U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT – original Class 1 to 3 and Class 2[1] to 3

Docket Number:	PHMSA-2008-0159
Pipeline Operator:	Texas Gas Transmission, LLC
Date Requested:	May 16, 2008
Code Section(s):	49 CFR § 192.611(a)

Grant of Special Permit:

By this order, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to Texas Gas Transmission, LLC (TXGT) waiving compliance from 49 CFR § 192.611(a) for four natural gas transmission pipeline segments in Graves County, Kentucky as described below. The Federal pipeline safety regulations in 49 CFR § 192.611(a) require natural gas pipeline operators to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location.

Special Permit Segments and Inspection Area:

<u>Graves County, Kentucky</u>

PHMSA waives compliance from 49 CFR § 192.611(a) for four natural gas transmission pipeline segments on the 26" Main Line 26-1, 26" Main Line 26-2 and the 30" Main Line 30-1 pipelines, where a change has occurred from a Class 1 location to a Class 3 location and a Class 2[2] to Class 3 in Graves County, Kentucky. This special permit allows TXGT to continue to operate each ***special permit segment*** at its current maximum allowable operating pressure (MAOP) of 810 pounds per square inch gauge (psig) for the Main Line 26-1 and Main Line 26-2 and an MAOP of 840 psig for the Main Line 30-1 pipelines.

This special permit applies to the ***special permit segments*** defined using the TXGT mile post (MP) references as follows:

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[1] This segment was originally a Class 1 area that was upgraded to Class 2 via § 192.611 (a) hydrostatic test.
[2] This segment was originally a Class 1 area that was upgraded to Class 2 via § 192.611 (a) hydrostatic test.

- ***Special permit segment 1*** - *26" Main Line 26-1* – 334 feet, Mile Post 385+3800 to Mile Post 385+4134
- ***Special permit segment*** *2 - 26" Main Line 26-2* - 2499 feet, Mile Post 385+3885 to Mile Post 386+1104
- ***Special permit segment 3*** - *30" Main Line 30-1* - 2488 feet, Mile Post 385+3898 to Mile Post 386+1106
- ***Special permit segment 4*** - *30" Main Line 30-1* - 200 feet, Mile Post 390+2858 to Mile Post 390+3058

Special permit inspection area - the area that extends 220 yards on each side of the centerline along the entire length of the Main Lines 26-1, 26-2 and 30-1 pipelines from:

- 26" Main Line 26-1: Mile Post 360+3800 to Mile Post 408+1368
- 26" Main Line 26-2: Mile Post 360+3885 to Mile Post 408+1368
- 30" Main Line 30-1: Mile Post 360+3898 to Mile Post 408+1368

The ***special permit inspection areas*** are located in Obion, Weakley, Graves and Marshall Counties, Kentucky. The *special permit inspection areas* start downstream of the Kenton Compressor Station and ends at the Calvert City Compressor Station – Mile Post 408+1368.

PHMSA grants this special permit based on the findings set forth in the *"Special Permit Analysis and Findings"* document, which can be read in its entirety in Docket No. PHMSA-2008-0159 in the Federal Docket Management System (FDMS) located on the internet at www.Regulations.gov.

Conditions:

PHMSA grants this special permit subject to the following conditions:

1) TXGT must continue to operate the ***special permit segments*** at or below their existing MAOP as follows: Main Line 26-1 – MAOP 810 psig; Main Line 26-2 – MAOP 810 psig; and Main Line 30-1 - MAOP 840 psig.

2) TXGT must incorporate each ***special permit segment*** into its written integrity management program (IMP) as a *"covered segment"* in a *"high consequence area (HCA)"* per § 192.903, except for the reporting requirements contained in § 192.945. TXGT need not include the ***special permit segments*** described in this special permit in its IMP baseline assessment plan unless those areas meet the conditions of an HCA per § 192.905.
3) TXGT must perform a close interval survey (CIS) of the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of all ***special permit inspection areas*** not later than one year after the grant of this special permit and remediate any areas of inadequate cathodic protection. A CIS and remediation need not be performed if TXGT has performed a CIS and remediation on the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of all ***special permit inspection areas*** less than four years prior to the grant of this special permit. If factors beyond TXGT's control prevent the completion of the CIS and remediation within one year, a CIS and remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region not later than one year after the grant of this special permit.
4) TXGT must perform periodic CIS of the ***special permit segments*** at the applicable reassessment interval(s) for a "covered segments" determined in concert and integrated with in-line inspection (ILI) in accordance with 49 CFR 192 Subpart O reassessment intervals as contained in 49 CFR §§ 192.937 (a) and (b) and 192.939.
5) TXGT must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey of each ***special permit segment*** not later than one year after the grant of this special permit to verify the pipeline coating conditions and to remediate any integrity issues in the ***special permit segments***. A DCVG or ACVG survey and remediation need not be performed on ***special permit segments*** if TXGT has performed a DCVG or ACVG and remediation on the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of all ***special permit inspection areas*** less than four years prior to the grant of this special permit. TXGT must remediate any damaged coating indications found during these assessments that are classified as moderate (i.e. 35% IR and above for DCVG or 50 dBμV and above for ACVG) or severe based on NACE International Recommended Practice 0502-2002, *"Pipeline External Corrosion Direct Assessment Methodology"*, (NACE RP 0502-2002). A minimum of two coating survey assessment classifications must be excavated, classified and/or remediated per each survey

crew per each time the survey is performed. If factors beyond TXGT's control prevent the completion of the DCVG or ACVG survey and remediation within one year, a DCVG or ACVG survey and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region not later than one year after the grant of this special permit.

6) TXGT must evaluate the Main Lines 26-1, 26-2 and 30-1 pipelines for stress corrosion cracking (SCC) as follows:

   a) TXGT must perform a stress corrosion cracking direct assessment (SCCDA) or other appropriate assessment method for SCC [such as pressure test or ILI with a crack detection tool] of the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of all ***special permit inspection areas*** according to the requirements of § 192.929 and/or NACE RP 0204-2008 not later than one year after of the grant of this special permit. The SCCDA or other approved method must address both high pH SCC and near neutral pH SCC. An SCCDA need not be performed if TXGT has performed an SCCDA of the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of the ***special permit inspection areas*** less than four years prior to the grant of this special permit. If factors beyond TXGT's control prevent the completion of the SCCDA survey and remediation within one year, an SCCDA and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region not later than one year after the grant of this special permit. [TXGT may eliminate this Condition 6 (a), provided TXGT provides an engineering assessment showing that the pipeline does not meet any of the criteria for both near neutral and high pH SCC per the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, *"Managing System Integrity of Gas Pipelines"* (ASME B31.8S) Appendix A3, or NACE 0204 -2008, *"Stress Corrosion Cracking (SCC) Direct Assessment Methodology"*, Section 1.2.1.1 and 1.2.2]

   b) If the threat of SCC exists as determined in Condition 6 (a) and when the TXGT Main Lines 26-1, 26-2 and 30-1 pipelines are uncovered for any reason to comply with the special permit and integrity management activities in the ***special permit inspection areas*** and the coating has been identified as poor during the pipeline examination, then the TXGT must directly examine the pipe for SCC using an accepted industry detection practice such as dry or wet magnetic particle tests. Poor coating is a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe, is porous, has pin holes, and/or shields the cathodic protection. Visual inspection is not sufficient to determine 'poor coating' and it is expected that a holiday detection test at the correct voltage will be performed. TXGT must keep coating records at all excavation locations in the ***special permit inspection areas*** to demonstrate the coating condition.

7) TXGT must submit the DCVG or ACVG, CIS and SCCDA [or other approved methods of determining SCC] findings including remediation actions in a written report to the Director, PHMSA Southern Region, not later than two years after the grant of this special permit.
8) TXGT must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the inspection and reassessment intervals by in-line inspection (ILI) including both metal loss and geometry tools of the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of the ***special permit inspection areas*** at a frequency consistent with 49 CFR Part 192, Subpart O.
9) TXGT must amend applicable sections of its O&M manual(s) to incorporate the inspection and reassessment intervals by CIS of the Main Lines 26-1, 26-2 and 30-1 ***special permit segments*** at a frequency consistent with 49 CFR Part 192, Subpart O.
10) The assessments of the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of the ***special permit inspection areas*** using ILI must conform to the required maximum reassessment intervals specified in § 192.939.
11) TXGT must schedule future reassessment dates for the Main Lines 26-1, 26-2 and 30-1 pipelines along the entire length of the ***special permit inspection areas*** according to § 192.939 by adding the required time interval to the previous assessment date.
12) TXGT must ensure its damage prevention program incorporates the applicable best practices of the Common Ground Alliance (CGA) within the ***special permit inspection areas***.
13) TXGT must give a minimum of 14 days notice to the Director, PHMSA Southern Region to enable him/her to observe the excavations relating to Condition numbers 5, 6 (b), 19, 20, 21, 22 and 23 of field activities in the *special permit inspection areas*. Immediate response conditions do not require 14 days notice, but the PHMSA Region Director should be notified by TXGT no later than two business days after the immediate condition is discovered.
14) TXGT must not let this special permit impact or defer any of the operator's assessments for HCAs under 49 CFR Part 192, Subpart O.

15) Within three months following the grant of this special permit and annually[3] thereafter, TXGT must report the following to the Director, PHMSA Southern Region:

a) In the first annual report, TXGT should describe the economic benefits of the special permit including both the costs avoided from not replacing the pipe and the added costs of the inspection program. Subsequent annual reports should address any changes to these economic benefits.

b) In the first annual report, fully describe how the public benefits from energy availability. This should address the benefits of avoided disruptions as a consequence of pipe replacement and the benefits of maintaining system capacity. Subsequent reports must indicate any changes to this initial assessment.

c) The number of new residences, other structures intended for human occupancy and public gathering areas built within the ***special permit inspection areas***.

d) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year in the ***special permit inspection areas.***

e) Any reportable incident, any leak normally indicated on the DOT Annual Report and all repairs on the pipeline that occurred during the previous year in the ***special permit inspection areas***.

f) Any on-going damage prevention initiatives affecting the ***special permit inspection areas*** and a discussion of the success of the initiatives.

g) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

16) At least one cathodic protection (CP) pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. This requirement applies to any HCA within the ***special permit inspection areas***.

17) If any annual CP test station readings on the Main Lines 26-1, 26-2 and 30-1 pipelines within the ***special permit inspection areas*** fall below 49 CFR Part 192, Subpart I requirements, remediation must occur within six months and include a CIS on each side of the affected test station to the next test station and any identified corrosion system

[3] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a Special Permit dated January 21, 2009 must be received by PHMSA no later than January 31, each year beginning in 2010.

modifications to ensure corrosion control. If factors beyond TXGT's control prevent the completion of remediation within six months, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than the end of the six months completion date.

18) Interference Currents Control: Control of induced AC from parallel electric transmission lines and other interference issues in the ***special permit inspection areas***, that may affect the pipeline must be incorporated into the operations of the pipeline and addressed. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place within one year of the date of this special permit.

19) Field Coating: The coatings used on the pipeline and girth weld joints in the ***special permit segments*** must be non-shielding to CP. In the event that the coating type is unknown or is known to shield CP for girth weld joints then TXGT will take special care to:
   a) Analyze ILI logs in the areas of girth welds for potential corrosion indications,
   b) Any ILI corrosion indications above 30% wall loss at girth welds where the coating type is unknown or is known to shield CP, girth weld joints must be exposed and evaluated each time the ILI is run or until the girth weld coating is replaced,
   c) A minimum of two girth weld joints at locations most likely to have shielding and corrosion shall be exposed and evaluated each time ILI is run. If corrosion is found, the next most likely joint is to be exposed and evaluated until no corrosion is found.

20) Anomaly Evaluation and Repair:
   a) <u>General</u>: TXGT must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used.
   b) <u>Dents</u>: TXGT must repair dents to the Main Lines 26-1, 26-2 and 30-1 pipelines in the ***special permit inspection areas*** in accordance with § 192.933 repair criteria. ***Special permit inspection areas*** must have a geometry tool inspection as part of the initial ILI. The geometry tool can be from past ILI inspections. The timing for these dent repairs should follow TXGT O&M Manual but must not be longer than one year after discovery.
   c) <u>Repair Criteria</u>: Repair criteria apply to anomalies located on the Main Lines 26-1, 26-2 and 30-1 pipelines within the ***special permit inspection areas*** when they have been excavated and investigated in accordance with §§ 192.485 and 192.933 as follows: ***Special permit segments*** - repair any anomaly to meet either: (1) a failure pressure ratio (FPR) less than or equal to 1.39 for original Class 1 location pipe in a Class 3 location

operating up to 72% of the specified minimum yield strength (SMYS); (2) an anomaly depth greater than 40% of pipe wall thickness.

i) ***Special permit inspection areas*** - Anomaly evaluations and repairs in the ***special permit inspection areas*** must be performed in accordance with §§ 192.485 and 192.111 incorporating appropriate class location design factors, except HCAs outside of the ***special permit segments*** may be repaired in accordance with § 192.933.

ii) ***Special permit inspection areas*** - the response time must be in accordance with 49 CFR Part 192, Subpart O, the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, *"Managing System Integrity of Gas Pipelines"* (ASME B31.8S) and TXGT's Integrity Management Program.

d) <u>Response Time for ILI Results</u>: The following guidelines provide the required timing for excavation and investigation of anomalies based on ILI results. Reassessment by ILI will "reset" the timing for anomalies not already investigated and/or repaired. TXGT must evaluate ILI data by using either the ASME Standard B31G, *"Manual for Determining the Remaining Strength of Corroded Pipelines"* (ASME B31G), the modified B31G (0.85dL) or R-STRENG for calculating the predicted FPR to determine anomaly responses.

i) ***Special permit segments:***

- <u>Immediate response</u>: Any anomaly within a ***special permit segment*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; (2) an anomaly depth equal to or greater than 80% wall thickness loss.
- <u>One-year response:</u> Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.39; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
- <u>Monitored response</u>: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets both: (1) an FPR greater than 1.39; (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

ii) ***Special permit inspection areas:*** The response time must be in accordance with 49 CFR Part 192, Subpart O, or TXGT's Integrity Management Program, which ever is shorter. Anomaly evaluations and repairs must be performed in accordance with

§§ 192.485 and 192.111 incorporating appropriate class location design factors, except HCA's outside of the ***special permit segments*** may be repaired in accordance with §192.933.

21) TXGT must provide records to PHMSA to demonstrate the girth welds on the Main Lines 26-1, 26-2 and 30-1 pipelines were nondestructively tested at the time of construction in accordance with:

a) The Federal pipeline safety regulations at the time the pipelines were constructed or at least 1% of the girth welds in each ***special permit segment*** were non-destructively tested after construction but prior to the application for this special permit provided at least two girth welds in each ***special permit segment*** were excavated and inspected.

b) If TXGT cannot provide girth weld records to PHMSA to demonstrate either of the above in Condition 21 (a), TXGT must accomplish either (i) or (ii) and (iii) of the following:

   i) Certify to PHMSA in writing that there have been no in-service leaks or breaks in the girth welds on the Main Lines 26-1, 26-2 and 30-1 pipelines within the entire ***special permit inspection areas*** for the entire life of the pipelines, or

   ii) Evaluate the terrain along the ***special permit segments*** for threats to girth weld integrity from soil or settlement stresses and remediate all such integrity threats, and

   iii) Excavate[4], visually inspect and nondestructively test at least two girth welds on the Main Lines 26-1, 26-2 and 30-1 pipelines in each ***special permit segment*** in accordance with the American Petroleum Institute Standard 1104, *"Welding of Pipelines and Related Facilities"* (API 1104) as follows:

      A. Use the edition of API 1104 current at the time the pipelines were constructed, or

      B. Use the edition of API 1104 recognized in the Federal pipeline safety regulations at the time the pipelines were constructed; or

      C. Use the edition of API 1104 currently recognized in the Federal pipeline safety regulations

c) If any girth weld in any of the ***special permit segments*** is found unacceptable in accordance with API 1104, TXGT must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the special

[4] TXGT must evaluate for SCC any time the Main Lines 26-1, 26-2 and 30-1 pipelines are uncovered in accordance with Condition 6 (b) of this special permit.

permit segments based upon the repair findings and the threat to the ***special permit segments***. TXGT must submit the inspection and remediation plan to the Director, PHMSA Southern Region and remediate girth welds in the ***special permit segments*** in accordance with the inspection and remediation plan within 60 days of finding girth welds that do not meet this Condition 21 (c).

d) Additionally, all oxy-acetylene girth welds, mechanical couplings and wrinkle bends in ***special permit segments*** must be removed.

e) TXGT must complete the girth weld testing, and the girth weld inspection and remediation plan, within six months after the grant of this special permit. If factors beyond TXGT's control prevent the completion of these tasks within six months, the tasks must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region not later than six months after the grant of this special permit.

22) TXGT must identify all shorted casings within the ***special permit segments*** not later than six months after the grant of this special permit and classify any shorted casings as either having a "metallic short" (the carrier pipe and the casing are in metallic contact) or an "electrolytic short" (the casing is filled with an electrolyte) using a commonly accepted method such as the Panhandle Eastern, Pearson, DCVG, ACVG or AC Attenuation.

a) Metallic Shorts: TXGT must clear any metallic short on a casing in the ***special permit segments*** not later than six months after the short is identified.

b) Electrolytic Shorts: TXGT must remove the electrolyte from the casing/pipe annular space on any casing in the ***special permit segments*** that has an electrolytic short not later than six months after the short is identified.

c) All Shorted Casings: TXGT must install external corrosion control test leads on both the carrier pipe and the casing in accordance with § 192.471 to facilitate the future monitoring for shorted conditions and may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material which provides a corrosion inhibiting environment provided an assessment and all repairs were completed.

If TXGT identifies any shorted casings within the ***special permit segments,*** they must monitor all casings within the *special permit segments* for shorts at least once each calendar quarter, but at intervals not to exceed 100 days, for four consecutive calendar quarters after the grant of this special permit. The intent is to identify through monitoring the calendar quarter(s) when electrolytic casing shorts are most likely to be identified. TXGT must then monitor all casings for shorts within the ***special permit segments*** at least once each calendar year during the calendar quarter(s) when electrolytic casing shorts are most likely to be identified. Any casing shorts found in the ***special permit segments*** at any time must be classified and cleared as explained above.

23) Pipe Seam Evaluations: TXGT must identify any pipeline in a ***special permit inspection area*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacture of the pipe, or other issues. Once TXGT has identified such issues, they must complete one or all of the following:

   a) TXGT must perform an engineering analysis to determine if there are any pipe seam threats on the Main Lines 26-1, 26-2 and 30-1 pipelines located in the ***special permit inspection area***. This analysis must include the documentation that the processes in 'M Charts' in "*Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*" by Kiefner and Associates updated April 26, 2007 under PHMSA Contract DTFAA-C0SP02120 and Figure 4.2, 'Framework for Evaluation with Path for the Segment Analyzed Highlighted' from TTO-5 "*Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*" by Michael Baker Jr., and Kiefner and Associates, et. al. under PHMSA Contract DTRS56-02-D-70036 were utilized along with other relevant materials. If the engineering analysis shows that the pipe seam issues on the Main Lines 26-1, 26-2 and 30-1 pipelines located in the ***special permit inspection area*** are not a threat to the integrity of the pipeline, TXGT does not have to complete Conditions 23 (b) through 23 (e). If there is a threat to the integrity of the pipeline, then one or more of Conditions 23(b) through 23 (e) must be completed; or

   b) The ***special permit segment*** pipeline must be hydrostatically tested to a minimum pressure of 100 percent SMYS, per 49 CFR Part 192, Subpart J requirements for eight continuous hours, within 1 year of issuance of this special permit if no 49 CFR Part 192, Subpart J had been performed since 1971. The hydrostatic test must confirm no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic issue. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service within 60 days of the failure; or

   c) If the pipeline in the ***special permit inspection area*** has experienced a seam leak or failure in the last 5 years and no hydrostatic test meeting the conditions per 49 CFR Part 192, Subpart J was performed after the seam leak or failure, then a hydrostatic test must be performed within one year after the grant of this special permit on the ***special permit segment*** pipeline; and

d) If the pipeline in the ***special permit segment*** has any LF ERW seam or EFW seam conditions as noted in (i), (ii), or (iii) below, the ***special permit segment*** pipeline must be replaced:

   i) constructed or manufactured prior to 1954 and has had any pipe seam leaks or ruptures in the ***special permit inspection area***, or

   ii) has unknown manufacturing processes, or

   iii) has known manufacturing or construction issues that are unresolved [such as concentrated hard spots, hard heat-affected weld zones, selective seam corrosion, pipe movement that has lead to buckling, have had past leak and rupture issues, or any other systemic issues].

   iv) If the pipeline in the ***special permit segment*** has a reduced longitudinal joint seam factor, below 1.0, as defined in § 192.113 the ***special permit segment*** pipeline must be replaced.

24) Hydrostatic Testing: Main Lines 26-1 ***"Special permit segment 1"*** and 26-2 ***"Special permit segment 2"*** pipelines must be hydrostatically tested to a minimum pressure of 100 percent SMYS, per 49 CFR Part 192, Subpart J requirements for eight continuous hours, and within 1 year of issuance of this special permit. The hydrostatic test must confirm no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to the Director, PHMSA Southern Region PHMSA no later than 60 days after the failure.

25) TXGT must maintain the following records for each ***special permit segment***:

   a) Documentation showing that each ***special permit segment*** has received a § 192.505, Subpart J, hydrostatic test for eight continuous hours and at a minimum pressure of 1.25 X MAOP. If TXGT does not have hydrostatic test documentation, then the ***special permit segment*** must be hydrostatically tested to meet this requirement within one year of receipt of this special permit.

composition of either the American Petroleum Institute Standard 5L, 5LX, or 5LS, *"Specification for Line Pipe"* (API 5L) approved by the 49 CFR § 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR § 192 then the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that does not have mill test reports for the pipe can not be authorized per this special permit.

c) Documentation of compliance with all conditions of this special permit must be kept for the applicable life of this special permit for the referenced ***special permit segments*** and ***special permit inspection areas.***

26) PHMSA may extend the original ***special permit segments*** to include contiguous segments of the Main Lines 26-1, 26-2 and 30-1 pipelines up to the limits of the ***special permit inspection areas*** pursuant to the following conditions. TXGT must:

a) Provide at least 90 days advanced notice to the Director, PHMSA Southern Region and PHMSA Headquarters of a requested extension of the Main Lines 26-1, 26-2 and 30-1 ***special permit segments*** based on actual class location change and include a schedule of inspections and of any anticipated remedial actions. If PHMSA Headquarters or the Regional Director make a written objection before the effective date of the requested special permit segments extension (90 days from receipt of the above notice), the requested special permit extension does not become effective.

b) Complete all inspections and remediation of the proposed special permit segments extension to the extent required of the original the Main Lines 26-1, 26-2 and 30-1 ***special permit segments.***

c) Apply all the special permit conditions and limitations included herein to all future extensions.

27) Certification: A senior executive officer of TXGT must certify in writing the following:

a) That the TXGT pipeline ***special permit inspection areas*** and ***special permit segments*** meets the conditions described in this special permit,

b) That the written manual of O&M procedures for the TXGT pipeline has been updated to include all additional operating and maintenance requirements of this special permit; and

c) That TXGT has implemented all conditions as required by this special permit.

TXGT must send a copy of the certification required in Condition 27 with the required senior executive signature and date of signature to the Director, PHMSA Southern Region within one year of the date of this special permit.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether TXGT has complied with the specified conditions of this special permit.
2) Should TXGT fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require TXGT to comply with the regulatory requirements in 49 CFR § 192.611.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and TXGT to comply with the regulatory requirements in 49 CFR § 192.611.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify TXGT in writing of the proposed action and provide TXGT an opportunity to show cause why the action should not be taken unless PHMSA determines that taking such action is immediately necessary to avoid the risk of significant harm to persons, property or the environment (see 49 CFR § 190.341(h)(2)).
5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR § 1.53.

Issued in Washington, DC on FEB 27 2009.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety