U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

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Lakewood, CO 80228

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NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 29, 2007

Mr. Randy Barnard
VP Operations and Gas Control
Williams Gas Pipeline
2800 Post Oak Blvd
P.O. Box 1396
Houston, TX 77056

CPF 5-2007-1001

Dear Mr. Barnard:

On March 13-17 and March 27–30, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected your Integrity Management Program in Salt Lake City, Utah.

As a result of the inspection, it appears you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violation(s) are:

1. **§192.947 What records must an operator keep?**

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

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

- **Item 1A: §192.947(d) & §192.905 (a)**

  At the time of inspection documentation demonstrating what methods were used for identification of each HCA segment was not available. [A.01.b]

  Evidence: Williams did not produce documents demonstrating the method used for identification of each HCA.

2. **§192.905 How does an operator identify a high consequence area?**

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

   (b)(1) Identified sites...

   (2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

   (i) Visible marking (e.g., a sign); or
   (ii) The site is licensed or registered by a Federal, State, or local government agency; or
   (iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

- **Item 2A: §Part 192.905 (a)**

  System maps and the GIS system used by WGP have not established a suitable means of documenting segment locations in high consequence areas. WGP has indicated that pipeline location accuracy ranges from survey quality up to +/- 40 feet. WGP has not taken action to address these known inaccuracies in its HCA identification process which could lead to existing HCAs not being identified. No additional buffers have been considered to account for potential pipeline location inaccuracies. Quality assurance methods are not defined for assuring collected data is accurately integrated into either the GIS or onto HCA identification alignment sheets. [A.01.c]

  Evidence: WGP IMP Overview Chapter 4, High Consequence Areas, Appendix A

- **Item 2B: §Part 192.905 (b)(2)**

  In the absence of public official input, the operator must use one of the following in order to identify an identified site: 1) Visible markings such as signs, 2) Facility licensing or registration data on file with Federal, State, or local government agencies, or 3) Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public. However, WGP has not used these other sources of information in support of the December 17, 2004 deadline for locating identified sites. Additionally, WGP does not have procedures governing the performance of locating identified sites using these types of other sources information. [A.03.b]

  Evidence: WGP' s IM procedure 10.09.01.10, Establishing Class and HCA Location, Section 8.1.10

3. **§192.907 What must an operator do to implement this subpart?**

   §192.907 (a) General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in § 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

- **Item 3A: §192.907(a)**

  The rule requires that HCA identification be completed by December 17, 2004. However, certain activities necessary to comply with this completion date were not initiated until Spring 2005. The HCA identification process to locate identified sites in Class I and II locations (Method 1) was still ongoing as of April and May 2005. Public officials were not contacted for the location of identified sites until April 2005. Follow-up activities required to be taken in the event that public officials do not provide identified site information using other required sources does not appear to have been undertaken. [A.01.d]

Evidence: Letter to Emergency Responder, 3/2005 (First issuance of this letter)

4. §192.905 How does an operator identify a high consequence area?

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

§192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in § 192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—
  (i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or
(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—
(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to [20 x (660 feet [or 200 meters]/ potential impact radius in feet [or meters])**2]).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)- month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

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

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d \2\)), where `r' is the radius of a circular area in feet surrounding the point of failure, `p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and `d' is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; ibr, see § 192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

- **Item 4A: §Part 192.903 High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows: (1)**

  Method 1 used on the Transco system was applied incorrectly in that the full length of Class 3 and.4 locations have not been included in HCA boundaries. [A.04.a]

  Evidence: Alignment Sheet, Location Class Determination and Qualification Record, MP 1782.125 to 1783.750, Somerset and Middlesex Counties, NJ Main Line, DOT-NJ-8.

- **Item 4B: §Part 192.903 High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows: (1)(iv)**

  The IMP rule requires that a high consequence area be established for areas in Class 1 and Class 2 piping locations where the potential impact circle contains an identified site. Field personnel were tasked with collecting information on identified sites prior to being trained on the requirements. Field personnel were not trained until April to June of 2005. For the Transco system (MD, VA & NJ), documentation showed apparent identified sites that were not included in the HCAs. The reviews for HCAs on some of the Transco areas were not started until the March of 2005 timeframe. [A.04.c]

  Evidence: Alignment Sheet, Location Determination and Pipeline Qualification Record, MP 1408.000 to 1410.87, Pittsylvania County, VA, Main Line, DOT-V-9
  Alignment Sheet, Location Determination and Pipeline Qualification Record, MP 1457.375 to 1459.375, Appomattox, VA, Main Line, DOT-V-25B

- **Item 4C: §192.903 Identified site means each of the following areas: (a) & (b)**

  WGP IMP Overview Chapter 4, Section 4.8 defines a day as a continuous 8-hour period when analyzing structures to determine if they qualify as identified sites. For example a picnic area would have to sustain 20 or more persons on site for 8 hours a day, 5 days a week, and 10 weeks in any 12 month period. This definition of a day is inconsistent with rule requirements as the 20 or more persons criteria applies to their presence at a location at any point in time. [A.03.a]

Evidence: WGP IMP Overview Chapter 4, High Consequence Areas, Section 4.8

- **Item 4D: §192.903 High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows: (3)**

  HCAs defined for the Northwest Gas system do not include the axial extension of the potential impact circle along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy (e.g., HCA 1401 Ft Lewis to Sumner MP 1346.844 – GIS shows HCA length as 0.174 miles but if axial extension is considered the length is 0.42 miles). [A.02.b]

  Evidence: WGP's procedure 10.19.01.10, Establishing Class and HCA Locations, Section 8.1.5
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1401
  Northwest Pipeline HCA list – HCA 1401 MP1346.844 (shows length as .7 miles)
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 591.9958 to 592.6174
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Soda Springs to Lava Hot Springs, MP 541.1691 to 541.7532
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Soda Springs to Lava Hot Springs, MP 542.6616 to 542.9956
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 573.3549 to 573.917
  GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 590.8329 to 591.1995

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

(a) Threat identification…

(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…

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

(1) Third party damage...

(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

- **Item 5A: §192.917(e)(4)**

  WGP does not have procedures to evaluate 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 B31.8S-2001, Appendix A4.3 and ASME B31.8S-2001, Appendix A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. Procedures are not in place to verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion anomalies. [B.01.d]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 7.1.1 and Procedure 70.17.01.16, Pigging – Inline Inspection

- **Item 5B: §192.917(b)**

  The rule requires that individual data elements be brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. However, this required data integration has not occurred. WGP plans to perform this activity using their GIS / risk assessment model that is scheduled for implementation in December 2006. [C.02.f]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 4.0

- **Item 5C: §192.917(b)**

  Processes have not been defined for the responsibilities for data collection or how the data sets are assembled, how accuracy is verified, how the data is maintained, or defining the sets of data that must be collected. WGP has the intent and is in the process of developing a GIS that they will use to integrate data comprehensively by the end of 2006. [C.02.b]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 4.0

- **Item 5D: §192.917(b)**

  WGP does not have processes for verifying data quality. Procedures do not require that conservative assumptions be applied if data is missing or suspect. It is not clear that conservative values have actually been applied; for example, pipe line sections containing LFERW pipe default to a non-conservative value without verifying operating pressures have actually been at MAOP. Records are not maintained that identify how unsubstantiated data are used. The program does not specify that additional inspections or field data collection efforts must be initiated for missing / suspect data. [C.02.d]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 4.0; Items C.02.d ii, and iv listed as NA in the WGP Protocol Cross Reference list

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

(a) Assessment methods...

(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 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...

- **Item 6A: §192.921(b)**

  The Transco BAP includes several segments at the bottom of the prioritization schedule that have not been analyzed for risk. These segments have been prioritized as the lowest risk on the BAP schedule based solely on SME input. The basis for this prioritization without a risk analysis has not been documented. [B.02.b]

  Evidence: TRANSCO Baseline Assessment Plan

- **Item 6B: §192.921(d)**

  There were numerous errors in the initial HCA identification process; as such verification that the BAP schedule meets the rule completion schedule requirements cannot be made. The BAP has not been updated to reflect new HCAs and identified sites identified in the March – May 2005 field surveys that were conducted to locate identified site information that was not collected in support of the December 17, 2004 requirement for HCA identification. Additionally, the BAP does not include HCA segment mileage that was erroneously left out on the Northwest system since the axial extension of potential impact circles was not included in the defined HCAs. Furthermore, Method 1 used on the Transco system appears to be applied incorrectly in that the full length of Class 3 and 4 locations have not been included in HCA boundaries. [B.02.d]

Evidence: GIS overview showing covered segment length of HCA 1401 Ft. Lewis to Sumner
GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 591.9958 to 592.6174
GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Soda Springs to Lava Hot Springs, MP 541.1691 to 541.7532
GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Soda Springs to Lava Hot Springs, MP 542.6616 to 542.9956
GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 573.3549 to 573.917
GIS overview showing covered segment length of HCA, Northwest Pipeline, Line 1400 – Lava Hot Springs to Pocatello, MP 590.8329 to 591.1995
Alignment Sheet Location Class Determination and Pipeline Qualification Record, MP 1782.125 to 1783.750, Somerset and Middlesex Counties, NJ, Main Line, DOT-NJ-8
Revision Histories for the Northwest, Transco, and Gulfstream Baseline Assessment Plans

7. §192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

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

§192.907 What must an operator do to implement this subpart?
(b) Implementation Standards. In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (ibr, see §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

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

(a) Time-Dependent
(1) External Corrosion

(2) Internal Corrosion
(3) Stress Corrosion Cracking
(b) Stable
(1) Manufacturing Related Defects
(2) Welding/Fabrication Related
(3) Equipment
(c) Time-Independent
(1) Third Party/Mechanical Damage
(2) Incorrect Operations
(3) Weather Related and Outside Force

...The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third party damage. ...

- **Item 7A: §192.907(b)**

  The initial risk assessment and subsequent baseline assessment decisions were based on a risk model that is no longer supported. This risk model is being replaced by an in-house model that will not be in place until December 2006. The initial model fails to satisfy rule requirements. There is a lack of documented procedures that include required activity steps, responsibilities, data inputs and outputs, and documentation requirements. There is no documented basis for threat weightings factors used in the initial risk model that was used for development of their BAP; documentation of interacting threats have not been considered, and documentation of the elimination of threats is not conducted until after the completion of risk ranking. [C.01.a]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 3.2
  Procedure 70.18.01.03, Minimizing, Mitigating, and Monitoring Stress Corrosion Cracking, Appendix A, WGP Assessment Plans, and Appendix B, Monitoring Pipeline for SCC
  Stress Corrosion Cracking Checklist, HCA 2436, MP 27.1 to 27.28
  Stress Corrosion Cracking Checklist, HCA 2436 MP 27.29 to 27.72
  Stress Corrosion Cracking Checklist, HCA 2479 MP 27.1 to 27.28
  Stress Corrosion Cracking Checklist, HCA 2479 MP 27.29 to 27.72
  Stress Corrosion Cracking Checklist, HCA 1401 MP 865.52 to 865.99
  Stress Corrosion Cracking Checklist, HCA 0030, Main Line A, MP 303.38 to 307.38

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

(a) Definition. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.
(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr,

see § 192.7), section 6.4, and in NACE RP 0502-2002 (ibr, see § 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the 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).

(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.

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

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

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

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

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

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502-2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502-2002);

(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

(iv) **Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502-2002.**

(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE RP0502-2002.)

- **Item 8A: §192.925(b)**

Although WGP's ECDA procedure 20.19.01.02 requires that the operator follow the data requirements in ASME B31.8S Section 4.2 and NACE RP 0502 section 3.2, the ECDA documents reviewed on several completed ECDA's did not contain all of the information required by WGP's procedure. In addition there was no documentation on what assumptions were made and what information was required to assure the feasibility of each ECDA project. [D.02.a]

Evidence: WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8B: §192.925(b)(1)**

Per WGP's ECDA procedure 20.19.01.02 sections 3.1.1 and 3.1.2, WGP was to perform a feasibility assessment for each ECDA performed. Of the ECDA's reviewed there were no documents showing that any feasibility assessments were performed. [D.02.b]

Evidence: WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8C: §192.925(b)(1)**

Per the requirements in NACE RP 0502 Section 3.4, there was no documentation on the indirect inspection tool selection criteria. In addition, it appeared tool selection followed

ECDA region determination rather than preceding it. Also, WGP is using guided wave in casings without required notification. [D.02.c]

Evidence: Procedure 20.19.01.02, Performing External Corrosion Direct Assessment (ECDA)

WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8D: §192.925(b)(1)(ii)**

Panhandle B is not a NACE recognized assessment tool for ECDA indirect inspections. [D.02.c]

Evidence: NACE RP 0502, Table 2

Use of Panhandle B identified by WGP during the inspection.

- **Item 8E: §192.925(b)(1)(ii)**

Although the ECDA procedures specify that casings and other areas are separate regions, in one of the ECDA's reviewed (1400 line, Glenn's Ferry) a cased crossing was part of the single ECDA region along with road crossings and other areas. [D.02.d]

Evidence: ECDA Glenn's Ferry HCA 1400 Buhl to Mt. Home MP 756.6128.

- **Item 8F: §192.925(b)(1)(i)**

The ECDA procedure 20.19.01.02 does not include the 192.925 requirement that initial ECDA assessments include more restrictive criteria for the pre-assessment and that this be documented. [D.02.e]

Evidence: Procedure 20.19.01.02, Performing External Corrosion Direct Assessment (ECDA)

- **Item 8G: §192.925(b)(2)**

There is no documentation that the start and finish of each ECDA region in the completed assessments were not physically marked nor is the amount of overlap for each tool documented. [D.03.a]

Evidence: WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8H: §192.925(b)(2)**

  WGP's ECDA procedure 20.19.01.02 section 5.1.4 requires that the indirect inspection results be integrated with other data obtained in the pre-assessment such as encroachments and foreign line crossings, this is not evident in the ECDA assessments reviewed (1400 line Glenn's Ferry and Oreland, Mercer and Harrison projects). [D.03.b]

  Evidence: Procedure 20.19.01.02, Performing External Direct Assessment (ECDA), Section 5.1.4.

  WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

  ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

  ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8I: §192.925(b)(3)**

  The ECDA procedure does not follow the NACE RP for all required excavations. A review of several ECDA projects showed that in one case only half the number of required excavations was made based on the NACE RP and the ECDA procedure. [D.04.a]

  Evidence: Procedure 20.19.01, Performing External Corrosion Direct Assessment (ECDA)

  WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

  ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

  ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8J: §192.925(b)(3)(iii)**

  There is no documentation that any internal notifications were made based on the results of what was learned in the ECDA projects completed to date. [D.04.g]

  Evidence: WGP Transco, ECDA Project, Oreland 12 Inch Extension, Mercer 16 Inch Lateral, and Harrison 10 Inch Lateral

  ECDA Glenn's Ferry 1400 Buhl to Mt. Home MP 756.6128

  ECDA Glenn's Ferry 1401 Buhl to Mt. Home MP 756.6155

- **Item 8K: §192.925(b)(4)**

  The WGP ECDA procedure does not have the corrected NACE RP 0502 formula for determining the remaining life nor does it include the NACE default corrosion rate where corrosion rates are not documented. One of the evaluated ECDA projects used these incorrect formulas and default values. [D.05.a]

Evidence: Procedure 20.19.01.02, Performing External Corrosion Direct Assessment (ECDA)

9. §192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas…

- **Item 9A: §192.927(a)**

  WGP does not have a technical justification for eliminating the internal corrosion threat in areas where ECDA is being utilized. Therefore, an ICDA procedure is required or another assessment method must be utilized. [D.06.a]

  Evidence: There is no ICDA procedure.

  WGP IM Overview Chapter 8, Section 8.2.2

  Internal Corrosion Threat Checklist, HCA 2436, MP 27.1 to 27.28

  Internal Corrosion Threat Checklist, HCA 2436, MP 27.29 to 27.72

  Internal Corrosion Threat Checklist, HCA 2479, MP27.1 to 27.28

  Internal Corrosion Threat Checklist, HCA 2479, MP 27.29 to 27.72

  Internal Corrosion Threat Checklist, HCA 0030 Harrison, MP 1.59 to 1.9

  Teleconference with Transco Gas Control who established that process equipment was taken out of service due to damage from Katrina and unprocessed gas was being introduced into the system that may exceed the water quantity limits.

10. §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity? COMMENT since the probable violation stated below is only for 937(b), it is not necessary to restate the regulatory text (in yellow) for 937(a) and 937(c). This same comment applies to other sections in the letter in which there appears to be more regulatory text than needed.

(a) General. …….

(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.

- **Item 10A: §192.937(b)**

  WGP's IMP section 9.1.1.5 of procedure 10.25.01.02, SME's determine reassessment intervals during the annual risk assessment results review. No annual review has been completed to date to determine the reassessment interval of completed baseline assessments. [F.01.a,b]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threats Analysis, Section 9.1.1.5

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

(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 (ibr, 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.

(b) Third party ...

(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.

- **Item 11A: §192.935(a)**

  WGP has not identified or implemented any preventive and mitigative measures as required in procedure their IMP procedure 10.25.01.02, Section 9. [H.01.b]

Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 9.0

- **Item 11B: §192.935(c)**

  WGP globally evaluated the effectiveness of ASV's and RCV's for their pipelines. WGP did not delineate a process that evaluates the impact on risk on individual covered segments of installing ASV's and RCV's. [H.07.a]

  Evidence: Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 9.1.1

  Policy 20.15.00, Remedial Measures: Transmission Lines

12. §192.909 How can an operator change its integrity management program?

(a) General. An operator must document any change to its program and the reasons for the change before implementing the change.

- **Item 12A: §192.909(a)**

  The WGP Integrity Management Program change log does not provide a detailed description of changes that were made to the Integrity Management Plan or Procedures. [K.01.a]

  Evidence: WGP Protocol Cross Reference lists this protocol as NA

13. §192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (see § 192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, see § 192.7) for more detailed information on the listed element.)

(a) An ...

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by--

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

- **Item 13A: §192.911(k) ASME B31.8S-2001, section 11 (b)**

  Some important system changes were not reported to the IMP team that could have affected pipeline integrity. [K.02.d]

  Evidence: Teleconference with WGP Transco Gas Control where the introduction of unprocessed gas into Transco due to equipment outages from Katrina was unknown to the Integrity management group. The IM group was assuming that all gas in the WGP system met tariff requirements for water content and they were using that as a basis for not performing ICDA on segments where ECDA was being used as the sole assessment method.

- **Item 13B: §192.911(k) ASME B31.8S-2001, section 11 (d)**

  The Management of Change form had an approval process that was described in Procedure 10.29.01.02. The forms reviewed by the Inspection Team indicated that approval for startup/change was at times the first dated signature on the form when the procedure would indicate that it should be the final signature. MOC examples reviewed (MOCR-BOD-2005-14 and MOCR-BOD-2005-15) reflect the occurrence of required management approvals for modification prior to completion of the specified pre-modification reviews. Final approvals for the completed startup/change occurred prior to the pre-modification reviews and modification approvals. MOCR-110-2005-01 and -02, Palmetto-2006-2, MOCR-180-2005-02 do not reflect some approval signatures or approval dates. MOCR-110-2006-001 involves replacement of a rupture device and it would be expected that Engineering (Pipeline Design) or IMP review would be required. [K.02.e]

  Evidence: MOCR-110-2005-01

  MOCR-110-2005-02

  MOCR-110-2006-01

  MOCR-BOD-2005-14

  MOCR-BOD-2005-15

  MOCR-Palmetto-2006-2

  MOCR-180-2005-02

- **Item 13C: §192.911(k) ASME B31.8S-2001, section 10.3**

  There is no internal communication procedure as required per the rule. [M.01.b]

  Evidence: Per the WGP Protocol Cross Reference list this protocol is NA

- **Item 13D: §192.911(m)**

  No procedure exists to handle safety concerns that PHMSA and/or local regulatory authorities raise. [M.02.a]

  Evidence: Per WGP Protocol Cross Reference list this protocol is NA

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violation(s) and has recommended that you be preliminarily assessed a civil penalty of $351,000 as follows:

Item number	PENALTY
[1A]	$26,000
[2A]	$26,000
[2B]	$26,000
[3A]	$43,000
[4A]	$43,000
[4B]	$43,000
[4C]	$26,000
[4D]	$43,000
[5A]	$15,000
[5B]	$15,000
[5D]	$15,000
[6B]	$6,000
[7A]	$6,000
[8A]	$3,000
[8B]	$3,000
[8I]	$3,000
[11A]	$3,000
[13C]	$3,000
[13D]	$3,000
	$351,000

Warning Items

With respect to items 5C, 6A, 8C, 8D, 8E, 8F, 8G, 8H, 8J, 10A, 11B, 12A, 13A and 13B we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to promptly correct these item(s). Be advised that failure to do so may result in Williams Gas Pipeline being subject to additional enforcement action.

Proposed Compliance Order

With respect to items 5A, 5B, 5D, 6B, 7A, 8I, 8K, 9A, 13C and 13D pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Williams Gas Pipeline. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Response to this Notice

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. 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.

In your correspondence on this matter, please refer to **CPF 5-2007-1001** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Compliance Proceedings

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Williams Gas Pipeline a Compliance Order incorporating the following remedial requirements to ensure the compliance of Williams Gas Pipeline with the pipeline safety regulations:

1. In regard to Item Number 5A of the Notice pertaining to evaluation of a covered pipeline segment containing low frequency electric resistance welded pipe (ERW), lap welded pipe, or other pipe that satisfies the conditions specified in ASME B31.8S-2001, Appendix A4.3 and ASME B31.8S-2001, Appendix A4.4. WGP must conduct a study of all pipeline segments located within an HCA to determine if it contains any pipe meeting the definition as described above. Furthermore, this study must evaluate any covered or non-covered segment in the pipeline system with such pipe that has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years.

2. In regard to Item Number 5B of the Notice pertaining to the lack of data integration. WGP must perform a complete data integration of all known information about the entire Northwest and Transco Pipeline systems in conjunction with each HCA area.

3. In regard to Item Number 5D of the Notice pertaining to missing data and conservative assumptions that can be used in their risk analysis, WGP must define and justify any conservative assumptions made during their risk analysis process. Furthermore, WGP must develop a program and process to obtain missing data for future risk analysis determination.

4. In regard to Item Number 6B of the Notice pertaining to numerous errors in the initial HCA identification process, WGP must completely conduct their initial HCA identification process over with the new revised procedures produced from this inspection.

5. In regard to Item Number 7A of the Notice pertaining to the risk analysis conducted by WGP, the operator must conduct a complete new risk analysis with a new risk model that considers all risk factors applicable to each HCA segment.

6. In regard to Item Number 8I of the Notice pertaining to the incorrect number of excavations required for the direct examination piece of the ECDA procedures, WGP must re-examine all of their ECDA projects and conduct all of the excavations required by Part 192.

7. In regard to Item Number 8K of the Notice pertaining to the incorrect NACE RP 0502 formula for determining the remaining life and the incorrect default corrosion rate, WGP must re-evaluate and recalculate the remaining life for each corrosion anomaly based on the correct values. WGP must then determine if any additional excavations are required and report the number of increased excavations to PHMSA.

8. In regard to Item Number 9A of the Notice pertaining to Internal Corrosion Direct Assessment (ICDA), WGP must develop an ICDA plan and process to evaluate the threat of internal corrosion. Furthermore, WGP must conduct an assessment for

ICDA on all areas where ECDA has been used or is planned to be used or develop a sound technical justification for each HCA area why internal corrosion is not a threat.

9. In regard to Item Number 13C of the Notice pertaining to internal communications procedures, WGP must develop an internal communications plan.

10. In regard to Item Number 13D of the Notice pertaining to procedures to handle safety concerns communicated from regulatory authorities, WGP must develop a process in which to handle such requests and concerns.

11. The operator will have 60 days from the issuance of the Final Order in which to complete the above compliance order items.

12. WGP shall maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.