U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety Administration**

400 Seventh Street, S.W.
Washington, D.C. 20590

JUL 27 2006

Mr. David Jones
Vice President, Eastern Operations
Tennessee Gas Pipeline
An Affiliate of El Paso Corporation
2 Brentwood Commons, Suite 190
Brentwood, TN 37027

Re: CPF No. **2-2006-1007H**

Dear Mr. Jones:

Enclosed is a Corrective Action Order issued by the Acting Associate Administrator for Pipeline Safety in the above-referenced case. It requires you to take certain corrective actions with respect to the operation of your 24-inch transmission pipeline Line 100-1, which extends from Campbellsville, Kentucky to Clay City, Kentucky. Service is being made by certified mail and facsimile. Your receipt of the enclosed document constitutes service of that document. The terms and conditions of this Final Order are effective upon receipt.

Sincerely,

James Reynolds
Pipeline Compliance Registry
Office of Pipeline Safety

Enclosure

VIA CERTIFIED MAIL (RETURN RECEIPT REQUESTED) AND TELECOPY

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

In the Matter of **TENNESSEE GAS PIPELINE,** **An Affiliate of El Paso Corporation** **Respondent**	**CPF No. 2-2006-1007H**

CORRECTIVE ACTION ORDER

Purpose and Background

This Corrective Action Order is being issued, under authority of 49 U.S.C. § 60112, to require Tennessee Gas Pipeline (Respondent), an affiliate of El Paso Corporation (El Paso), to take the necessary corrective action to protect the public and environment from potential hazards associated with its 24-inch natural gas transmission pipeline that extends from Campbellsville, Kentucky to Clay City, Kentucky (hereinafter referred to as Line 100-1).

On July 22, 2006, a failure occurred on Respondent's 24-inch Line 100-1 pipeline approximately six miles southeast of Clay City, Kentucky, resulting in the release and ignition of natural gas. The cause of the failure is unknown. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety, Southern Region and the Kentucky Public Service Commission initiated an investigation of this failure.

Preliminary Findings

1. At approximately 12:30 p.m. EDT, on July 22, 2006, a segment of Respondent's 24-inch Line 100-1 ruptured, resulting in an estimated release of 42,946 MSCF of natural gas near Clay City in Clark County, Kentucky. A fire ensued and was extinguished at 1:33 p.m. EDT.

2. The rupture and fire occurred at Mile Post 105.1 +3.7, approximately 6 miles southeast of Clay City, Kentucky, 11 miles southeast of Winchester, Kentucky and 11 miles northeast of Mount Sterling, Kentucky.

3. No injuries or fatalities occurred. Three (3) homes were evacuated and minor damage occurred on nearby property.

4. The preliminary investigation indicates external pitting corrosion in an area approximately 2 – 3 feet long near the fracture, and within about 2 - 4 inches of the longitudinal seam. The fracture followed the edge of the longitudinal seam in the area of the pitting.

5. Following the July 22, 2006 failure, Respondent's personnel isolated the segment of pipeline involved in the failure by closing the nearest upstream mainline block valve (MLV 105-1) at 1:26 p.m. and isolation valves at the nearest downstream valve at Compressor Station 106 at 1:07 p.m. MLV 105-1 is located approximately four miles upstream of the failure site. Compressor Station 106 is located approximately two miles downstream of the failure site.

6. The failure occurred in a 90 mile section between Respondent's Campbellsville, Kentucky Compressor Station 96 and the Clay City, Kentucky Compressor Station 106, approximately 2 miles upstream of the Clay City Station.

7. Approximately 25 feet of pipe blew out of the ground and landed about 200 feet on the hill from the failure site on or near the Respondent's 800 system right-of-way. The section of pipe was twisted and mangled. External coating was completely burned off the section of pipe that was blown out of the ground.

8. The 84 mile long section of Line 100-1 upstream of the failure valve section is under pressure. The six miles long failure valve section is currently depressurized and out of service.

9. At the time of the incident, the Line 100-1 pressure at a meter station located 21 miles upstream was 721 psig. The estimated failure site pressure was 716 psig. The maximum allowable operating pressure (MAOP) of this line segment is 750 psig.

10. The investigation is ongoing. The failed pipe segment along with adjacent pieces was transported to El Paso's metallurgical laboratory located in Dearborn, Michigan for further analysis.

11. The Line 100-1 pipeline was installed in 1944 and is constructed of 24-inch x 0.250-inch w.t., API 5L-X50 pipe manufactured by A.O. Smith. The protective coating is coal tar enamel (TGF-2).

12. The pipeline is owned by El Paso's Pipeline Group, which owns and operates approximately 48,000 miles of natural gas pipeline. Respondent, an affiliate of El Paso, operates nearly 14,000 miles of pipeline, including approximately 1,508 pipeline miles of interstate natural gas transmission lines in the state of Kentucky. Respondent's pipelines

traversing Kentucky include the 100 and 800 systems, of which a portion is located in shale terrain.

13. Line 100-1 passes through mostly rural areas in Kentucky, with some Class 2 and Class 3 location areas, in addition to other populated areas designated as High Consequence Areas (HCAs). The pipeline also passes through large and small communities along the route as well as crossing state and interstate highways, rivers, and streams. The failure occurred in a Class 2 location area.

14. In 1986, Respondent internally inspected the failed line section using a Tuboscope low-resolution magnetic flux leakage inline inspection (ILI) tool.

15. The pipeline failed in the bottom of a valley in an area of wet shale. Shale terrain in this part of Kentucky is known to cause corrosive environments on buried pipelines. A major pipeline failure occurred on Respondent's 26-inch Line 100-3 on July 23, 1980, approximately three miles from the July 22, 2006 failure. The subsequent investigation revealed that several operational and hydrostatic test pipeline failures had occurred on Respondents System 100 pipelines in shale terrain near Clay City, and were attributable to external bacterial corrosion.

16. Line 100-1 was last pressure tested in 1986 at a minimum pressure of 940 psig for eight hours with no leaks. In 1981, Line 100-1 was pressure tested at a minimum pressure of 974 psig for eight hours with no leaks. Line 100-1 was also pressure tested in 1971 at a minimum pressure of 938 psig for eight hours with two leaks. Line 100-1 was pressure tested in 1967 at a minimum pressure of 936 psig for twenty-four hours with two leaks.

17. Respondent conveyed that an ILI run was scheduled to be run in the failed section during the week of July 24, 2006.

<u>Determination of Necessity for Corrective Action Order and Right to Hearing</u>

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action as appropriate. The basis for making the determination that a pipeline facility is hazardous, requiring corrective action, is set forth both in the above referenced statute and 49 C.F.R. §190.233, a copy of which is enclosed.

Section 60112, and the regulations promulgated thereunder, provide for the issuance of a Corrective Action Order without prior opportunity for notice and hearing upon a finding that failure to issue the Order expeditiously will result in likely serious harm to life, property or the environment. In such cases, an opportunity for a hearing will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that the continued operation of this pipeline without corrective measures would be hazardous to life, property and the environment. Additionally, after considering the age of the pipe, circumstances surrounding this failure, the proximity of the pipeline to high consequence areas, the nature of the product the pipeline transports, the pressure required for transporting the material, the uncertainties as to the cause of the failure, and the ongoing investigation to determine the cause of the failure, I find that a failure to issue expeditiously this Order, requiring immediate corrective action, would result in likely serious harm to life, property, and the environment.

Accordingly, this Corrective Action Order mandating needed immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may request a hearing, to be held as soon as practicable, by notifying the Associate Administrator for Pipeline Safety in writing, delivered personally, by mail or by telecopy at (202) 366-4566. The hearing will be held in Atlanta, Georgia or Washington, D.C. on a date that is mutually convenient to PHMSA and Respondent.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other longer term measures that need to be taken. Tennessee Gas Pipeline will be notified of any additional measures required and amendment of this Order will be considered. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Action

Pursuant to 49 U.S.C. § 60112, I hereby order Tennessee Gas Pipeline to immediately take the following corrective actions with respect to its 24-inch transmission pipeline Line 100-1:

1. The operating pressure on Line 100-1 at the failure location, including any gas pressure required to run ILI tools prior to resuming operation, is not to exceed 80 percent of the operating pressure in effect immediately prior to the July 22, 2006 failure. Specifically, the operating pressure at the failure location is not to exceed 572.8 psig. This pressure restriction will 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, Southern Region, OPS. If the results of any action undertaken pursuant to this Order dictate a reduction in the allowable operating pressure below that imposed by this Order, Respondent must further reduce the operating pressure accordingly.

2. Conduct a detailed metallurgical analysis of the pipe that failed on July 22, 2006 to determine the cause and contributing factors.

    A. When handling and transporting the failed pipe section and any other evidence from the failure site, document the chain-of-custody;

B. Obtain prior approval of the metallurgical testing protocol from the Director, Southern Region, OPS; and

C. Prior to commencing the metallurgical testing, provide the Director, Southern Region, OPS with the scheduled date, time, and location of the testing to allow a PHMSA representative to witness it.

D. Ensure that the laboratory distributes all resulting metallurgical reports, whether draft or final, to OPS at the same time as they are made available to Respondent.

3. Submit a written plan, with a schedule, to verify the integrity of the line segment from the Campbellsville Compressor Station 96 and Clay City Compressor Station 106. The plan must provide integrity testing that addresses all known or suspected factors in the failure, including, but not limited to:

   A. ILI tool surveys and remedial action. The type of internal inspection tools used shall be technologically appropriate for assessing the system based on the type of failure that occurred on July 22, 2006, with emphasis on identifying and evaluating the following: 1) anomalies associated with dents, gouges and grooves; 2) metal loss due to corrosion; 3) the orientation of the longitudinal seam of the pipe; 4) pipe deformation, and 5) longitudinal cracks, mill defects and stress corrosion cracking.

   B. A detailed description of the inspection and repair criteria that will be used in the field evaluation of the anomalies that are excavated. This is to include a description of how any defects are to be graded and the schedule for repairs or replacement.

   C. An evaluation of the line for areas of damaged or disbonded coating, including but not limited to, a current interrupted close-interval survey.

   D. Integration of all available data from internal inspections, metallurgical analyses, and historical data, including repair and cathodic protection records.

   E. Hydrostatic pressure testing of the line segment and/or other mitigative measures required to address the cause and contributing factors to the July 22, 2006 pipeline failure.

4. Review applicable historical, operational, maintenance and incident information on the 100 and 800 System pipeline segments that traverse through shale terrain in Kentucky, along with the results of the failure analysis required in Item 2. Determine if additional actions and/or preventive measures are necessary to reduce the risk of a failure similar the one that occurred on July 22, 2006. Information such as pipeline vintage, type of coating, prevalence of disbonded coating, most recent ILI surveys, pressure test, close-interval survey should be

considered. Within 45 days, submit documentation to show completion to Director, Southern Region, OPS.

5. Submit the plan required of Item 4 and the results of the requirements in Item 5 to: Director, Southern Region, OPS, 233 Peachtree Street, Suite 600, Atlanta, GA 30303. The plan must be revised, as necessary, to incorporate new information obtained during the failure investigation and remedial activities undertaken pursuant to this Order. Submit any such plan revisions to the Director for prior approval. The Director, Southern Region, OPS, may approve plan elements incrementally.

6. Implement the plan as it is approved, including any revisions to the plan.

7. The Director, Southern Region, OPS, may allow the removal or modification of the pressure restriction set forth in Item 1 upon a written request from Respondent demonstrating that the hazard has been abated and that restoring the pipeline to its pre-failure operating pressure is 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. Appeals to determinations of the Director, Southern Region, OPS, will be subject to the decision of the Acting Associate Administrator for Pipeline Safety.

8. The Director, Southern Region, OPS, may grant an extension of time for compliance with any of the terms of this order for good cause. A request for an extension must be in writing.

The corrective actions required by this Corrective Action Order are in addition to and do not waive any requirements that apply to the pipeline under any other order issued to Respondent under authority of 49 U.S.C. chapter 601, under 49 C.F.R. Part 191, or under any other provision of Federal or state law.

Failure to comply with this Order may result in the assessment of civil penalties of up to $100,000 per violation per day pursuant to 49 U.S.C. 60122, and in referral to the Attorney General for imposition of civil judicial penalties or other appropriate relief in United States District Court pursuant to 49 U.S.C. 60120.

T. L. Willke

Theodore L. Wilke
Acting Associate Administrator
for Pipeline Safety

JUL 27 2006

Date Issued