U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT – Class 2 to 3 (using original Class 1 pipe)

Docket Number:	PHMSA-2007-27647
Requested By:	Great Lakes Gas Transmission Limited Partnership
Date Requested:	March 14, 2007
Code Sections:	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 Great Lakes Gas Transmission Limited Partnership (GLGT) waiving compliance from 49 CFR § 192.611(a) for a segment of GLGT's 100 Line south of the Straits of Mackinac in Emmet County, MI 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 Segment and Inspection Area:

Emmet County, MI

PHMSA waives compliance from 49 CFR § 192.611(a) for a natural gas transmission pipeline segment on GLGT's 100 Line pipeline where a change has occurred from a Class 2[1] location to a Class 3 location south of the Straits of Mackinac in Emmet County, MI. This special permit allows GLGT to continue to operate the ***special permit segment*** at its current maximum allowable operating pressure (MAOP) of 974 pounds per square inch gauge (psig).

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

- ***Special permit segment*** - 720 feet of the GLGT 100 Line pipeline from mile post (MP) 709.79 to MP 709.93.

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

Special permit inspection area - the area that extends 220 yards on each side of the centerline along the entire length of the GLGT 100 Line pipeline from GLGT's 36-inch pig launcher at MP 685.31 (approximately 24.48 miles upstream of the ***special permit segment***) to the suction side of GLGT's Boyne Falls Compressor Station (Station No. 11) at MP 722.85 (approximately 12.92 miles downstream of the ***special permit segment).*** [Note: The ***special permit inspection area*** extends approximately 37.54 miles.]

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-2007-27647 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) GLGT must continue to operate the ***special permit segment*** at or below their existing MAOP as follows: 100 Line – MAOP of 974 psig.
2) GLGT must incorporate the ***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. GLGT need not include the ***special permit segment*** described in this special permit in its IMP baseline assessment plan unless those areas meet the conditions of an HCA per § 192.905.
3) GLGT must perform a close interval survey (CIS) of the 100 Line pipeline along the entire length of the ***special permit inspection area*** no 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 GLGT has performed a CIS and remediation on the 100 Line pipeline along the entire length of the ***special permit inspection area*** less than four years prior to the grant of this special permit. If factors beyond GLGT'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 Central Region no later than one year after the grant of this special permit.

4) GLGT must perform periodic CIS of the ***special permit segment*** at the applicable reassessment interval(s) for a "covered segment" determined in concert and integrated with in-line inspection (ILI) in accordance with 49 CFR § 192 Subpart O reassessment intervals as contained in 49CFR §§ 192.937 (a) and (b) and 192.939.
5) GLGT must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey of the ***special permit segment*** no later than one year of the grant of this special permit to verify the pipeline coating conditions and to remediate any integrity issues in the ***special permit segment***. A DCVG or ACVG survey and remediation need not be performed on ***special permit segments*** if GLGT has performed a DCVG or ACVG and remediation on the 100 Line pipeline along the entire length of the ***special permit inspection area*** less than four years prior to the grant of this special permit. GLGT 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. If factors beyond GLGT'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 Central Region no later than one year after the grant of this special permit.
6) GLGT must evaluate the 100 Line pipeline for stress corrosion cracking (SCC) as follows:
   a) GLGT 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 100 Line pipeline along the entire length of the ***special permit inspection area*** according to the requirements of § 192.929 and/or NACE RP 0204-2008 no 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 GLGT has performed an SCCDA of the 100 Line pipeline along the entire length of the ***special permit inspection area*** less than four years prior to the grant of this special permit. If factors beyond GLGT'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 Central Region no later than one year after the grant of this special permit. [GLGT may eliminate this Condition 6 (a), provided GLGT 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*", Sections 1.2.1.1 and 1.2.2].

b) If the threat of SCC exists as determined in Condition 6 (a) and when the GLGT 100 Line pipeline is exposed for any reason in the ***special permit inspection area*** and the coating has been identified as poor during the pipeline examination, then the GLGT 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. GLGT must keep coating records at all excavation locations in the ***special permit inspection areas*** to demonstrate the coating condition.

7) GLGT must submit the DCVG, CIS and SCCDA [or other approved methods of determining SCC] findings including remediation actions in a written report to the Director, PHMSA Central Region, no later than two years after the grant of this special permit.

8) GLGT 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 100 Line pipeline along the entire length of the ***special permit inspection area*** at a frequency consistent with 49 CFR Part 192, Subpart O.

9) GLGT must amend applicable sections of its O&M manual(s) to incorporate the inspection and reassessment intervals by CIS of the 100 Line pipeline ***special permit segment*** at a frequency consistent with 49 CFR Part 192, Subpart O.

10) The assessments of the 100 Line pipeline along the entire length of the ***special permit inspection area*** using ILI must conform to the required maximum reassessment intervals specified in § 192.939.

11) GLGT must schedule ILI reassessment dates for the 100 Line pipeline along the entire length of the ***special permit inspection area*** according to § 192.939 by adding the required time interval to the previous assessment date.

12) GLGT must ensure its damage prevention program incorporates the applicable best practices of the Common Ground Alliance (CGA) within the ***special permit inspection area***.

13) GLGT must give a minimum of 14 days notice to the Director, PHMSA Central Region to enable him/her to observe the excavations relating to Conditions 5, 6 (b), 19, 20, 21, 22 and 23 of field activities in the ***special permit inspection area***. Immediate response conditions do not require the 14 days notice, but the PHMSA Region Director should be notified by GLGT no later than two business days after the immediate condition is discovered.

14) GLGT 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[2] thereafter, GLGT must report the following to the Director, PHMSA Central Region:

   a) In the first annual report, GLGT 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 area***.

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[2] 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.

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 area***.

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 area***.

f) Any on-going damage prevention initiatives affecting the ***special permit inspection area*** 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 area***.

17) If any annual CP test station readings on the 100 Line pipeline within the ***special permit inspection area*** 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 modifications to ensure corrosion control. If factors beyond GLGT'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 Central 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 area***, 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 segment*** 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 GLGT must 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) General: GLGT must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used.

b) Dents: GLGT must repair dents to the 100 Line pipeline in the ***special permit inspection area*** in accordance with § 192.933 repair criteria. ***Special permit inspection area*** 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 GLGT's O&M Manual but must not be longer than one year after discovery.

c) Repair Criteria: Repair criteria apply to anomalies located on the 100 Line pipeline within the ***special permit inspection area*** when they have been excavated and investigated in accordance with §§ 192.485 and 192.933 as follows:

i) ***Special permit segment*** - repair any anomaly that meets either: (1) a failure pressure ratio (FPR) less than or equal to 1.39 for Class 2[3] 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.

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

iii) ***Special permit inspection area*** - the response time must be in accordance with 49 CFR Part 192, Subpart O, the applicable edition of the American Society of

[3] This segment was originally a Class 1 area that was upgraded to Class 2 via § 192.611 (a) hydrostatic test. Pipe is original class 1 with a design factor of 0.72.

Mechanical Engineers Standard B31.8S, *Managing System Integrity of Gas Pipelines* (ASME B31.8S) and GLGT's Integrity Management Program.

d) Response Time for ILI Results: 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. GLGT 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 segment:***

- Immediate response: 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.
- One-year response: 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.
- Monitored response: Any anomaly within a ***special permit segment*** with original Class 1[4] 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 area:*** The response time must be in accordance with 49 CFR Part 192, Subpart O, or GLGT's Integrity Management Program, which ever is shorter. Anomaly evaluations and repairs be performed in accordance with §§ 192.485 and 192.111 incorporating appropriate class location design factors, except HCAs outside of the ***special permit segment*** may be repaired in accordance with § 192.933.

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

21) GLGT must provide records to PHMSA to demonstrate the girth welds on the 100 Line pipeline 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 GLGT cannot provide girth weld records to PHMSA to demonstrate either of the above in Condition 21 (a), GLGT 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 100 Line pipeline within the entire ***special permit inspection area*** for the entire life of the pipeline; or

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

   iii) Excavate[5], visually inspect and nondestructively test at least two girth welds on the 100 Line pipeline in the ***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 segment*** is found unacceptable in accordance with API 1104, GLGT must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segment*** based upon the repair findings and the threat to the ***special permit segment***. GLGT must submit the inspection and remediation plan to the Director,

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[5] GLGT must evaluate for SCC any time the 100 Line pipeline is uncovered in accordance with Condition 6 (b) of this special permit.

PHMSA Central Region and remediate girth welds in the ***special permit segment*** 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) GLGT 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 GLGT'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 Central Region no later than six months after the grant of this special permit.

22) GLGT must identify all shorted casings within the ***special permit segment*** no 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: GLGT must clear any metallic short on a casing in the ***special permit segments*** no later than six months after the short is identified.

b) Electrolytic Shorts: GLGT must remove the electrolyte from the casing/pipe annular space on any casing in the ***special permit segment*** that has an electrolytic short no later than six months after the short is identified.

c) All Shorted Casings: GLGT 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 GLGT identifies any shorted casings within the ***special permit segment***, they must monitor all casings within the ***special permit segment*** 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. GLGT must then monitor all casings for shorts within the ***special permit segment*** 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 segment*** at any time must be classified and cleared as explained above.

23) Pipe Seam Evaluations: GLGT 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 GLGT has identified such issues, they must complete one or all of the following:

a) GLGT must perform an engineering analysis to determine if there are any pipe seam threats on the 100 Line pipeline 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 100 Line pipeline located in the ***special permit inspection area*** are not a threat to the integrity of the pipeline, then GLGT 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 one 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 five 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***,

   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].

e) 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) Not/ Applicable (N/A) – no condition

25) GLGT 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 GLGT 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.

b) Documentation (mill test reports) showing that the pipe in each ***special permit segment*** meets the wall thickness, yield strength, tensile strength and chemical 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 segment*** to include contiguous segments of the 100 Line pipeline up to the limits of the ***special permit inspection area*** pursuant to the following conditions. GLGT must:

a) Provide at least 90 days advanced notice to the Director, PHMSA Central Region and PHMSA Headquarters of a requested extension of the 100 Line pipeline ***special permit segment*** based on actual class location change and include a schedule of inspections and of any anticipated remedial actions. If PHMSA Headquarters or Central Regional Director makes a written objection before the effective date of the requested special permit segment 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 segment extension to the extent required of the original 100 Line pipeline ***special permit segment.***

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

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

a) That the GLGT pipeline ***special permit inspection area*** and ***special permit segment*** meets the conditions described in this special permit,

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

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

GLGT 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 Central 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 GLGT has complied with the specified conditions of this special permit.
2) Should GLGT fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require GLGT 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 require GLGT 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 GLGT in writing of the proposed action and provide GLGT 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