U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

409 3rd Street, SW, Suite 300
Washington, DC 20024

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

May 8, 2009

Mr. Jeff Barger
Vice President, Operations
Dominion Transmission, Inc.
445 West Main Street
Clarksburg, WV 26301

CPF 1-2009-1003M

Dear Mr. Barger:

From July to November 2008, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the New York Public Service Commission, and the West Virginia Public Service Commission pursuant to Chapter 601 of 49 United States Code inspected Dominion Transmission, Inc. (DTI) procedures for Operations and Maintenance (O&M) and Design and Construction.

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

1. **§ 192.307 Inspection of materials.**

   Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

DTI procedures do not designate responsibility for inspection or require that damage to pipe and components be documented and controlled

2. **§ 192.313 Bends and elbows.**

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

DTI construction specifications have been established to define pipe field bending requirements but the procedures have not been established that would provide direction, acceptance criteria, and documentation requirements to be used by craftsmen and / or inspectors in the field.

3. **§ 192.319 Installation of pipe in a ditch.**

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

DTI construction procedures do not ensure that methods are used to prevent the overstressing of pipe when it is lowered into the ditch.

4 **§ 192.325 Underground clearance**

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

DTI's Design and Construction Manual should specify acceptable materials for use as an insulator between the pipeline and underground structures in close proximity.

5. **§ 192.243 Nondestructive testing.**

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures

DTI does not have a process for ensuring that NDT procedures are qualified to API 1104 section 9 and that they are conducted by a trained and qualified person.

6. **§ 192.243 Nondestructive testing.**

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).

DTI procedures have not been established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).

7. **§ 192.243 Nondestructive testing.**

(d) When nondestructive testing is required under §192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

DTI Standard Operating Procedures (SOP) do not specify that all field butt welds that are nondestructively tested must have their entire circumference tested as required by §192.243(d).

8. **§ 192.243 Nondestructive testing.**

e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under §192.241(b).

DTI procedures do not require that a sample of each welder's work for each day be nondestructively tested, when nondestructive testing is required under §192.241(b)

9. **§ 192.55 Steel pipe.**

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

DTI Design and Construction (D&C) Manual section 2.2 inappropriately refers to 192 Appendix A for the referenced pipe specifications rather than 192 Appendix B.

10. **§ 192.159 Flexibility.**

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

DTI does not include parameters in the design criteria for when thermal expansion must be considered and evaluated by DTI engineering.

11. **§ 192.161 Supports and anchors.**

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

DTI's D&C Manual does not address the need to consider pulsation studies to ensure that pipeline and associated equipment have sufficient anchors and supports to prevent or dampen out excessive vibration. The D&C Manual does not provide a link or reference to standard drawings for support and anchor design.

12. § 192.179 Transmission line valves.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

DTI's D&C Manual does not provide guidance on the type and level of protection to be used to prevent block valve tampering or damage based on site specific circumstances.

13. § 192.179 Transmission line valves.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

DTI's D&C Manual Table 4.6 is limited to pipelines 30 inches and smaller although larger pipe sizes are used in the DTI pipeline system. The D&C Manual needs to address all sizes used in DTI construction to insure that blowdown valves installed have enough capacity to allow the transmission line to be blown down as rapidly as practical.

14. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

The DTI emergency plan does not include coordination provisions when larger incident command centers are established that may include other organizations such as the fire department or other government agencies that may be on location following a significant emergency.

15. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

DTI emergency procedures do not specify the site-specific equipment (also contractor equipment) that must be available and operable to support emergency response. DTI procedures do not address checks of emergency equipment to ensure operability for emergency response.

16. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

DTI site-specific emergency plans do not include all necessary direct phone numbers to contact local emergency responders. For Fire Departments, Emergency Medical Services and Law Enforcement agencies, only an outside line "911" phone number is listed under "Phone Numbers".

17. § 192.615 Emergency plans.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

The DTI emergency preparedness liaison process does not ensure that the responsibility and resources of each government organization that may respond to a gas pipeline emergency is learned.

18. § 192.615 Emergency plans

(b) Each operator shall:

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

DTI emergency procedures do not define the process for review of employee actions to determine if emergency procedures were followed and are effective.

19. § 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

DTI has not defined the process for analyzing accidents and failures of equipment, and how to communicate lessons learned. As an example, the pipeline failure investigation report for the 12/1/2007 accident on pipeline TL-453 does not document, or reference, the actions taken to identify, and prevent recurrence of, internal corrosion at pot drips on transmission lines.

20. § 192.731 Compressor stations: Inspection and testing of relief devices.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

At the time of the inspection, DTI representatives stated they were not able to ensure that compressor station emergency shutdown systems (ESD) inspections do not repeatedly use the same ESD activation point as was used in previous year's testing Which ESD device is tested is apparently not tracked or recorded. While DTI procedures state that the emergency shutdown test activation point should be different from the previous successful test, there is no process defined to ensure that no activation point is repeated from the previous year.

21. § 192.736 Compressor stations: Gas detection.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

DTI compressor station inspection records do not specify the type of CGI sensor that is being inspected. Different CGI sensors have different maintenance requirement schedules. The type of sensor must be known to schedule the required quarterly or annual inspection.

22. § 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

DTI SOP 210/02 does not define what are the "Accepted and expected limits" for regulator shutoff.

DTI procedures do not define relief device set-points. DTI procedures do not address build-up pressure of the relief valve to achieve full open condition.

DTI procedures for relief device pressure calculations do not account for inlet and outlet piping restrictions which might affect proper pressure set-point.

23. § 192.745 Valve maintenance: Transmission lines.

(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

DTI procedures do not clearly define partial operation of valves during inspection for ensuring proper operation of the valves during an emergency.

DTI procedures do not define the terms good, fair, poor, or pitted are used on valve inspection documentation.

24. § 192.745 Valve maintenance: Transmission lines.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

DTI has not established procedures to specify how proper lubrication of valves is to be conducted for valves found in need of remedial action.

25. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) ***Maintenance and normal operations.*** **The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.**

The process for evaluating the effectiveness of DTI procedures is not described in the DTI SOPs.

26. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(c) ***Abnormal operation.*** **For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:**

(1) Responding to, investigating, and correcting the cause of:

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

DTI procedures do not give descriptions of significant hazards that require system shutdown.

DTI procedures do not address the evaluation of system abnormal operating conditions to ensure that other pipeline facilities have not been damaged, or that other similar facilities will not experience the same abnormal operating condition.

DTI procedures do not specify whether root cause analysis, or other types of analyses should be used to determine the cause of abnormal operating conditions. Possible significant factors to consider in the analysis are not addressed.

27. § 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

DTI SOP 330 / 01 states that purging is not required when the volume of gas is so small that a potential hazard does not exist. However, the criteria defining a "small" amount of gas is not provided to determine when purging may not be necessary.

DTI SOP 330 / 01, Section VII.F states that end point samples "may" be taken with an accurately calibrated combustible gas indicator (CGI), natural gas detecting instrument, gravity measuring instrument, oxygen indicator, or other approved device to ensure the completeness of the purge.

One of these instruments "must" be used in order to establish that air / gas concentration meets the acceptance limits specified in SOP 330 / 01 Section VII.E.

28. § 192.491 Corrosion control records.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

DTI corrosion control documentation procedures related to §192.481(b) do not provide sufficient detail necessary to ensure that the inspection process identifies and gives particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, and at specific locations within a DTI station or at other facility areas.

29. § 192.461 External corrosion control: Protective coating.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

DTI procedures are not adequate to ensure that pipe coating is not damaged when pulled through borings or horizontal directional drillings.

30. § 192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

DTI Corrosion Control Procedure 070, SOP 06, uses the permissive terminology "should" or "may" for specifying external protective corrosion control requirements when the intent is that the requirements "shall" or "must" be met. Definitions and expectations for "should" and "shall" requirements are outlined in ASME B31.8S which is incorporated into portions of Part 192 by reference.

31. § 192.453 General.

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

DTI procedures and program documentation do not define the pipeline corrosion control qualifications for company and contractor personnel involved with carrying out the corrosion control procedures for the design, installation, operation, and maintenance of cathodic protection systems, and other pipeline corrosion control methods.

32. § 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

DTI SOP 070 / 03 Section V.A states that the cathodic protection requirements may be modified for temporary pipeline installations with an operating life not to exceed five (5) years beyond installation as long as prior approval is received from the Pipeline Integrity Section. However, it does not specify that the temporary condition must not be detrimental to public safety.

33. § 192.463 External corrosion control: Cathodic protection.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

DTI SOP 070 / 07, Cathodic Protection Criteria, Section II.A states that the amount of cathodic protection applied shall be controlled to prevent damage to the protective coating or the pipe. However, procedures do not define criteria on how to control the amount of cathodic protection applied to prevent damage to the pipe coating.

34. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

DTI procedures are inadequate to control internal corrosion. The procedures do not ensure that fluid samples from drips are consistently taken following the annual blowdown of transmission lines, and that those samples are analyzed for evidence of conditions conducive to internal corrosion.

DTI inspection history detail drip blowing forms do not indicate if fluids, other than just water, are removed from the pipelines. DTI procedures needs to address other fluids found in the drip blowing process.

35. § 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

The DTI Pipeline Repair Manual allows for the use of the Clock Spring repair method for permanent repair of wall thickness loss due to internal corrosion as long as the internal corrosion is no longer active. DTI procedures do not specify when internal corrosion is no longer active, or define how to determine when internal corrosion is no longer active.

36. § 192.471 External corrosion control: Test leads.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

DTI procedures for thermowelding of test leads do not require verification of pipe wall thickness to ensure the thermowelding process does not create a stress concentration on the pipe due to inadequate pipe wall thickness.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

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

In correspondence concerning this matter, please refer to **CPF 1-2009-1003M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Byron E. Coy, P.E.
Director, Eastern Region
Pipeline and Hazardous Materials Safety Administration

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