



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

VIA CERTIFIED MAIL AND FAX TO: (205-325-7528)

March 11, 2011

Mr. Bill Cope
Vice President Eastern Operations
Tennessee Gas Pipeline Company
569 Brookwood Village, Suite 501
Birmingham, AL 35209

Re: CPF No. 3-2011-1001S

Dear Mr. Cope:

Enclosed please find a Notice of Proposed Safety Order (Notice) issued in the above-referenced case. The Notice proposes that you take certain measures with respect to Tennessee Gas Pipeline Company's Line 200 system. Your options for responding are set forth in the Notice. Your receipt of the Notice constitutes service of that document under 49 C.F.R. § 190.5.

We look forward to a successful resolution of this matter to ensure pipeline safety. Please direct any questions on this matter to me at (816) 329-3800.

Sincerely,

A handwritten signature in black ink, appearing to read 'D. Barrett', written over a horizontal line.

David Barrett
Director, Central Region

Enclosures: Notice of Proposed Safety Order and Copy of 49 CFR § 190.239

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
CENTRAL REGION
KANSAS CITY, MISSOURI 64106

In the Matter of)	
Tennessee Gas Pipeline Company,)	
Respondent.)	CPF No. 3-2011-1001S

NOTICE OF PROPOSED SAFETY ORDER

Background and Purpose

Pursuant to Chapter 601 of title 49, United States Code, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has initiated an investigation of the safety of Tennessee Gas Pipeline Company's (TGP) Line 200 pipeline system, including an incident that occurred on February 10, 2011 in which TGP's Line 200-4 pipeline ruptured resulting in an explosion and fire. On March 1, 2011, PHMSA expanded its investigation to include a girth weld failure that occurred on TGP's Line 200-1 pipeline, approximately one-half mile downstream of Compressor Station 209 in Guernsey County, Ohio.

As a result of the investigation, it appears that a condition or conditions exist on the segment of the Line 200 pipeline system running from Compressor Station 200 to Compressor Station 219, including the Pittsburgh Spur (Lines 217A-100 and 217A-200) (the "Affected Segments"), that pose a pipeline integrity risk to public safety, property or the environment. Pursuant to 49 U.S.C. § 60117(l), PHMSA issues this Notice of Proposed Safety Order, notifying you of the preliminary findings of the investigation and proposing that you take measures to ensure that the public, property, and the environment are protected from the potential risk.

Preliminary Findings

- TGP's Line 200-4 pipeline is part of an interstate natural gas transmission system that transports natural gas from the Gulf of Mexico to the East Coast. TGP operates approximately 876 miles of pipeline in the state of Ohio. In the Mercer Operating Area, TGP operates the Carrollton Compressor Station and four parallel mainline segments: Lines 200-1 (26-inch diameter); 200-2 (26-inch diameter); 200-3 (26-inch

diameter); and 200-4 (36-inch diameter). The parallel mainline segments are divided into four mainline valve sections. The mainline valve sections are designated as sections 214–219. The Pittsburgh Spur consists of two pipelines (16-inch and 24-inch diameter) from the 217 valve section in Ohio to the vicinity of Pittsburgh, Pennsylvania.

- On February 10, 2011, at approximately 10:30 p.m. EST, a failure occurred on Line 200-4 in mainline valve section 214 (Line Section 214-4) in Columbiana County, Ohio at a public road in a rural, Class 1 area, approximately 2.5 miles southeast of the town of Hanoverton. The rupture occurred at a cased road crossing and resulted in the release of an undetermined amount of natural gas which ignited into a fireball and continuing fire that burned until approximately 2:00 a.m. the next morning. The rupture produced two craters 16 feet apart and exposed approximately 226 feet of pipe.
- Gas escaping from ancillary piping on an above-ground mainline valve (MLV 215-3) on one of the parallel pipelines also ignited and continued to burn until Line 214-3 was isolated and blown down at approximately 4:40 a.m. the next morning. One home located approximately 1000 feet from the failure location was temporarily evacuated. There were no injuries reported as a result of the release.
- TGP reported the incident to the National Response Center (NRC) on February 11, 2011 at 12:25 a.m. (NRC Report #967142). PHMSA initiated an investigation of the incident, which involved an on-site investigation at the failure location.
- The TGP control center received notification of the release by a third-party. The operator's controllers reviewed pressure and flow SCADA information to confirm the failure. At approximately 10:55 p.m., controllers shut down the Carrollton compressor station and closed MLV 214-4. Within approximately one hour following the failure, TGP had closed the upstream and downstream valves and isolated the failed section.
- At the time of the failure, MLV 215-4 was equipped with an auto-close control device. This valve closed between 10:30 p.m. and 10:40 p.m. MLV 215-4 is located approximately 50 feet downstream of the failure site.
- TGP assessed damage on the adjacent pipelines. Line Sections 214-1, 214-2, and 214-3 were initially reviewed for collateral damage caused by the rupture of Line Section 214-4. The current repairs associated with Section 214-1 include above-ground jumper piping replacement at MLV 215-1.
- Line Section 214-4 (the failed pipeline section) remains isolated and blown down from MLV 214 to MLV 216. Line Sections 214-1, 214-2 and 214-3 are back in service. TGP has removed the failed section of pipe and transported it to a third-party metallurgical laboratory for evaluation to establish probable cause.
- The rupture occurred beneath McKaig Road, inside a 42-inch steel casing. PHMSA investigators and TGP visually examined the failed pipe and casing at the scene, and

observed a failure along the entire circumference of a girth weld of the pipe inside the casing, although information from visual inspections was limited due to pipe movement and damage from the rupture and fire. The condition or conditions on the pipeline that caused the failure are unknown at this time, but the same condition(s) that caused the failure could be present (or could develop) on other areas of the pipeline and impair the reliability and serviceability of the pipeline.

- Line Section 214-4 is 36-inch diameter, 0.344-inch wall thickness, Grade API 5L X-60 pipe manufactured by National Tube with double-submerged arc-welded (DSAW) seams, constructed in 1964. The coating is coal tar, and the pipeline is cathodically protected with impressed current. The rupture occurred internal to a casing associated with a road crossing.
- The maximum allowable operating pressure (MAOP) for each of the four parallel mainline segments is 790 psig. The discharge pressure at the Carrollton Compressor Station was approximately 733 psig at the time of the failure.
- Between Carrollton Compressor Station, which is the first station immediately upstream of the failure site, and Cranberry Compressor Station, which is the first station downstream, Line 200-4 crosses heavily traveled public roadways, including Interstate 76, U.S. Routes 11 and 30, and several Ohio State Routes. The pipeline also travels in the vicinity of populated areas, including Columbiana City.
- TGP performed an inline inspection (ILI) of the pipeline in 2005 with high resolution magnetic flux leakage (MFL) and caliper tools. The company has indicated that a review of the ILI information at that time revealed no actionable features at or near the failure site, but there were 13 anomalies investigated in 2006. TGP performed significant work in 2005 to make the line capable of being assessed by ILI.
- On March 1, 2011, a girth weld failure occurred on TGP's Line 200-1 pipeline, approximately one-half mile downstream of Compressor Station 209 in Guernsey County, Ohio. The pipe that failed on Line 200-1 is 26-inch diameter, 0.281 wall thickness, X-52 pipe manufactured by A.O. Smith, and installed in 1950. Line section 209-1 remains out of service.
- On November 30, 2010, TGP experienced a pipeline failure on another of its natural gas pipelines, designated as Line 100-2 in Natchitoches, Louisiana. The apparent cause was a wrinkle bend failure. PHMSA issued a Corrective Action Order to TGP on December 3, 2010, as a result of that incident (CPF No. 4-2010-1007H).

Proposed Issuance of Safety Order

Section 60117(l) of Title 49, United States Code, provides for the issuance of a safety order, after reasonable notice and the opportunity for a hearing, requiring corrective measures, which may include physical inspection, testing, repair, or other action, as appropriate. The basis for making

the determination that a pipeline facility has a condition or conditions that pose a pipeline integrity risk to public safety, property, or the environment is set forth both in the above-referenced statute and 49 C.F.R. § 190.239, a copy of which is enclosed.

After evaluating the foregoing preliminary findings of fact and considering the age of the pipeline, the proximity of the pipeline to public roadways and populated areas, the hazardous nature of the product being transported, the pressure required for transporting the material, the ongoing investigation to determine the condition(s) that caused the pipeline failure, the likelihood that the condition(s) causing the failure could be present or could develop on other areas of the pipeline, and the likelihood that such condition(s) could again impair the serviceability of the pipeline, it appears that the continued operation of the pipeline without corrective measures would pose a pipeline integrity risk to public safety, property, or the environment.

Accordingly, PHMSA issues this Notice of Proposed Safety Order to notify TGP of the proposed issuance of a safety order and to propose that the company take the measures specified herein to address the potential risk.

Response to this Notice

In accordance with 49 C.F.R. § 190.239, you have 30 days following receipt of this Notice to submit a written response to the Regional Director who issued the Notice. If you do not respond within 30 days, this constitutes a waiver of your right to contest the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to you and to issue a safety order.

In your response, you may notify the Regional Director that you intend to comply with the terms of the Notice as proposed, or you may request that an informal consultation be scheduled. Informal consultation provides you with the opportunity to explain the circumstances associated with the risk condition(s) alleged in the notice and, as appropriate, to present a proposal for a work plan or other remedial measures, without prejudice to your position in any subsequent hearing. If you and PHMSA agree within 30 days of informal consultation on a plan and schedule for you to address each identified risk condition, we may enter into a written consent agreement (Agreement). PHMSA would then issue an administrative consent order incorporating the terms of the agreement.

If a consent agreement is not reached, or if you have elected not to request informal consultation, you may request an administrative hearing in writing within 30 days following receipt of the Notice or within 10 days following the conclusion of an informal consultation that did not result in a consent agreement, as applicable. Following a hearing, if the Associate Administrator finds the facility to have a condition that poses a pipeline integrity risk to the public, property, or the environment in accordance with 49 C.F.R. § 190.239, the Associate Administrator may issue a Safety Order.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for

confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

In your correspondence on this matter, please refer to CPF 3-2011-1001S and for each document you submit, please provide a copy in electronic format whenever possible.

Proposed Corrective Measures

Pursuant to 49 U.S.C. § 60117(l) and 49 C.F.R. § 190.239, PHMSA proposes to issue to Tennessee Gas Pipeline Company (TGP) a Safety Order (Order) incorporating the following remedial requirements with respect to the TGP Line 200 pipeline system:

1. Prior to resuming operation of the Line 200-4 from MLV 214-4 to MLV 216-4, develop and submit a written restart plan for approval by the Director, Central Region, PHMSA (Director) for this segment. The restart plan must provide for adequate patrolling of the pipeline during the restart process, specify a daylight restart, include a hydrostatic test of section MLV 214-4 to MLV 215-4, and detail advance communications with local emergency response officials. The restart plan must include actions taken by TGP to confirm the integrity of pipeline facilities that were damaged, or were suspected of being damaged, as a result of the incident, prior to restart.
2. After receiving approval from the Director to restart, the operating pressure from MLV 214-4 to MLV 216-4 must not exceed 80% of the actual operating pressure in effect immediately prior to the February 10, 2011 failure. Specifically, the discharge pressure at the Carrollton Compressor Station into Line 4 must not exceed 586 psig. This pressure reduction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly. Prior to the operating pressure being increased, identification of all auto-close valve locations will be communicated to the controllers. The pressure restriction must remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director, as set forth in Item 15. If the results of any action undertaken pursuant to the Order or Agreement necessitate a reduction in the operating pressure permitted by the Order or Agreement, TGP must further reduce the operating pressure accordingly and notify the Director.
3. Prior to resuming operation of the Line 200-1 from MLV 209-1 to MLV 210-1, develop and submit a written restart plan for approval by the Director, Central Region, PHMSA (Director) for this segment. The restart plan must provide for adequate patrolling of the pipeline during the restart process, specify a daylight restart, and detail advance communications with local emergency response officials.

4. After receiving approval from the Director to restart, the operating pressure from MLV 209-1 to MLV 210-1 must not exceed 80% of the actual operating pressure in effect immediately prior to the March 1, 2011 failure. Specifically, the discharge pressure at the Station 209 into Line 1 must not exceed 567 psig. This pressure reduction requires any relevant remote or local alarm limits, software programming set-points or control points, and mechanical over-pressure devices to be adjusted accordingly. Prior to the operating pressure being increased, identification of all auto-close valve locations will be communicated to the controllers. The pressure restriction must remain in effect until written approval to increase the pressure or return the pipeline to its pre-failure operating pressure is obtained from the Director, as set forth in Item 15. If the results of any action undertaken pursuant to the Order or Agreement necessitate a reduction in the operating pressure permitted by the Order or Agreement, TGP must further reduce the operating pressure accordingly and notify the Director.

5. Within 15 days of receipt of the Order or Agreement, submit a plan to conduct an airborne instrumented leak survey of the 200 system (all pipelines) from Compressor Station 200 to Compressor Station 219 (including the Pittsburgh Spur) detailing the schedule for the expeditious completion of the leak survey within 30 days of initiating the survey. The plan will include a summary report detailing the findings of the leak survey to be provided directly from the airborne instrumented leak survey provider to the Director. This summary report should include a description of any elements affecting the leak survey data, the area covered and associated ranges of the leak survey findings (height of flight and width of area surveyed), verification that all of the pipeline corridors, including the areas associated with crossover piping located between lines, has been reviewed, and any other items of significance such as accuracy of the instrumentation or malfunction of equipment. The Director is to receive distribution of all resulting reports in their entirety, including all media, whether draft or final, at the same time they are made available to TGP.

Submit a separate report detailing the schedule of planned maintenance activities to occur as a result of the leak survey for the 200 system.

Continue to perform patrol surveillance activities at periods of 2 times per month for pipe Sections MLV 209-1 to MLV 214-1 and MLV 214-4 to MLV 219-4, until approved otherwise by the Director.

6. Within 45 days of the Director's approval of testing protocols, complete third-party mechanical and metallurgical testing and failure analysis of the Line 200-4 failed pipe and the additional girth weld containing a crack-like indication (606+35.8) that was located upstream of the failed weld. The Line 200-1 failed girth weld and 2 additional girth welds adjacent to the failed weld shall also be subjected to metallurgical testing and failure analysis. The testing and analysis must be completed as follows:

- (A) Document the chain of custody when handling and transporting the failed pipe section and other evidence originating from the failure site;
 - (B) Utilize mechanical and metallurgical testing protocols, including selection of the testing laboratory, approved by the Director;
 - (C) Prior to commencing the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow a PHMSA representative to witness the testing; and
 - (D) Ensure that the testing laboratory distributes all resulting reports in their entirety, including all media, whether draft or final, to the Director at the same time they are made available to TGP.
7. Conduct an evaluation of previous in-line inspection (ILI) results, including a review and reporting by the ILI vendors' analysts (including raw data) of the failed girth weld and the girth weld with a crack-like indication, to establish ILI capability for detecting and identifying girth weld features or anomalies as follows:
- (A) Within 30 days of receipt of the Order or Agreement, re-evaluate the 2005 in-line inspection results from MLV 214-4 to MLV 219-4 to determine whether any features with similar characteristics to the feature at the failure site are present elsewhere on this portion of Line 200-4.
 - (B) Within 60 days of receipt of the Order or Agreement, re-evaluate all ILI data available for Affected Segments; including, but not limited to Line 200-1 and Line 200-4, to determine if any features of a similar characteristic to that at the failure sites are present elsewhere on the Affected Segments. The re-evaluation of the ILI data is to be performed by the tool vendor.
8. Within 60 days of receipt of the Order or Agreement, perform in-line inspection from MLV 209-1 to MLV 214-1 and specifically evaluate girth weld ILI data. The data analysis will be completed within 30 days of successful completion of the ILI. The ILI vendor shall evaluate the results per a performance specification specific to girth weld anomalies.
9. Within 90 days of receipt of the Order or Agreement, submit a report that provides a detailed review of all SCADA activities that relate to Lines 200-1 and 200-4 regarding the March 1 and February 10, 2011 incidents. SCADA enhancements identified during this review shall be included in the report, which will include approximate timelines for implementation of such enhancements. Activities reviewed and summarized must include, but may not be limited to: controller actions on the day before the incident, the day of the incident, and the day after the incident; maintenance activities (same three days); controller notes or logs (same three days); actual and calculated instrumentation readings (same three days); available communication statistics (same three days, including pressure and flow value poll

times); other SCADA equipment functions (same three days); and SCADA maintenance requests and status (during the 6 months preceding the incident). The report should also include a review of 30 days of detailed pressure information to document any changes in operating conditions since February 10, 2011. The report should provide a specific summary regarding whether or not the controllers had adequate information to recognize an abnormal operating condition on either event date in the control room. If adequate information did not exist to recognize these conditions, identify enhancements for the SCADA activities that could provide the necessary data and allow for controller recognition.

10. Within 120 days of receipt of the Agreement or Order, develop and submit to the Director for prior approval a remedial work plan that includes corrective measures. The work plan must provide for the verification of the integrity of the Affected Segments and must fully address all known or suspected factors that caused or contributed to the February 10, and March 1, 2011 incidents, including, but not limited to:
 - (A) The integration of the information developed from the actions required by the Agreement or Order with all historical construction, operating, maintenance, testing, and assessment data for the entire Affected Segments including:
 - (i) Within 90 days of the Agreement or Order, complete a root cause failure analysis for Line 200-1 and Line 200-4, relating to the February 10 and March 1, 2011 incidents that is supplemented and facilitated by an independent third-party expert acceptable to the Director. Elements of the root cause analysis must include, but not be limited to: scoping document of the root cause analysis; procedures associated with root cause analysis; multiple methods used for the analysis and updates on each method as it progresses; contributory factors; documentation of the decision-making process; and a final report of the root cause process results, including any lessons learned and whether the findings are applicable to other locations within the TGP System.
 - (ii) No longer than 30 days after the completion of the root cause failure analysis, integrate the findings of the root cause failure analysis into other data integration efforts and the remedial work plan.
 - (B) The performance of additional field testing, inspections, and evaluations to determine whether and to what extent the conditions associated with the failure, or any other integrity-threatening conditions are present elsewhere on the Affected Segments. Data-gathering activities must include a review of the failure history (in-service and pressure test failures) of the entire length of the Affected Segments and development of a written report containing all available information regarding locations, dates, and causes of failures. Include a detailed description of TGP's plan to confirm the integrity of the applicable sections of the Affected Segments, including the criteria to be used

for the evaluation and prioritization of any integrity threats and anomalies that are identified. Make the results of the actions required by this provision available to the Director or PHMSA representative;

- (C) The performance of repairs or other corrective measures that fully remediate the condition(s) associated with the pipeline failures and any other integrity-threatening condition everywhere along Affected Segments where such conditions are identified by the evaluation process. Include a detailed description of the repair criteria and method(s) to be used in undertaking any repairs or other remedial actions;
 - (D) Provisions for continuing long-term periodic testing and integrity verification measures to ensure the ongoing safe operation of the Affected Segments considering the results of the analyses, inspections, and corrective measures undertaken pursuant to the Safety Order; and
 - (E) A proposed risk-based schedule for completion of the actions required by paragraphs (A) through (D) of this Item, including a schedule associated with all elements of the internal root cause analysis. Provide the Director with advance notice of scheduled repairs.
11. The remedial work plan becomes incorporated into the Order and must be revised as necessary to incorporate the results of actions undertaken pursuant to the Order and whenever necessary to incorporate new information obtained during the failure investigations and remedial activities. Submit any such plan revisions to the Director for prior approval. The Director may approve plan elements incrementally.
 12. Implement the remedial work plan as approved by the Director, including any revisions to the plan. The results of all actions taken in accordance with the approved plan must be available for review by PHMSA or its representative.
 13. Submit monthly reports to the Director that: (1) include available data and results of the testing and evaluations required by the Order; and (2) describe the progress of the repairs and other actions being undertaken as a result of the Order. The first monthly report is due on the last day of the month following receipt of the Order. The regular intervals for submitting reports may be adjusted with prior approval of the Director.
 14. It is requested that TGP maintain documentation of the costs associated with implementation of the Safety Order, and include in each report submitted pursuant to Item 13, the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.
 15. The Director may allow the removal or modification of the pressure restriction set forth in Items 2 and Item 4 upon a written request from TGP demonstrating that the

hazard has been abated and that restoring the pipeline, or portion thereof, to its pre-failure operating pressure would be justified, based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.

16. The Director may grant an extension of time for compliance with any of the terms of the Safety Order upon a written request timely submitted demonstrating good cause for an extension.
17. TGP may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator are final.

The above actions proposed to be required by this Notice of Proposed Safety Order are in addition to and do not waive any requirements that apply to TGP's pipeline system under 49 C.F.R. Parts 190 through 199, under any other order issued to TGP under authority of 49 U.S.C. Chapter 601, or under any other provision of Federal or State law.

After receiving and analyzing additional data in the course of this proceeding and implementation of the work plan, PHMSA may identify other safety measures that need to be taken. In that event, TGP will be notified of any proposed additional measures and, if necessary, amendments to the work plan or safety order.



David Barrett
Director, Central Region
Pipeline and Hazardous Materials Safety Administration

March 11, 2011
Date issued

§190.239 Safety orders.

(a) When may PHMSA issue a safety order? If the Associate Administrator, OPS finds, after notice and an opportunity for hearing under paragraph (b) of this section, that a particular pipeline facility has a condition or conditions that pose a pipeline integrity risk to public safety, property, or the environment, the Associate Administrator may issue an order requiring the operator of the facility to take necessary corrective action. Such action may include physical inspection, testing, repair, risk assessment, risk control, data integration, information management, or other appropriate action to remedy the identified risk condition.

(b) How is an operator notified of the proposed issuance of a safety order and what are its response options? (1) Notice of proposed safety order. PHMSA will serve written notice of a proposed safety order under §190.5 to an operator of the pipeline facility. The notice will allege the existence of a condition that poses a pipeline integrity risk to public safety, property, or the environment, and state the facts and circumstances that support issuing a safety order for the specified pipeline or portion thereof. The notice will also specify proposed testing, evaluations, integrity assessment, or other actions to be taken by the operator and may propose that the operator submit a work plan and schedule to address the conditions identified in the notice. The notice will also provide the operator with its response options, including procedures for requesting informal consultation and a hearing. An operator receiving a notice will have 30 days to respond to the PHMSA official who issued the notice.

(2) Informal consultation. Upon timely request by the operator, PHMSA will

provide an opportunity for informal consultation concerning the proposed safety order. Such informal consultation shall commence within 30 days, provided that PHMSA may extend this time by request or otherwise for good cause. Informal consultation provides an opportunity for the respondent to explain the circumstances associated with the risk condition(s) identified in the notice and, where appropriate, to present a proposal for corrective action, without prejudice to the operator's position in any subsequent hearing. If the respondent and Regional DirectorPHMSA agree within 30 days of the informal consultation on a plan for the operator to address each risk condition, they may enter into a written consent agreement and Associate AdministratorPHMSA may issue a consent order incorporating the terms of the agreement. If a consent agreement is reached, no further hearing will be provided in the matter and any pending hearing request will be considered withdrawn. If a consent agreement is not reached within 30 days of the informal consultation (or if informal consultation is not requested), the Associate Administrator may proceed under paragraphs (b)(3) through (5) of this section. If PHMSA subsequently determines that an operator has failed to comply with the terms of a consent order, PHMSA may obtain any administrative or judicial remedies available under 49 U.S.C. 60101 et seq. and this part. If a consent agreement is not reached, any admissions made by the operator during the informal consultation shall be excluded from the record in any subsequent hearing. Nothing in this paragraph (b) precludes PHMSA from terminating the informal consultation process if it has reason to believe that the operator is not engaging in good faith discussions or otherwise concludes that further consultation would not be productive or in the public interest.

(3) Hearing. An operator receiving a notice of proposed safety order may contest the notice, or any portion thereof, by filing a written request for a hearing within 30 days following receipt of the notice or within 10 days following the conclusion of informal consultation that did not result in a consent agreement, as applicable. In the absence of a timely request for a hearing, the Associate Administrator may issue a safety order in the form of the proposed order in accordance with paragraphs (c) through (g) of this section.

(4) Conduct of hearing. An attorney from the Office of Chief Counsel, PHMSA, will serve as the Presiding Official in a hearing under this section. The hearing will be conducted informally, without strict adherence to formal rules of evidence in accordance with §190.211. The respondent may submit any relevant information or materials, call witnesses, and present arguments on the issue of whether a safety order should be issued to address the alleged presence of a condition that poses a pipeline integrity risk to public safety, property, or the environment.

(5) Post-hearing action. Following a hearing under this section, the Presiding Official will submit a recommendation to the Associate Administrator concerning issuance of a final safety order. Upon receipt of the recommendation, the Associate Administrator may proceed under paragraphs (c) through (g) of this section. If the Associate Administrator finds the facility to have a condition that poses a pipeline integrity risk to public safety, property, or the environment, the Associate Administrator will issue a safety order under this section. If the Associate Administrator does not find that the facility has such a condition, or concludes that a safety order is otherwise not warranted, the Associate Administrator will withdraw the notice and

promptly notify the operator in writing by service as prescribed in §190.5. Nothing in this subsection precludes PHMSA and the operator from entering into a consent agreement at any time before a safety order is issued.

(6) Termination of safety order. Once all remedial actions set forth in the safety order and associated work plans are completed, as determined by PHMSA, the Associate Administrator will notify the operator that the safety order has been lifted. The Associate Administrator shall suspend or terminate a safety order whenever the Associate Administrator determines that the pipeline facility no longer has a condition or conditions that pose a pipeline integrity risk to public safety, property, or the environment.

(c) How is the determination made that a pipeline facility has a condition that poses an integrity risk? The Associate Administrator, OPS may find a pipeline facility to have a condition that poses a pipeline integrity risk to public safety, property, or the environment under paragraph (a) of this section:

(1) If under the facts and circumstances the Associate Administrator determines the particular facility has such a condition; or

(2) If the pipeline facility or a component thereof has been constructed or operated with any equipment, material, or technique with a history of being susceptible to failure when used in pipeline service, unless the operator involved demonstrates that such equipment, material, or technique is not susceptible to failure given the manner it is being used for a particular facility.

(d) What factors must PHMSA consider in making a determination that a risk condition is present? In making a determination under paragraph (c) of this section, the Associate Administrator, OPS shall consider, if relevant:

(1) The characteristics of the pipe and other equipment used in the pipeline facility involved, including its age, manufacturer, physical properties (including its resistance to corrosion and deterioration), and the method of its manufacture, construction or assembly;

(2) The nature of the materials transported by such facility (including their corrosive and deteriorative qualities), the sequence in which such materials are transported, and the pressure required for such transportation;

(3) The characteristics of the geographical areas where the pipeline facility is located, in particular the climatic and geologic conditions (including soil characteristics) associated with such areas;

(4) For hazardous liquid pipelines, the proximity of the pipeline to an unusually sensitive area;

(5) The population density and growth patterns of the area in which the pipeline facility is located;

(6) Any relevant recommendation of the National Transportation Safety Board issued in connection with any investigation conducted by the Board;

(7) The likelihood that the condition will impair the serviceability of the pipeline;

(8) The likelihood that the condition will worsen over time; and

(9) The likelihood that the condition is present or could develop on other areas of the pipeline.

(e) What information will be included in a safety order? A safety order shall contain the following:

(1) A finding that the pipeline facility has a condition that poses a pipeline integrity risk to public safety, property, or the environment;

(2) The relevant facts which form the basis of that finding;

(3) The legal basis for the order;

(4) The nature and description of any particular corrective actions to be required of the operator; and

(5) The date(s) by which the required corrective actions must be taken or completed and, where appropriate, the duration of the order.

(f) Can PHMSA take other enforcement actions on the affected facilities? Nothing in this section precludes PHMSA from issuing a Notice of Probable Violation under §190.207 or taking other enforcement action if noncompliance is identified at the facilities that are the subject of a safety order proceeding.

[Amdt. 190-[13], 73 FR 16562, Mar. 28, 2008; Amdt. 190-[14], 74 FR 2889, January 16, 2009]