MAY 02 2011

Mr. Randy Barnard
President
Williams Gas Pipeline
The Williams Companies, Inc.
2800 Post Oak Boulevard
Houston, TX 77056

RE: CPF No. 5-2007-1001

Dear Mr. Barnard:

Enclosed please find the Final Order issued in the above-referenced case. It makes findings of violation, assesses a reduced civil penalty of $306,000, and specifies actions that need to be taken by Williams Gas Pipeline to comply with the federal pipeline safety regulations. When the civil penalty has been paid and the terms of the compliance order completed, as determined by the Director, Western Region, this enforcement action will be closed. Service of the Final Order by certified mail is deemed effective upon the date of mailing, or as otherwise provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Chris Hoidal, Director, Western Region, OPS
Ms. Teresa Silcox Torrey, Senior Counsel, Williams Gas Pipeline
296 Chipeta Way, Salt Lake City, UT 84108

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Williams Gas Pipeline, a division of The Williams Companies, Inc.,	)	**CPF No. 5-2007-1001**
	)	
Respondent.	)	

FINAL ORDER

On March 13-17 and March 27-30, 2006, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), conducted an on-site pipeline safety inspection of the facilities and records of Williams Gas Pipeline's Integrity Management Program (IMP) at its offices in Salt Lake City, Utah. Williams Gas Pipeline (Williams or Respondent) is a division of The Williams Companies, Inc., a global energy company that transports approximately 12 percent of the natural gas consumed in the United States.[1] The inspection covered three gas transmission systems operated by Williams: (1) Northwest Pipeline, with approximately 4,000 miles of pipeline running from Canada to the Pacific Northwest; (2) Transco Pipeline, with approximately 12,800 miles of pipeline running from Texas into the Southeast and Northeast; and (3) Gulfstream Pipeline, with approximately 700 miles of pipeline running from Alabama across the Gulf of Mexico to Florida.

As a result of the inspection, the Director, Western Region, OPS (Director), issued to Respondent, by letter dated January 29, 2007, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent committed certain violations of 49 C.F.R. Part 192 and assessing a civil penalty of $351,000 for the alleged violations. The Notice also proposed that Respondent be required to take certain measures to correct the alleged violations. It also proposed finding that Respondent had committed certain other probable violations of 49 C.F.R. Part 192 and warning Respondent to take appropriate corrective action or be subject to future enforcement action.

[1] The Williams Companies' website (http://www.williams.com/gas_pipeline/) (last accessed 3/15/11).

Williams responded to the Notice by letter dated, March 1, 2007 (Response). Respondent contested several allegations, offered information and exhibits in support of its position, and requested mitigation of the proposed penalty. Williams also raised a legal challenge that PHMSA did not have authority, under the Pipeline Safety Improvement Act of 2002 (PSIA) or the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES), at the time of the alleged violations to issue civil penalties or compliance orders in gas integrity management cases. Respondent argued that the Notice constituted an illegal retroactive application of PSIA and PIPES not expressly authorized or intended by Congress.[2]

Williams requested a hearing, which was subsequently held on May 23, 2007, in Denver, Colorado, with an attorney from the Office of Chief Counsel, PHMSA, presiding. After the hearing, Respondent provided a post-hearing submission dated June 21, 2007 (Closing).

Authority of PHMSA to Enforce Integrity Management Regulations

As a preliminary matter, Respondent argued that 49 U.S.C. § 60109(c)(9)(A)(iii)[3] only permits PHMSA to act under § 60109(a)(2) to order an operator to revise its IMP with a Notice of Amendment type of enforcement action (amend the program plans and procedures). Williams further argued that the statute precludes or does not give PHMSA the authority to act under any other section of Chapter 601 to enforce integrity management program regulations by issuing compliance orders and civil penalties. Respondent also argued that Congress provided operators a four-year period to go from an IMP framework to a fully thought out, robust IMP.

With the enactment of the PSIA, the U.S. Congress directed the Department of Transportation, PHMSA, to establish and issue regulations detailing standards for the implementation of an integrity management program. The PIPES Act of 2006 codified the integrity management program.

The authority set forth in §§ 60119 and 60122 to enforce pipeline safety standards, laws and regulations through compliance orders and civil penalties has been codified since 1979 and nothing in PSIA or the PIPES Act affected this authority.

Any suggestion that, prior to the PIPES Act, section 60109(c)(9)(A)(iii) limited the agency's authority with respect to operator conduct and to only require an operator to amend an inadequate or noncompliant integrity management program is therefore incorrect.

Considering the authority established in §§ 60118 and 60122; the legislative history of both PSIA of 2002 and PIPES Act of 2006; and the legal issues presented, I find that PHMSA had the authority and did properly exercise the full spectrum of enforcement tools upon a determination that a risk analysis or integrity management program is inadequate or noncompliant.

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[2] *Response*, at 2-3.

[3] Subsection 60109(c)(9)(A)(iii) states: "If the Secretary determines that a risk analysis or integrity management program does not comply with the requirements of this subsection or regulations issued as described in paragraph (2), has not been adequately implemented, or is inadequate for the safe operation of a pipeline facility, *the Secretary may conduct proceedings under this chapter*." (emphasis added)

FINDINGS OF VIOLATION

The Notice alleged that Respondent violated 49 C.F.R. Part 192, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. §§ 192.947(d) and 192.905(a), which state:

> **§ 192.947 What records must an operator keep?**
> An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.
> (a) . . .
> (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) 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.)

The Notice alleged that Respondent violated 49 C.F.R. §§ 192.947(d) and 192.905(a) by failing to describe and document in its IMP which method it had applied to each portion of its pipeline system to identify High Consequence Area (HCA) segments.[4] The Notice also alleged that Williams had failed to maintain records to support any decision, analysis or process developed and used to implement its IMP. Specifically, it alleged that Respondent failed to keep documents supporting the process(es) that had been used to identify each HCA segment.
At the hearing, Williams acknowledged that its IMP procedures needed to include stronger language stating what data and methodology were used for identifying HCAs, yet submitted page

[4] A "High Consequence Area" is defined as: 1) an offshore area; or any class location unit that has 10 or fewer buildings intended for human occupancy; (2) any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy; (3) any class location unit that has 46 or more buildings intended for human occupancy; or (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. 49 C.F.R. 192.5 (b)(3); or (4) any class location unit where buildings with four or more stories above ground are prevalent. 49 C.F.R. 192.5 (b)(4).

1 of Chapter 4 of its IMP Overview to demonstrate its compliance with the regulations. OPS responded by pointing out that while page 1indicated the use of Method 1 in identifying HCAs,[5] the OPS inspection team had discovered indications that Method 2 was also used. OPS argued that the inspection team found inconsistencies between Respondent's summary and its actual procedures.

Williams explained that the inconsistencies in Chapter 4 of its IMP Overview resulted from a typographical error and that in addition to correcting this error, the company had revised its Baseline Assessment Plan (BAP) to include the correct method being used for each HCA. However, Respondent did not deny that it had failed to provide the OPS inspection team with documentation of the methods it had used to identify each HCA segment.

Accordingly, after considering all of the evidence, I find that Williams violated 49 C.F.R. §§ 192.947(d) and 192.905(a) by failing to describe and document in its IMP which methods it had applied to each portion of its pipeline to identify HCA segments by the December 17, 2004 deadline (December 2004 Deadline) imposed under 49 C.F.R. § 192.907(a).

Item 2A: The Notice alleged that Respondent violated 49 C.F.R. § 192.905(a), which states:

> **§ 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.)

The Notice alleged that Respondent violated 49 C.F.R. § 192.905(a) by failing to describe in its IMP which method it had applied to each portion of its pipeline to identify HCA segments. Specifically, it alleged that the system maps and the GIS system used by Respondent failed to establish a suitable means of documenting segment locations in HCAs. According to the Notice,

[5] Operators may identify HCAs using either of two methods:

- Method 1: A pipeline segment is located in a high consequence area if any of the following apply:
    - A Class 3 location under 192.5; or
    - A Class 4 location under 192.5; or
    - Any area outside a Class 3 or Class 4 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
    - The area within a potential impact circle containing an identified site.
- Method 2: A pipeline segment is located in a high consequence area if any of the following apply:
    - The area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
    - The area within a potential impact circle contains an identified site.

Williams' personnel acknowledged during the OPS inspection that the accuracy of its pipe-segment locating process ranged from survey quality to +/- 40 feet and that Respondent had not taken any action to address these known inaccuracies in its HCA identification process.

At the hearing, Williams posed that it was unnecessary to account for uncertainties in its HCA identification process. Respondent argued that § 192.905(a) did not require system maps or GIS systems, nor did it address quality assurance methods. Respondent advised that every year it performed a structure survey to review data on its GIS.

In response, OPS asserted that, during the March 13, 2006 inspection, Williams' process for conversion from legacy alignment sheets and survey notes to GIS was discussed and fully explained. OPS testified that discussions with Respondent included past and current processes and activities and focused on continuous improvement of centerline accuracy, including collection of survey grade points, ortho-photo centerline and ortho-photo structure location corrections. OPS also testified that Engineering Services Management of Change (MOC) and annual update processes were shared and discussed on March 16, 2006, to further reinforce continuous improvement processes related to GIS centerline data integrity and related facility drawings. OPS explained that the issue was the need to factor uncertainty into HCA identification and to document a suitable means of delineating segment locations.

In response and in support of its position, Williams introduced INGAA's letter to Stacey Gerard, former Associate Administrator of PHMSA, as documentation that the application of uncertainty factors to the identification of HCAs was "overkill," based on the ratio of assessment of non-covered segments to covered segment miles. Respondent argued that it had discussed and described this process to the OPS inspection team.

OPS responded that the company's identification process was inadequate and still under development, at a time when a more mature process should have been in place. Based upon its inspection and review of Chapter 4 of Respondent's *IMP Overview*, OPS contended that Williams had applied no safety factors to the calculation of potential impact radii[6] (PIRs) in the HCA identification process. OPS staff testified that during the inspection, Respondent had not described the PIR of the method used to establish HCAs and that the inspection team had found no documentation that Williams had considered additional buffers to account for potential pipeline location inaccuracies. Furthermore, OPS explained that many HCAs had not been identified when inspectors reviewed the company's alignment sheets.

Accordingly, after considering all the evidence, I find that Williams violated 49 C.F.R. § 192.905(a) by failing to describe in its IMP which method it had applied to each portion of its pipeline to identify HCA segments, in that the inaccurate maps and electronic GIS system used by the company failed to properly document segment locations.

Item 2B: The Notice alleged that Respondent violated 49 C.F.R. § 192.905(b), which states:

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[6] "Potential impact radius" is defined in § 191.903 as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

> **§ 192.905 How does an operator identify a high consequence area?**
>
> (a) . . .
>
> (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.
>
> (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.

The Notice alleged that Respondent violated 49 C.F.R. § 192.905(b) by failing to use certain information available to it in cases where public officials with safety or emergency response or planning responsibilities had informed the company that they did not have information delineating identified sites. Specifically, the Notice alleged that Williams had failed, by the December 2004 Deadline, to use visible markings, licensing or registration by a governmental agency, or listing on the Internet or other public available maps maintained by governmental entities to delineate identified sites in lieu of obtaining relevant information from public officials. In addition, it alleged that Williams did not have procedures on how it located identified sites using such alternative sources of information. During the OPS inspection, the inspector conducted a review of Respondent's procedures, including *IM Procedure 10.09.01.10, Establishing Class and HCA Location, Section 8.1.10,* and alleged that they did not address the need to use these other information sources.

As for the first allegation, Williams acknowledged at the hearing that it had not been able, by the December 2004 Deadline, to secure information on potential identified sites with its April 2005 mail-out to public officials having safety or emergency response or planning responsibilities. Respondent argued nevertheless that the regulation did not require that a mail-out be undertaken to public officials for the purposes of obtaining identified site information. It also reiterated its position that it had not been informed by any public official that it lacked sufficient information to identify an identified site. Respondent further advised that it had completed a pilot project to evaluate the use of Standard Industrial Classification (SIC)[7] codes (Method 3 suggested in Part 192), which is a query from available lists, and had found the results to be insufficiently accurate.

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[7] SIC Codes are used to create targeted mailing lists by industry type.

I find that although Williams had some documentation showing potential identified sites through the use of alignment sheets, there were no dates on these sheets earlier than 2006; therefore, these sheets are not probative of whether or not the company used such information prior to the December 2004 Deadline. I also find that even if Respondent had other marked-up alignment sheets prior to 2006, they were not provided at the time of the inspection, during the hearing, or with the Closing.

There is no evidence in the record that Respondent had made any effort to obtain information from public officials to gather data on potential identified sites prior to the December 2004 Deadline. Williams testified that it had used "visible markings such as signs" to delineate identified sites; however, such information is only allowed under the regulation to be used to the extent that the operator is unable to obtain information from public officials. The intent of the regulation is to require operators to seek information from public officials who are better informed than operators about where identified sites are located, how to avoid damaging such sites, how to recognize and report emergencies that may arise, and how to protect isolated population areas located near pipelines. It is only when such information is unavailable from public officials that operators may use other data sources to delineate identified sites.

As for the second allegation that it lacked proper procedures for using alternative information sources, Williams submitted a copy of its *2004 Field Instructions*,[8] which quoted language from § 192.905 defining the term "identified sites" and stating: "*This year we'll also have to locate "high consequence areas" called identified sites. We will be required to locate these all the way out to the 660" line.*" These Field Instructions, however, do not contain detailed procedures describing the use of alternative information sources.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.905(b), by failing to use alternative sources of information to identify HCAs after being unable to obtain information from public officials regarding identified sites, by the December 2004 Deadline.

Item 3: The Notice alleged that Respondent violated 49 C.F.R. § 192.907(a), which states:

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

[8] *Closing*, DVD, at 47.

Item 3 of the Notice alleged that Respondent violated 49 C.F.R. § 192.907(a) by failing to meet the December 2004 Deadline for developing and following a written IMP that contained all the elements described in § 192.911 and that addressed the risks on each covered transmission pipeline segment. Specifically, the Notice alleged that Williams' records revealed that, as of April and May 2005, the company's HCA identification process was still incomplete. For example, it alleged that public officials had not been contacted for the location of identified sites until April 2005.

At the hearing, Respondent repeated its response to Item 2B above and argued that as of the December 2004 Deadline, public officials had not provided any information on identified sites. It further argued that § 192.907(a) did not require that a mail-out be undertaken to public officials for the purposes of obtaining identified site information. Instead, the company indicated that it had identified HCAs in Class 1 and 2 areas by the December 2004 Deadline using information obtained from routine operation and maintenance activities.

OPS responded that Williams did not even start to contact public officials until 2005, after the December 2004 Deadline. OPS argued that because Respondent had not sought information on identified sites from public officials in a timely manner, its delineation of identified sites was incomplete as of the December 2004 Deadline.

After considering all the evidence, I find that none of the documentation submitted by Respondent during the hearing or in the company's Closing demonstrates that the identified sites were properly delineated prior to the December 2004 Deadline. Therefore, I find Respondent violated 49 C.F.R. § 192.907(a), by failing to develop and follow a written IMP by the December 2004 Deadline that contained all the elements described in § 192.911 and that addressed the risks on each covered transmission pipeline segment.

Item 4: The Notice alleged that Respondent violated 49 C.F.R. § 192.905(a), as quoted above, by failing to properly identify HCA areas using one of the methods described in paragraphs (1) or (2) (Methods 1 and 2) below from the definition of "High Consequence Area" provided in § 192.903. That section states, in relevant part:

> **§ 192.903 What definitions apply to this subpart?**
> The following definitions apply to this subpart: . . .
> *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.)….
>
> *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;…

Item 4A of the Notice alleged that Respondent violated 49 C.F.R. § 192.905(a) by failing to properly apply Method 1 in delineating HCAs, insofar as the full length of Class 3 and 4 locations[9] was not included in the HCAs. Specifically, the Notice alleged that the OPS inspection[10] had revealed that, in an effort to use Method 1, Williams had failed to include the full length of its Class 3 and 4 locations within HCA boundaries and that therefore these locations were not properly scheduled for assessment or repairs.

At the hearing, Respondent asserted that it had correctly applied Method 1, but acknowledged that not all HCAs had been identified as of the OPS IMP audit in March 2006. The company advised that data was still being analyzed and HCA determinations were still pending.

Williams also acknowledged that the HCA boundaries were shorter than the Class 3 dimensions but disagreed with OPS' assertion that a portion of the HCAs had therefore not been properly scheduled for assessment or repair. Williams contended that when it undertook External Corrosion Direct Assessment (ECDA), it would visit each site to confirm the actual, required

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[9] A Class 3 location is defined as: (i) any class location unit that has 46 or more buildings intended for human occupancy; or (ii) an area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) 49 C.F.R. § 192.5 (b)(3).

A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent. 49 C.F.R. § 192.5(b)(4).

[10] The OPS inspection included a review of Respondent's Alignment Sheet, Location Class Determination and Qualification Record, MP 1782.125 to 1783.750, Somerset and Middlesex Counties, NJ Main Line, and DOT-NJ-8. Pipeline Safety Violation Report, at 10.

length of pipe to be inspected. At that point, the company would assess the entire length of the HCA. Respondent further contended that when using in-line inspection (ILI), it analyzed data for the entire ILI run, not just for the HCA areas.

In its Closing, Williams posed that not correctly identifying the length of the Class 3 and 4 locations used in Method 1 was irrelevant since it visited each site to confirm the actual, required length of the pipe to be inspected and then the entire length of the HCA would be assessed. For ECDA, Respondent stated that the length of the HCA segments was also irrelevant because the company performed actual field measurements. The company further posed that it treated immediate repair conditions in non-covered segments the same as those in covered segments. OPS countered that the issue was not whether Williams took alternative measures to protect the integrity of the pipeline, but, rather, whether the company properly used Method 1 under § 192.905(a) to identify HCAs. In addition, OPS noted that the company's repair procedures did not include a specific timeframe for repairing immediate conditions in non-covered segments. Therefore, if an immediate condition were located just outside an HCA segment that should have included the condition, then the condition would not get repaired in a timely manner.

Accordingly, based upon the company's own admission and a review of all of the evidence, I find that Williams violated 49 C.F.R. § 192.905(a), by failing to adequately establish HCA areas using Method 1, as described in § 192.903.

Item 4B of the Notice alleged that Respondent violated 49 C.F.R. § 192.905(a), as quoted above, by failing to properly identify HCA areas using Method 1, as described in the definition of "High Consequence Area" under § 192.903. Specifically, the Notice alleged that Williams failed to properly identify HCAs under that portion of Method 1 which calls for the identification of areas "in a Class 1 or Class 2 location where the potential impact circle contains an identified site." According to the Notice, documentation reviewed during the inspection [11] showed identified sites on Williams' Transco system that the company had failed to include in HCAs. The Notice alleged that the HCA identification process was flawed insofar as the company's field personnel were not even trained in the HCA identification process until well after the December 2004 Deadline.

At the hearing, Williams indicated that training was an ongoing part of its continuous improvement process and that in February 2004, its field personnel had been given instructions on locating and reporting structures along the pipeline. The company further contended that it had completed company-wide training that restated IMP requirements such as collecting information on identified sites and that the April-June 2005 training mentioned by the OPS inspection team was *additional* training that covered the entire IM program. In its Closing, Respondent provided a copy of its *2004 Field Instructions*.[12]

[11] Respondent's Alignment Sheet, Location Determination and Pipeline Qualification Record, MP 1408.000 to 1410.87, Pittsylvania County, VA, Main Line, DOT-V-9. Respondent's Alignment Sheet, Location Determination and Pipeline Qualification Record, MP 1457.375 to 1459.375, Appomattox, VA, Main Line, and DOT-V-25B. Violation Report, pp. 12 and 45.

[12] *Closing,* at 47.

OPS responded that although the *2004 Field Instructions* acknowledged identified sites must be identified, Williams did not provide evidence at the time of the inspection that any identified sites had actually been identified. OPS testified that its inspection had revealed a company e-mail sent in February 2004, entitled "2004 House Count Instructions." OPS asserted that an examination of the document showed that the *2004 Field Instructions* were not training materials and did not indicate that Respondent's employees had actually been trained to delineate identified sites.

After considering all the evidence, I find that the field instructions that were provided as part of the Closing were not provided to the OPS inspection team at the time of the audit. Although Respondent's *2004 Field Instructions* acknowledged that identified sites must be identified, I see no evidence showing that any sites had actually been identified or that actual training had been provided to company personnel, as would be reflected by sign-in sheets or similar documentation. I also find that Respondent's personnel collected information on identified sites prior to being properly trained.

As a result, Respondent failed to properly identify HCA areas using Method 1 in its HCA identification process, as there was no evidence that Williams considered identified sites that lay within the potential impact circle of the Class 1 and 2 locations. Accordingly, upon review of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.905(a) by failing to properly use Method 1, as described in § 192.903, to include certain identified sites in its HCAs.

Item 4C of the Notice alleged that Respondent violated 49 C.F.R. § 192.905(a), as quoted above, by failing to properly identify HCA areas using Method 1, as described in the definition of "High Consequence Area" under § 192.903. Specifically, it alleged that Williams improperly applied Method 1 by failing to designate certain outdoor areas and buildings as "identified sites." Section 192.903 provides that "[a]n 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" shall be considered an "identified site." In addition, it provides that "[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" shall also be considered an identified site.

The Notice alleged that Williams' procedure, *WGP IMP Overview Chapter 4, Section 4.8*, defined the term "day" as a continuous 8-hour period, for purposes of determining whether structures or outdoor areas qualified as identified sites. This definition, OPS asserted, was inconsistent with the regulation, insofar as the 20-or-more-persons criterion applied to the presence of people at a particular location at *any* point in time, not just for a continuous 8-hour period. For example, using the definition of "day" set forth in Respondent's procedure, a picnic area would have to sustain 20 or more persons on site for eight hours a day, five days a week, for 10 weeks (i.e., 50 days) in any 12-month period.

At the hearing, Respondent argued that its current *Procedure 10.09.01.10* met the requirements of §§ 192.903 and 192.905, which do not specify the length of a day. The company argued that the terms "day" and "occupied" in the regulation were nebulous and not clearly defined in 49 C.F.R. Part 192. In support of its position, Williams suggested that PHMSA's published guidance document, FAQ #211, directly asked for clarification but that the agency had pointedly steered clear of the issue and declined to define the length of a day.

Respondent's argument is specious. While it is correct that § 192.903 does not specify how many hours constitute a "day" for purposes of designating identified sites,[13] such detail is unnecessary. The FAQ #211 guidance document explicitly states that a site is considered an identified site if 20 or more persons occupy it for *any* length of time, unless they are in transit. I fail to see any ambiguity in the regulation. If a site is normally occupied for one hour or 23 hours per day, it is still considered a "day" for purposes of determining whether to classify the area as an identified site. By requiring that a site be occupied for at least eight hours per day, Respondent's procedure greatly reduces the number of sites with outdoor gathering areas or buildings that qualify for the additional protections required for HCAs. I do not believe such a procedure is consistent with the purpose or intent of the term "identified site" in § 192.903.[14]

Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.905(a) by failing to adequately use Method 1, as described in the definition of "High Consequence Area" under § 192.903, to designate certain outdoor areas and buildings as identified sites.

Item 4D of the Notice alleged that Respondent violated 49 C.F.R. § 192.905(a), as quoted above, by failing to properly designate HCA areas, as defined under § 192.903. Specifically, it alleged that Williams failed to apply the axial extension of the potential impact circle along the length of the pipeline, from the outermost edge of the first potential impact circle containing either an identified site or 20 or more buildings intended for human occupancy, to the outermost edge of the last contiguous potential impact circle containing such sites. The Notice alleged, for example, that for HCA 1401 - Ft. Lewis to Sumner MP 1346.844, the company's GIS showed the HCA length as being 0.174 miles, but that if the potential impact circle were properly extended, the length would be 0.42 miles.

At the hearing, Respondent acknowledged that its HCAs with identified sites from its 2004 survey failed to include the proper axial extensions and indicated that a detailed review of all its HCAs would be completed by April or May 2006. The company further advised that its baseline assessment HCA lengths would be adjusted as necessary following such comprehensive review.[15]

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[13] FAQ-211 states: "Time limit for gathering of 20 people. If a building or outside area is typically or normally occupied by 20 or more people while in use, then the location is considered an identified site. The rule provides that operators can rely on information from local public officials with emergency response or planning responsibilities to make these determinations. Operators need not consider persons who merely pass through an area, since these persons are considered to be in transit and cannot truly be said to 'occupy' the location."

[14] In support of its position, OPS cited two other guidance documents, *Advisory Bulletin ABD-03-03*, dated July 17, 2003, and *FAQ #18*, which states: "Practical Limits on Searching for Identified Sites. Are there practical limits on an operator's search for identified sites? Yes. An operator is expected to make a reasonable effort to identify sites meeting the criteria for 'identified sites.' The rule requires that operators consider information they have gleaned from routine operations and maintenance activities along the pipeline and from public officials responsible for safety or emergency response/planning who indicate to the operator that they know of locations near the pipeline meeting these criteria. If no public officials have such knowledge, then the operator must identify facilities that either: (1) have visible signs; (2) are licensed by a Federal, State, or local government agency; or (3) appear on a list or map available from such an agency."

[15] Although Respondent acknowledged that some of the HCA boundaries listed in the Notice needed to be extended, the company questioned the suggestion that a portion of its HCA has not been scheduled for assessment or repair. *See* Violation Report, at 16.

Respondent provided two other rationales for the process it had used to delineate identified sites. First, the company explained that when using ILI, it had analyzed data for the entire ILI run, not just for HCAs, and that its procedures did not differentiate responses based on whether an anomaly was located in an HCA or not. Second, it argued that a significant factor contributing to the abbreviated length of the HCAs was that paragraph 3 of the definition of "High Consequence Area" in § 192.903 was actually missing from the published 2004, 2005, and 2006 Code of Federal Regulation (CFR). Respondent stated that its employee who initially identified the HCAs made an error by interpreting the code without the benefit of this paragraph.

As to the first argument, OPS responded that Respondent's misapplication of the process for identifying covered segments was the issue, not the methodology by which Williams read its own ILI data, and that if the company had performed the HCA determination process correctly, it would have picked up many additional HCAs. As for the second, I would note that the Federal Register is the main source for U.S. government agencies to promulgate proposed rules through official publication, for seeking comment from the public, for responding to those comments, and for issuing Final Rules that are incorporated into the CFR. The Supreme Court has held that the appearance of rules and regulations in the Federal Register gives legal notice of their content and they are accordingly binding, regardless of whether actual knowledge of their content or of hardship resulting from innocent ignorance, thus approving the principle of constructive notice with regard to rules and regulations and placing them on a par with statutory law.[16] Everyone is charged with knowledge of federal laws and United States Statutes at Large. Congress has provided that the publication of rules and regulations in the Federal Register gives sufficient legal notice of their contents.[17]

Finally, I would note that even if the wrong version of § 192.903 were, in fact, published in the CFR, Respondent's argument would serve only to potentially mitigate the seriousness of the offense, not to negate it altogether. Therefore, I have addressed this argument in the "Assessment of Penalty" section below.

Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.905(a) by failing to properly designate the length of HCA areas, as defined under § 192.903, by extending the potential impact circle axially along the length of the pipeline, as more fully described above.

Item 5A: The Notice alleged that Respondent violated 49 C.F.R. § 192.917, which states, in relevant part:

> **§ 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

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[16] *Federal Crop Ins. Corporation v. Merrill et al*., 332 U.S. 380, 68 S.Ct. 1, 175 A.L.R. 1075, 92 L.Ed. 10 (Nov. 10, 1947).

[17] 49 Stat. 502, 44 U.S.C. § 307, 44 U.S.C.A. § 307 (appearing in its present form at 44 U.S.C. § 1507 (1976)). 332 U.S. at 384-85, 68 S.Ct. at 3.

> 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 non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment . . . .

Item 5A of the Notice alleged that Respondent violated 49 C.F.R. § 192.917(e)(4) by failing to develop and follow procedures for identifying whether its covered pipeline segments contained low frequency electric resistance welded (ERW) pipe, lap welded pipe, or other pipe that satisfied the conditions specified in ASME B31.8S-2001 (ASME Standard), Appendices A4.3 and A4.4, and whether any covered or non-covered segments in its system with such pipe had experienced seam failure, or whether the operating pressure on any covered segment had increased over the maximum operating pressure experienced during the preceding five years. Specifically, it alleged that Williams did not have procedures in place to verify that the assessment method(s) it had selected for such pipe were proven to be capable of assessing seam integrity and detecting seam corrosion anomalies.[18]

Respondent contested this Item, asserting that it did indeed have procedures requiring its employees to review certain checklists to determine whether the selected assessment method(s) were capable of assessing seam integrity and detecting seam corrosion. The company also asserted that it had provided the OPS inspection team with an example of its checklist and explained that it had reviewed pressure tests, ILIs, and the checklists to gather information for the purpose of determining whether there was a threat posed by ERW pipe.

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[18] 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;* Violation Report, *at 18.*

OPS rejected this evidence and presented testimony that Respondent's procedures were no more than a bullet checklist, requiring the marking of boxes and including a statement that if no data were available, then it should be assumed that ERW pipe was not present. OPS further asserted that the checklist Respondent referred to as its "procedures" contained no detailed step-by-step information to provide guidance for its employees.

I agree with OPS. The unavailability of identified data elements is not a justification for the exclusion of a threat from an operator's integrity management program. Depending on the importance of the data, additional inspection actions or filed data collection efforts may be required.[19] The checklists and rudimentary procedures Williams had in place both failed to meet the minimum requirements of the ASME Standard or to provide a rigorous risk analysis process that could determine whether an actual threat existed from ERW pipe.

Accordingly, upon consideration of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.917(e)(4) by failing to develop and follow adequate procedures for identifying whether its covered pipeline segments contained ERW pipe, lap welded pipe, or other pipe that satisfied the conditions specified in the ASME Standard, Appendices A4.3 and A4.4, and whether any covered or non-covered segments in its system with such pipe had experienced seam failure, or whether operating pressure on the covered segments had increased over the maximum operating pressure experienced during the preceding five years.

Item 5B of the Notice alleged that Respondent violated 49 C.F.R. § 192.917(b), as quoted above, by failing to develop and implement an IMP that adequately identified and evaluated the potential threats to its covered pipeline system by gathering and integrating existing data and information on the entire pipeline that could be relevant to the covered segments. Specifically, the Notice alleged that Williams failed to properly integrate the required data by the December 2004 Deadline. The regulation requires that individual data elements be brought together and analyzed to determine the relevance of specific threats.[20]

At the hearing, Respondent contended that it had procedures in place, prior to the December 2004 Deadline, to fully integrate and analyze the required data for risk assessment and threat analysis. Respondent explained that, during the inspection, there may have been miscommunication during the discussion with the OPS team about Respondent's old risk model, as opposed to its new one. The company indicated that it had produced GIS sheets and a business plan, with schematics, for a more robust data integration system, prior to the December 2004 Deadline.

OPS acknowledged that while Williams did have a method to *aggregate* data, the company failed to have procedures in place to actually analyze individual data elements, to determine the relevance of specific threats and to support an improved analysis of overall risk. OPS explained that during the inspection, the company had indicated that it planned to perform this activity, using its GIS/risk assessment model, by December 2006, two years after the December 2004 Deadline.

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[19] ASME Standard, Appendices A4.3 and A4.4

[20] Evidence: *Procedures 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 4.0;* Violation Report, *at 19.*

I find that Respondent provided GIS sheets to the OPS inspection team for review and that the company was in the midst of an ongoing process for developing a GIS that would comprehensively integrate all relevant data. However, I further find that the record does not contain sufficient evidence to show that Respondent had the required data integration process in place as of the December 2004 Deadline. Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.917(b) by failing to develop and implement an IMP that adequately identified and integrated the individual data elements needed to determine the potential threats to its covered pipeline system.

Item 5D of the Notice alleged that Respondent violated 49 C.F.R. § 192.917(b), as quoted above, by failing to have a process in its IMP for verifying data quality, insofar as the company's procedures did not require conservative assumptions to be applied if certain data were missing or suspect.[21] The Notice also alleged that it was not clear whether conservative values had actually been applied. For example, pipeline sections containing ERW pipe defaulted to a non-conservative value without verifying that operating pressures had actually been at the maximum allowable operating pressure (MAOP). The Notice also alleged that Respondent failed to maintain records showing how unsubstantiated data was used and failed to specify that additional inspections or field data collection efforts were necessary if data were missing or suspect.

At the hearing, Respondent contended that its *Procedures 10.25.01.02, Section 4,* and *70.18* called for the use of a "Threats Checklist," which was used by subject matter experts (SMEs) to determine where conservative assumptions should be applied, based upon the SMEs' skill, experience and work on the job on a daily basis. Williams further contended that all of its ERW pipelines were treated as high-risk lines.

OPS reiterated that § 192.917(b) requires operators to gather data and integrate existing data and information on their entire pipelines and not just on covered segments. According to the agency, Williams acknowledged that all of the data required by the ASME Standard had not been captured or integrated into its GIS system. OPS further contended that the ASME Standard requires that if a data element is missing for a particular threat, then the operator must assume that the threat applies.[22] I can find nothing in the record to show that Williams actually applied conservative assumptions in such situations.

Accordingly, upon consideration of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.917(b) by failing to have an adequate process in its IMP for gathering and integrating data on its entire pipeline, insofar as it lacked processes for verifying data quality or for applying conservative assumptions if data were missing or suspect.

Item 6B: Item 6B of the Notice alleged that Respondent violated 49 C.F.R. § 192.921(d), which states:

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[21] Evidence: *Procedures 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 WGP's *Protocol Cross Reference List*.

[22] ASME Standard, Appendix A4.2.1. Once data is collected, it must be turned into transparent information. Operators can refer to the OPS Gas Integrity Management Advisory Bulletin ADB-03-07 of November 17, 2003 (68 FR 64948) for an explanation of how OPS interprets the statutory requirement "to begin assessments" and for guidance on what steps OPS considers to be acceptable for conducting the baseline assessment process.

§ 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 (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.

The Notice alleged that Respondent violated 49 C.F.R. § 192.921(d) by failing to prioritize all its covered pipeline segments for the baseline assessment in such a manner that its assessment schedule could be properly verified. Specifically, the Notice alleged that Williams had made numerous errors in its initial HCA identification process, which resulted in an inability to verify that the assessment schedule set forth in its BAP met the requirements in the regulation. The Notice further alleged that the company's BAP failed to include certain HCA segment mileage that had been erroneously omitted, as discussed in Item 4D above, and that Method I had been improperly applied to the Transco system such that the full length of Class 3 and 4 locations were not included in HCA boundaries. These errors resulted in a failure to properly prioritize and set an assessment schedule for these lines. At the hearing, Respondent did not contest these allegations. Accordingly, after considering all of the evidence, I find Respondent violated 49 C.F.R. § 192.921(d).

Item 7: The Notice alleged that Respondent violated 49 C.F.R. § 192.907(b), which states:

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

(a) . . . .

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *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.

The Notice alleged that Respondent violated 49 C.F.R. § 192.907(b) by failing to follow the requirements of Subpart O of 49 C.F.R. Part 192 and the ASME Standard in the development and implementation of its IMP. Specifically, it alleged that Williams failed to identify and evaluate all potential threats to each covered pipeline segment as described in 49 C.F.R. § 192.917(a) by the December 2004 Deadline.[23] According to OPS, Respondent's initial risk

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[23] This subsection states:

"(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:

assessment and subsequent baseline assessment decisions were based on a risk model that failed to document the basis for threat-weighting factors, that failed to consider interacting threats, and that failed to document the elimination of certain threats until after the risk ranking had been completed. It also alleged that there was a lack of certain documented procedures, including required activity steps, responsibilities, data inputs and outputs, and documentation requirements.

At the hearing, Respondent argued that its initial risk assessment and subsequent baseline assessment decisions were based on a viable and industry-accepted risk model known as the "Bass-Trigon Integrity Assessment Program" (B-T Model). Respondent argued that the B-T Model used at the time of its BAP development was fully supported and implemented, with 10 years of operational history, and that it addressed all of the data requirements of the ASME Standard, Appendix A. Respondent further argued that it had procedures in place that included activity steps, responsibilities, data inputs as documented in the algorithm, and data outputs, as documented in the risk assessment reports and its BAP. Lastly, it argued that the use of a risk model was not required by the rule and that the ASME Standard listed SMEs as an acceptable risk assessment approach.

Respondent defended its risk assessment process by arguing that no threats had been eliminated, that all threats had been considered as potential threats, and that the interactive nature of various threats had been considered in determining the relativity of the risks. The results of the relative risk assessment were then used to prioritize the covered segments, in conjunction with SME review and validation. The most significant risk factors were then determined through the completion of a "Threats Checklist" by SMEs that provided criteria for the elimination of threats from further consideration. Then the appropriate integrity assessment method was determined, based on the threats to which a particular segment was susceptible.

In response, OPS argued that the B-T Model being used at the time of the inspection failed to cover *all* of the threats enumerated in the ASME Standard, most notably stress corrosion cracking (SCC).[24] OPS asserted that Williams had a history of leaks and failures attributed to SCC and yet failed to consider that SCC could be present along its system. OPS also asserted that the Threats Checklists was developed and implemented in 2006 and that Williams had failed to present any evidence that it had a documented process to identify threats as of the December 2004 Deadline. OPS also testified that there was no indication that the default weightings used by Williams in the B-T Model were ever modified using an SME approach.

I agree with OPS. In particular, I find that the B-T Model used by Williams did not cover all of the threats identified in the ASME Standard, including SCC, which is a known condition on portions of Respondent's pipeline. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.907(b) by failing to identify and evaluate all potential threats to each covered pipeline segment as described in 49 C.F.R. § 192.917(a) by the December 2004 Deadline.

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(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."

[24] ASME Standard, Section 2.2, Integrity Threat Classification.

Item 8: The Notice alleged that Respondent violated 49 C.F.R. § 192.925, which states:

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

(a) *Definition*. 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 (incorporated by reference, *see* § 192.7), section 6.4, and in NACE [Recommended Practice (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).

(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 RP 0502-2002, 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; ... .

(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) ...

(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 RP 0502-2002.

(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 RP 0502-2002.)

Item 8A of the Notice alleged that Respondent violated 49 C.F.R. § 192.925(b) by failing to use direct assessment to assess the threat of external corrosion in a manner that followed the requirements of the ASME Standard, section 4.2, and NACE RP 0502-2002 (NACE Standard), section 3.2. Specifically, it alleged that Williams failed to follow its own *Procedure 20.19.01.02,* which required the company to use the data requirements from ASME Standard, section 4.2, and NACE Standard, section 3.2, to address the four elements constituting an ECDA program, namely, preassessment, indirect examination, direct examination, and post-assessment. It also alleged that there was no documentation showing what assumptions had been made or what information was required to assure the feasibility of each ECDA project.

At the hearing, Respondent asserted that it had used all data sets required by the rule during the ECDA preassessment process, but acknowledged the need to have a form explicitly listing all the data requirements. Respondent stated that it would develop a new form for *Procedure 20.19.01* that would be completed for all ECDA projects[25] and that it would include all of the information listed in the ASME Standard, section 4.2.2 Table 1, section 4.4, Table 2, and in the NACE Standard, section 3.2.2, Table 1. Respondent further acknowledged in its Closing[26] that it had not "met expectations" in regard to the implementation of its ECDA procedures but disagreed with PHMSA's assertion that the company had failed to put forth a good-faith effort to achieve compliance.[27] Williams also acknowledged that it had not met PHMSA's "expectations" for performing ECDA.

After considering all the evidence, I find that Respondent failed to follow its own ECDA procedures for preassessment, indirect examination, direct examination, and post-assessment. Although Respondent has since developed new ECDA procedures and has retroactively applied

[25] *Closing,* DVD, Sections 2 and 3, at 8-38.

[26] *Closing,* DVD, at 160.

[27] Violation Report, at 29. Respondent may have misinterpreted the Violation Report, which asserted that there was no basis to support a *reduction* in a civil penalty based upon the reasonableness of the operator's understanding of the regulatory requirements.

them to completed ECDAs, the record indicates that at the time of the inspection, Williams failed to demonstrate compliance with the regulation. Accordingly, I find that Respondent violated 49 C.F.R. § 192.925(b) by failing to use ECDA in a manner that followed the requirements of the ASME Standard, section 4.2, and the NACE Standard.

Item 8B of the Notice alleged that Respondent violated 49 C.F.R. § 192.925(b)(1), as quoted above, by failing to implement an ECDA plan that included preassessment procedures meeting the requirements of ASME Standard, section 6.4, and the NACE Standard, section 3. Specifically, it alleged that Williams failed to follow its own *Procedure 20.19.01.02, sections 3.1.1* and *3.1.2*, for conducting feasibility assessments on each ECDA performed. Under the NACE Standard, section 3,[28] an operator must conduct a feasibility assessment to determine whether conditions exist on the pipeline that would allow ECDA to be used.[29] The Notice alleged that the ECDAs performed by Respondent and reviewed by OPS included no documents showing that any feasibility assessments had been performed.

At the hearing, Respondent contended that it did, in fact, conduct feasibility studies that met the requirements of the NACE Standard, section 3.3. The company advised that it had used the term "applicability" in its procedures, rather than "feasibility," and that it had performed a field study for each segment before any indirect inspections were performed. Respondent explained that after the OPS 2006 audit, it had revisited each ECDA project, using the guidelines set out in its new ECDA procedure. Williams further contended that all previously-performed ECDA pipeline segments continued to be viable candidates for ECDA implementation and that it intended to develop a form to document each feasibility assessment.

OPS responded that the feasibility studies, if performed at all by Williams, had not been documented and that its inspection revealed no documentation to indicate that a single ECDA meeting the requirements of § 192.925(b)(1) had been completed or initiated.. For example, OPS referenced the preassessment documentation for the MERCA ECDA,[30] noting that it did not identify regions, tools, etc. OPS also pointed out that the MERCA ECDA did not document the parameters required by Respondent's own *Procedure 20.19.01.02, Corrosion Control.*

I have given full consideration to all of the evidence and arguments presented by OPS and Respondent. I find, despite Williams' contention that it conducted feasibility studies, the company failed to document or demonstrate that such studies were actually conducted. This is substantiated by the company's own acknowledgment that it intended in the future to develop a form to document each such feasibility study. I further find that Respondent failed to demonstrate that it followed its own *Procedure 20.19.01.02, sections 3.1.1* and *3.1.2*, to conduct feasibility assessments for each ECDA performed. It is immaterial whether Respondent retroactively determined that ECDA was applicable to a particular segment. Accordingly, I find Respondent violated 49 C.F.R. § 192.925(b)(1) by failing to implement an ECDA plan that

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[28] According to NACE Standard, section 3.3.1, a pipeline operator shall integrate and analyze the data collected above to determine whether conditions exist for which indirect inspection tools cannot be used or that would preclude ECDA application.

[29] NACE Standard, section 3.3.

[30] *Closing*, DVD, Pre-Assessment and site visit report, at 292. MERCA: 16" pipeline with 1.25 miles of HCA.

included preassessment procedures meeting the requirements of ASME Standard, section 6.4, and the NACE Standard, section 3.

Item 8I of the Notice alleged that Respondent violated 49 C.F.R. § 192.925(b)(3), as quoted above, by failing to implement ECDA procedures that met the requirements of the NACE Standard, section 5, for all required excavations. Specifically, the Notice alleged that OPS' review of several ECDA projects showed that Williams performed only half the number of excavations that were required under the NACE Standard and the company's own ECDA procedure.[31]

At the hearing, Respondent acknowledged that the number of digs selected for some ECDA direct inspections did not meet PHMSA expectations. The company contended that there was a difference between PHMSA's interpretation of the NACE Standard and its own, but that it had revised its *ECDA Procedure 20.19.01.02* to clarify the required number of digs and that it had scheduled subsequent excavations on previously completed ECDA projects.

I find no evidence in the record that Respondent had ECDA procedures in place at the time of the OPS inspection that followed the NACE Standard, which provides detailed guidance for an initial ECDA inspection by an operator.[32] The company's argument that the allegation of violation stemmed from a difference in interpretation of the regulatory requirements is unpersuasive for purposes of determining whether a violation occurred. Accordingly, after consideration of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.925(b)(3) by failing to implement ECDA procedures that met the requirements of the NACE Standard, section 5, for all required excavations.

Item 8K of the Notice alleged that Respondent violated 49 C.F.R. § 192.925(b)(4), as quoted above, by failing to develop and implement procedures that met the NACE Standard for post-assessment and continuing evaluation. Specifically, it alleged that Williams used the wrong NACE formula for its remaining life calculations, thereby creating a high probability that some anomalies in HCA segments would not be excavated or repaired, as required, prior to the next assessment.[33] It further alleged that although the company's ECDA procedure included the NACE default corrosion rate, actual corrosion rates were not documented. The Notice specified one particular ECDA project reviewed during the OPS inspection, where the incorrect formulas and default values were used.

At the hearing, Williams acknowledged that it had used the incorrect formula in its ECDA procedure, that this error had been pointed out by the inspector during the OPS audit, and that the company had corrected it at that time.

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[31] *Excavation 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.

[32] NACE RP 0502, Section 1 and Section 5.10.

[33] *WGP Procedure 20.19.01.02, Performing External Corrosion Direct Assessment (ECDA).*

After considering all the evidence and arguments, I find that Respondent is correct about the typographic error in the NACE formula. However, in March 2004, NACE published an errata sheet, correcting the published error. I find that although Williams subsequently used the appropriate formula, the substantive outcome did not change. I further find that although Williams made corrections during the OPS audit, the company did not made the necessary recalculations on anomalies that had already been, or should have been, excavated. Accordingly, after considering all of the evidence, I find that Respondent violated 49 C.F.R. § 192.925(b)(4) by failing to use the correct NACE Standard formula for determining remaining life and the correct default corrosion rate where the actual one had not been documented.

Item 9: The Notice alleged that Respondent violated 49 C.F.R. § 192.927 (a), which states:

> **§ 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 CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

Item 9A of the Notice alleged that Respondent violated 49 C.F.R. § 192.927(a) by failing to identify areas along its pipeline where water or other electrolyte might be introduced during normal operation, to determine if internal corrosion were likely to exist, and by failing to provide an analysis or justification for eliminating internal corrosion as a threat. Specifically, the Notice alleged that Williams did not have a technical justification for eliminating the threat of internal corrosion in those areas where ECDA was being utilized and therefore should have been using ICDA or some other assessment method for internal corrosion.

At the hearing, Respondent argued that it did have a technical justification for eliminating internal corrosion as a threat. Respondent posed that it had considered nine potential threats,[34] that such threats all existed as a continuum, that they could not be totally eliminated, and that all such threats existed on all pipeline sections to some degree. On the other hand, Williams argued that not all segments had to be assessed for all threats if a particular threat were so minimal as to be irrelevant. The company argued that it had real-time monitoring equipment and scrubbers to ensure that no “wet gas” entered the system and therefore there was no threat of internal corrosion.

The company contended that it also used a “Threats Checklist” to establish a minimum threat threshold. It asserted that it had used this Checklist to eliminate internal corrosion as a threat for

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[34] Evidence: 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; Internal Corrosion Threat Checklist, HCA 2479, MP 27.1 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.

all these ECDA projects. If a SME responded “yes” to any of four questions on the Checklist, then an assessment was required.[35]

OPS responded that the checklists reviewed by OPS showed that Williams had dismissed the possibility of internal corrosion on all the ECDA projects reviewed by OPS.[36] OPS stated that during a teleconference with the Transco Operations Center, company personnel had indicated that Transco’s process equipment had been taken out of service due to damage from Hurricane Katrina and that unprocessed gas possibly exceeding the water quantity limits had been introduced into the system. The record also shows that the company had also provided moisture data from Station 150 - Mooresville, NC, for the period 6/1/2005 to 12/28/2005; from Station 120 – Stockbridge, GA, for the period 1/1/2005 to 5/1/2007; from Station 150 - Mooresville, NC, from 1/1/2005 to 5/1/2007; from Station 160 - Moore, SC, from 1/1/2005 to 5/1/2007; and from Station 165 - Pittsylvania, VA, from 1/1/2005 to 5/1/2007.

Williams argued that the four questions on its Checklist were sufficient to eliminate internal corrosion as a threat. The company maintained that its gas contained less than 7 lb/MMSCF water vapor and therefore that internal corrosion was not a threat and an ICDA procedure unnecessary. Respondent argued that the one Transco ECDA project referenced (0030 Harrison, MP 1.59 to 1.9) was over 1,000 miles downstream from the Gulf, that the gas transported through this HCA had gone through numerous scrubbers and compressors, and that gas-quality data indicated that gas quality at the ECDA site was well within acceptable limits.

OPS countered that during its inspection, it had requested, but had not been provided, documentation showing that the line had been dried out and liquid subsequently introduced. OPS asserted that the unprocessed gas would have been introduced in Louisiana and that the closest measurement provided was in South Carolina, more than 700 plus downstream from where the gas came ashore. OPS asserted that this would not be considered adequate technical justification to conclude that the pipeline system *south* of this location was free of liquids. OPS asserted that Respondent had been transporting unprocessed gas for approximately six to seven months, yet the company’s IM team lacked an accurate picture of what the operating conditions were for that part of the system.

Accordingly, after considering all of the evidence and arguments, I find that Respondent violated 49 C.F.R. § 192.927(a) by failing to identify areas along its pipeline where water or other electrolyte might be introduced during normal operation, to determine if internal corrosion were likely to exist, and by failing to provide an analysis or justification for eliminating internal corrosion as a threat .

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[35] The Threats Checklists included the following questions: 1) Has internal corrosion ever been found in this pipe segment or a parallel segment operating under similar conditions within 100 miles of this HCA? 2) Is this segment in a portion of the system where gas is ever expected to contain more than 7 lb/MMscf water vapor? 3) Has free water ever been found in the station scrubbers located within 100 miles or less of this HCA? and 4) Are there other issues to warrant an integrity assessment?

[36] 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, MP 27.1 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.

Item 11A: The Notice alleged that Respondent violated 49 C.F.R. § 192.935(a), which states:

> **§ 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 (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.

Item 11A of the Notice alleged that Respondent violated 49 C.F.R. § 192.935(a) by failing to take additional measures beyond those already required by Part 192 to prevent pipeline failures and to mitigate the consequences of failures in HCAs. Specifically, it alleged that Williams failed to take additional preventive and mitigative (P&M) measures required by its own *IMP Procedure 10.25.01.02, Performing WGP Risk Assessment and Threat Analysis, Section 9.*

At the hearing, Respondent acknowledged that it had not provided documentation for additional P&M measures it had implemented as of the date of the inspection. Respondent advised that it had discussed additional measures with an SME, including the possibility of burying pipe deeper than required and testing 100% of welds. Respondent also advised that it intended to inspect and assess nearly 4,000 miles of pipeline by the end of 2007, far exceeding the approximate 700 miles required by the rule. The company further asserted that it had implemented or was already doing many of the P&M measures listed in its *Procedure 10.25.01, section 9*, including: 1) computerized monitoring with a SCADA system that continuously measured thousands of data points and was manned 24 hours; 2) improved pipe design; 3) additional emergency response training, including a web-based training module; 4) public education; and 5) increased surveillance by inspecting pipeline via aircraft on a weekly basis.

OPS pointed out that the activities outlined by Williams were basic measures generally required under 49 C.F.R. Part 192. OPS explained that the purpose of the Gas IMP rule was to require *additional* P&M measures in higher-risk HCA areas.

After considering all the evidence and arguments, I find that Respondent's explanation and response to the allegation confirm the findings of the OPS inspection team that no additional P&M activities had been undertaken or considered by the Respondent. I find that Respondent violated 49 C.F.R. § 192.935(a) by failing to employ additional preventive and mitigative measures to reduce risk of incidents in HCA areas, as required by the regulation and the company's own procedures.

Item 13: The Notice alleged that Respondent violated 49 C.F.R. § 192.911, which states, in relevant part:

> **§ 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 (incorporated by reference, *see* § 192.7) for more detailed information on the listed element.)
> (a) . . .
> (k) A management of change process as outlined in ASME/ANSI B31.8S, section 11. . .
> (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 13C of the Notice alleged that Respondent violated 49 C.F.R. § 192.911(m) by failing to have an IMP that included an internal communication procedure. Specifically, it alleged that Williams' IMP did not have a communication plan having the elements listed in the ASME Standard, section 10.3.[37]

At the hearing, Respondent argued that both § 192.911(m) and section 10 of B31.8S required operators merely to have an internal communication "plan," not a "procedure," as alleged in the Notice. In support of it position, Respondent asserted that the ASME Standard states: "Operator management and operations personnel must understand and support the integrity program." The company contended that its "Other Documentation" listed the methods it was using to comply with the IMP requirements and that its internal communication plan was described in Chapter 12 of the *IMP Overview*. It further argued that a summary of its plan had been communicated on the company's WGP's webpage and that, as an example of its internal communications, the company's president, Mr. Phil Wright, had declared on Williams' intranet and at the end of chapter 1 a commitment to the program. Finally, Respondent asserted that it had performed comprehensive training on the company's IMP for its operations personnel.

OPS responded by asserting that while Section 12.3 of the company's *IMP Overview* stated that "an internal communication process has been developed," no documented plan or procedure was ever provided to the OPS Inspection Team, nor was one presented as evidence in this proceeding. Section 10.3 of the ASME Standard states:

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[37] Item 13C in the Notice included a typographical error that improperly cited 49 C.F.R. § 192.911(k), instead of § 192.911(m); the latter requires that operators have a communication plan. Because both the substantive text of the Notice and the operator's Response treated Item 13C as an alleged violation of § 192.911(m), I find such error in the Notice to be harmless.

> **10.3 Internal Communications**
> Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures reviewed on a periodic basis and resulting adjustments to the integrity management program should also be part of the internal communications plan.

According to this standard, an IMP needs to have an internal communications component that includes "performance measures" and "resulting adjustments" that need to be made to the IMP and how these will be communicated to company personnel. I fail to see that Williams has presented any evidence demonstrating that it actually had developed or implemented any sort of specific internal communications element as part of its IMP, as required by the ASME Standard. Accordingly, upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.911(m) by failing to develop an IMP with an internal communication plan that included the elements of ASME Standard, section 10.3.

Item 13D of the Notice alleged that Respondent violated 49 C.F.R. § 192.911(m) by failing to have an IMP that contained a communication plan that included procedures for addressing safety concerns raised by OPS and state or local regulatory authorities. At the hearing, Respondent did not contest this allegation. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. § 192.911(m).

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to an administrative civil penalty not to exceed $100,000 per violation for each day of the violation, up to a maximum of $1,000,000 for any related series of violations. In determining the amount of a civil penalty under 49 U.S.C. § 60122 and 49 C.F.R. § 190.225, I must consider the following criteria: the nature, circumstances, and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; the Respondent's ability to pay the penalty and any effect that the penalty may have on its ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require. The Notice proposed a total civil penalty of $351,000 for the violations cited above.

Item 1A: The Notice proposed a civil penalty of $26,000 for Respondent's violation of 49 C.F.R. §§ 192.947(d) and 192.905(a), for failing to describe and document in the company's IMP which method it applied to each portion of the its pipeline system to identify HCA segments. The Notice also alleged that Williams failed to maintain records demonstrating compliance with the integrity management regulations. As discussed above, I found that Williams did not mention Northwest Pipeline in its description of the methods used prior to the December 2004 Deadline, nor did the company provide OPS with proper documentation at the time of the inspection. Maintaining such documentation of compliance with the integrity management regulations is important to enable OPS to determine if a company is in compliance. Without documentation to verify which method has been used to identify HCAs, it is nearly impossible to verify that all HCAs have, in fact, been identified. Respondent has not produced any evidence or put forth any argument that would warrant a reduction in the penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $26,000 for the violation of 49 C.F.R. §§ 192.947(d) and 192.905(a).

Item 2A: The Notice proposed a civil penalty of $26,000 for Respondent's violation of 49 C.F.R. § 192.905(a), for failing to describe in the company's IMP which method it was applying to each portion of its pipeline system to identify each HCA segment. The Notice also alleged that the system maps and the GIS system used by Respondent failed to establish a suitable means of documenting segment locations in HCAs. As discussed above, I found that Williams not only failed to describe which methods it was applying to each portion of its system, but also found that the company failed to take action to address known inaccuracies in its HCA identification process and to describe the PIRs of the methods used to establish HCAs. If left uncorrected, such an error would diminish the effectiveness of the other risk-based requirements imposed by the IMP regulations and create a potential threat to public safety. Therefore, having reviewed the record and considered the gravity of the violation and other assessment criteria, I assess Respondent a civil penalty of $26,000 for the violation of 49 C.F.R. § 192.905(a).

Item 2B: The Notice proposed a civil penalty of $26,000 for Respondent's violation of 49 C.F.R. § 192.905(b)(2), for failing to use certain alternative information in cases where public officials with safety or emergency response or planning responsibilities had informed the company that they did not have information delineating identified sites. As noted above, I found that Williams failed to demonstrate that it had a process in place to use such alternative sources by the December 2004 Deadline. There is no evidence in the record that contradicts the OPS inspection report. Failure to identify those HCA segments having the highest potential for failure by the deadline increased the risk of harm to the public. Accordingly, having reviewed the record and considered the gravity of the violation and other assessment criteria, I assess Respondent a civil penalty of $26,000 for the violation of 49 C.F.R. § 192.905(b)(2).

Item 3: The Notice proposed a civil penalty of $43,000 for Respondent's violation of 49 C.F.R. § 192.907(a), for failing to meet the December 2004 Deadline for developing and following a written IMP that contained all the elements described in § 192.911 and that addressed the risks on each covered pipeline segment. As noted above, I found that that none of the documentation submitted by Respondent during the hearing or in the Closing demonstrated that it had determined any identified sites prior to the December 2004 Deadline. Respondent objected to the proposed civil penalty for this Item, contending that the gravity of the violation was minimal, that it had made a good-faith effort to comply with the IMP regulations, and that it had an ongoing commitment to structure identification along the pipeline. On the contrary, I find that mitigation of the civil penalty is not warranted. Williams asserted that it made a good-faith effort to comply with the regulation, yet I can find no evidence in the record that the company made a concerted effort to complete a rigorous HCA identification process by the December 2004 Deadline. Respondent has not provided any evidence that would justify mitigation of the proposed civil penalty. Therefore, having reviewed the record and considered the gravity of the violation and the other assessment criteria, I assess Respondent a civil penalty of $43,000 for violation of 49 C.F.R. § 192.907(a).

Item 4A: The Notice proposed a civil penalty of $43,000 for Respondent's violation of 49 C.F.R. § 192.905(a), for failing to properly establish HCA areas using Method 1 from the definition of "HCA" in § 192.903. As noted above, I found that Williams failed to properly identify all HCAs using Method 1 and that its HCA boundaries were shorter than the Class 3 and Class 4 dimensions required under § 192.903. As a result, the HCA sites referenced in the Notice did not have the correct length of pipe within their boundaries. Properly identifying HCAs is important in mitigating the consequences of pipeline failures in HCAs and reducing the risk of harm to the public. Accordingly, having reviewed the record and considered the gravity of the violation and other assessment criteria, I assess Respondent a civil penalty of $43,000 for violation of 49 C.F.R. § 192.905(a).

Item 4B: The Notice proposed a civil penalty of $43,000 for a separate violation of 49 C.F.R. § 192.905(a), for failing to properly establish HCA areas using Method 1 from the definition of "HCA" in § 192.903. Specifically, the Notice alleged that the OPS inspection revealed sites on the Transco system that met the definition of "Identified sites" in § 192.903 but had not been included among the system's HCAs. Despite the fact that the company's own documentation showed sites that appeared to qualify as HCAs, I found that the company had failed to actually identify where Method 1 called for the inclusion of Class 1 or Class 2 locations. Such omissions results in a greater risk of harm to the public in those areas where Respondent failed to adequately identify HCAs. Having reviewed the record and considered the gravity of the violation and other assessment criteria, I assess Respondent a civil penalty of $43,000 for violation of 49 C.F.R. § 192.905(a).

Item 4C: The Notice proposed a civil penalty of $26,000 for another violation of 49 C.F.R. § 192.905(a), for failing to properly identify HCA areas using Method 1 from the definition of "HCA" under § 192.903. Specifically, it alleged that Williams improperly applied Method 1 by failing to designate certain outdoor areas and buildings as "Identified sites." As noted above, I found that the company improperly applied the term "day" for purposes of identifying outdoor areas as HCAs, with the result that certain areas were improperly omitted as HCAs. Having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $26,000 for violation of 49 C.F.R. § 192.905(a).

Item 4D: The Notice proposed a civil penalty of $43,000 for Respondent's violation of 49 C.F.R. § 192.905(a), for failing to apply the axial extension of the potential impact circle along the length of the pipeline from the outermost edge of the first potential impact circle containing either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle containing either an identified site or 20 or more buildings intended for human occupancy. Respondent contended that a mitigating factor contributing to the abbreviated length of the HCAs was that paragraph 3 of the definition of a "High Consequence Area" in § 192.903 was actually missing from the 2004, 2005, and 2006 Code of Federal Regulation (CFR) books. I find that even if the wrong version of § 192.903 were, in fact, published in the CFR, it still does not justify Respondent's failure to comply with the regulation or mitigate the seriousness of the offense. If left uncorrected, the failure to properly identify HCAs diminishes the effectiveness of other risk-based requirements imposed by the IMP regulations and creates a potential threat to public safety. Having reviewed the record and considered the gravity of the violation and other assessment criteria, I assess Respondent a civil penalty of $43,000 for violation of 49 C.F.R. § 192.905(a).

Item 5A: The Notice proposed a civil penalty of $15,000 for Respondent's violation of 49 C.F.R. § 192.917(e)(4) for failing to have a procedure in place to verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion. As discussed above, I found that Respondent failed to meet the minimum requirements of the ASME Standard or to provide a rigorous risk analysis process that could determine whether an actual threat existed from ERW pipe. Respondent argued that the penalty for this Item should be withdrawn. Although Williams failed to have an adequate procedure in place, OPS agrees that the violation is adequately addressed through a compliance order. Accordingly, the proposed civil penalty for Item 5A is withdrawn.

Item 5B: The Notice proposed a civil penalty of $15,000 for Respondent's violation of 49 C.F.R. § 192.917(b) for failing to identify and evaluate the potential threats to a covered pipeline segment by gathering and integrating existing data and information on the entire pipeline that could be relevant to the covered segment. As discussed above, I found that Williams lacked adequate processes for verifying data quality or for applying conservative assumptions if data were missing or suspect. Respondent argued that the penalty for this Item should be withdrawn. Although the company failed to have adequate processes in place, OPS agrees that the violation is adequately addressed through a compliance order. Accordingly, the proposed civil penalty for Item 5B is withdrawn.

Item 5D: The Notice proposed a civil penalty of $15,000 for Respondent's violation of 49 C.F.R. § 192.917(b) for failing to have adequate processes in its IMP for verifying data quality. As discussed above, I found that Williams failed either to properly verify data or apply conservative assumptions if data were missing or suspect. Respondent argued that the penalty for this Item should be withdrawn. Although the company failed to have adequate processes in place, OPS agrees that the violation is adequately addressed through a compliance order. Accordingly, the proposed civil penalty for Item 5D is withdrawn.

Item 6B: The Notice proposed a civil penalty of $6,000 for Respondent's violation of 49 C.F.R. § 192.921(d), for failing to prioritize all its covered pipeline segments for the baseline assessment in such a manner that its assessment schedule could be properly verified. During the hearing, Respondent conceded that the allegation was true. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $6,000 for violation of 49 C.F.R. § 192.921(d).

Item 7: The Notice proposed a civil penalty of $6,000 for Respondent's violation of 49 C.F.R. § 192.907(b), for failing to follow the requirements of this subpart and of the ASME Standard and its appendices to identify and evaluate all potential threats to each covered pipeline segment. As noted above, I found that Respondent failed to properly identify and evaluate all potential threats to each covered pipeline segment by the December 2004 Deadline. The risk model used by Williams failed to satisfy all of the requirements of the regulation, For example, the model eliminated SCC as a threat, but without engineering data to confirm that SCC did not exist as a threat or that it had been considered under the SME approach. Furthermore, the record shows that the company had suffered a number of leaks and failures attributed to SCC in the past.

An effective integrity management program depends upon the use of risk models that are comprehensive and accurate in their consideration of all threats applicable to a particular pipeline system. The risk model used in this case failed to meet the ASME Standard. Respondent has failed to present any evidence that would warrant a reduction in the proposed penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $6,000 for violation of 49 C.F.R. § 192.907(b).

Item 8A: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.925(b) for failing to use direct assessment to assess the threat of external corrosion in accordance with the ASME Standard, section 4.2, and the NACE Standard, section 3.2. As discussed above, I found that Williams failed to follow these standards and its own ECDA procedures for pre-assessment, indirect examination, direct examination, and post-assessment. Respondent has failed to present any evidence that would warrant a reduction in the amount of the proposed penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.925(b).

Item 8B: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.925(b)(1) to follow its *ECDA Procedure 20.19.01.02*, *sections 3.1.1* and *3.1.2,* to conduct feasibility assessments for each ECDA performed. It is irrelevant that Respondent retroactively determined that ECDA was applicable. The NACE guidelines are clear that a feasibility study is required prior to conducting the assessment as does Respondent's procedures. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.925(b)(1).

Item 8I: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.925(b)(3) for failing to have ECDA procedures that follow NACE RP0502 for all required excavations. Respondent advised that it had revised its *ECDA Procedure 20.19.01.02* to clarify the required number of digs and to meet or exceed those stated in NACE RP 0502. The fact that Respondent had changed its procedure and had scheduled additional digs further support a finding of violation. Respondent has failed to present any evidence that would warrant a reduction in the amount of the proposed penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.925(b)(3).

Item 11A: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.935(a) for failing to employ additional preventive and mitigative measures to reduce risk of incidents in HCA areas, as required by the regulation and Respondent's procedures. An operator must provide protection for pipeline segments to prevent a pipeline failure and to mitigate the consequences of failures in HCAs. Respondent has failed to present any evidence that would warrant a reduction in the amount of the proposed penalty. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.935(a).

Item 13C: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.911(m) for failing to include in its management of change process, as outlined in the ASME Standard, section 10.3, procedures on when, where, and how information is internally communicated. Whatever information an operator relies on to constitute compliance with the integrity management requirements, the operator must provide sufficient detail to demonstrate compliance so that OPS cannot readily determine what those documents are and where they might be located. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.911(m).

Item 13D: The Notice proposed a civil penalty of $3,000 for Respondent's violation of 49 C.F.R. § 192.911(m) for failing to have procedures for addressing safety concerns raised by PHMSA and local regulatory authorities. At the hearing, Respondent did not dispute this allegation. Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a civil penalty of $3,000 for violation of 49 C.F.R. § 192.911(m).

In summary, having reviewed the record and considered the assessment criteria for all the Items above, I assess Respondent a total civil penalty of **$306,000**.

Respondent has provided no information that indicates payment of this penalty would adversely affect its ability to continue in business.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 269039, Oklahoma City, OK 73125; (405) 954-8893.

Failure to pay the **$306,000** civil penalty will result in accrual of interest at the current annual rate in accordance with 31 U.S.C. § 3717, 31 C.F.R. § 901.9 and 49 C.F.R. § 89.23. Pursuant to those same authorities, a late penalty charge of six percent (6%) per annum will be charged if payment is not made within 110 days of service. Furthermore, failure to pay the civil penalty may result in referral of the matter to the Attorney General for appropriate action in a United States District Court.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 5A, 5B, 5D, 6B, 7, 8I, 8K, 9A, 13C and 13D in the Notice for violations of 49 C.F.R. §§ 192.917(e)(4), 192.917(b), 192.917(b), 192.921(d), 192.907(b), 192.925(b)(3), 192.925(b)(4), 192.927(a), 192.911(m), and 192.911(m), respectively.

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of gas or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. Pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violation of § 192.917(e)(4) (**Item 5A**), Respondent must conduct a study of all pipeline segments located within each HCA to determine if it contains any pipe meeting the criteria set forth in

§ 192.917(e)(4). This study must evaluate any covered or non-covered segment in the pipeline system having such pipe and that has experienced seam failure or that the operating pressure pipe on the covered segment has experienced an increase over the maximum operating pressure during the preceding five years.

2. With respect to the violation of § 192.917(b) (**Item 5B**), Respondent 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. With respect to the violation of § 192.917(b) (**Item 5D**), Respondent must define and justify any conservative assumptions made during its risk analysis process. Respondent must also develop a program and process to obtain missing data for future risk analysis determinations.

4. With respect to the violation of § 192.921(d) (**Item 6B**), Respondent must conduct its initial HCA identification process all over again, using revised procedures produced pursuant to this Final Order.

5. With respect to the violation of § 192.907(b) (**Item 7**), Respondent must conduct a completely new risk analysis, using a new risk model that considers all risks factors applicable to each HCA segment.

6. With respect to the violation of § 192.925(b)(3) (**Item 8I**), Respondent must re-examine all of its ECDA projects and conduct all of the excavations required by Part 192.

7. With respect to the violation of § 192.925(b)(4) (**Item 8K**), Respondent must re-evaluate and re-calculate the remaining life for each corrosion anomaly based on the correct values. Williams must then determine if any additional excavations are required and report the number of increased excavations to PHMSA.

8. With respect to the violation of § 192.927(a) (**Item 9A**), Respondent must develop an ICDA plan and process to evaluate the threat of internal corrosion. In addition, Williams must either 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 describing why internal corrosion is not a threat.

9. With respect to the violation of § 192.911(m) (**Item 13C**), Respondent must develop a communication plan meeting the requirements of the ASME Standard, section 10.3.

10. With respect to the violation of § 192.911(m) (**Item 13D**), Respondent must develop a communication plan that includes a process for handling requests and addressing safety concerns raised by PHMSA and local regulatory authorities.

11. Within 60 days of receipt of this Final Order, Williams must complete the work required compliance terms in paragraphs 1-10 above.

12. Respondent is requested to 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, 12300 W. Dakota Avenue, Suite 110, Lakewood, CO 80228. It is requested that these costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total costs associated with replacement, additions and other changes to pipeline infrastructure.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent demonstrating good cause for an extension.

Failure to comply with this Order may result in administrative assessment of civil penalties not to exceed $100,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

WARNING ITEMS

With respect to Items 5C, 6A, 8C, 8D, 8E, 8F, 8G, 8H, 8J, 10, 11B, 12, 13A, and 13B, the Notice alleged probable violations of Part 192 but did not propose a civil penalty or compliance order for these items. Therefore, these are considered to be warning items. The warnings were for:

> 49 C.F.R. § 192.917(b) **(Notice Item 5C) –** Respondent's alleged failure to have defined processes for assigning responsibilities for data collection or how data sets are assembled, how their accuracy is verified, how data is maintained, or what sets of data must be collected; and
>
> 49 C.F.R. § 192.921(b) **(Notice Item 6A) –** Respondent's alleged failure to prioritize covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. Respondent's BAP has several segments at the bottom of the prioritization schedule that have not been analyzed for risk; and
>
> 49 C.F.R. § 192.925(b)(1) **(Notice Item 8C) –** Respondent's alleged failure to maintain and provide documentation on the indirect inspection tool selective criteria. Tool selection followed ECDA region determinations, rather than preceding them.
>
> 49 C.F.R. § 192.925(b)(1)(ii) **(Notice Item 8D) –** Respondent's alleged failure to use a NACE-recognized assessment tool for ECDA indirect inspections.
>
> 49 C.F.R. § 192.925(b)(1)(ii) **(Notice Item 8E) –** Respondent's alleged failure to follow its own ECDA procedures specifying that casings and other areas are

separate regions. Specifically, in one of the ECDAs reviewed (1400 line, Glenn's Ferry), a cased crossing was part of the single ECDA region, along with road crossings and other areas.

49 C.F.R. § 192.925(b)(1)(i) **(Notice Item 8F) –** Respondent's alleged failure to include and document in its *ECDA Procedures 20.19.01.02* a requirement that initial ECDA assessments include more restrictive criteria for the initial pre-assessment conducted.

49 C.F.R. § 192.925(b)(2) **(Notice Item 8G) –** Respondent's alleged failure to provide documentation in its completed assessments that the start and finish of each ECDA region is properly marked and the amount of overlap for each tool.

49 C.F.R. § 192.925(b)(2) **(Notice Item 8H) –** Respondent's alleged failure to follow its own *ECDA Procedure 20.19.01.02, section 5.1.4,* requiring that indirect inspection results be integrated with other data obtained in the pre-assessment process, such as encroachments and foreign line crossings.

49 C.F.R. § 192.925(b)(3)(iii) **(Notice Item 8J) –** Respondent's alleged failure to provide documentation that internal notifications were made based on the results of what was learned in the ECDA projects completed as of January 29, 2007.

49 C.F.R. § 192.937(b) **(Notice Item 10) –** Respondent's alleged failure to complete an annual review to determine the reassessment interval of completed baseline assessments, as required by Respondent's own procedures.

49 C.F.R. § 192.935(c) **(Notice Item 11B) –** Respondent's alleged failure to delineate a process for evaluating the potential safety impact on individual covered segments of installing automatic shut-off valves and remote control valves.

49 C.F.R. § 192.909(a) **(Notice Item 12) –** Respondent's alleged failure to include in its IMP change log a detailed description of changes made to its IMP.

49 C.F.R. § 192.911(k) **(Notice Item 13A) –** Respondent's alleged failure to report to its IMP team important system changes that could affect pipeline integrity. In a teleconference with the Transco Operations Center, Respondent indicated that the process equipment was taken out of service due to damage from Hurricane Katrina and unprocessed gas was being introduced into the Transco pipeline system that may exceed the water quantity limits.

49 C.F.R. § 192.911(k), the ASME Standard, section 11(d) **(Notice Item 13B) –** Respondent's alleged failure to follow its own *MOC Procedure 10.29.01.02,* that required an approval process for startups/changes.

Respondent presented information in its Response showing that it had taken certain actions to address the cited items. Having considered such information, I find, pursuant to 49 C.F.R.

§ 190.205, that probable violations of 49 C.F.R. § 192.917(b) (Notice Item 5C), 49 C.F.R. § 192.921(b) (Notice Item 6A), 49 C.F.R. § 192.925(b)(1) (Notice Item 8C), 49 C.F.R. § 192.925(b)(1)(ii) (Notice Item 8D), 49 C.F.R. § 192.925(b)(1)(ii) (Notice Item 8E), 49 C.F.R. § 192.925(b)(1)(i) (Notice Item 8F), 49 C.F.R. § 192.925(b)(2) (Notice Item 8G), 49 C.F.R. § 192.925(b)(2) (Notice Item 8H), 49 C.F.R. § 192.925(b)(3)(iii) (Notice Item 8J), 49 C.F.R. § 192.937(b) (Notice Item 10), 49 C.F.R. § 192.935(c) (Notice Item 11B), 49 C.F.R. § 192.909(a) (Notice Item 12), 49 C.F.R. § 192.911(k) (Notice Item 13A) and 49 C.F.R. § 192.911(k) (Notice Item 13B) have occurred and Respondent is hereby advised to correct such conditions. In the event that OPS finds a violation for any of these items in a subsequent inspection, Respondent may be subject to future enforcement action.

Under 49 C.F.R. § 190.215, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be sent to: Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. PHMSA will accept petitions received no later than 20 days after receipt of service of this Final Order by the Respondent, provided they contain a brief statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.215. The filing of a petition automatically stays the payment of any civil penalty assessed. Unless the Associate Administrator, upon request, grants a stay, all other terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Jeffrey D. Wiese Associate Administrator for Pipeline Safety	Date Issued