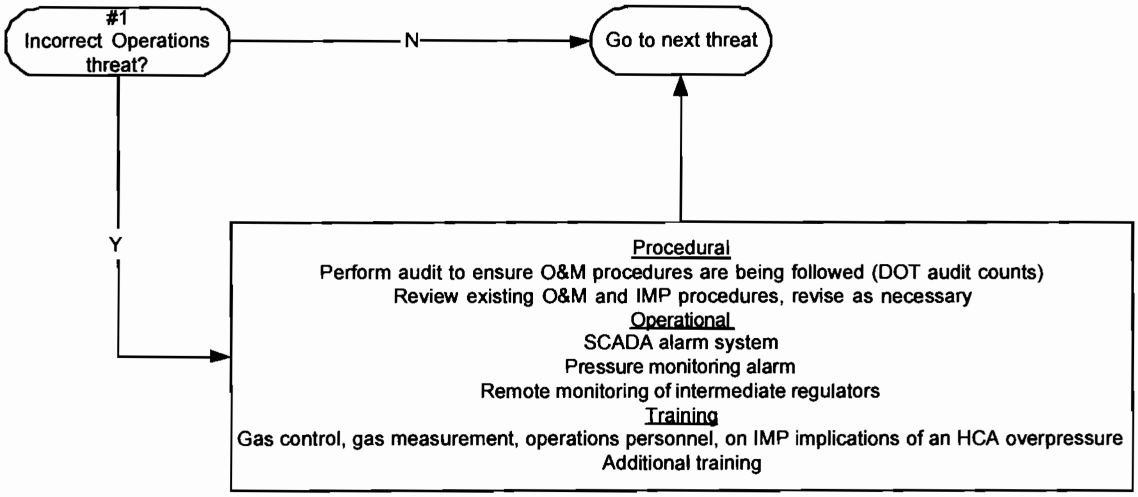
Construction



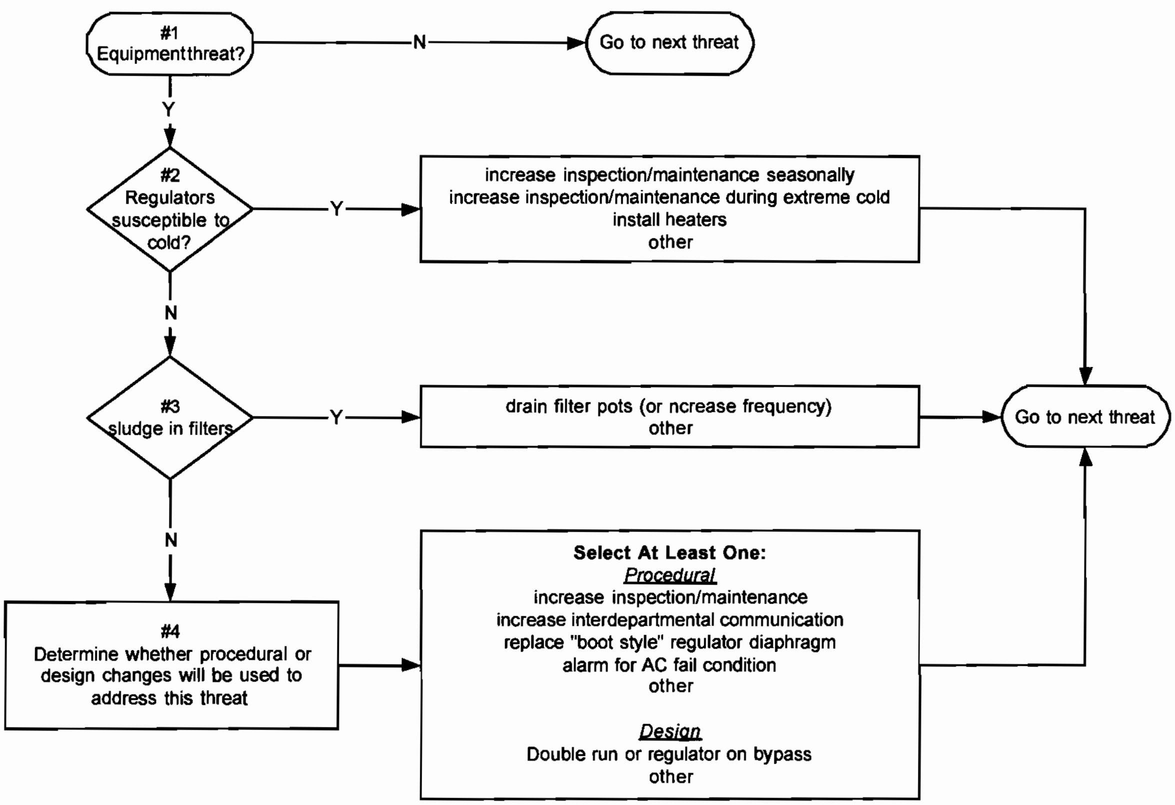
Manufacturing



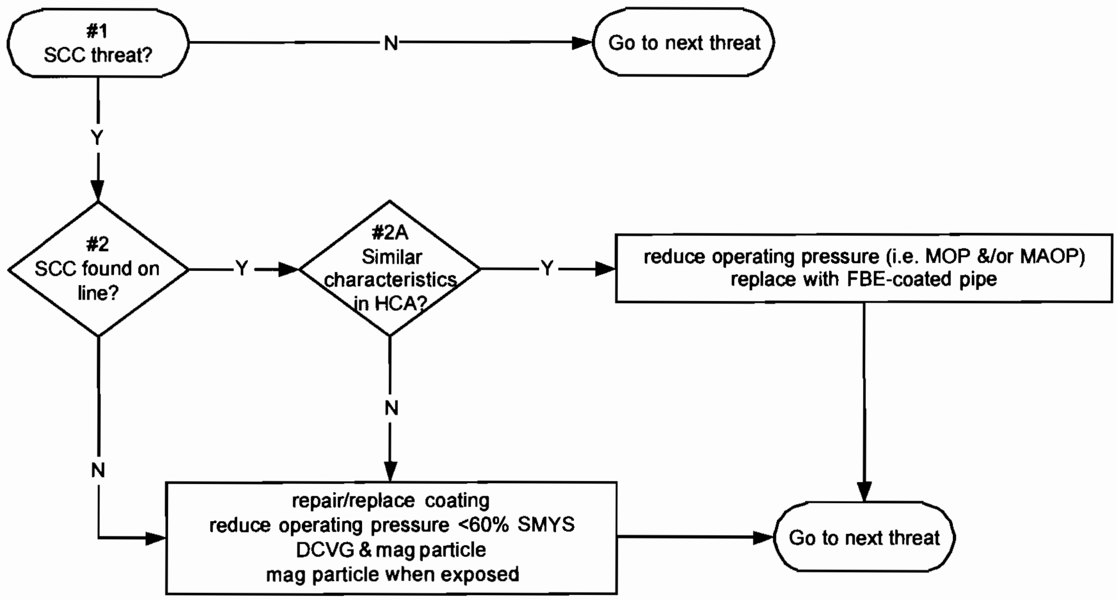
Incorrect Operations



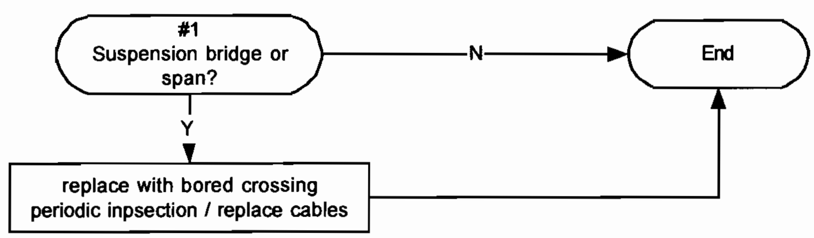
Equipment



SCC



Cylclic Fatigue



PREVENTIVE & MITIGATIVE MEASURE SELECTION FORM

Report Tracking Number: ______________________

Instructions:

Complete this form for each HCA (or group of HCAs). Contiguous or adjacent HCAs may be grouped if similar conditions are present.
Review P&M measures only for Identified Threats on the HCA(s).
Answer each Yes/No question and mark all selected P&M measures with a ✓ or an 'X".
Data sources or other resources to utilize in answering a particular question are shown in italicized parentheses below the question.

Document selections of "Other" &/or justify selections of "No additional measure" in the space provided at the end of each section.
This space may also be used to describe any P&M measures in detail. Attach additional pages if necessary.

Definitions:

***P&M Measure**: An action to reduce the likelihood or mitigate the consequence of failure that is above & beyond the requirements of Part 192.*
NOTE: "No additional measure" may be selected if current practices exceed Part 192 (meet the definition of P&M Measure).

***Similar Characteristics**: 2 or more segments of the same general pipe material, seam type, operating conditions, soil characteristics, & environment.*

SECTION 1: REVIEWER INFORMATION

District: ______________________ **Review Date:** ______________________

Reviewer / SME / District Manager: ______________________

List any other SME's consulted:

______________________ ______________________

______________________ ______________________

______________________ ______________________

______________________ ______________________

SECTION 2: SUMMARY OF HCA

Line	Begin Series	Begin Engr. Station	End Series	End Engr. Station

SECTION 3: EXTERNAL CORROSION THREAT

Yes **No**

1 **Has External Corrosion resulted in any of the following in the HCA or on a segment of the line with similar characteristics?** ☐ ☐

- **Leak due to External Corrosion (not including isolated occurrences)**
- **External Corrosion that required remediation other than coating repair**

(SSCGP-0231 Leak Forms, Pipeline Safety / DOT records, SSCGP-199 Root Cause Analysis form)
Refer to Procedure IMP.E2.ASMT.06 "Finding Corrosion in an HCA" for description of an isolated occurrence.

If no, skip to question #2.

1a **If yes , was an ILI tool run or indirect inspection survey (CIS, DCVG) performed to determine the full extent of the problem?** ☐ ☐

If no, select an indirect survey or leak control as P&M measure and skip to question #1c.

___ Close Interval Survey (CIS)
___ Current Attenuation Survey (Pipeline Mapper)
___ DCVG Survey
___ Cell-to-Cell (Hot Spot) Survey

1b **In the opinion of the SME, is the corrosion severe and/or widespread?** ☐ ☐

If yes, select one of the following and skip to the next threat.

___ Repair, sleeve
___ Repair/replacement, improved coating type (i.e. FBE)
___ Replacement, like-for-like
___ Install gas monitoring equipment or other leak control measures
___ Replacement, heavier wall thickness
___ MAOP reduction, temporary or permanent
___ MOP reduction, temporary or permanent
___ No additional measure

If no, skip to question #2.

1c **Will measures selected in #1a above take more than 1 year to implement?** ☐ ☐

If yes, consider whether additional temporary measures should be implemented in the meantime.

___ Increase land patrol
___ Additional temporary measure not required

If no, skip to the next threat.

		Yes	No
2	**Has poor coating condition, disbondment, or uncoated pipe been identified in the HCA?** *(SSCGP-0092 Inspection Reports, ECDA reports, CIS survey results, DCVG survey results)* *If no, skip to question #3.*	☐	☐
2a	**Has a DCVG been performed?**	☐	☐
2b	**If no to Question #2a, is DCVG feasible?** If yes, determine whether a survey should be performed to determine the extent of the coating problem. ___ DCVG Survey ___ No additional measure	☐	☐
2c	**If yes to Question #2a, are coating problems widespread throughout the line? Select one of the following and skip to the next threat.** ___ Recoat entire segment ___ CIS Survey ___ Repair & spot recoat any severe indications ___ No additional measure	☐	☐
3	**Are there any metallic shorted casings in the HCA?** *(Shorted Casing Report, PCS database, O&E database, Corrosion Technician)* If yes, perform one of the following: ___ Dig out casing end, clear short, insert new insulator ___ Replace carrier pipe, install new insulators and end seals ___ Monitor casing vents with gas detection equipment during casing leak patrols ___ Relocate line to eliminate casing	☐	☐
4	**Is the current CP system effective with no active corrosion present?** *(Corrosion Technicians, Corrosion Control records - PCS database, CP Annual Report)* If yes, select one of the following: ___ Install CP coupons ___ Install additional CP test stations (if distance between stations >1 mile) ___ Install rectifier alarms at manned location ___ Install remote rectifier monitoring equipment (i.e. bullhorn) ___ No additional measure If no, select a Monitoring action as the P&M measure. ___ Install CP coupons ___ Install additional CP test stations (if distance between stations >1 mile) ___ Increase land patrol	☐	☐

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 2: INTERNAL CORROSION THREAT

		Yes	No
1	**Has Internal Corrosion resulting in any of the following in the HCA or on a segment of the line with similar characteristics?** **· Leak** **· Internal wall loss detected by ILI or insepction** *(SSCGP-0231 Leak Forms, Pipeline Safety / DOT records, ILI reports, SSCGP-0092 Inspection* If no, skip to question #2.	☐	☐
1a	**Have multiple leaks or Immediate Repair Conditions due to Internal Corrosion occurred on this line?** If yes, collaborate with Pipeline Safety to determine whether a pressure reduction should be implemented and skip to the next threat. ___ MOP reduction, temporary or permanent ___ MAOP reduction, temporary or permanent ___ Repair/replacement, like-for-like ___ Repair/replacement, heavier wall thickness ___ Pressure reduction not required to ensure public safety ___ Repair/replacement not required to ensure public safety	☐	☐
1b	**Does active internal corrosion exist within the HCA?** If yes, consider repair/replacement as a P&M measure even if the segment meets RSTRENG or B31G criteria for continued use and skip to the next threat.. ___ Repair/replacement, like-for-like ___ Repair/replacement, heavier wall thickness ___ Repair/replacement not required to ensure public safety ___ Install or increase frequency of internal corrosion monitoring ___ Implement or increase inhibitor/biocide program ___ Increase pig frequency If no, select a measure to enhance the corrosion control program and skip to the next threat. ___ Implement or increase inhibitor/biocide program ___ Install or increase frequency of internal corrosion monitoring ___ Increase pig frequency	☐	☐

		Yes	No
2	**Is the line piggable?** *If no, skip to question #3.*	☐	☐
2a	**Is the line routinely pigged?** If no, consider whether routine pigging is appropriate: ___ Implement routine pig cleaning program, skip to next threat. ___ Pigging not required based on historical conditions, skip to question #3.	☐	☐
2b	**If line is routinely pigged, is excessive liquid/sludge removed during cleaning?** *"Excessive" determined according to the judgment of the Subject Matter Expert.* If yes, perform one or both of the following and skip to next threat. ___ Increase the pigging frequency ___ Sample liquid/sludge after pigging (O&M procedure 70.55.01)	☐	☐
3	**Is there a liquid sampling location on the line (or upstream segment)?** If yes, perform one of the following: ___ Gas analysis at receipt points ___ Routine sampling ___ Water sampling (including MIC testing, if enough liquid is present) If no, consider where an additional sampling location should be installed: ___ Install sampling location and skip to next threat ___ Skip to question 4.	☐	☐
3a	**Are corrosive agents (i.e. H_2S, O_2, etc) present in the line?** *(Gas Analysis reports, Liquid Analysis reports)* If yes, perform one of the following and skip to next threat. ___ Chemical injection (biocide/inhibitor) ___ Other (specify) ___ Install scrubber/separator ___ No additional measure	☐	☐
4	**Are there drips/headers within the HCA?** If yes, select one of the following: ___ Increase frequency for blowing drips ___ Chemically treat drips when blowing down ___ Blow down headers on settings ___ No additional measure If no, select one of the following: ___ Install internal weight loss coupons or probes ___ Design any new line segments to include weight loss coupons and water analysis locations at all receipt points above and beyond requirements of part 192. **Ensure coupons /probes are removed prior to pigging.*	☐	☐

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION [illegible]: THIRD PARTY DAMAGE THREAT

		Yes	No
1	**Is the HCA in an area of frequent current construction activity?** *(One-Call records, Subject Matter Expert field knowledge)* If yes, identify possible P&M measures: ___ Conduct safety meeting with developers/contactors ___ Drive HCA ROW bi-weekly during construction ___ Install additional temporary line markers during construction	☐	☐
2	**Is the HCA in an area with frequent One-Calls &/or multiple line crossings/encroachments?** *(One-Call records, Subject Matter Expert field knowledge)* If yes, identify possible P&M measures: ___ Increase public education ___ Install concrete / pipe barricade at meter setting ___ Install concrete coating at line crossings ___ Install warning tape mesh when line exposed ___ Aerial patrol ___ Increase land patrol ___ Install additional line-of-sight markers (reduce distance between markers ___ Install impact protection monitoring system (Threat Scan)	☐	☐
3	**Does the HCA contain above-ground facilities or exposed or shallow pipe?** *(O&E Database, Subject Matter Expert field knowledge)* If yes, identify possible P&M measures: ___ Increase depth of cover ___ Install concrete / pipe barricade at meter setting ___ Install concrete coating at line exposure(s) ___ Aerial patrol ___ Increase facility protection/security (i.e. fence, lock, barb wire, etc.)	☐	☐

Yes No

4 **Is the HCA's ROW overrun with trees or other vegetation?** ☐ ☐
(Subject Matter Expert field knowledge)
If yes, identify possible P&M measure:
___ Clear and maintain ROW

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5 **Was one or more possible P&M measures identified in questions #1-4 above?** ☐ ☐
If yes, determine which measure (or combination of measures) identified above provides the most effective prevention or mitigation strategy for this HCA. Indicate choice below.
Most effective strategy determined according to the judgment of the Subject Matter Expert in collaboration with Pipeline Safety. May consider the effect on Risk of Failure (ROF) scores when determining most effective method.

___ Conduct safety meeting with developers/contactors
___ Drive HCA ROW bi-weekly during construction
___ Aerial patrol
___ Increase land patrol
___ Increase public education
___ Increase depth of cover
___ Clear and maintain ROW
___ Install additional temporary line markers during construction
___ Install additional line-of-sight markers (reduce distance between markers
___ Install warning tape mesh when line exposed
___ Install concrete / pipe barricade at meter setting
___ Install concrete coating at line crossings
___ Increase facility protection/security (i.e. fence, lock, barb wire, etc.)
___ Install impact protection monitoring system (Threat Scan)

If no, select one of the following as P&M measures:
___ Perform bi-weekly aerial or land patrol
___ Perform instrumented land patrol (rather than non-instrumented)

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 6: OUTSIDE FORCE / WEATHER-RELATED THREAT

Yes No

1 **Is Outside Force / Weather-Related Threat identified for this HCA?** ☐ ☐
(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP))
If no, skip to CONSTRUCTION THREAT

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2 **Does the HCA cross a lake, river or other fast-moving body of water?** ☐ ☐
(O&E Database, Subject Matter Expert field knowledge)
If yes, identify possible P&M measures:
___ Install river weights at correct spacing
___ No additional measure
___ Other (specify)

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3 **Is the HCA susceptible to cold weather (ie. ice loading and/or frost heave)?** ☐ ☐
(Subject Matter Expert field knowledge)
If yes, identify possible P&M measures:
___ Visually inspect during icing conditions to identify stresses on pipeline
___ Increase depth of cover
___ Increase land patrol frequency
___ Lower pipeline

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4 **Does the HCA contain a suspension bridge, mechanical span or a crossing susceptible to high external loads (ex. Railroads, road crossings with grade changes)?** ☐ ☐
(O&E Database, Subject Matter Expert field knowledge)
If yes, identify possible P&M measures:
___ Replace using a bored crossing
___ Perform periodic inspection of span (i.e. rollers, tensions, etc.) and replace stretched cables if necessary

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5 **Is the HCA susceptible to flooding?** ☐ ☐
(Subject Matter Expert field knowledge)
If yes, identify possible P&M measures:
___ Patrol the pipeline during/after floods
___ Install river weights at correct spacing
___ Reduce operating pressure when flood conditions present
___ Other (specify)

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6 **Is the HCA susceptible to ground movement, soil subsidence, liquefaction, or unstable slopes?** ☐ ☐
(Subject Matter Expert field knowledge)
If yes, identify possible P&M measures:
___ Stabilize the soil
___ Relocate line to less-susceptible ground
___ Monitor line by comparing inertial mapping unit ILI results from different years
___ Increase land patrol frequency
___ Install strain monitoring equipment

		Yes	No
7	**Does the HCA contain facilities susceptible to lightning?** *Any above-ground facility could be susceptible to lightning.* If yes, identify possible P&M measures: ___Inspect facilities after lightning storm ___Use redundant systems for safety-related equipment	☐	☐
8	**Is the HCA near active blasting areas or susceptible to earthquake damage?** *(Subject Matter Expert field knowledge)* If yes, identify possible P&M measures: ___Line patrol or leak survey after seismic event ___Line patrol or leak survey if blasting activites exceed limits (O&M 70.07.02)	☐	☐
9	**Was more than one possible P&M measure identified in questions #2-8 above?** If yes, determine which measure (or combination of measures) identified above provides the most effective prevention or mitigation strategy for this HCA. Indicate choice below. *Most effective strategy determined according to the judgment of the Subject Matter Expert in collaboration with Pipeline Safety. May consider the effect on Risk of Failure (ROF) scores when determining most effective method.* ___Inspect facilities after lightning storm ___Patrol the pipeline during/after floods ___Patrol the pipeline after blasting activity/seismic event ___Increase land patrol frequency ___Relocate line to less-susceptible ground ___Use redundant systems for safety-related equipment ___Replace span using a bored crossing ___Install river weights at correct spacing ___Increase depth of cover ___Lower pipeline ___Stabilize the soil ___Install strain monitoring equipment ___Reduce operating pressure when flood conditions present ___Other (specify) ___Monitor line by comparing inertial mapping unit ILI results from different years ___Perform periodic inspection of span (i.e. rollers, tensions, etc.) and replace stretched cables if necessary If no, select a monitoring action as the P&M measure. ___Perform bi-weekly aerial patrol ___Increase land patrol frequency ___Perform instrumented land patrol (rather than non-instrumented) ___Other (specify)	☐	☐

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 7: CONSTRUCTION THREAT

		Yes	No
1	**Is Construction Threat identified for this HCA?** *(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP))* If no, skip to MANUFACTURING THREAT	☐	☐
2	**Does the HCA contain non-reinforced acetylene welded or mechanically coupled joints?** *(O&E Database, Subject Matter Expert field knowledge)* If yes, perform one of the following and skip to next threat. ___Replace acetylene welds &/or mechanical couplings (i.e. when exposed for another reason, not a special dig) ___Reinforce acetylene welds &/or mechanical couplings (i.e. when exposed for another reason, not a special dig) ___Replace coupled pipe in Class 3 area	☐	☐
3	**Does the HCA contain wrinkle bends?** *(O&E Database, Subject Matter Expert field knowledge)* If yes, perform one of the following: ___Perform magnetic particle inspection at wrinkle bends (i.e. when exposed for another reason, not a special dig) ___Remove wrinkle bends (i.e. when exposed for another reason, not a special dig)	☐	☐
4	**If none of the conditions in questions #2 and #3 apply, select one or more of the following P&M measures.** Whenever the HCA segment is exposed: ___Inspect girth weld ___Install epoxy-filled sleeve ___Weld wrap / reinforce girth welds Other measures: ___Track historical max. operating pressure in O&E database ___Reduce pressure below 30%SMYS ___Replace segment		

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 8: MANUFACTURING THREAT

		Yes	No
1	**Is Manufacturing Threat identified for this HCA?**	☐	☐

(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP), Baseline Assessment Plan)
If no, skip to INCORRECT OPERATION THREAT

If yes, select one or more of the following P&M measures.

Whenever the HCA segment is exposed:
___ Perform instrumented inspection on long seam

Other measures:
___ Track historical max. operating pressure in O&E database
___ Reduce pressure below 30%SMYS   ___ Replace segment

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 9: INCORRECT OPERATION THREAT

		Yes	No
1	**Is Incorrect Operations Threat identified for this HCA?**	☐	☐

(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP))
If no to Question 1, skip to EQUIPMENT THREAT

If yes, select one or more of the following P&M measures.
Procedural:
___ Perform audit to ensure O&M procedures are being followed (DOT audit counts)
___ Review existing O&M and IMP procedures, revise as necessary

Operational monitoring:
___ SCADA alarm system (i.e. Low-Low alarms)   ___ Remote monitoring of intermediate regulators
___ Pressure monitoring alarms

Training:
___ Training for gas control, gas measurement, operations personnel, on IMP implications of an HCA overpressure
___ Additional training (describe)

Implementation Date: ______________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 10: EQUIPMENT THREAT

		Yes	No
1	**Is Equipment Threat identified for this HCA?** *(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP))* If no, skip to STRESS CORROSION CRACKING THREAT	☐	☐
2	**Are regulators in this HCA susceptible to icing from extreme cold?** *(Subject Matter Expert field knowledge)* If yes, select a P&M measure and skip to next threat.	☐	☐

___ Increase inspection/maintenance seasonally   ___ Increase inspection/maintenance during extreme cold
___ Install heaters on regulators and pilots   ___ Other (specify)

Yes No

3 **Are filters susceptible to sludge?** ☐ ☐

(Subject Matter Expert field knowledge)

If yes, select a P&M measure and skip to next threat.

___ Drain control filter pots (or increase frequency) ___ Other (specify)

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4 **If none of the conditions in questions #2-3 above apply, select one or more of the following P&M measures.**

Procedural changes:

___ Increase inspection/maintenance ___ Increase interdepartmental communication Re: equipment issues

___ Replace "boot style" regulator diaphragm every 3 years (O&M Procedure 60.02.00)

___ Alarm for AC fail condition > 1 hour results in call from Gas Control to District

___ Other (specify)

Design considerations:

___ Either use double run or install regulator on bypass ___ Other (specify)

Implementation Date: ____________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 11: STRESS CORROSION CRACKING (SCC) THREAT

Yes No

1 **Is SCC Threat identified for this HCA? (Either high pH or near-neutral pH)** ☐ ☐

(SSCGP-IMP-0302 Threat Analysis Form, Risk Assessment Program (RAP))

If no, skip to CYCLIC FATIGUE THREAT (Internal Pressure Fluctuation)

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2 **Has SCC been found on the line?** ☐ ☐

(Corrosion Technician, Corrosion Records, O&E database - Integrity Event table)

If no, perform one of the following:

___ Repair/replace coating ___ Reduce operating pressure below 60% SMYS

___ Perform DCVG survey & perform magnetic particle inspection at areas of poor coating

___ Magnetic particle inspection* in areas meeting SCC criteria whenever exposed (i.e. when exposed for another reason, not a special dig)

2a **Do similar characteristics exist within the HCA?** ☐ ☐

(O&E database, Risk Assessment Program (RAP))

___ Reduce operating pressure to slow crack growth (i.e. reduce MOP &/or MAOP)

___ Replace with new, FBE-coated pipe

**Do not remove well-bonded coating that is in good condition.*

Implementation Date: ____________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.

SECTION 12: CYCLIC FATIGUE THREAT

Yes No

1 **Does the HCA contain a suspension bridge or mechanical span?** ☐ ☐

(O&E Database, Subject Matter Expert field knowledge)

If yes, consider the following P & M measures

___ Replace span using a bored crossing

___ Perform periodic inspection of span (i.e. rollers, tensions, etc.) and replace stretched cables if necessary

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Implementation Date: ____________________

Use the space provided below to describe any unique situations or P&M measures selected. Provide a detailed description whenever "Other" measure is selected or if no P&M measure has been selected.