U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

FINAL ENVIRONMENTAL ASSESSMENT
and
FINDING OF NO SIGNIFICANT IMPACT

Special Permit Information:

Docket Number:	PHMSA-2016-0158
Requested By:	Tennessee Gas Pipeline Company, LLC
Operator ID#:	19160
Original Date Requested:	December 8, 2016
Issuance Date:	April 11, 2022
Code Section(s):	49 CFR 192.611(a) and (d), and 192.619(a)

I. Background

The National Environmental Policy Act (NEPA), 42 United States Code (USC) 4321 – 4375 et seq., Council on Environmental Quality Regulations, 40 Code of Federal Regulation (CFR) 1500-1508, and U.S. Department of Transportation (DOT) Order No. 5610.1C, requires the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] to analyze a proposed action to determine whether the action will have a significant impact on the human environment. PHMSA analyzes special permit requests for potential risks to public safety and the environment that could result from our decision to grant, grant with additional conditions, or deny the request. As part of this analysis, PHMSA evaluates whether a special permit would impact the likelihood or consequence of a pipeline failure as compared to the operation of the pipeline in full compliance with the Federal pipeline safety regulations. PHMSA's environmental review associated with the special permit application is limited to

[1] References to PHMSA in this document means PHMSA OPS.

impacts that would result from granting or denying the special permit. PHMSA developed this assessment to determine what effects, if any, our decision will have on the environment.

Pursuant to 49 U.S.C. 60118(c) and 49 CFR 190.341, PHMSA may only grant special permit requests that are not inconsistent with pipeline safety. PHMSA will impose conditions in the special permit if we conclude they are necessary for safety, environmental protection, or are otherwise in the public interest. If PHMSA determines that a special permit will be inconsistent with pipeline safety or is not justified, the application will be denied.

The purpose of this final environmental assessment (FEA) is to comply with NEPA for the Tennessee Gas Pipeline Company, LLC (TGP)[2] application for a special permit request to waive compliance with the requirements of 49 CFR 192.611(a) "Change in class location: Confirmation or revision of maximum allowable operating pressure" for approximately 0.648 miles of 30-inch diameter, and 0.074 miles of 31-inch gas transmission pipelines located in New York and Texas. This FEA and finding of no significant impact (FONSI) are prepared by PHMSA to assess the pipeline special permit request, in accordance with 49 CFR 190.341, and is intended to specifically analyze any environmental impact associated with the waiver of 49 CFR 192.611(a) and (d), and 192.619(a).

II. Introduction

Pursuant to 49 United States Code 60118(b) and 49 CFR 190.341, TGP submitted an application for a special permit to PHMSA on December 8, 2016, requesting that PHMSA waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) to permit TGP to maintain the maximum allowable operating pressure (MAOP) of three (3) pipeline segments located in Wyoming County, New York and one (1) pipeline segment located in Harris County, Texas, for which the class location has changed from Class 1 to Class 3 due to a population density increase near the pipeline. Without the special permit, 49 CFR 192.611(a) will require TGP to replace the ***special permit segments*** or reduce the pipeline MAOP.

[2] Tennessee Gas Pipeline Company, LLC is owned by Kinder Morgan, Inc.

PHMSA will grant a special permit to waive certain regulatory requirements where it is consistent with pipeline safety and which is typically contingent on the performance of additional measures beyond minimum Federal pipeline safety regulations, in accordance with 49 CFR 190.341.

III. Regulatory Background

PHMSA regulations at 49 CFR 192.611(a) require that an operator confirm or revise the MAOP of a pipe segment that is in satisfactory condition when the hoop stress of the segment is no longer commensurate with class location. Under 49 CFR 192.611(a), an operator may be required to reduce the operating pressure of a pipe segment, or alternatively, may have to replace the pipe in order to maintain the MAOP. Under 49 CFR 192.619(a)(2) the ***special permit segment*** would be required to be pressure tested to 1.5 times MAOP for eight (8) hours. Below are the relevant text of 49 CFR 192.611(a) and (d) and 192.619(a):

<u>**49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.**</u>

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding

hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

49 CFR 192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?

(a)(2)(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Table 1 to Paragraph (a)(2)(ii)

Class location	Factors, [1] segment -			
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

- Which requires Class 3 location pipe to be pressure tested to 1.5 times MAOP.

IV. Purpose and Need

TGP requested a special permit, and PHMSA has reviewed the special permit application for implementing increased integrity management (IM) activities in lieu of replacing pipe within the ***special permit segments*** located on TGP's 31-inch diameter Line 100-2 Pipeline located in Harris County, Texas and the 30-inch diameter Line 200-2 Pipelines in Wyoming County, New York, where the class location has changed from a Class 1 to a Class 3 location, and to include contiguous ***special permit segment*** extensions that may experience further development and class change in the future. This special permit consists of four (4) ***special permit segments*** and waives the requirements of 49 CFR Part 192.611(a) and (d) with implementation of the special permit conditions. The class location in the ***special permit segment*** originally changed from Class 1 to Class 3 in 2014. The special permit that PHMSA is issuing will allow TGP to maintain the MAOP of three (3) pipeline segments located in Wyoming County, New York and one (1) pipeline segment located in Harris County, Texas, for which the class location has changed from Class 1 to Class 3 due to population density increase. Without the special permit, 49 CFR 192.611(a) will require TGP to replace the four (4) ***special permit segments*** or reduce pipeline MAOP.

Attachments A1 through **A4** are general maps that includes the TGP Line 100-2 and 200-2 Pipeline route maps showing the ***special permit segments*** and ***special permit inspection areas***.

PHMSA is granting the special permit, which includes conditions for the 3,809.03 feet (approximately 0.721 miles) of ***special permit segments*** and the 74.30 miles of ***special permit inspection areas***. The special permit allows continued operation at the existing MAOP in the event of future class changes within the ***special permit inspection areas*** (***special permit segment extensions***) if the ***special permit segment extensions*** meet the special permit conditions applicable to ***special permit segments***.

V. Site Description

On the condition that TGP complies with the terms and conditions set forth below, the special permit waives compliance from 49 CFR 192.611(a) and (d) and 192.619(a)(2) for approximately 0.721 miles of gas transmission pipelines on the 31-inch diameter Line 100-2 and the 30-inch diameter Line 200-2 Pipelines. In each location, the class location has changed from Class 1 to Class 3 location in Wyoming County, New York and Harris County, Texas.

VI. Special Permit Segments and Special Permit Inspection Areas

This special permit pertains to the specified ***special permit segments*** and corresponding ***special permit inspection areas*** defined in this section. This special permit allows TGP to maintain the current MAOP of 750 pounds per square inch gauge (psig) on the 31-inch diameter Line 100-2 and 878 psig on 30-inch diameter Lines 200-2 Pipelines.

1) **Special Permit Segment**:

   This special permit applies to the ***special permit segments*** in **Table 1 – Special Permit Segments** and are identified using the TGP survey station (SS) references.

Table 1 – Special Permit Segments										
Special Permit Segment Number[3]	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)
404	31	100-2	389.08	20-2 – 36818	20-2 – 37207	Harris, TX	1	1948	DSAW	750
418	30	200-2	1,425.64	231-2 – 341	231-2 – 1782	Wyoming, NY	1	1991	DSAW	878
419	30	200-2	557.16	231-2 – 2153	231-2 – 2710	Wyoming, NY	21	1991	DSAW	878
420	30	200-2	1,437.15	231-2 – 7917	231-2 – 9354	Wyoming, NY	4	1991	DSAW	878

Notes: Double Submerged Arc Welded (DSAW) is a pipe longitudinal weld seam type.

2) **Special Permit Inspection Area**:

The ***special permit inspection areas*** are defined as the area that extends 220 yards on each side of the centerline as listed in **Table 2 – Special Permit Inspection Areas**.

Table 2 – Special Permit Inspection Areas							
Special Permit Inspection Area Number	Special Permit Segment(s) Included	Outside Diameter (inches)	Line Name	Master Segment Name	Start Survey Station (SS)	End Survey Station (SS)	Length[4] (miles)
1	404	31	100-2	17-2D to 20-2A (END LOOP)	17-2S LAUNCHER – 1376.71	20-2 RECIEVER – 39038.15	35.63
2	418, 419, 420	30	200-2	229-2 TO 232-2 (END OF LOOP)	229-2S – 336.8	232-2 – 17315.4	38.67

PHMSA is granting this special permit request based on this document and the "Special Permit Analysis and Findings" document, which is incorporated by reference into this document and can be read in its entirety in Docket No. PHMSA-2016-0158 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

---

3 On February 3, 2022, TGP rescinded requested ***special permit segments number 401, 402, 403, 405, 406, 407, 409, 410, 411, 412, 413, 414, 415, 416, 417, 421, 422, 423, 428, and 429.*** ***Segment number 408*** was also rescinded by TGP on February 7, 2022. These segments were withdrawn at the request of PHMSA.

4 If the ***special permit inspection area*** footage does not extent from launcher to receiver then the ***special permit inspection area*** would need to be extended.

VII. Alternatives

1) <u>Alternative 1: "No Action" Alternative</u>

Denial of the special permit will require the replacement and pressure testing of all the pipeline segments associated with this special permit request, which includes approximately 10.193 miles of mainline pipe. If TGP opted not to replace the relevant segments of pipeline, 49 CFR 192.611 requires a reduction in the pipeline MAOP.[5]

2) **<u>Alternative 2: "Selected" Alternative</u>**

PHMSA will grant a special permit with conditions to maintain pipeline integrity. All of the ***special permit segments*** must be treated as high consequence areas (HCAs) under an integrity management program (IMP; 49 CFR Part 192, Subpart O) as a requirement of the special permit.

All of the special permit conditions are attributes of a robust IMP. These special permit conditions include conducting periodic: Close interval surveys, cathodic protection (CP) reliability improvements, stress corrosion cracking assessment, running inline inspection (ILI) assessments (smart pigs), interference current control surveys, remediating ILI findings through anomaly evaluation and repairs, pipe seam evaluations, pipe properties records review and documentation, and maintaining line-of-sight markers. Many of these integrity activities are currently required in 49 CFR Part 192, Subpart O, an IMP to manage HCAs at specified reassessment intervals. The assessment and reassessment intervals, the level of remediation and the maintenance activities required in a special permit are more stringent to maintain pipe integrity and protect both the public and the environment for the class location units in which the ***special permit segments*** are located.

<u>Overview of Special Permit Conditions</u>:

To provide an equivalent level of safety in the absence of either lowering the pipeline operating pressure or upgrading the pipe, this special permit has additional operations and

---

[5] These regulatory options are specified in 49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

maintenance requirements (conditions) which are intended to decrease the likelihood of a release of gas. PHMSA believes that these additional measures designed to prevent leaks and ruptures will ensure that the special permit is not inconsistent with pipeline safety. This section provides an overview of the special permit conditions. For TGP specific technical requirements, see the special permit conditions in **Attachment D – Special Permit Conditions**.

1) **<u>Current Status of Pipe in the Ground</u>**

   To ensure that key characteristics of the pipe currently installed in a ***special permit segment*** are known, records that confirm pipe specifications, successful pressure tests, and girth weld non-destructive tests are required. Should records be unavailable or unacceptable, additional activities as detailed in the special permit must be completed. If these additional activities are not completed or should pipe be discovered that does not meet specific requirements of eligibility, the ***special permit segment*** must be replaced.

2) **<u>Operating Conditions</u>**

   The ***special permit inspection area*** must continue to be operated at or below the existing MAOP until a restoration or uprating plan has been approved, if allowed by the special permit. To ensure compliance with special permit conditions, TGP's Operations and Maintenance Manual (O&M), IMP, and Damage Prevention (DP) program must be modified to implement the special permit conditions. In addition, PHMSA must approve any long-term flow reversals that will impact a ***special permit segment***.

3) **<u>Threat Management</u>**

   Threats are factors that can lead to the failure of a pipeline. Activities are required to identify, assess, remediate, and monitor threats to the pipeline.

   a) **General activities.** TGP must perform annual data integration and identification of threats to which the ***special permit inspection area*** is susceptible. These activities must include integrity assessments with specific ILI tools, strict anomaly repair criteria, and appropriate environmental assessment and permitting. Additional integrity assessment methodologies may be used if allowed by the special permit.

Integrity assessments must then be conducted periodically at an interval determined in the special permit for each threat identified.

b) **External corrosion control requirements.** The special permit requires additional activities to monitor and mitigate external corrosion. These activities include installation and annual monitoring of CP test stations, periodic close interval surveys (CIS), and clearing or remediating shorted casings that may impede CP effectiveness. These activities ensure the appropriate level of CP is reaching the pipeline in areas where coating loss or damage has occurred in order to prevent or mitigate external corrosion. In addition, TGP will be required to develop and implement a plan that identifies and remediates interference from alternating or direct current (AC/DC) sources (such as high-voltage powerlines) that could adversely impact the effectiveness of CP.

c) **Internal corrosion control requirements.** The special permit includes gas quality specifications to mitigate internal corrosion because internal corrosion is highly dependent on the quality of the gas transported within the pipeline.

d) **Stress corrosion cracking (SCC) requirements.** To ensure that SCC is discovered and remediated, any time a pipe segment is exposed during an excavation TGP must examine coating to determine type and condition. If the coating is in poor condition, TGP must conduct additional SCC analysis. If SCC is confirmed, TGP must implement additional special permit defined remediation and mitigation.

e) **Pipe seam requirements.** TGP must perform an engineering integrity analysis to determine susceptibility to seam threats. TGP must conduct an assessment for any ***special permit segment*** with an identified seam threat to ensure the issue is not systemic in nature.

f) **External pipe stress requirements.** Upon identification of any source of external stress on the pipeline (such as soil movement), TGP must develop procedures to evaluate and periodically monitor these stresses.

g) **Third-party specific requirements.** To assist in identifying the pipeline location and minimizing the chance of accidental pipeline strikes, TGP must install and maintain line-of-site markers for the pipeline. TGP must perform mitigation activities for any location where a depth-of-cover survey shows insufficient soil cover.

4) **Consequence Mitigation**

To ensure quick response and decreased adverse outcome in the event of a failure, each side (upstream and downstream) of the ***special permit segment*** must have and maintain operable automatic shutdown valves (ASV) or remote-controlled valves (RCV). TGP must monitor valves through a control room with a supervisory control and data acquisition (SCADA) system. In addition to the mainline valves, should a crossover or lateral connect between the valve locations, additional isolation valves may be required. To ensure a leak is discovered promptly, leakage surveys are required twice a year.

5) **Gas Leakage Surveys and Remediation**

The ***special permit segment*** and ***special permit inspection area*** have requirements in the special permit to conduct leakage surveys more frequently than is presently required in 49 CFR 192.706. Gas leakage surveys using instrumented gas leakage detection equipment must be conducted along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher, and ILI receiver facilities in each ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. The type of leak detection equipment used, survey findings, and remediation of all instrumented gas leakage surveys must be documented by TGP. The special permit will require a three-step grading process with a time interval for remediation based upon the type of leak.

6) **Post Leak or Failure**

Should an in-service leak occur, the leak must be graded and remediated as required in the permit. In addition, for all in-service or pressure test leak/failure(s), TGP must conduct a root cause analysis to determine the cause. If the cause is determined to be systemic in nature, TGP must implement a remediation plan or the ***special permit segment*** must be replaced, as determined by the special permit specific conditions.

7) **Class Location Study and Potential Extension of Special Permit Segment**

TGP must conduct a class location study at an interval specified in the special permit. This allows TGP to quickly identify extended locations that must comply with the ***special permit segment*** requirements. TGP may extend a ***special permit segment*** with proper notification, update of the FEA, and implementation of all requirements in the special permit.

8) **PHMSA Oversite and Management**

PHMSA maintains oversight and management of each special permit. This includes annual meetings with executive level officers on special permit implementation status, written certification of the special permit, special permit required notification of planned activities, notification of root cause analysis results, and notification prior to certain excavation activities so that PHMSA may observe.

9) **Documentation**

The special permit holder must maintain documentation that supports compliance with special permit conditions for the life of the pipeline.

VIII. Affected Resources and Environmental Consequences

Potential risks from the waiver to pipeline integrity will be analyzed for each ***special permit segment*** to evaluate the potential for impacts or increased risk to safety or environmental resources.

1) **Affected Resources and Environmental Consequences of the Selected Action**

Will a special permit benefit the public? If so, please explain how.

Allowing TGP to avoid pipeline replacement while requiring compliance with special permit conditions including integrity management provides safety to the public, but also has far fewer environmental impacts, including decreased greenhouse gas (GHG) emissions. To replace a pipeline, TGP must blowdown the entirety of a segment of pipe between two (2) isolating valves (approximately 5 to 15 miles) or install stopples to reduce the segment length in order to replace any small portion of pipe (i.e., 200 feet) in that segment. In a blowdown, the operator releases to atmosphere the entire contents (pure natural gas) of the pipeline. These blowdown emissions vary depending upon the diameter of the pipeline and operating pressure.

Safety:

a) Describe potential safety risks that could be associated with waiving the cited regulations. How could those risks be relevant to the operation and operation history of this pipeline? How will the protections normally provided by the regulation be provided under the special permit, if granted?

Class locations are based upon the population (dwellings for human occupancy) within a "class location unit" which is defined as an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile of pipeline. These locations are determined by surveying the pipeline for population growth. The more conservative safety factors are required as dwellings for human occupancy (population growth) increases near the pipeline. TGP must conduct surveys and document population growth within 220 yards on either side of the pipeline. A higher population along the pipeline may trigger any of the following for the ***special permit segment*** with the higher population: A reduced MAOP, a new pressure test at a higher pressure, or new pipe with stronger pipe (through pipe wall thickness or higher steel strength) to protect against integrity risks to occupants along the ***special permit segment***.

The special permit conditions are designed to identify and mitigate integrity issues that could threaten the pipeline segment and cause failure. The effect of the monitoring and maintenance requirements in the special permit conditions will protect the integrity of the pipe and the population living near the pipeline segment to a similar degree of a lower MAOP, new pressure test, or a thicker walled or higher-grade-strength pipe without the special permit integrity management (IM) protections.

The safety risk with respect to this request for a special permit focuses on maintaining the integrity of the pipeline and on the risk, it poses to the increased population near the pipeline to mitigate a possible failure of the pipeline. Granting this special permit does not increase the potential impact radius (PIR) the radius of a circle within which the potential failure of the pipeline could have significant impact on people or property) of the pipeline. However, the risk from the increased human population around the pipeline is mitigated through implementation of the special permit conditions.

TGP must implement the special permit conditions to maintain pipeline integrity on the ***special permit segment*** and ***special permit inspection area*** as defined in the special permit and for the duration of the special permit.

Full implementation of the conditions in the special permit by TGP will provide an equivalent level of safety for the public and environment. The ***special permit segment*** will be treated as an HCA with the additional risk analysis and remedial activities associated with this designation. The special permit also includes a number of conditions that address potential safety threats and risks. Among these are incorporation of these ***special permit segments*** into the Kinder Morgan Integrity Management Program, additional close interval corrosion surveys, additional CP monitoring, a more comprehensive stress corrosion cracking assessment program, an ILI program with intervals not to exceed seven (7) years, anomaly evaluation and repair with more stringent remediation criteria, additional testing and remediation of interference currents caused by induced alternating current sources, pipe seam evaluations, criteria for the identification of pipe properties, installation of line-of-sight markers, and the integration of all inspection and remediation data. This comprehensive list of additional risk related conditions incorporated in the special permit is intended to provide for a significant added level of safety for the existing pipeline segments.

b) Will operation under a special permit change the risk of rupture or failure?

Operation under the special permit is not expected to have an additional impact on the risk of failure or rupture as the operating conditions of the pipeline segments have not changed. ***Special permit segments*** must be inspected at intervals similar to IMP intervals, which will maintain the integrity of the pipe segments over the life of the special permit.

c) If a failure occurred, will consequences and spill or release volumes be different if PHMSA granted the permit?

The consequences of any spill or release will not be impacted as a result of the special permit and the potential for such an event is expected to be less likely with the added safety programs noted above.

d) For Part 192 special permit request, will the Potential Impact Radius (PIR) of a rupture change under the special permit? Please calculate and provide the PIR data, if applicable. Will more people be affected by a failure if PHMSA granted the permit?

The PIR, as calculated in accordance with 49 CFR 192.903, does not change under the special permit since maximum allowable operating pressure and pipe diameter will not change, thus there is no additional impact on the public.

e) Will operation under the special permit have an effect on pipeline longevity or reliability? Will there be any life cycle or maintenance issues?

Operation under the special permit conditions provide an additional level of safety and will have a positive impact on pipeline longevity and reliability. TGP does not anticipate any deleterious life cycle or maintenance issues related to operation of the pipeline with the special permit.

Environmental Impacts:

a) Explain how operation under the special permit will impact the environment as compared to the status quo in the absence of a special permit, either positively, negatively, or not at all.

Increased maintenance, monitoring, and repair standards required by the special permit conditions could lead to increased yet sporadic and temporary vehicle presence, excavation activity, emissions, and noise along the four (4) ***special permit segments*** and their ***special permit inspection areas*** throughout the duration of the special permit. Unless mitigated, exposed soil resulting from excavation can cause increased airborne dust, erosion, and siltation of nearby waterways. In any single location, the impacts will likely be minimal and temporary. The special permit conditions are designed and intended to decrease the likelihood of a pipeline anomaly forming or increasing to a severity that could result in pipeline failure.

Approval of the special permit will have a positive impact for those units that do not require pressure testing or replacement, since TGP's activities will have negligible, if any, environmental impact. TGP will avoid disturbing the right of way of property owners except for the additional inspections that may be required to satisfy the conditions of the special permit, such as those related to the IMP for HCAs, additional verification digs, and potential anomaly evaluations/repairs.

For each individual maintenance activity, TGP will evaluate the potential environmental consequences and affected resources of land disturbances and water body crossings caused by construction activities (including adding, modifying, replacing, or removing any facility) for the related environmental permits associated with any TGP activity. This evaluation is outlined in Kinder Morgan's Operating and Maintenance Procedure (O&M) 1205: Land Disturbance, Construction, and Environmental Permits, and referenced forms and procedures. This procedure requires obtaining the required permits prior to conducting any construction activity. These procedures ensure that all activities resulting in land disturbances or construction of new or modified facilities comply with the requirement to obtain all applicable environmental permits and other applicable environmental authorizations. These procedures contain information required to identify activities subject to Federal, state, and local environmental authorizations related to the work and to obtain those authorizations. The procedures require a review by TGP Environmental Services staff prior to the start of work, incorporation of environmental requirements into the project implementation, and ensuring outstanding (environmental) requirements are incorporated into facility operation.

If the activities do not qualify under the requirements of 2.55(a) or 2.55(b) facilities or the blanket certificate, TGP will pursue authorization in accordance with Section 7 of the Natural Gas Act.[6]

b) Explain whether and how operation under the special permit will impact each of the environmental resources set out in the Site Description portion of this document: land

[6] See **Attachment B**.

use planning, surface waters (including wetlands), drinking water, soils and vegetation, wildlife habitats (including fisheries), cultural resources, socioeconomics, Native Americans, etc.? Focus on environmental aspects that are impacted. Are there any geologic hazards? Will any of these impacts be significant?

As already noted, this special permit involves pipeline facilities at various locations. Airborne dust emissions, erosion, and siltation to nearby waterbodies can result from exposed soil that exists during excavation activities that may be required to comply with the IM conditions. These impacts will be addressed and mitigated in accordance with the applicable Kinder Morgan procedures and Federal Energy Regulatory Commission (FERC or Commission) requirements, see **Attachment B**. Approval of the special permit request will avoid disturbance to the environment, public roadways, businesses, and homes since pipe replacement will not be required.

c) Discuss direct, indirect, and cumulative impacts.

The majority of the pipeline segments addressed by this special permit have been buried and undisturbed for many years. The current pipeline cover has therefore returned to its original state in most cases. Impacts resulting from pressure testing, anomaly repairs, or pipe replacement will be temporary in nature and the pipeline right of way will be restored in accordance with required environmental regulations. Direct, indirect, or cumulative impacts associated with activities related to the special permit or denial of the special permit will not be significant.

d) Briefly summarize environmental aspects that will not be impacted. Explain why these resources won't be impacted.

If the ***special permit segment*** does not require pressure testing, anomaly repair, or pipe replacements, it will be operated in nearly the same manner as it is currently operated. The special permit will allow the ***special permit segments***, approximately 0.721 miles of pipeline, to remain in their current state and not require excavation or disruption of landowner activities. Unless localized excavations are needed, right of way activities (such as additional pipeline markers) may increase in frequency due to the special permit conditions, but it is anticipated that there will be a very minimal added environmental impact related to those activities, and the intention of these maintenance activities is to avoid pipeline leaks or failures. All ILI tool inspections to determine any pipeline integrity issues due to corrosion or third-party damage would be propelled down the pipeline by gas flow volumes pushing the ILI tools through the pipeline segment. Other IM inspections will be performed along the ***special permit segment*** right of way.

e) Explain whether and how each of these safety measures addresses the safety risks and environmental impacts, if any, of granting the permit.

Each of the special permit conditions have been included and designed to address the anticipated safety risks and environmental impacts of the TGP ***special permit segments*** covered by the special permit.

f) Explain whether there will be any safety risks or environmental impacts beyond those that will exist in the absence of a special permit.

There are currently no known safety threats or risks or environmental impacts that are not addressed by the special permit conditions. The ***special permit segments*** included in the special permit are currently operating safely and are expected to continue to perform in that same manner with implementation of the special permit conditions by TGP.

g) Will implementation of the safety measures themselves have any environmental impacts? If so, will they be significant? Discuss direct, indirect, and cumulative impacts.

The additional safety measures provided by the special permit conditions are not expected to have any significant environmental impacts other than the potential issues already noted that are related to the required pressure tests and/or pipe replacements. TGP follows a rigorous procedural process as dictated by Federal, state, and local entities to assure compliance with all environmental regulations and requirements as outlined in this prior section.

PHMSA has reviewed the 49 CFR Part 192 requirements for replacing the pipeline and the conditions of the special permit including integrity management practices and considers both to have similar environmental and right-of-way impacts. These impacts will be mitigated by following the FERC procedures outlined in **Attachment B**.

TGP will submit an annual report to FERC pursuant to Section 2.55(b) concerning replacement activities performed in the prior calendar year that were exempt from the advance notification requirements as specified in Section 2.55(b)(2). The following items are provided to FERC:

(i) A brief description of the pipeline facilities to be replaced (including pipeline size and length, compression horsepower, design capacity, and cost of construction);

(ii) Current U.S. Geological Survey 7.5-minute series topographic maps showing the location of the facilities to be replaced; and

(iii) A description of the procedures to be used for erosion control, revegetation and maintenance, and stream and wetland crossings.

TGP will submit an annual report of Blanket Certificate Activities performed pursuant to Sections 157.208, and 385.2011 of the FERC regulations. The following information will be provided pursuant to the applicable blanket certificate regulation:

- Section 157.208 (Construction, acquisition, operation, replacement, and miscellaneous rearrangement of facilities):

  (1) A description of the facilities installed pursuant to this section, including a description of the length and size of pipelines, compressor horsepower, metering facilities, taps, valves, and any other facilities constructed;

  (2) The specific purpose, location, and beginning and completion date of construction of the facilities installed, the date service commenced, and, if applicable, a statement indicating the extent to which the facilities were jointly constructed;

  (3) The actual installed cost of each facility item listed pursuant to paragraph (e)(1), separately stating the cost of materials and labor as well as other costs allocable to the facilities;

  (4)(i) A description of the contacts made, reports produced, and results of consultations which took place to ensure compliance with the Endangered Species Act, the National Historic Preservation Act and the Coastal Zone Management Act;

(ii) Documentation, including images, that show restoration of work areas is progressing appropriately;

(iii) A discussion of problems or unusual construction issues, including those identified by affected landowners, and corrective actions taken or planned; and

(5) For acquisitions of facilities:

(i) A statement referencing the date of issuance, docket number, and title of the proceeding for any certificate issued by the Commission authorizing the facilities acquired; and

(ii) The amounts recorded in the accounts of the vendor (seller or lessor) that apply to the facilities acquired and the accumulated provisions for depreciation, depletion, and amortization.

h) Environmental Justice

PHMSA has analyzed the issuance of the special permit for environmental justice impacts. Because the special permit will reduce environmental impacts and improve safety in the ***special permit segments*** with a low population density and pipe integrity that allows usage of IM to avoid pipe removal or replacement of the existing pipe, no negative impact will occur to any population, including environmental justice communities with higher concentrations of low-income and/or minority populations. Furthermore, although minor increases in excavation activities could occur in the ***special permit inspection areas***, the special permit conditions will increase the level of safety. Even though the ***special permit inspection areas*** have not currently undergone an increase in population density necessary for a class location change, these segments will benefit from higher standards for inspection, maintenance, and repair required under the special permit. Therefore, this action is consistent with the DOT Order on Environmental Justice, "Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," DOT 5610.2C May 14, 2021.

i) Climate Change

The issuance of the special permit will result in avoiding the release of unburned methane gas, a potent GHG. If the special permit was denied and TGP had to replace the relevant segments of pipeline, TGP would have to blowdown the entirety of a segment of pipe between two (2) isolating valves at a reduced pressure in order to replace any small portion of pipe (i.e. 200 feet) in that segment. In a blowdown, the operator releases to atmosphere the entire contents (pure natural gas) of the pipeline. The quantity of blowdown emissions depends upon the diameter of the pipeline and operating pressure. However, increased monitoring, maintenance, and repair activities in the ***special permit inspection areas*** could offset some of the gains of avoiding blowdown. These conditions are designed to reduce the likelihood of a pipeline failure, which could have catastrophic safety and environmental impacts.

2) **Comparative Environmental Impacts of Alternatives**

If the special permit was not granted for any of the ***special permit segments***, TGP must comply with 49 CFR 192.611(a) and (d), and 192.619(a).

Denial of the permit and full adherence to the 49 CFR Part 192 would afford the protections described above that are associated with either: A lower MAOP, new pressure test, or heavier walled or higher-grade pipe. Denial of the special permit would mean that the special permit condition IM portions would probably not be implemented in non-HCA locations, such as the ***special permit inspection areas***.

Denial of the special permit would require excavation to remove existing pipe, acquiring environmental permits where necessary, and pressure testing of the replacement pipeline segments. This action would create an impact to vegetation, soils, and possibly waterways due to the excavation, use of public roadways, and the impacted right of way during construction.

TGP will evaluate the potential environmental consequences and affected resources of land disturbances and water body crossings caused by construction activities (including adding, modifying, replacing, or removing any facility) for the related environmental permits associated with any TGP activity. This evaluation is outlined in Kinder Morgan's Operating and Maintenance Procedure (O&M) 1205: Land Disturbance, Construction, and

Environmental Permits, and referenced forms and procedures, which requires obtaining the permits prior to conducting any construction activity. These procedures ensure that all activities resulting in land disturbances or construction of new or modified facilities comply with the requirement to obtain all applicable environmental permits and other applicable environmental authorizations. These procedures contain information required to identify activities subject to Federal, state, and local environmental authorizations related to the work and to obtain those authorizations. The procedures require a review by TGP Environmental Services staff prior to the start of work, incorporation of environmental requirements into the project implementation, and ensuring outstanding (environmental) requirements are incorporated into facility operation.

If the activities do not qualify under the requirements of 2.55(a) or 2.55(b) facilities or the blanket certificate, TGP will pursue authorization in accordance with Section 7 of the Natural Gas Act.

IX. Request for Public Comments Placed on Docket PHMSA-2016-0158

PHMSA published the special permit request in the Federal Register (82 FR 21298) for a 30-day public comment period from May 5, 2017 through June 5, 2017. PHMSA sought comments on any potential environmental impacts that could result from the selection of either alternative, including the special permit conditions.

PHMSA received one (1) public comment concerning this special permit request through June 5, 2017. PHMSA received comments from the Pipeline Safety Trust (PST) which asked PHMSA to examine a number of topics including how to further reduce methane emissions from pipeline blowdowns where, due to the age and relatively thin pipe wall thickness, the extent of required integrity digs and other activities may cause as many emissions and impacts to the public as replacing the pipe. PST also noted that new pipe may lead to lower consequences on a pipeline failure, and finally, details on unique circumstances that led TGP to believe that applicability of the regulations are unnecessary for these pipelines under 49 CFR 190.341(c)(4).

PST states that Class 1 to Class 3 pipe replacement should not be avoided due to a gas pipeline blowdown and should not be considered a safety or environmental benefit of granting a special permit. PST argues the operator should use blowdown mitigation measures for pipe replacements. PST states that if emissions are unavoidable for all segments, public safety should be a deciding factor in whether to waive important safety regulations like pipe wall dimensions and strength.

- PHMSA agrees that the requirements regarding pipe wall thickness dimensions and strength are important safety requirements. PHMSA has reviewed this special permit application to ensure the special permit conditions address pipeline safety and integrity threats to the pipeline in the ***special permit segments*** and ***special permit inspection areas***. Based on that analysis, the ***special permit segments*** (4 segments) have documentation supporting suitability for continued operation to remain in service and will be subject to the additional safety conditions of the permit. The conditions will require TGP to provide a systematic program to review and remediate the pipeline for safety concerns in its Operations and Maintenance (O&M) Manual and procedures. Additional operational integrity reviews and remediation requirements will also be required.
- TGP must follow present Federal, state, and local regulations for emission mitigation including for methane emissions (such as when used for pipeline blowdowns or venting to reduce gas pressure or volume) when integrity assessments, repairs, or pressure testing is required on the four (4) ***special permit segments***.

PST states the draft Environmental Assessment (DEA) included with the application does not provide a complete comparison of the effects of granting or denying the permit. Next, PST states that the special permit application fails to provide an explanation of the unique circumstances that make the regulation unnecessary or inappropriate. Finally, PST states that the operator has not provided rationale for the continuous requests for special permits and at what point should pressure reduction or pipe replacement to comply with 49 CFR 192.611 be required.

- PHMSA placed the DEA in Docket Number: PHMSA-2016-0158 for public comment. After receipt and review of public comments PHMSA completed the final EA (FEA).

- PHMSA uses strict criteria when determining whether Class location waivers will provide an equivalent level of safety to people and the environment as the Federal pipeline safety regulations, and that criteria does not include the consideration of avoidance of blowdowns. Please see the Federal Register Notice, "Pipeline Safety: Development of Class Location Change Waiver Criteria," (69 FR 38948, June 29, 2004) for detailed description of the criteria, as well as the unique circumstances class changes present for pipeline operators.
- Finally, 49 CFR 190.341 does not limit an operator to how many miles of pipe that it can submit for special permit consideration, which includes a Class 1 to Class 3 location change.
- The IM criteria for Class 1 to 3 special permits for assessments, evaluation, remediation and reassessments of threats to the pipeline is a continuation of 49 CFR Part 192, Subpart O requirements and will not have any effects on the environment that have not already been considered in the regulations. PHMSA has a special permit condition requiring activities to meet Federal, state, and local environmental regulations.

The special permit application from TGP, special permit conditions, special permit analysis and findings, and FEA and FONSI are available in Docket No. PHMSA-2016-0158 at: www.regulations.gov.

X. Finding of No Significant Impact

In consideration of the FEA and special permit conditions explained above, PHMSA finds that granting this special permit with conditions that requires TGP to operate the four (4) ***special permit segments*** on the 31-inch diameter Line 100-2 Pipeline located in Harris County, Texas, and the 30-inch diameter Line 200-2 Pipelines located in Wyoming County, New York, at either their current or at a reduced MAOP for a Class 1 to 3 location change segment will not be inconsistent with pipeline safety. This special permit grant is based upon TGP's implementation of the special permit conditions. In the four (4) ***special permit segments*** TGP must identify, assess, and remediate threats including threats to the pipe body, weld seams and girth welds, and the cause of these integrity threats or replace the pipe, as required in the special permit conditions. This permit will require TGP to implement additional conditions on the operations, maintenance, and integrity management of the ***special permit segments*** and ***special permit inspection areas***.

XI. Bibliography

No other agencies were consulted, but PHMSA considered environmental information, special permit conditions, and documents submitted by TGP.

Attachments:

Attachment A – Maps of ***TGP Special Permit Segments*** and ***Special Permit Inspection Areas***

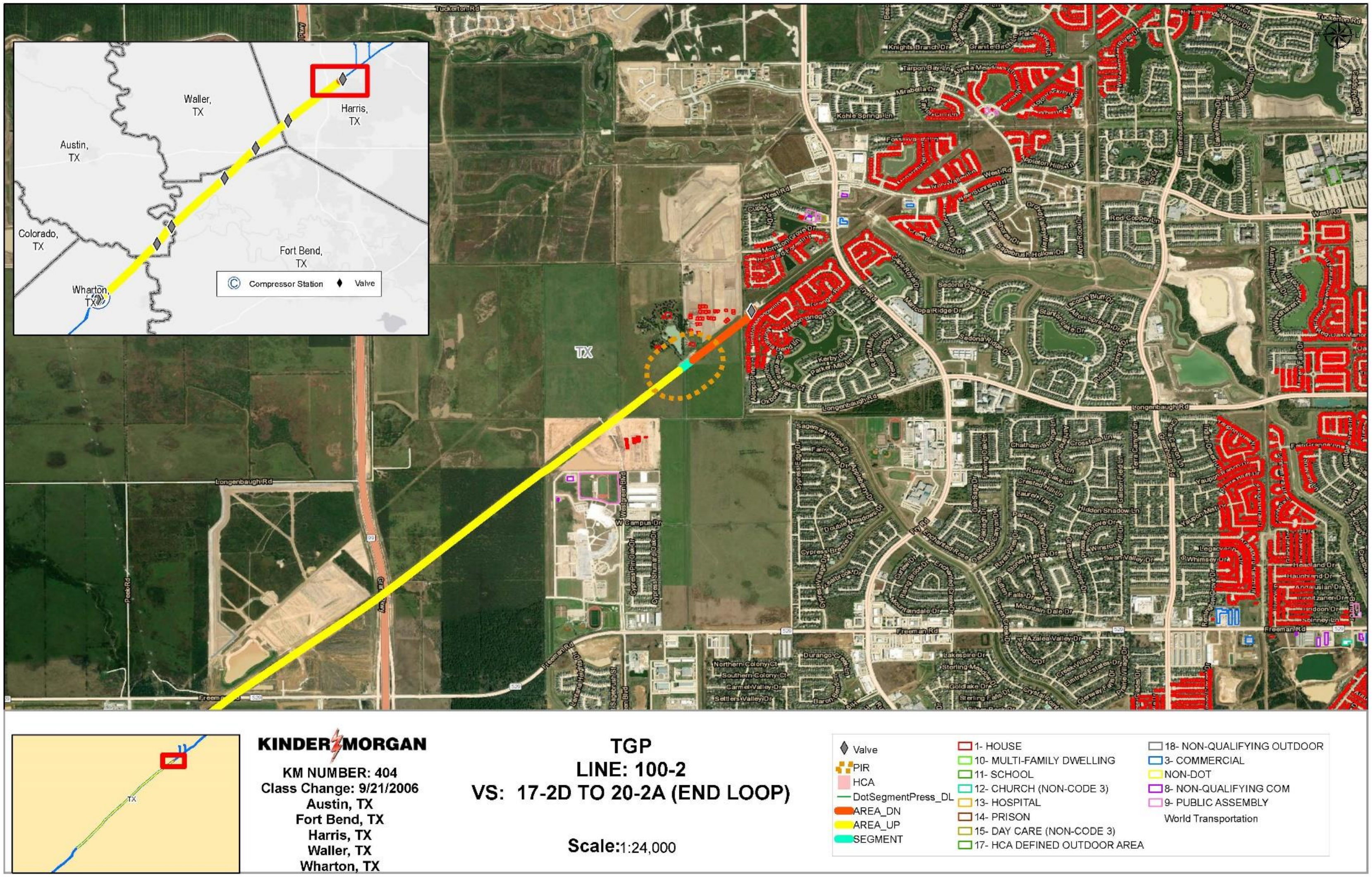
Attachment B – Guidance of Repairs to Interstate Natural Gas Pipelines Pursuant to FERC Regulations (July 2005)

Attachment C – Section 3, ASME B31.8S, 2004

Attachment D – Special Permit Conditions – developed by PHMSA

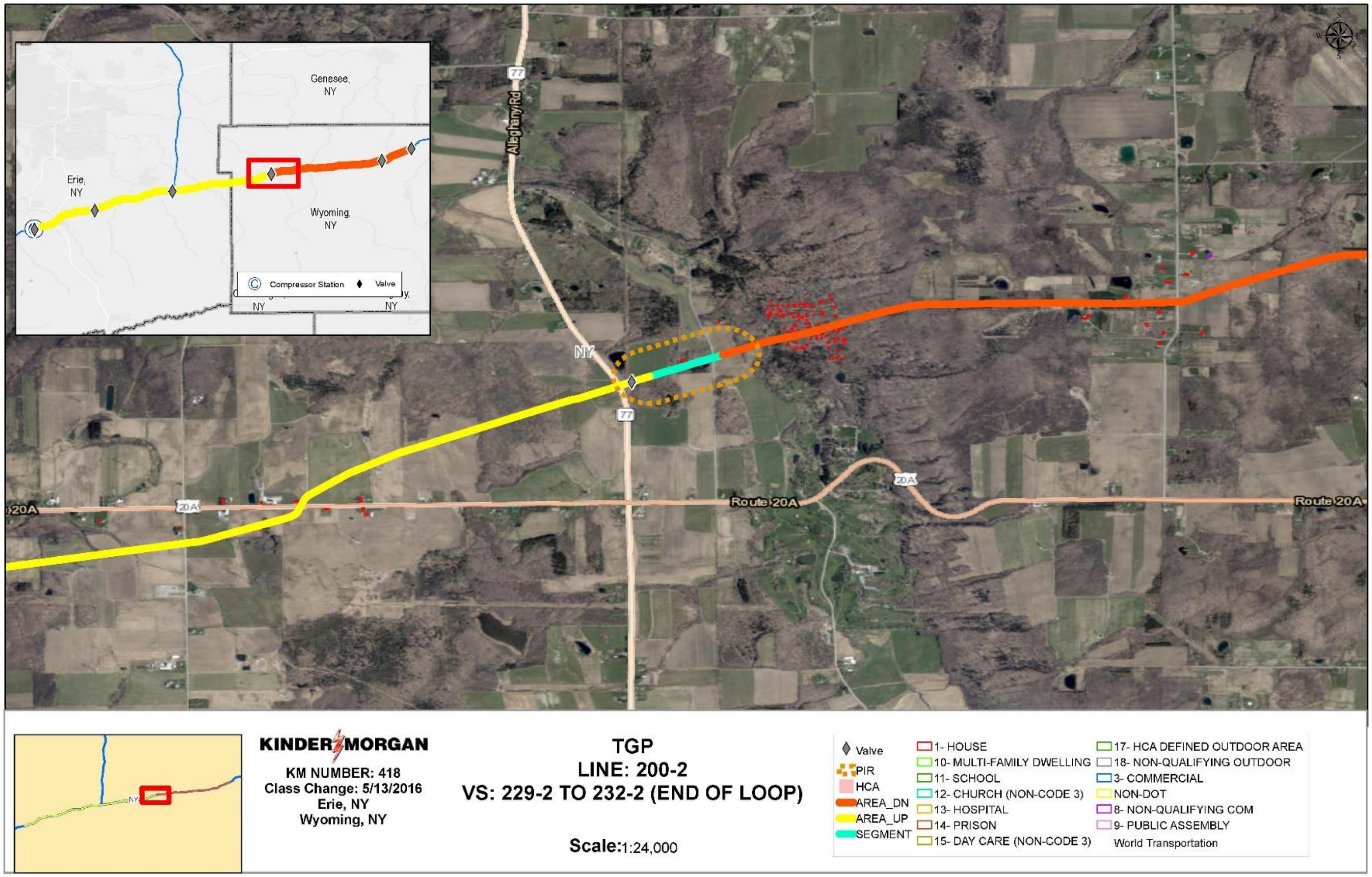
Completed by PHMSA in Washington, DC on: **April 11, 2022**

Attachment A-1 - Special Permit Segments and Inspection Area Route Maps
Special Permit Segment #404



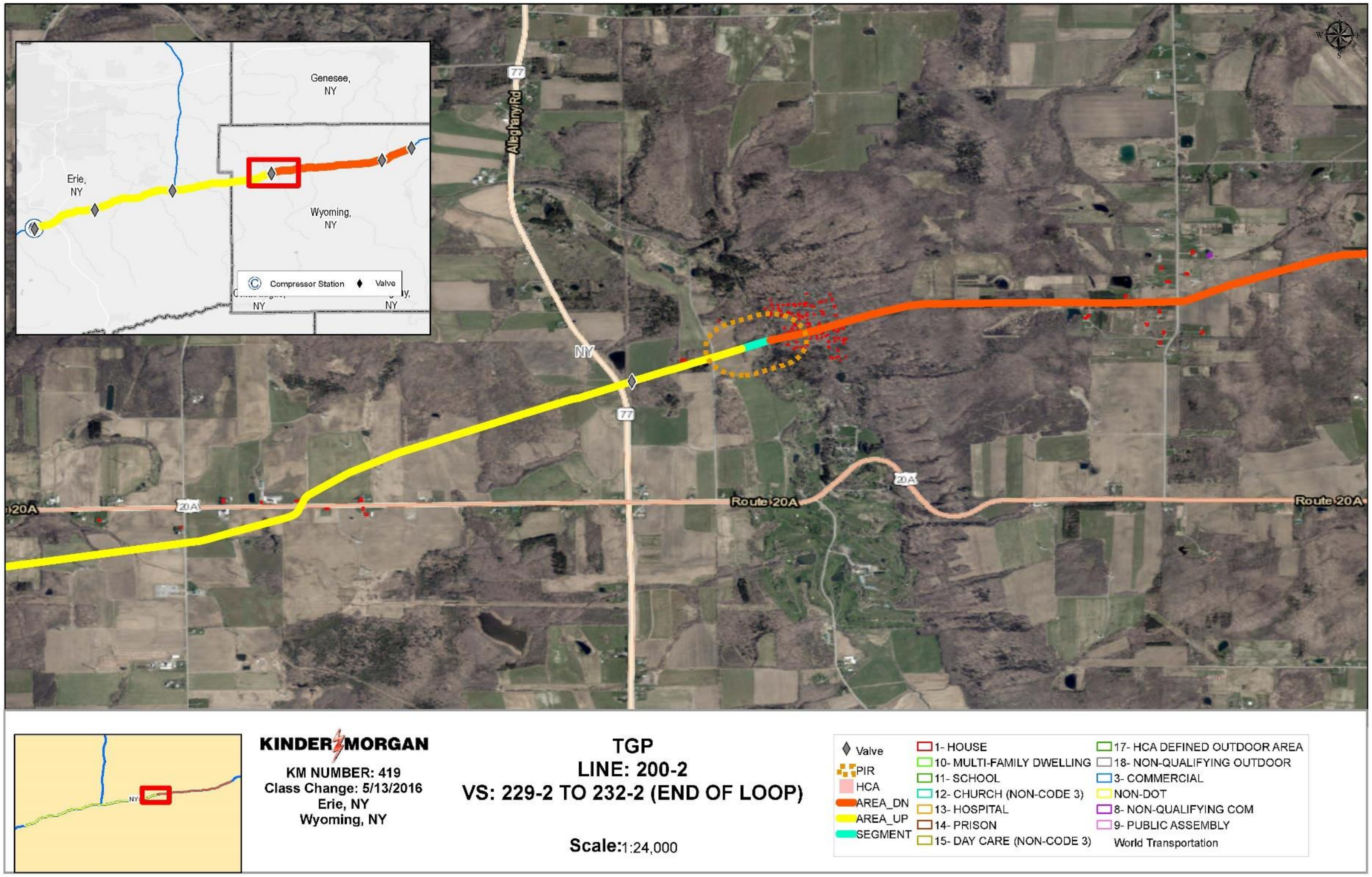
Attachment A-2 - Special Permit Segments and Inspection Area Route Maps

Special Permit Segment #418



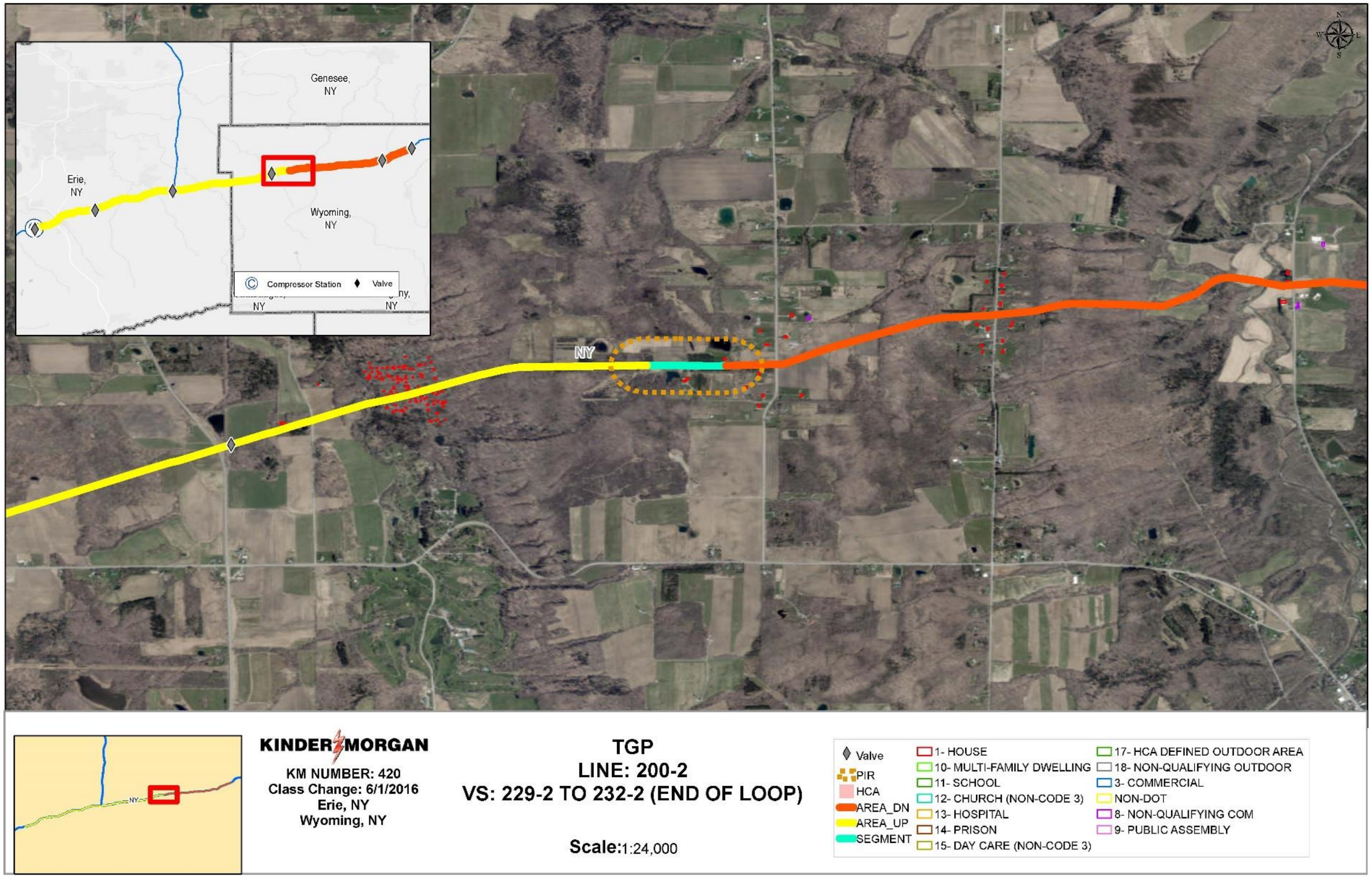
Attachment A-3 - Special Permit Segments and Inspection Area Route Maps

Special Permit Segment #419



Attachment A-4 - Special Permit Segments and Inspection Area Route Maps

Special Permit Segment #420



Attachment B

Guidance on Repairs to Interstate Natural Gas Pipelines Pursuant to FERC Regulations

(July 2005)

I. GUIDANCE ON ACTIVITIES ALLOWED UNDER THE FERC REGULATIONS

The guidance we[7] are providing here is to help the interstate natural gas pipeline industry (industry), agencies and other interested parties understand better the expedition of projects under the Pipeline Safety Improvement Act of 2002 (PSIA).[i] This guidance explains which repair projects occurring as a result of the integrity management program require no/or minimal notification to the Federal Energy Regulatory Commission (FERC or Commission) before starting the project, versus those that could require a complete analysis under Commission regulations.

A summary of the potential construction options is provided below: You can access these regulations and the Natural Gas Act through our website at http://www.ferc.gov/legal/ferc-regs.asp (access Title 18 CFR).

- Section 2.55(a) (auxiliary installations)
- Section 2.55(b) (replacement of facilities)
- Blanket Certificate (Subpart F of Part 157)
- Section 7 of the Natural Gas Act (Operation and Maintenance)

II. SUMMARY OF ALLOWABLE ACTIVITIES UNDER FERC PROGRAMS

A. **Operation and Maintenance of Certificated Projects**

Operation and routine maintenance activities can be done without any authorization from FERC beyond the certificate authorizing the construction/operation of the facilities. All the testing

---

7 The pronouns we, us, and our refer to the staff of the FERC's Office of Energy Projects.

including, if necessary, excavating the pipeline for direct inspection can be done if all construction related activities remain in the original right-of-way footprint. If the inspection indicates pipe replacement is needed, then under certain conditions it can be done under the exemption from certificate authorization provided by section 2.55(b) of the regulations (which is explained in detail below in the Summary of FERC Programs). These conditions are:

a. The replaced pipe goes in the same permanent right-of-way as the pipe being replaced.
b. Replacement of the pipeline uses the same construction area that was used in the original installation.
c. The new pipe has substantially equivalent capacity as the replaced pipe.

If these conditions can't be met, then the authorization conferred by the blanket certificate may be able to be used. The blanket certificate program includes conditions requiring consultations with federal agencies for endangered species, essential fish habitat, cultural resources, and coastal zone management concerns among others. The blanket certificate also has project cost limitations.

If the blanket certificate program is used but a variance from a measure in our Plan or Procedures[8] is needed, the company should contact staff immediately so that we can be sure to process a written request quickly. Initial contact information is provided at the end of this guidance. Failure to make this contact can result in a delay.

If the requirements of the blanket program cannot be met, then the company must get a project-specific certificate to authorize the replacement.

None of these regulations exempt the industry from the applicable portions of any other agency's authority. Actions covered by section 2.55(b) are not federal actions by FERC and therefore do not require any FERC involvement in compliance with any regulations such as the Endangered Species Act or the National Historic Preservation Act. However, if these or any other statutes have requirements applicable to non-governmental entities, they still apply. Under the blanket

8 Plan = Upland Erosion Control, Revegetation and Maintenance Plan. Procedures = Wetland and Waterbody Construction and Mitigation Procedures. These documents can be found at www.ferc.gov/industries/gas/enviro/guidelines.asp

program or the regular certificate process FERC does have an obligation to be involved, either through regulation (the blanket program) or actively in the case of a certificate filing.

B. **<u>Section 2.55(a) and 2.55(b)</u>**

This section covers installation of auxiliary facilities [2.55(a)] and replacement of facilities [2.55(b)] which are physically deteriorated or obsolete as long as there will be no reduction or abandonment of service through the facilities, and the replacement will have substantially the equivalent design capacity as the original facility. See appendix 1 to this guidance for a description of the kinds of installations which qualify as auxiliary under section 2.55(a).

These 2.55(a) facilities and 2.55(b) replacements are exempt from Natural Gas Act regulations and there are no requirements to comply with standard environmental conditions. However, all replacement facilities must be constructed within the same right-of-way, compressor station, or other aboveground facility site as the facility being replaced. In addition, all construction activity involved with the installation of such replacements must use only the land area originally used for installation of the facilities being replaced. Clarification of the requirement for the use of the same construction area may be found in appendix A to Part 2 of the Commission's regulations. (See appendix 2

to this guidance)

An Annual Report must be filed by May 1 of each year, which identifies all replacement projects completed during the previous calendar year that do not exceed the cost limit specified in column 1 of Table I of 18 CFR section 157.208(d) (less than $8,000,000 in 2005). Replacement projects that exceed this amount require advanced notification to the FERC. Annual reports are not required for projects that require Advance Notification or that only involve aboveground replacement and did not involve compression facilities or the use of earthmoving equipment.

If a replacement project exceeds the cost limitation (over $8,000,000 in 2005), an Advance Notification must be filed at least 30 days before beginning construction (unless immediate replacement is required to comply with U.S. Department of Transportation (DOT) safety regulations).

For both the Annual Report and Advance Notification, the following information must be provided for our review of each project:

- A description of the facilities, including the pipeline length and diameter, capacity and cost, compressor horsepower, metering facilities, taps, valves, etc.;
- The specific reason for replacement of the facilities;
- For 30-day Advance Notifications, a general location map (showing the facilities in relation to existing facilities);
- A current USGS 7.5-minute-series topographic map (showing the location of each facility);
- The actual (or anticipated) start and end dates of construction; and
- A description of the procedures to be used for erosion control, revegetation and maintenance, and stream and wetland crossings (a plan should be submitted, but it does not have to be our recommended Plan and Procedures).

C. **Blanket Certificate - Subpart F of Part 157**

Pipeline integrity repairs, replacements, construction, or abandonment activities which do not meet the requirements of 2.55(a) or 2.55(b) facilities must be authorized under one of several sections of the blanket certificate:

- section 157.208, construction, acquisition, operation, and replacement of any eligible facility or miscellaneous rearrangement of any facilities; or
- section 157.209, temporary compression facilities.

The primary portion of the blanket program which would apply to Integrity Management issues is section 157.208. [9] That section provides for two types of facilities; (1) “eligible” facilities, and (2) “any” facilities.

(1) An “eligible” facility is completely defined in section 157.202. Briefly, it is any facility, other than mainline pipeline and compression facilities, needed to provide service within certificated levels, or facilities to allow the certificate holder to receive gas into its system and interconnections for transporters of gas under Part 284. In addition, it includes any replacement (including mainline) that doesn’t qualify under section 2.55 because of incidental increases in capacity or the need to move the facility or use new workspace. Finally, replacements and the modification of facilities (including mainline) to rearrange gas

---

[9] Sections 157.211, delivery points, and 157.216, abandonment, may in some cases be needed, but would usually be associated with more significant activity under section 157.208.

flows or increase compression to restore service in an emergency due to sudden unforeseen damage to mainline facilities are eligible facilities.

If an activity involves an eligible facility or qualifies as a miscellaneous rearrangement, it may proceed under section 157.208 with certain conditions. The blanket certificate program requires that all projects must be completed in compliance with section 157.206(b). (See further discussion of these standard conditions below.)

(2) The broad category of "any" facility is used in the context of authorization to do miscellaneous rearrangements of "any" facility. This authorization has only one restriction—it doesn't include underground storage injection/withdrawal wells. The blanket allows "miscellaneous rearrangement" of "any" facility where "miscellaneous rearrangement" means relocation or modification that does not result in any change of service, and which is on the same property or is required:

- By highway or dam construction, encroachment of residential, commercial, or industrial areas, erosion, or changes in water courses; or
- To respond to natural forces to ensure safety or maintain operational integrity.

If there is a change of service or something that is other than a simple relocation or modification of an existing facility, then the activity is not a miscellaneous rearrangement. It becomes a construction, acquisition, operation, or replacement which can only be done if the facility is an "eligible" facility.

Minor projects[10] under section 157.208(a) and temporary compression under section 157.209 may be done automatically under the appropriate requirements of those sections. These activities are subject to the Annual Report.

In addition, construction projects under section 157.208 above $8,000,000 require prior notice to the Commission before start of the activity. For these activities, there is a 45day period following the Commission's notice of the Prior Notice filing during which protests of the activity may be filed. If there are no protests, the activity may begin on the 46th day. If there are protests, the activity may not go forward under the blanket regulations unless the protests are

[10] Minor projects are those that do not exceed the cost limit specified in column 1 of Table I of 18 CFR section 157.208(d) (less than $8,000,000 in 2005).

withdrawn. If all protests are withdrawn, the activity may proceed on the day following the withdrawal of the last protest. Otherwise the Commission must issue an Order before the project can be constructed.

The following sections describe the standard environmental conditions which apply to any construction under the blanket program and all the primary requirements for section 157.208 activities.

a) Standard Environmental Conditions for All Blanket Projects

The standard environmental conditions and requirements of section 157.206(b) apply to all projects under the blanket program of Subpart F of Part 157 or to NGPA section 311 facilities used to provide Part 284 transportation, but only if the project involves ground disturbance or changes to operational air or noise emissions. This section of the regulations states that the company will adopt the requirements set forth in section 380.15, Siting and Maintenance Requirements, and "shall issue the relevant portions thereof to construction personnel, with instructions to use them." In addition, it states that all activities will be consistent with all applicable law and the provisions of the following statutes and regulations or compliance plans developed to implement them.

- Clean Water Act and the National Pollutant Discharge Elimination System Program
- Clean Air Act
- National Historic Preservation Act of 1966 (NHPA)
- Archeological and Historic Preservation Act of 1974
- Coastal Zone Management Act of 1972 (CZM)
- Endangered Species Act of 1973 (ESA)
- Executive Order 11988 (May 24, 1977) requiring federal agencies to evaluate the potential effects of any actions it may take on a floodplain
- Executive Order 11990 (May 24, 1977) requiring an evaluation of the potential effects of construction on wetlands
- Wild and Scenic Rivers Act
- National Wilderness Act
- National Parks and Recreation Act of 1978

- Magnuson-Stevens Fishery Conservation and Management Act

In order to be in compliance with these statutes under the blanket program for replacements/integrity management projects which cannot be done under 2.55(b), the project sponsor:

- Must comply with Appendix I of Subpart F, involving consultation with the U.S. Fish and Wildlife Service and/or the U.S. Department of Commerce, National Oceanic and Atmospheric Administration (as appropriate), and the project may go forward only if this consultation results in the agency(ies) concluding that:
    - There are no listed or proposed species or their critical habitat in the project area, or
    - There are listed species or their critical habitat in the project area, but the project is not likely to adversely affect a listed species or its habitat, or
    - There is no need for further consultation
- If <u>proposed</u> species or their critical habitat occur within the project area, the project sponsor implements (at its discretion) mitigation resulting from continued consultation with the agency(ies).
- Must comply with Appendix II of Subpart F, involving consultation with the State Historic Preservation Office (SHPO) and/or the Tribal Historic Preservation Officer (THPO) (as appropriate), and this consultation results in the agency(ies) concurring that:

- No surveys are required, and no eligible properties are in the project area;
- Surveys are required and that as a result of the surveys no eligible properties are found in the project area; or
- There are eligible properties in the project area, but the project will have no effect on any such cultural resource property.

- Must obtain the appropriate state agency's determination that the project will comply with the state's coastal zone management plan unless the appropriate state agency waives its right of review, if applicable;

- Must adhere to the Commission staff's current Plan and Procedures, or must obtain staff or appropriate state or federal agency approval to use other specific alternatives;
- Must make sure that the project will not have a significant adverse impact on a sensitive environmental area (see table 1 for the list of sensitive environmental areas from 18 CFR 157.202(b)(11));
- Must make sure that the noise attributable to any new compressor station, compression added to an existing station, or any modification, upgrade or update to an existing station does not exceed an L_{dn} of 55 dBA at any noisesensitive area (NSA) (such as schools, hospitals, or residences) unless the NSA is established after facility construction or modification.

If a project cannot meet all of the above conditions, then it is not allowed to proceed under the blanket program. If it is to proceed, a filing must be made to the Commission for a certificate under section 7 of the NGA.

A project is not allowed under the blanket program if the activity is located within 0.5 mile (project authorized under section 157.208 only) of a nuclear power plant which is either operating or under construction, or for which a construction permit has been filed with the Nuclear Regulatory Commission.

Table 1

Sensitive Environmental Areas

The habitats of species which have been identified as endangered or threatened under the Endangered Species Act and Essential Fish Habitat as identified under the Magnuson-Stevens Fishery Conservation and Management Act
National or State Forests or Parks
Properties listed on, or eligible for inclusion in, the National Register of Historic Places, or the National Register of Historic Landmarks
Floodplains and wetlands
Designated or proposed wilderness areas, national or state wild and scenic rivers, wildlife refuges and management areas and sanctuaries
Prime agricultural lands, designated by the Department of Agriculture
Sites which are subject to use by American Indians and other Native Americans for religious purposes

b) Landowner Notification

With two exceptions, landowner notification is required prior to any construction of projects done for the integrity management program under the Subpart F blanket program. One exception is any replacement which is not foreseen and requires immediate attention. Another exception is any replacement which would meet the section 2.55(b) requirements except that the replacement is not of the same capacity.

The definition of "landowner" is found in section 157.6(d)(2). The specific requirements for the contents of the landowner notice are in section 157.203(d).

For automatically authorized projects, landowners must be notified at least 30 days prior to commencing construction or at the time the company initiates easement negotiations, whichever is earlier. A landowner may waive the 30-day prior notice requirement in writing, as long as the notice has been provided.

For projects for which the Commission must receive advance notification, the landowners must be notified within at least three (3) business days following the date that a docket number is assigned to the notice by the Commission, or at the time the company initiates easement negotiations, whichever is earlier.

c) Annual Report for Construction Projects (sections 157.208(a & b) and section 157.209

Projects that qualify for automatic authorization are for (1) projects constructed under section 157.208; (2) do not exceed the cost limit specified in column 1 of Table I of section 157.208(d) (less than $8,000,000 in 2005); and, (3) meet the requirements of section 157.209. These projects are reported on an annual basis in an Annual Report that is due by May 1 of each year.

For projects constructed under section 157.208(a) and section 157.209, the annual report must provide a description of the contacts made, reports produced, and results of consultations completed before construction to comply with the ESA, NHPA, and CZM. The annual report must also provide the date and name of the agency that cleared the project. Actual documentation is not required, although it is helpful to include the "clearance" from the agency.

Projects conducted under section 157.208(b) also must be included in the annual report. However, since environmental information was provided in the notice filed prior to construction, no additional environmental information is required for the annual report.

d) Contents of a Prior Notice Filing Under section 157.208(b)

Projects that require prior notice under section 157.208(b) are those that cost more than the limitations set forth in column 1 but less than the amount specified in column 2 of Table I in section 157.208(d) (from $8,000,000 to $22,000,000 in 2005). For these projects, a concise analysis of the relevant issues outlined in section 380.12 is required in addition to a general description of the activity that is to take place. For projects to be completed under this section, include the following environmental information for each project:

- A description of the facilities, including the length and diameter, wall thickness and maximum allowable operating pressure of the pipeline; for compressors, the size, type and number of compressor units, horsepower required, horsepower existing and proposed, volume of fuel gas, suction and discharge pressure and compression ratios; metering facilities, taps, valves, etc.;
- The specific purpose of the facilities and relationship to other existing and planned facilities;
- A general location map (showing the facilities in relation to existing facilities);
- USGS 7.5-minute-series topographic maps or maps of equivalent detail (showing the location of each facility) and any sensitive environmental area within 0.25 mile of construction;
- The anticipated start and end dates of construction;
- A concise analysis summarizing the existing environmental conditions, the anticipated significant impacts as a result of construction of the facilities, and mitigation measures proposed to reduce or avoid impact on the quality of the human environment, including impact on sensitive environmental areas;

- A statement that the project will comply with the requirements of section 157.206(b), including for compression facilities, the Clean Air Act and the applicable state implementation plans developed under the Clean Air Act, and the Ldn of 55 dBA at any NSA;
- Copies of correspondence or documentation of consultation with the FWS, SHPO, and appropriate state coastal zone management agency as described above under reporting requirements for Annual Reports; and
- Copies of all agreements received to comply with the ESA, the NHPA, and the CZM.

e) Additional Projects that could occur as a result of the Integrity Management Program

Potentially delivery point and abandonment projects could occur in relation to integrity management repairs/replacements, if so then the regulations in section 157.211 and section 157.216 must be followed.

Installation of delivery points under section 157.211(a)(1), and abandonment under section 157.216(a), may be done automatically under the appropriate requirements of those sections. Projects that qualify for automatic authorization are those that meet the applicable subsections of section 157.211 or section 157.216. These projects are reported on an annual basis in an Annual Report that is due by May 1 of each year. For section 157.211 and for section 157.216, if earth disturbance was involved, only the date of the "clearance" is required.

Activities which require prior notice include the installation of delivery points under section 157.211(a)(2), and abandonment under section 157.216(b).

f) Prior Notice Filings under section 157.211(a)(2) and section 157.216(b)

Although the regulations do not specifically require the filing of environmental information for construction or abandonment of facilities under these sections (other than USGS maps), the standard environmental conditions of section 157.206(b) apply to these projects. However, the following environmental information will assist us in our review:

- A description of the activity and its purpose;
- The anticipated start and end dates of activity;

- The county/parish and state where the activity will take place;
- A general location map of where the activity will take place (copies of pipeline system maps or USGS topographic maps are acceptable provided that enough detail is included to allow us to locate the facilities in the field);
- A statement that the project will comply with the requirements of section 157.206(b) before construction; and
- Copies of correspondence or documentation of consultation (e.g., telephone conversations or meetings) with the:
    - FWS and NMFS (see Appendix I of Subpart F, referenced at section 156.206(b)(3)(i));
    - SHPO and THPO (see Appendix II of Subpart F, referenced at section 156.206(b)(3)(ii)); and
- Consistency determination from the appropriate agency that administers the state's coastal zone management plan, if applicable.

D. **Where to go for questions**

Contact: Mr. Douglas A. Sipe

Project Manager, Gas Branch 2

douglas.sipe@ferc.gov

202.502.8837

Or

Mr. John S. Leiss

Chief, Gas Branch 2

john.leiss@ferc.gov

202.502.8058

Federal Energy Regulatory Commission

888 First Street, NE

Washington DC 20426

i. On November 15, 2002, Congress passed the Pipeline Safety Improvement Act of 2002 (PSIA), which was signed into law on December 17, 2002, and codified at 49 U.S.C. 60109.

This law requires the Research and Special Programs Administration/Office of Pipeline Safety of the DOT to ‘‘issue regulations prescribing standards to direct an operator’s conduct of a risk analysis and adoption and implementation of an integrity management program’’ no later than 12 months after December 17, 2002. The statute sets forth minimum requirements for integrity management programs for gas pipelines located in High Consequence Areas (HCAs).

The final DOT regulations require operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm, i.e., could impact HCAs. The rule requires gas transmission pipeline operators to perform ongoing assessments of pipeline integrity, to improve data collection, integration, and analysis; to repair and remediate the pipeline as necessary; and to implement preventive and mitigative actions. The regulations comprehensively address statutory mandates, safety recommendations, and conclusions from accident analyses, all of which indicate that coordinated risk control measures are needed to improve pipeline safety.

The PSIA directed federal agencies and departments having jurisdiction over the permitting of work needed for pipeline repairs to establish a coordinated and expedited pipeline repair permit review process. The process must be designed to enable pipeline operators to commence and complete all activities necessary to carry out pipeline repairs within the time periods to be established and specified by the Secretary of Transportation, pursuant to the PSIA, and in accordance with the statutory and regulatory requirements of the other agencies.

In accordance with Section 16 of the PSIA, to carry out this mandate and in recognition of the fact that timely repair of both natural gas and hazardous liquid pipelines is essential to facilitate the nation’s ability to meet the goal of sufficient availability and use of natural gas and liquid fuels, several federal agencies have entered into a Memorandum of Understanding (MOU). Agencies who signed the MOU are: Council on Environmental Quality; DOT; Environmental Protection Agency; Department of the Interior; Department of Commerce; Department of Defense; FERC; Department of Agriculture; Department of Energy; and the Advisory Council on Historic Preservation.

Appendix 1:
2.55(a) Auxiliary Facilities

(a) Auxiliary installations.

(1) Installations (excluding gas compressors) which are merely auxiliary or appurtenant to an authorized or proposed transmission pipeline system, and which are installations only for the purpose of obtaining more efficient or more economical operation of the authorized or proposed transmission facilities, such as: Valves; drips; pig launchers/receivers; yard and station piping; cathodic protection equipment; gas cleaning, cooling and dehydration equipment; residual refining equipment; water pumping, treatment and cooling equipment; electrical and communication equipment; and buildings.

Appendix 2:
Appendix A to Part 2--Guidance for Determining the Acceptable Construction Area for Replacements

These guidelines shall be followed to determine what area may be used to construct the replacement facility. Specifically, they address what areas, in addition to the permanent right-of-way, may be used.

Pipeline replacement must be within the existing right-of-way as specified by Sec.

2.55(b)(1)(ii). Construction activities for the replacement can extend outside the current permanent right-of-way if they are within the temporary and permanent right-of-way and associated work spaces used in the original installation.

If documentation is not available on the location and width of the temporary and permanent rights-of-way and associated work space that was used to construct the original facility, the company may use the following guidance in replacing its facility, provided the appropriate easements have been obtained:

a. Construction should be limited to no more than a 75-foot-wide right-of-way including the existing permanent right-of-way for large diameter pipeline (pipe greater than 12 inches in diameter) to carry out routine construction. Pipeline 12 inches in diameter and smaller should use no more than a 50-foot-wide right-of-way.

b. The temporary right-of-way (working side) should be on the same side that was used in constructing the original pipeline.

c. A reasonable amount of additional temporary work space on both sides of roads and interstate highways, railroads, and significant stream crossings and in side slope areas is allowed. The size should be dependent upon site-specific conditions. Typical work spaces are:

ITEM	Typical extra area (width/length)
Two lane road (bored)	25-50 by 100 feet
Four lane road (bored)	50 by 100 feet
Major river (wet cut)	100 by 200 feet
Intermediate stream (wet cut)	50 by 100 feet
Single railroad track	25-50 by 100 feet

d. The replacement facility must be located within the permanent right-of-way or, in the case of nonlinear facilities, the cleared building site. In the case of pipelines this is assumed to be 50-feet-wide and centered over the pipeline unless otherwise legally specified.

However, use of the above guidelines for work space size is constrained by the physical evidence in the area. Areas obviously not cleared during the original construction, as evidenced by stands of mature trees, structures, or other features that exceed the age of the facility being replaced, should not be used for construction of the replacement facility.

If these guidelines cannot be met, the company should consult with the Commission's staff to determine if the exemption afforded by Sec. 2.55 may be used. If the exemption may not be used, construction authorization must be obtained pursuant to another regulation under the Natural Gas Act.

Attachment C-1 – Section 3, ASME B31.8S, 2004

keep the public informed about their integrity management efforts. This plan shall provide information to be communicated to each stakeholder about the integrity plan and the results achieved. Paragraph 10 provides further information about communications plans.

2.4.4 Management of Change Plan. Pipeline systems and the environment in which they operate are seldom static. A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated. After these changes are made, they shall be incorporated, as appropriate, into future risk assessments to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the plan's mitigative activities should be used as a feedback for systems and facilities design and operation. Paragraph 11 discusses the important aspects of managing changes as they relate to integrity management.

2.4.5 Quality Control Plan. Paragraph 12 discusses the evaluation of the integrity management program for quality control purposes. That paragraph outlines the necessary documentation for the integrity management program. The paragraph also discusses auditing of the program, including the processes, inspections, mitigation activities, and prevention activities.

3 CONSEQUENCES

3.1 General

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result from a failure. Risk may be decreased by reducing either the likelihood or the consequences of a failure, or both. This paragraph specifically addresses the consequence portion of the risk equation. The operator shall consider consequences of a potential failure when prioritizing inspections and mitigation activities.

The B31.8 Code manages risk to pipeline integrity by adjusting design and safety factors, and inspection and maintenance frequencies, as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequences of a failure.

Paragraph 3.2 describes how to determine the area that is affected by a pipeline failure (potential impact area) in order to evaluate the potential consequences of such an event. The area impacted is a function of the pipeline diameter and pressure.

3.2 Potential Impact Area

The refined radius of impact for natural gas is calculated using the formula

$$r = 0.69 \cdot d\sqrt{p} \qquad (1)$$

where

d = outside diameter of the pipeline, in.
p = pipeline segment's maximum allowable operating pressure (MAOP), psig
r = radius of the impact circle, ft

EXAMPLE: A 30 in. diameter pipe with a maximum allowable operating pressure of 1,000 psig has a potential impact radius of approximately 660 ft.

$$\begin{aligned} r &= 0.69 \cdot d\sqrt{p} \\ &= 0.69\,(30 \text{ in.})(1{,}000 \text{ lb/in.}^2)^{1/2} \\ &= 654.6 \text{ ft} \approx 660 \text{ ft} \end{aligned}$$

Use of this equation shows that failure of a smaller diameter, lower pressure pipeline will affect a smaller area than a larger diameter, higher pressure pipeline. (See GRI-00/0189.)

NOTE: 0.69 is the factor for natural gas. Other gases or rich natural gas shall use different factors.

Equation (1) is derived from

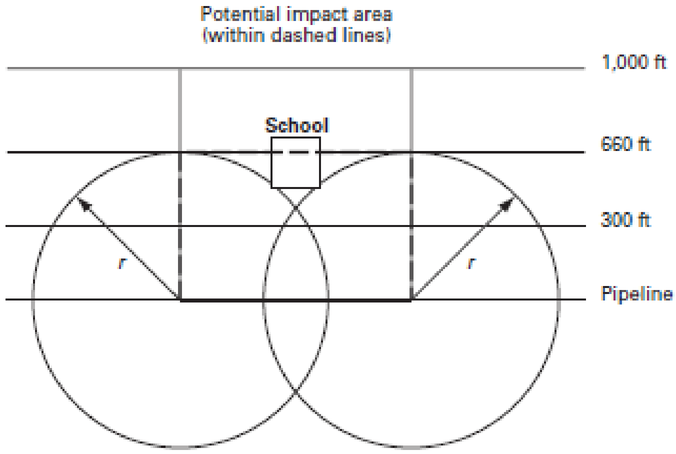
$$r = \sqrt{\frac{115{,}920}{8} \cdot \mu \cdot \chi_g \cdot \lambda \cdot C_d \cdot H_C \cdot \frac{Q}{a_o} \cdot \frac{pd^2}{I_{th}}}$$

where

C_d = discharge coefficient
H_C = heat of combustion
I_{th} = threshold heat flux
Q = flow factor = $\gamma\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{2(\gamma-1)}}$
R = gas constant
T = gas temperature
a_o = sonic velocity of gas = $\sqrt{\frac{\gamma RT}{m}}$
d = line diameter
m = gas molecular weight
p = live pressure
r = refined radius of impact
γ = specific heat ratio of gas
λ = release rate decay factor
μ = combustion efficiency factor
χ_g = emissivity factor

In a performance-based program, the operator may consider alternate models that calculate impact areas and consider additional factors, such as depth of burial, that may reduce impact areas. The operator shall count the number of houses and individual units in buildings within the potential impact area. The potential impact area extends from the center of the first affected circle to the center of the last affected circle (see Fig. 3). This housing unit count can then be used to help determine the relative consequences of a rupture of the pipeline segment.

Attachment C-2 – Section 3, ASME B31.8S, 2004



GENERAL NOTE: This diagram represents the results for a 30 in. pipe with an MAOP of 1,000 psig.

Fig. 3 Potential Impact Area

The ranking of these areas is an important element of risk assessment. Determining the likelihood of failure is the other important element of risk assessment (see paras. 4 and 5).

3.3 Consequence Factors to Consider

When evaluating the consequences of a failure within the impact zone, the operator shall consider at least the following:

(a) population density

(b) proximity of the population to the pipeline (including consideration of manmade or natural barriers that may provide some level of protection)

(c) proximity of populations with limited or impaired mobility (e.g., hospitals, schools, child-care centers, retirement communities, prisons, recreation areas), particularly in unprotected outside areas

(d) property damage

(e) environmental damage

(f) effects of unignited gas releases

(g) security of gas supply (e.g., impacts resulting from interruption of service)

(h) public convenience and necessity

(i) potential for secondary failures

Note that the consequences may vary based on the richness of the gas transported and as a result of how the gas decompresses. The richer the gas, the more important defects and material properties are in modeling the characteristics of the failure.

4 GATHERING, REVIEWING, AND INTEGRATING DATA

4.1 General

This paragraph provides a systematic process for pipeline operators to collect and effectively utilize the data elements necessary for risk assessment. Comprehensive pipeline and facility knowledge is an essential component of a performance-based integrity management program. In addition, information on operational history, the environment around the pipeline, mitigation techniques employed, and process/procedure reviews is also necessary. Data are a key element in the decision-making process required for program implementation. When the operator lacks sufficient data or where data quality is below requirements, the operator shall follow the prescriptive-based processes as shown in Nonmandatory Appendix A.

Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program.

4.2 Data Requirements

The operator shall have a comprehensive plan for collecting all data sets. The operator must first collect the data required to perform a risk assessment (see para.

Attachment D – Special Permit Conditions

1) **Condition 1 - Maximum Allowable Operating Pressure**

   a) **Maximum Allowable Operating Pressure**: TGP must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP of 750 pounds per square inch gauge (psig) for the 31-inch diameter Line 100-2 Pipeline and at an MAOP of 878 psig for the 30-inch diameter Line 200-2 Pipeline.

   b) **Pressure Test**: TGP must identify previous pressure tests for each ***special permit segment***. Pressure test records for each ***special permit segment*** must meet 49 CFR 192.517(a) and be traceable, verifiable, and complete (TVC)[11] as required in 49 CFR 192.624(a)(1).[12]

      i) TGP must furnish TVC pressure test records to the Director, PHMSA Engineering and Research Division, and to the Director, PHMSA Southern Region, within 60 days of the grant of the special permit. The pressure test records must be compliant with **Condition 1(b)**.[13] TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, that the TVC pressure test records are compliant with 49 CFR 192.517(a), 192.624(a)(1), and 192.619(a)(1) through (a)(4) for a Class 1 location, or TGP must pressure test the ***special permit segment*** in accordance with **Condition 1(b)(ii)**.

      ii) If TGP does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated

---

[11] TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments"; 84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.

[12] TGP has furnished TVC pressure test records to PHMSA for the ***special permit segments*** that meet **Condition 1(b)**.

[13] The pressure test records must cover the entire length of the ***special permit segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a pressure test are not acceptable TVC pressure test records.

pressure test, the ***special permit segment*** must be hydrostatically tested[14] to a minimum of 1.39 times the MAOP for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J, within 18 months of the grant of this special permit.[15]

c) **MAOP Restoration or Uprating of Previously De-rated Pipe**: MAOP restoration or uprating is not approved for this special permit.

2) **Condition 2 - Procedure Updates**

Within 90 days of the grant of the special permit, TGP must develop and maintain procedures in accordance with 49 CFR 192.603 and 192.605 that incorporate the special permit condition requirements as follows:

a) **Operations and Maintenance Manual**: TGP must amend the applicable sections of its Operations and Maintenance (O&M) manual(s) and procedures to incorporate the special permit conditions.

b) **Integrity Management Program**:

i) TGP must incorporate each ***special permit segment*** into its written integrity management (IM) program procedures as if the ***special permit segment*** is a "covered segment" as defined in 49 CFR 192.903, except for the reporting requirements contained in 49 CFR 192.945.[16] A ***special permit inspection area*** outside of a ***special permit segment*** is not required to be included as "covered segments" in accordance with 49 CFR 192.903.

---

14 For all in-service and pressure test failures, TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

15 The grant of this special permit, as used throughout, is the signed issuance date of the special permit.

16 TGP must follow the reporting requirements in **Condition 15 – Annual Report** as well as those noted throughout the conditions contained herein.

ii) The ***special permit inspection area*** and ***special permit segment*** must have integrity threats identified, assessed, and remediated in accordance with these special permit conditions, 49 CFR 192.917, and 49 CFR Part 192, Subpart O.

iii) Any high consequence area (HCA) in either a ***special permit segment*** or a ***special permit inspection area*** must be assessed and remediated for threats in accordance with these special permit conditions and 49 CFR Part 192, Subpart O.

iv) All permit conditions that are applicable to a ***special permit segment*** or to a ***special permit inspection area*** are applicable to HCAs where the HCA overlaps a ***special permit segment*** or a ***special permit inspection area***.

v) All special permit conditions that are applicable to a ***special permit inspection area*** are also applicable to the ***special permit segment***. A ***special permit segment*** must meet the requirements of 49 CFR 192, Subpart O, if Subpart O is more stringent than the special permit conditions.

vi) The ***special permit inspection area*** must be able to be assessed using inline inspection (ILI) tools, including tethered or remotely controlled tools, in accordance with 49 CFR 192.150 and 192.493.

c) **<u>Damage Prevention Program</u>**: TGP must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[17] in its damage prevention (DP) program.

3) **<u>Condition 3 – Corrosion Control</u>**

TGP must promptly address any corrosion control deficiencies in a ***special permit segment*** that are indicated by the inspection and testing programs required under 49 CFR 192.463 and 192.465.

a) **<u>Cathodic Protection Test Station Spacing</u>**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each ***special permit segment***, with a spacing not to exceed ½ mile between CP pipe-to-soil test stations. In cases where

[17] Common Ground Alliance. (March 2020). Best Practices Guide. Retrieved from: https://commongroundalliance.com/BPguide.

obstructions or restricted areas prevent such test station placement, the test station must be placed in the closest practical location, not to exceed a 3,000-foot spacing. CP pipe-to-soil test stations must be installed within 12 months of the grant of this special permit.

b) **<u>Annual Monitoring of Test Station Potential Measurements</u>**: At least once every calendar year, not to exceed 15 months, TGP must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for the ***special permit segment*** and must include "on and off" potential measurements. Test station readings (pipe-to-soil potential measurements) must comply with Appendix D – Section I.A. (1) of 49 CFR Part 192 or remediation detailed in paragraph (c) of this condition is required. For hard spots identified with a Brinell Hardness (HB) of 300 HB or greater, CP voltage levels must be maintained more electro-positive than minus 1.2 volts direct current (DC).

c) **<u>Inadequate Cathodic Protection Level Determination</u>**:

   i) In instances where inadequate potentials are a result of an electrical short to an adjacent foreign structure, a rectifier malfunction, an interruption of power source, or an interruption of CP current due to other non-systemic or location-specific causes, TGP must document and repair these instances. A close interval survey (CIS) will not be required.

   ii) All other instances must be assessed as detailed in **Condition 4 – Close Interval Surveys**.

d) **<u>Remedial Action Plans</u>**:

   i) Within six (6) months of identifying a deficiency, TGP must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the finding, TGP must apply for any necessary environmental permits (federal or state).

   ii) TGP must complete the remediation and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the deficiency finding or as soon as practicable after obtaining the necessary permits.

4) **Condition 4 – Close Interval Surveys**

a) **Survey Methodology and Boundaries**:

i) TGP must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***special permit segment***.[18]

ii) TGP must evaluate each ***special permit segment*** in accordance with 49 CFR 192.463.

iii) For inadequate CP level determination described in **Condition 3(c)(ii)**, TGP must conduct a CIS in both directions from the test station with an inadequate CP reading with the CIS ending at the adjacent test stations.

b) **Survey Intervals**: TGP must perform the CIS within the following timeframes:

i) Initial assessment must be completed for each newly incorporated and extended ***special permit segment*** within 12 months after the grant of the special permit. For a ***special permit segment*** renewal, the CIS may be conducted at the next reassessment interval.[19]

ii) Reassessments must be conducted every five (5) years not to exceed 66 months. CISs within the reassessment interval are not required to be performed in the same year as ILI reassessments.

c) **Survey Remediation and Remedial Action Plans**:

i) If a ***special permit segment*** requires the use of 100 millivolt shift criteria[20] or the installation of linear anodes along the ***special permit segment*** to meet the CP

---

[18] Each condition in this special permit that requires TGP to perform an action with respect to the ***special permit inspection area*** also requires TGP to perform that action on each ***special permit segment*** within the area.

[19] A CIS survey conducted in 2020 for a ***special permit segment*** that is permit condition compliant would not need to be resurveyed in 2021 but could wait until the next CIS survey reassessment time.

[20] A.W. Peabody, "Peabody's Control of Pipeline Corrosion," second edition, "Criteria for Cathodic Protection." "The 100mV polarization criterion should not be used in areas subject to stray current because 100 mV of polarization may not be sufficient to mitigate corrosion in these areas. This criterion also should not be used in areas where the intergranular form of external SCC, also referred to as high-pH or classical SCC, is suspected. The potential range for cracking lies between the native potential and -850 mV (CSE) such that application of the 100mV polarization criterion may place the potential of the structure in the range for cracking."

requirements of 49 CFR 192.463, it is not eligible to operate with a Class 1 pipe in a Class 3 location. TGP must either: (1) replace the pipe in the ***special permit segment*** with Class 3 location standard (design factor) pipe (see 49 CFR 192.111(a)); (2) recoat the pipe with non-shielding external coating within 12 months of the finding; or (3) lower the MAOP to meet 49 CFR 192.611.

ii) Within four (4) months of identifying a deficiency, TGP must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the remedial action plan being developed, TGP must apply for any necessary environmental permits (federal or state).

iii) TGP must complete remediation of each ***special permit segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[21]

5) **<u>Condition 5 – Inline Inspection</u>**

a) **<u>Threat Identification</u>**: TGP must implement data integration and identify integrity threats in the ***special permit inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.917 and **Condition 13(c) – Data Integration**. The stress corrosion cracking (SCC) threat assessment for the ***extended special permit segment***,[22] must be conducted using the current incorporated by reference (IBR) edition of the American Society of Mechanical Engineers (ASME) Standard B31.8S, "Managing System Integrity of Gas Pipelines" (ASME B31.8S) Appendix A3 and National Association of Corrosion Engineers (NACE) Standard Practice (SP) 0204-2008, "Stress Corrosion Cracking Direct Assessment Methodology," Sections 1.2.1.1 and 1.2.2.

---

[21] If remediation based upon the findings of the CIS is not practicable within 12 months of the CIS survey, TGP must submit a schedule and justify the delay 60 days prior to the 12-month completion requirement to the Director, PHMSA Southern Region. TGP must receive a “no objection” letter from the Director, PHMSA Southern Region, prior to a pipe coating remediation schedule extension.

[22] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

b) **<u>Inline Inspection Methodology</u>**: TGP must conduct instrumented ILI integrity assessments in accordance with 49 CFR 192.493, for each ***special permit inspection area*** for all threats identified in accordance with 49 CFR 192.919 and 192.921.

i) At a minimum, TGP must conduct ILI assessments for corrosion and denting with high-resolution (HR) magnetic flux leakage (HR-MFL) and HR deformation tools with deformation-extended sensor arms not limited by pig cups.

ii) For near-neutral or high-pH SCC (cracking threat), TGP must use an ILI tool[23] that will identify tight cracks.[24]

iii) A ***special permit segment*** with electric flash-welded (EFW) pipe must have an ILI tool assessment run for hard spots and cracking from hard spots.

iv) In a ***special permit inspection area*** that has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, TGP must run inertial measurement unit (IMU) and HR-deformation ILI tools for detection and remediation of strains and denting of the pipe body and girth welds from soil or pipe movements that impair pipeline integrity. Remediation must be conducted as determined by **Condition 13(j) – Pipe and Soil Movement**.

c) **<u>Inline Inspection Assessment Intervals</u>**: TGP must conduct initial assessments and reassessments for the ***special permit inspection area*** in accordance with the following:

i) Initial ILI assessments must be conducted as follows:

(1) If the ***special permit segment*** has EFW pipe, it must be assessed for hard spots within 18 months of the special permit grant date.

(2) If cracking has been identified as a threat for the ***extended special permit segment***, it must be assessed within 18 months of the special permit grant date.

---

[23] The crack ILI tool must be comparable to an electro-magnetic acoustic transducer (EMAT) ILI tool.

[24] TGP may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southern Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

(3) All other identified threats must be assessed within two (2) years of the special permit grant date.

(4) For newly identified threats, assessments must be completed within two (2) years of identification.

(5) Previous ILI assessments may be applied if **Condition 8 – Anomaly Evaluation and Remediation** is completed and the **Condition 5(c)(ii)** reassessment interval is maintained.

ii) Reassessments must be completed in accordance with the shortest interval of the following:

(1) 49 CFR 192.939(a);

(2) Intervals of five (5) calendar years not to exceed 66 months, if the ***special permit segment*** contains any of the following:

(a) low-frequency electric resistance welded (LF-ERW) or EFW pipe,

(b) hard spots,

(c) shorted carrier pipe to the casing,

(d) susceptible to SCC, or

(e) pipe or soil movement; or

(3) The engineering critical assessment (ECA) determined interval, if applicable.

iii) After conducting two (2) assessments of a threat, one (1) of which must be after the grant of this special permit, TGP may request reassessment intervals up to seven (7) years for that threat assessment. TGP must submit for and receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing this change.

iv) If factors beyond TGP's control prevent the completion of an assessment within the required timeframe or reassessment interval, TGP must perform the assessment as soon as practicable, and TGP must submit a letter justifying the delay and provide the anticipated date of completion to the Director, PHMSA Southern Region, no later than two (2) months prior to the end the timeframe or interval. TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, for the delay or must lower the MAOP of the ***special permit segment*** in accordance with 49 CFR 192.611.

d) **Remediation**: Anomaly assessments must be evaluated and remediated in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

6) **Condition 6 - Girth Welds**

a) **Construction Girth Weld Non-Destructive Test Records**: TGP must provide records to PHMSA that demonstrate the girth welds in the ***special permit inspection area*** were either:

i) Non-destructively tested (NDT) at the time of construction in accordance with the Federal pipeline safety regulations at the time the pipelines were constructed, or

ii) At least 1% of the girth welds and a minimum of two (2) girth welds in each ***special permit segment*** were NDT after initial construction and prior to the special permit application. TGP must demonstrate these welds were excavated, NDT, and repaired, if the welds do not meet Federal pipeline safety regulations at the time the pipelines were constructed.

b) **Missing Records**: If TGP cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, TGP must complete either **Condition 6(b)(i)** or both **Conditions 6(b)(ii)** and **(iii)** within 12 months of the grant of this special permit as follows:

i) Certify to PHMSA, in writing, that there have been no in-service leaks or breaks in the girth welds in the ***special permit inspection area*** for the life of the pipeline; or

ii) Evaluate the terrain along each ***special permit segment*** for threats to girth weld integrity from soil or settlement stresses, perform NDT, and remediate all such integrity threats;[25] and

iii) Excavate,[26] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance with the applicable American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

(1) Using the edition of API 1104 current at the time the pipeline was constructed;

(2) Using the edition of API 1104 IBR in the Federal pipeline safety regulations at the time the pipeline was constructed; or

(3) Using the edition of API 1104 currently IBR in 49 CFR 192.7.

c) **Defective Girth Welds**: If any girth weld in a ***special permit segment*** is found unacceptable in accordance with the API 1104 IBR Edition at the time of pipeline construction, TGP 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***. TGP must submit the inspection and remediation plan for girth welds to the Director, PHMSA Southern Region, and must receive a "no objection" letter for the girth weld remediation plan prior to its implementation.[27] TGP must remediate girth welds in the ***special permit segment***

[25] If a ***special permit segment*** has not had girth weld NDT to meet **Condition 6** – **Girth Welds** and has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, then **Condition 5(b)(iv)** must be conducted within 12 months of the finding.

[26] TGP must evaluate the pipe for SCC any time the ***special permit inspection area*** is uncovered or excavated in accordance with **Condition 8(b) or (c)** of this special permit. Pipe with fusion bonded epoxy coating does not require SCC evaluation when excavated unless SCC has been identified as a threat in the ***special permit inspection area***.

[27] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days of receipt with a decision letter, or either give TGP a request for additional information or a need of additional time for PHMSA to review the request.

in accordance with the inspection and remediation plan within 90 days of the "no-objection" letter receipt.[28]

7) **Condition 7 - Stress Corrosion Cracking Threat**

TGP must evaluate the entire length of each ***special permit inspection area*** for SCC as follows:

a) **Threat Assessments**: TGP must complete the SCC threat assessment as detailed in **Condition 5(a) – Threat Assessment**.

b) **SCC Integrity Assessment**: If the threat assessment required under **Condition 7(a)** indicates the ***extended special permit segment***[29] is susceptible to either near-neutral or high-pH SCC, TGP must perform an SCC assessment on the ***extended special permit segment*** in accordance with **Condition 5 – Inline Inspection**. SCC integrity assessment using spike pressure testing is not approved for this special permit.[30]

c) **Examination of Pipe**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, TGP must directly examine the pipe for SCC when the coating has been identified as poor during the pipeline examination. The examination must be conducted using an accepted crack detection practice in accordance with 49 CFR 192.710(c)(4), (d), and **Condition 7(d)** when the extended ***special permit segment*** is uncovered for any reason to comply with the special permit and IM activities, not including One Call activities (49 CFR 192.614).

d) **Inspection of Pipe at Excavations**: Except for pipe coated with non-shielding coatings (fusion-bonded or liquid-applied epoxy coatings) and excavations performed in accordance with 49 CFR 192.614(c), TGP must directly examine the pipe for SCC using

---

[28] TGP must include any plan requirements or comments received from the Director, PHMSA Southern Region, into the remediation plan.

[29] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

[30] TGP may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southern Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

non-destructive examination methods appropriate for the type of pipe and integrity threat conditions in the ditch. TGP must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[31] when an ***extended special permit segment*** is uncovered, and the coating has been identified as poor during the pipeline examination. Visual inspection is not sufficient to determine "poor coating." TGP must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe and/or shields the CP. TGP must keep coating records[32] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **<u>Discovery of SCC</u>**: If TGP discovers SCC[33] activity by any means within the ***extended special permit segment*** in similar pipe vintage (manufacturer, manufacturing time or age, diameter, wall thickness, grade, and seam type) and pipe coating vintage (in accordance with 49 CFR 192.917(e)), or the ***extended special permit segment*** has had an in-service or hydrostatic test SCC failure or leak,[34] the ***special permit segment*** must be further assessed and mitigated, within 18 months of finding SCC and reassessed every five (5) calendar years or less[35] based upon the evaluated growth of the SCC, using <u>one (1) of the following methods</u>:

---

[31] When MPI finds cracking, another method must be used to size the crack unless the crack can be completely ground out and still meet the pipeline MAOP.

[32] The records must include, at a minimum, a description of TGP's detection procedures, records of finding, and mitigation procedures implemented for the excavation.

[33] "SCC" activity shall be defined as greater than 20 percent wall thickness depth and 2-inches in length.

[34] For all in-service and pressure test failures, TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

[35] TGP has the option to submit a written request to the Director, PHMSA Southern Region, with a copy to the Director, PHMSA Engineering and Research Division, for extension of the crack assessment interval to seven (7) years, as defined in 49 CFR 192.939(a), if the ECA shows that five (5) calendar year assessments are not required. TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to extending the assessment interval to seven (7) calendar years.

i) **<u>Spike Hydrostatic Test Program</u>**:[36]

(1) TGP must perform its SCC spike hydrostatic test program in an ***extended special permit segment*** in accordance with 49 CFR 192.506 and include an ECA of the results that includes a determination of the reassessment interval, and

(2) If a joint of pipe in an ***extended special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, TGP must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended special permit segment*** with new pipe. TGP must complete a successful SCC hydrostatic test prior to returning the ***extended special permit segment*** to operational service;

ii) **<u>Crack Detection Tool Assessment</u>**: TGP must run an electro-magnetic acoustic transducer (EMAT) ILI tool or other equivalent crack detection ILI tool in the ***extended special permit segment***;

iii) **<u>MAOP Lowered</u>**: TGP must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

iv) **<u>Pipe Replacement</u>**: TGP must replace all pipe and comply with 49 CFR 192.611 and 192.619 in the ***special permit segment***; or

v) **<u>Operating Pressure Lowered</u>**: TGP must lower the operating pressure of the ***special permit segment*** to 20% below the maximum pressure during the preceding 90-day operating interval until TGP conducts an ECA and remediates the ***special permit segment***.

f) **<u>SCC Remediation Plan</u>**: If TGP discovers any SCC activity in the ***extended special permit segment***, TGP must submit an SCC remediation plan to the Director, PHMSA

---

[36] TGP may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Southern Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

Southern Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC.[37] The plan must:

i) Meet **Condition 7(e)** and include an SCC remediation/repair plan with SCC characterization and timing; or

ii) Include a technical justification that shows that TGP is addressing the threat for SCC in the ***special permit segment***.

8) **Condition 8 - Anomaly Evaluation and Remediation**

a) **General**: TGP must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. TGP must account for ILI tool tolerance and corrosion growth rates in determining scheduled response times and repairs and must document and justify the values used.

i) **ILI Tool Accuracy**: TGP must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration excavations and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). TGP must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to TGP. TGP must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. ILI tools used must be calibrated as follows:

(1) **General ILI Tool Calibration**: ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***special permit inspection area*** or from the complete ILI tool run segment if the continuous ILI segment is longer than the ***special permit inspection area***. ILI calibration excavations may include previously excavated anomalies or recent anomaly excavations with

[37] For TGP to go forward with the technical justification for addressing the SCC threat, TGP must receive a “no objection” letter from the Director, PHMSA Southern Region.

known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[38]

(2) **<u>EMAT ILI Tool Calibration</u>**:

(a) ILI calibration for EMAT ILI Tools must be based upon excavation results of a minimum of the two (2) most severe anomalies from a combined review of crack depth and length. If the EMAT tool identifies only one (1) anomaly, the anomaly must be excavated and assessed. TGP can propose alternative EMAT ILI Tool evaluation procedures to the Director, PHMSA Southern Region, but must receive a "no objection" letter prior to usage of these procedures.

(b) If the EMAT ILI tool does not identify any cracking anomalies above the minimum length and depth criteria for 90% probability of detection, TGP must provide the following to the Director, PHMSA Southern Region:

(1) EMAT ILI service provider report with any TGP provided reporting thresholds for cracking;

(2) Calibration data showing the ILI tool meets API Standard 1163 IBR - *Sections 6 - Qualification of Performance Specifications*, *Section 7 -*

[38] Other known and documented pipeline features that are appropriate for the type of ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration, TGP must complete the following: (1) submit a plan for using known and documented pipeline features such as calibration excavation data, to the Director, PHMSA Southern Region, with a copy to the Director, PHMSA Engineering and Research Division. The plan must include at least the following information: a) reason that known and documented pipeline features will be used in place of anomalies on the pipelines; b) the pipeline features that will be used for the ILI tool calibration; and c) the technical justification for using the pipeline features for ILI tool calibration; (2) receive a "no objection" letter from the Director, PHMSA Southern Region, prior to performing the ILI tool calibration using pipeline features; (3) submit a report to the Director, PHMSA Southern Region, with a copy to the Director, PHMSA Engineering and Research Division, and with the results of the use of pipeline features for the ILI tool calibration that includes technical documentation establishing the validity of using the pipeline features for the ILI tool calibration.

System Operational Verification, and *Section 8 - System Results Validation*, as applicable; and

(3) Previous in-ditch non-destructive examination records showing no SCC findings.

(4) TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, that no excavation is required for the EMAT ILI tool calibration.

ii) **Unity Plots**: The unity plots must show actual anomaly depth versus predicted depth.

iii) **ILI Tool Evaluations**: ILI tool evaluations for metal loss must use "6t x 6t"[39] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[40] must be within 180 days of any ILI tool run for each type of ILI tool (e.g., HR-geometry, HR-deformation, HR-MFL, EMAT, IMU, or other equivalent ILI tools).

b) **Remediation schedule for "special permit inspection area"**: TGP must remediate the ***special permit inspection area***[41] as follows:

i) **Immediate repair conditions for a "*special permit inspection area*"**: TGP must repair the following conditions immediately upon discovery in a ***special permit inspection area***:

(1) Metal loss anomaly where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with 49 CFR 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

---

39 "6t" means pipe wall thickness times six (6).

40 Discovery date is the day, month, and year that TGP receives the ILI tool run results from the ILI tool service provider.

41 Throughout this special permit, the ***special permit inspection area*** includes the ***special permit segment***, so any anomalies found in a ***special permit segment*** must be remediated to meet the requirements for a ***special permit inspection area*** in addition to the requirements of this condition for a ***special permit segment***. The ***special permit segment*** has additional remediation criteria in later sections of this special permit condition.

(2) Metal loss greater than 80% of nominal wall, regardless of dimensions.

(3) Metal loss preferentially affecting a detected pipe weld seam, and the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.25 times the MAOP or the metal loss is greater than 50% of pipe wall thickness.[42]

(4) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) A crack or crack-like anomaly meeting any of the following criteria:

(a) Crack depth plus any metal loss is greater than 50% of pipe wall thickness;

(b) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(c) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with 49 CFR 192.712(d), that is less than 1.25 times the MAOP.

(6) An indication or anomaly that, in the judgment of TGP, requires immediate action.

ii) **<u>One-year conditions – Hard Spots for a "special permit inspection area"</u>**: TGP must repair by installation of a Type B sleeve or cut-out and recoat within 12 months of discovery, any hard spots found in the pipe body of EFW pipe discovered after the grant of the special permit with a hardness on the Brinell Hardness scale (HB) of either (1) 300 HB or greater and 2-inches in length or width; (2) 300 HB or greater

[42] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

with any cracking or metal loss over 10% of wall thickness; or (3) a single reading of 320 HB or greater at any location.

iii) **<u>One-year conditions – dents, metal loss, and cracks for a "special permit inspection area"</u>**: TGP must repair the following conditions within 12 months of discovery in a ***special permit inspection area***:

(1) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with 49 CFR 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2 locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside of the ***special permit segment*** with a predicted failure pressure greater than 1.1 times the MAOP, TGP must follow the remediation schedule specified in ASME/ANSI B31.8S, Section 7, Figure 4.

(5) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with 49 CFR 192.712 less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

(6) Metal loss preferentially affecting a detected pipe weld seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0 (49 CFR 192.113), and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[43]

(7) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with 49 CFR 192.712(d) that is less than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, and 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.

iv) **Two-year condition for crack repairs for a "special permit inspection area"**: TGP must remediate any crack or crack-like anomaly that has a crack depth greater than 40% of the pipe wall thickness within two (2) years of discovery that are in the ***special permit inspection area*** and area outside of the ***special permit segment***.

(v) **Monitored conditions for a "special permit inspection area"**: TGP does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored conditions are the least severe and

[43] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

will not require examination and evaluation until the next scheduled integrity assessment.

(1) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(2) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and engineering analyses of the dent conducted in accordance with 49 CFR 192.712 and **Attachment A** demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(3) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and engineering analyses conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(4) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A** to demonstrate the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than or equal to 1.39 times the MAOP for Class 1 locations or where

Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[44]

(6) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with 49 CFR 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[45] The crack depth is less than 40% of the pipe wall thickness.

c) **<u>Remediation schedule for a "special permit segment"</u>**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, TGP must remediate conditions in a ***special permit segment*** as follows:[46]

i) **<u>One-year conditions for a "special permit segment"</u>**: TGP must repair the following conditions within one (1) year of discovery in a ***special permit segment***:

(1) **<u>Pipe Wall</u>**: Pipe wall thickness metal loss greater than 40%.

(2) **<u>Weld Metal</u>**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[47]

---

[44] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

[45] Failure stress pressure and crack growth analysis of cracks and crack-like defects must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, PAFFC, and PipeAccess™. All crack fracture mechanic evaluation models must be used within the assessment limits of the model.

[46] The ***special permit inspection area*** includes the ***special permit segment***, so any anomalies found in a ***special permit segment*** must be remediated to meet the requirements for a ***special permit inspection area*** in addition to the requirements in this condition. The ***special permit segment*** must also be remediated to meet all additional remediation requirements specifically for the ***special permit segment*** as required in the special permit conditions.

[47] ASME/ANSI B31G and R-STRENG are not acceptable evaluation methodologies for corrosion in pipe weld seams. Pipe weld seams must be evaluated using ECA methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

(3) **<u>Class 1 pipe</u>**: Any anomaly with a predicted failure pressure less than 1.39 times the MAOP.

(4) **<u>Class 2 pipe</u>**: Any anomaly with a predicted failure pressure less than 1.67 times the MAOP.

(5) **<u>Class 3 pipe</u>**: Any anomaly with a predicted failure pressure less than 2.0 times the MAOP.

ii) **<u>One-year crack repair conditions for a "special permit segment</u>**": TGP must repair all anomalies with a predicted failure pressure determined in accordance with 49 CFR 192.712(d) that is less than 1.39 times the MAOP, or a crack depth that is greater than 40% of the pipe wall thickness.

iii) **<u>Un-cleared shorted casing for a "special permit segment</u>**": TGP must repair within 12 months of discovery any identified corrosion, cracking or other anomaly that is shorted to a casing that is greater than 30% of the pipe wall thickness.

iv) **<u>Monitored conditions for a "special permit segment</u>**": TGP does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation in a ***special permit segment***. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment.

(1) **<u>Class 1 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 1.39 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(2) **<u>Class 2 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 1.67 times the MAOP and an anomaly depth less than or equal to 40% wall thickness loss.

(3) **<u>Class 3 pipe</u>**: Any anomaly with a predicted failure pressure greater than or equal to 2.0 times the MAOP and an anomaly depth less than or equal to 40% of pipe wall thickness.

9) **<u>Condition 9 - Pipe Casings</u>**

TGP must identify all shorted casings within a ***special permit segment*** no later than six (6) 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, Direct Current Voltage Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), or AC Attenuation.

a) **<u>Clear Shorted Casings</u>**: Where practical, TGP must clear shorted casings identified within a ***special permit segment*** no later than 12 months after the grant of this special permit as follows:

   i) **<u>Metallic Shorts</u>**: TGP must clear any metallic short on a casing in a ***special permit segment*** no later than 12 months after the short is identified.

   ii) **<u>Electrolytic Shorts</u>**: TGP must remove the electrolyte from the casing/pipe annular space on any casing in a ***special permit segment*** that has an electrolytic short within 12 months of identifying the short. If TGP identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

   iii) **<u>All Shorted Casings</u>**: TGP must install external corrosion control test leads on both the carrier pipe and the casing in accordance with 49 CFR 192.471 to facilitate the future monitoring for shorted conditions. TGP may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material that provides a corrosion-inhibiting environment provided TGP completed an assessment and all necessary repairs.

b) **<u>Remediation of Un-cleared Casing Shorts</u>**: If it is impractical for TGP to clear a shorted casing within a ***special permit segment***, TGP must document the actions taken to remediate the shorted casing and must receive a "no objection" letter from the Director, PHMSA Southern Region, to use ILI assessments instead of clearing the short.[48, 49] In addition to the notification, TGP must conduct the following:

i) A ***special permit segment*** with shorted casings must be assessed with the appropriate ILI tools (<u>a minimum of HR-MFL and HR-Deformation ILI and with EMAT ILI when a ***special permit segment*** is susceptible to SCC</u>) on a five (5) calendar year assessment schedule, not to exceed 66 months.

ii) TGP must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

10) <u>**Condition 10 - Pipe - Seam Evaluations**</u>

TGP must conduct engineering integrity assessments to identify any pipe in the ***extended special permit segment*** that may be susceptible to pipe seam leak, rupture, or other failure issues because of the vintage of the pipe, the manufacturer of the pipe, other physical or operational characteristics, or unknown pipe characteristics as follows:

a) <u>**Identify and Test Pipe Seam Issues**</u>:

i) Within 12 months of the special permit grant, TGP must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended special permit segment***.[50] This engineering integrity analysis must follow and document the processes listed herein along with other relevant materials:

(1) "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-COSP02120; and

---

[48] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

[49] TGP must send a copy of the actions taken to clear the shorted casing to the Director, PHMSA Engineering and Research Division.

[50] The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

(2) 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.

ii) If the engineering integrity analysis identifies pipe seam issues in the ***extended special permit segment*** that are a threat to the integrity of the pipeline, TGP must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, TGP must complete a hydrostatic test to a minimum of 1.39 times the MAOP for any identified ***special permit segment***.

b) **<u>Seam Leak or Failure</u>**:

i) If the pipeline experienced a seam leak or failure in the last five (5) years and TGP did not perform a hydrostatic test meeting **Condition 1(b)** after the seam leak or failure in the ***special permit segment*** of the same weld seam and manufacturer, then TGP must complete a hydrostatic test to a minimum of 1.39 times the MAOP within 18 months after the grant of this special permit in the ***special permit segment***.

ii) TGP must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure.[51]

c) **<u>Pipe Replacement</u>**: The ***special permit segment*** must be replaced if any of the following conditions exist or are discovered after the grant of this special permit:

i) The ***special permit segment*** has any direct current-electric resistance welded (DC-ERW) seam or pipe with a longitudinal joint factor below 1.0 as defined in 49 CFR 192.113;

---

[51] TGP must send a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

ii) The ***special permit segment*** pipe has any LF-ERW or EFW seam pipe joints that had pipe seam leaks or ruptures and the pipe has not been replaced with new pipe;[52]

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[53]

iv) The ***special permit segment*** pipe has unknown manufacturing processes (i.e., unknown seam type, yield strength, or wall thickness); or

v) The ***special permit segment*** pipe 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 led to buckling, past leak and rupture issues, or any other systemic issues.

d) **Girth Weld or Seam Weld Repairs**: Within a ***special permit segment***, TGP must remove and replace, in accordance with 49 CFR Part 192 requirements, all weld seam or girth weld repairs that have been made by the usage of fittings such as weldolets, threadolets, repair clamps, and pipe sleeves (steel or composite). This remediation must be completed within six (6) months of the grant of this special permit or within six (6) months of the identification.

e) **Remediation Plan**: TGP must remediate all weld seam leaks, failures, or ruptures[54] discovered in the ***special permit segment***. TGP must submit a seam remediation plan for the ***special permit segment*** to the Director, PHMSA Southern Region, no later than 30 days after finding a seam leak, seam failure, or seam rupture in the ***special permit segment*** containing one (1) of the following:

---

52 As of the date of the grant of this special permit, TGP reported no LF-ERW or EFW seam pipe in a ***special permit segment***.

53 As of the date of the grant of this special permit, TGP has identified pipe manufactured prior to 1954 in ***special permit segment 404***.

54 For all in-service and pressure test failures, TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

i) A longitudinal weld seam remediation/repair plan that meets **Condition 10** and includes replacement, hydrostatic testing, or ILI, with completion of the remediation/repair plan within six (6) months of discovery, or

ii) A technical justification that shows that the ***special permit segment*** is not at risk for future longitudinal seam leaks or failures.

11) **<u>Condition 11 - Control of Interference Currents</u>**

TGP must address induced alternating current (AC) from parallel electric transmission lines and other interference issues, such as direct current (DC), that may affect the pipeline in a ***special permit segment***. TGP must have an induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents within 12 months of the grant of this special permit.

a) **<u>Surveys</u>**: TGP must perform periodic interference surveys to detect the presence and level of any electrical stray current, including when there are current flow increases over the ***special permit segment*** grounding design from any co-located pipelines, structures, or high voltage alternating current (HVAC) powerlines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures.

b) **<u>Analysis of Results</u>**: TGP must analyze the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if the interference impedes the safe operation of the pipeline, or that may cause a condition that would adversely impact the environment or the public.

c) **<u>Remediation</u>**: Remedial action is required when the interference in the ***special permit segment*** is at a level that could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or may cause a condition that would adversely impact the environment or the public. Within six (6) months after completing the interference survey, TGP must develop a remediation procedure and apply for any necessary permits to conduct remediation. TGP must complete all remediation within six (6) months, or as soon as practicable, after obtaining the necessary permits for the remediation.

d) **Completion Schedules**: If environmental permitting or right-of-way factors beyond TGP's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, TGP must complete remediation as soon as practicable and submit a letter justifying the delay and providing the anticipated date of completion to the Director, PHMSA Southern Region, no later than one (1) month prior to the end of the six (6) month completion date. Any extended evaluation and remediation schedules submitted to PHMSA from TGP must receive a "no objection" letter from the Director, PHMSA Southern Region.

12) **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures**

TGP must automate mainline valves[55] for closure or demonstrate capability to manually close mainline valves in accordance with the requirements of this **Condition 12**. A ***special permit segment*** must have upstream and downstream remote-controlled valves (RCVs) so that the distance between the valves is no greater than 20 miles.[56] TGP must automate mainline valves to close in accordance with the requirements in **Condition 12** within 12 months of the grant of this special permit. The ***special permit segment*** must have procedures for rupture isolation as follows:

a) **Valve Locations**: RCVs must be installed as shown in **Table 4 - Valves and Lateral Locations with Isolations Methods**. All ***special permit segments*** must have telemetry connections to the TGP supervisory control and data acquisition (SCADA) system installed.

b) **Automatic Shutoff Valve Requirements**: This special permit does not allow the use of ASVs.

---

[55] A mainline valve is a sectionalizing valve used to isolate or stop gas flow upstream or downstream along the pipeline.

[56] If the distance between mainline isolation valves exceed 20 miles, additional mainline valve(s) must be added.

c) **<u>Remote Monitoring and Control</u>**: Each ***special permit segment*** must be controlled by a SCADA system and must be equipped for remote monitoring and control, or remote monitoring and automatic control, in accordance with 49 CFR 192.620(d)(3)(iii) and the below requirements in this **Condition 12**.

d) **<u>Crossover or Lateral Pipe Connection Isolation</u>**: If any crossover or lateral pipe[57] connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment). If the nearest valve for a gas receipt or delivery line to the ***special permit inspection area*** is not isolated, isolation valves must be installed within 12 months of the grant of this special permit.[58] Valves that are in the TGP O&M procedures as locked closed and that are only opened when manned by TGP operating personnel do not require RCVs or ASVs for closure.

e) **<u>Remote-Control and Automatic-Shutoff Valve Status</u>**:

   i) RCVs must be constantly monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure.

   ii) This special permit does not allow the use of ASVs.

f) **<u>Mainline Valve Closure</u>**: Closure of the appropriate valves following a pipeline leak or rupture must occur "as soon as practicable" and must not exceed 30 minutes from the "notification of potential rupture" as defined below:[59]

---

[57] **Table 4 - Valves and Lateral Locations with Isolations Methods** has a listing of all lateral valves. TGP must update **Table 4** if a lateral or crossover valve was not identified or is added after the grant of the special permit and submit this update in accordance with **Condition 15 – Annual Report**.

[58] Gas delivery or receipt pipelines must have a shutoff valve (gate or ball valve) either at the connection between the isolation valves for a ***special permit segment*** or at the delivery or receipt meter station. Any gas delivery or receipt station over 5-miles in length that is connected between the isolation valves for a ***special permit segment*** must have a RCV or ASV within 5-miles of the pipeline tie-in. For gas delivery or receipt pipelines manual shutoff valves can be used for isolation but must be closed within 30-minutes of the pipeline leak or rupture confirmation. Check valves cannot be used for pipelines over 8-inch diameter.

[59] The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by TGP through Gas Control or other field operations personnel monitoring of the appropriate pipeline pressures, pressure changes, or flow rate changes through a compressor discharge section or by location confirmation from responsible persons.

i) “Notification of Potential Rupture” means any of the following events that involve an unintentional or uncontrolled release of a large volume of gas from a transmission pipeline:

(1) A release of gas observed by or reported to TGP (e.g., by its controller(s) in a control room, field operations personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) that may be representative of an unintentional or uncontrolled release event meeting **paragraphs (2)** or **(3)** of this definition;

(2) TGP observes an unanticipated or unplanned pressure loss outside of the pipeline’s normal operating pressures, as defined in TGP’s written procedures. If TGP establishes an unanticipated or unplanned pressure loss threshold that is greater than a 10% pressure loss, occurring within a time interval of 15 minutes or less, TGP must document in its written procedures the need for a greater pressure-change threshold due to pipeline flow dynamics (including the pipeline operating pressure, gas flow rate or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

(3) TGP observes an unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication that may be representative of an event meeting **paragraph (2)** of this definition.

<u>Note:</u> Notification of potential rupture occurs when an event, as defined in this **section/paragraphs (2)** or **(3)** above, is first observed by or reported to TGP.

ii) TGP must evaluate and identify a rupture,[60] as defined above, as being either an actual leak event, rupture event, or non-rupture event in accordance with operating procedures and 49 CFR 192.615.

---

[60] For all in-service and pressure test failures, TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

g) **<u>Gas Control Center Monitoring</u>**: The TGP Gas Control Center must monitor the ***special permit inspection area*** 24 hours a day, seven (7) days a week, and must confirm the existence of a leak or rupture as soon as practicable in accordance with TGP pipeline operating procedures.

h) **<u>Remote Monitoring</u>**: TGP must maintain remote monitoring and automatic control equipment, mainline valves, mainline valve operators, and pressure sensors in accordance with 49 CFR 192.631 and 192.745. All remote monitoring and automatic control equipment, including pressure sensors, must have backup power to maintain communications and control to the TGP Gas Control Center during power outages.

i) **<u>Point-to-Point Verification</u>**: TGP must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with 49 CFR 192.631(c) and (e).

j) **<u>Valve Maintenance</u>**: TGP must maintain all valves used to isolate a leak or rupture in accordance with this special permit and 49 CFR 192.745.

k) **<u>Inoperable Valves</u>**: TGP must take remedial measures to correct any valve used to isolate a leak or rupture that is found to be inoperable or unable to maintain shutoff, as follows:

   i) Repair or replace the valve as soon as practicable but no later than six (6) months after the finding;

   ii) Designate an alternative valve within 14 calendar days of the finding while repairs are being made. Repairs must be completed within six (6) months; and

   iii) If valve repair or replacement cannot be met due to circumstances beyond TGP's control, TGP must notify, in writing, the Director, PHMSA Southern Region, of the reasons the schedule cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing the schedule change.

l) **<u>Emergency Communications</u>**:

   i) TGP must establish and maintain adequate means of communication with the appropriate public safety access point (9-1-1 emergency call center) or emergency management coordinating agency and must notify them, as well other emergency responders, if there is a leak or rupture, as required in 49 CFR 192.615;

ii) TGP must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other emergency management coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[61] and

iii) In accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631, TGP must establish actions required to be taken by a pipeline controller or the appropriate emergency response coordinator when an emergency occurs in the ***special permit inspection area***.

13) **Condition 13 - Special Permit Specific Conditions**

TGP must comply with the following requirements:

a) **Line-of-Sight Markers**: TGP must install and maintain line-of-sight markings on the pipeline in each ***special permit segment***, except in agricultural areas or large water crossings, such as lakes, where line-of-sight signage is not practical. Line-of-sight markers must be installed within six (6) months of the grant of this special permit and replaced as necessary by TGP within 30 days after identification of line-of-sight marker removal.

b) **Depth of Cover Survey**:

i) TGP must complete, within six (6) months of the grant of this special permit, a depth of cover survey for each ***special permit segment***.

ii) TGP must implement additional safety measures for any pipe in a ***special permit segment*** that does not meet 49 CFR 192.327(a) for a Class 1 location where there is a reduced depth of cover. A ***special permit segment*** with depth of cover less than 24-

[61] TGP must designate the pipeline controller or the appropriate operator emergency response coordinator in its operating procedures and train the designated individual for coordinating with emergency responders.

inches must be either lowered, have additional soil cover added, or have a concrete pad installed unless it is in consolidated rock.

iii) For TGP to use other remedial measures for depth of cover requirements that are based upon the threat, such as increased pipeline patrols or additional line markers, TGP must submit these procedures to the Director, PHMSA Southern Region, for a "no objection" letter prior to usage. The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

c) **Data Integration**: TGP must develop and maintain data integration[62] in accordance with 49 CFR 192.917, of all special permit condition findings and remediation in a ***special permit segment*** and ***special permit inspection area***. Data integration must be completed at least once each calendar year, with intervals not to exceed 15 months.

i) Data integration must include the following information: (1) Pipe diameter, wall thickness, grade, and seam type; (2) pipe coating; (3) MAOP; (4) class location, including boundaries on aerial photography; (5) HCAs, including boundaries on aerial photography; (6) hydrostatic test pressure, including any known test failures; (7) casings; (8) any in-service ruptures or leaks; (9) ILI survey results, including HR-MFL, HR-geometry/caliper, or deformation tools; (10) the most recent CIS results; (11) depth-of-cover surveys; (12) rectifier readings for the past five (5) years; (13) CP test point survey readings for the past five (5) years; (14) AC/DC interference surveys; (15) pipe coating surveys; (16) pipe coating and anomaly evaluations from pipe excavations; (17) SCC excavations and findings; and (18) pipe exposures from

[62] Data integration is defined as the gathering of relevant pipeline attributes, operational, maintenance, environmental, and integrity information and integrating this information together to assess threats to the pipeline and to use this information to conduct assessments and remediation for those threats.

encroachments.[63] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

ii) If requested by PHMSA, TGP must complete and submit data integration documentation and drawings, with four (4) years of prior data, beginning with the 2nd annual report of this modified special permit.

iii) TGP must maintain data integration as a composite of all applicable data elements in a comparable data viewer.

d) **<u>Pipe Properties Testing</u>**: If the pipe does not meet **Condition 16(b)**, TGP must test the pipe in a ***special permit segment*** as follows: [64]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[65, 66] pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or 192.105 for determining MAOP. Non-destructive or destructive tests, examinations, and assessments must be completed within 18 months of the grant of this special permit.

ii) TGP must test pipe in each ***special permit segment*** without TVC material properties and of different vintages as defined in **Condition 13(d)(iv)**. Material tests must be conducted at two (2) excavation sites per mile with excavations spaced between 1,320 to 3,960 feet in each mile segment. If the ***special permit segment*** is less than ½ mile, only one (1) excavation site is required.

---

[63] Hydrostatic test failures, in-service ruptures, rectifier readings, CP test point survey readings, AC/DC interference surveys, pipe coating surveys, pipe coating and anomaly evaluations from pipe excavations, SCC excavations and findings, and pipe exposures from encroachments must be maintained for data integration into a comparable data viewer. These data elements may not be on a drawing.

[64] TGP has furnished TVC material records to PHMSA for the special permit segments that meet **Condition 16(b)**.

[65] TVC procedures and records must follow the following: 1) "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments"; 84 FR 52218 to 52219; October 1, 2019; and 2) PHMSA Advisory Bulletin: Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; <u>https://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf</u>.

[66] Material records must cover the entire length of the ***special permit segment***, regardless of when the pipeline, single or multiple pipe joints, or other pipeline components were installed. Affidavits for a material record are not acceptable TVC material records.

iii) TGP must perform a minimum of two (2) destructive or NDT methods at an excavation site. TGP must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[67] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then TGP will confirm the yield strength of that individual pipe using destructive test methods or remove the ***special permit segment*** pipe. If ILI tools are used to verify the pipeline materials, TGP must submit an assessment procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to its usage.[68] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

iv) TGP must assess pipe in a ***special permit segment*** with missing mill test reports (MTRs) or missing mill inspection reports (i.e. Moody Engineering Reports) for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a 2-year interval), and construction dates (within a 2-year interval).

v) TGP cannot use the material properties determined from either destructive or NDT required by this condition to raise the original grade or specification of the pipeline material. TGP must use the applicable standard referenced in 49 CFR 192.7.

---

[67] TGP must submit the non-destructive assessment method and procedures to the Director, PHMSA Southern Region, and the Director, PHMSA Engineering and Research Division. The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

[68] TGP must send a copy of the assessment procedure to the Director, PHMSA Engineering and Research Division.

vi) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, TGP must use the above methodology, or TGP may elect to remove pipe joints for destructive testing.[69]

e) **Pipeline System Flow Reversals**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49 CFR 192.619(a)(1) or 192.611[70] in a ***special permit segment***, TGP must prepare a written plan that corresponds to the applicable criteria identified in the PHMSA Advisory Bulletin, ADB-2014-04, "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" (79 FR 56121; Sept. 18, 2014). TGP must submit the written flow reversal procedure to the Director, PHMSA Southern Region, and submit a copy of the plan to the Federal Docket for this special permit at www.regulations.gov.[71] TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing the pipeline system flow reversal through a ***special permit segment***.

f) **Environmental Assessments and Permits**: TGP must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings, and pipeline natural gas emissions from implementation of the special permit conditions for a ***special permit segment*** or ***special permit inspection area*** prior to the disturbance or activity. If a land disturbance, water body crossing, or pipeline natural gas emission is required, TGP must obtain and adhere to all applicable Federal, state, and local environmental permit requirements when conducting the special permit conditions activity.

---

[69] TGP must prepare a procedure in accordance with **Condition 13(d) – Pipe Properties Testing**, for material documentation and submit to the Director, PHMSA Southern Region, and receive a "no objection" letter prior to usage of the procedure. The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision. A copy of the procedure must be sent to the Director, PHMSA Engineering and Research Division.

[70] An example of exceedance of 49 CFR 192.619(a)(1) is a Grandfathered MAOP which has a design factor above 0.72. An example of exceedance of 49 CFR 192.611 is a Class 1 to 3 location change.

[71] TGP must send a copy of the flow reversal procedure to the Director, PHMSA Engineering and Research Division.

g) **<u>Gas Quality</u>**: TGP must transport gas through the ***special permit segment*** whose composition quality is suitable for sale to gas distribution customers, including no free-flow water or hydrocarbons, no water vapor content that exceeds acceptable limits for gas distribution customer delivery, hydrogen sulfide (H_2S) not to exceed one (1) grain per 100 cubic feet, or carbon dioxide (CO_2) not to exceed three (3) percent by volume.

h) **<u>Annual Class Location Study</u>**: TGP must conduct a class location study on the ***special permit inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.609.

i) **<u>Notifications</u>**: For any special permit condition that requires TGP to provide a notice for a "no objection" response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Southern Region, TGP must also send a copy to the State Agency that has interstate agent agreements with PHMSA and to the Director, PHMSA State Programs.

j) **<u>Pipe and Soil Movement</u>**: Girth weld strain from soil movement exerted onto the pipeline in the ***special permit segment*** must not exceed 0.5 percent and must account for girth weld misalignment. TGP must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. TGP must submit soil stress and strain evaluation and remediation procedures to the Director, PHMSA Southern Region, within three (3) months of identification and must receive a "no objection" letter prior to implementation.

k) **<u>Gas Leakage Surveys and Remediation</u>**:

   i) TGP must conduct gas leakage surveys using instrumented gas leakage detection equipment along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher and ILI receiver facilities in each ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. TGP must document the type of equipment used, survey findings, and remediation of all instrumented gas leakage surveys.

   ii) A gas transmission pipeline leak is a gas leak that can be seen, heard, felt, or detected by instrumented gas leakage detection equipment, or is an existing, probable, or future hazard to the public, operating personnel, property, or the environment. TGP must grade and remediate all gas transmission pipeline leaks in the ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in each ***special permit inspection area***, as follows:

(1) A Grade 1 leak requires immediate and/or continuous remediation efforts to stop the leak. A Grade 1 leak is defined as any of the following:

(a) Any leak which, in the judgment of the operating personnel at the scene, is regarded as an immediate hazard;

(b) Escaping gas that has ignited;

(c) Any indication of gas which has migrated into or under a building, or into a tunnel.

(d) Any reading at the outside wall of a building, or any reading where gas would likely migrate to an outside wall of a building;

(e) Any reading of 80% lower explosive limit (LEL), or greater, in a confined space;

(f) Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building; or

(g) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the public, property, or environment.

(2) A Grade 2 leak requires remediation activity to be completed within 30 days or must have continuous remediation efforts to stop the leak. A Grade 2 leak is defined as any of the following:

(a) Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building;

(b) Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak;

(c) Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak;

(d) Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard;

(e) Any reading between 20% LEL and 80% LEL in a confined space;

(f) Any reading on a pipeline operating at 30% SMYS or greater, in a Class 3 or 4 location, which does not qualify as a Grade 1 leak;

(g) Any reading of 80% LEL, or greater, in gas associated substructures; or

(h) Any leak which, in the judgement of operating personnel at the scene, is of sufficient magnitude to justify schedule repair.

(3) A Grade 3 leak must be reevaluated at the next scheduled survey, or within 7½ months of the date discovered, whichever occurs first, until the leak is cleared, re-graded, or remediated. Remediation of Grade 3 leaks must be completed within 24 months of discovery of the leak. A Grade 3 leak is defined as any of the following:

(a) Any reading of less than 80% LEL in small gas associated structures;

(b) Any reading in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building; or

(c) Any reading of less than 20% LEL in a confined space.

iii) When a pressure limiting device or relief valve allows a gas release to the atmosphere that is located along the ***special permit inspection area***, TGP must conduct an O&M procedure assessment of the pilot, springs, pressure gauges, and other pressure limiting equipment to ensure these items are properly functioning, sensing, and retaining set pressures. If a pressure limiting device or relief valve deficiency cannot be remediated, the pressure limiting device or relief valve must be replaced or continuously monitored until remediated. TGP cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by TGP from the Director, PHMSA Southern Region.

iv) TGP may request an extension of the remediation time interval requirements by sending a request to the Director, PHMSA Southern Region, but must receive a “no objection” letter from the Director, PHMSA Southern Region, prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[72]

l) **<u>Right-of-Way Patrols</u>**: In addition to the requirements of 49 CFR 192.705, TGP must perform right-of-way patrols as follows:

i) Aerial flyover patrols or ground patrols by walking or driving of a ***special permit segment*** right-of-way once each month, not to exceed 45 days, contingent on weather conditions. Should mechanical availability of the patrol aircraft or weather conditions become an extended issue, the ***special permit segment pipeline*** aerial flyover patrol must be completed within 60 days of the last patrol by other methods such as walking or driving the pipeline route, as feasible.

ii) If the schedule for either ground patrols or aerial flyover patrols cannot be met due to circumstances beyond TGP’s control, TGP must notify the Director, PHMSA Southern Region, in writing of the reasons the schedule cannot be met and obtain a letter of “No Objection” within three (3) business days of the exceedance.

m) **<u>Minimization of Gas Released to the Environment</u>**:

i) TGP must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. TGP must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. TGP must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that

[72] Any TGP request for a time interval extension for a 24-month remediation interval must be 90 days prior to the end of the 24-month remediation interval.

minimizes the release of gas to the environment and is consistent with pipeline safety.[73]

1) Isolate a smaller pipeline segment length by use of valves and/or the installation of control fittings near the pipe being replaced;

2) Flaring the gas released from the pipeline from the nearest isolation valves or control fittings from the pipe being replaced;

3) Pressure reduction in the pipeline segment by use of inline compression;

4) Pressure reduction by use of mobile compression from the nearest isolation valves from the pipe being replaced;

5) Transfer the gas to a lower pressure pipeline system or segment from the nearest isolation valves nearest to the pipe being replaced such as through a lateral delivering gas to another pipeline facility; or

6) An alternative method demonstrated to minimize the release of gas to the environment similar to the other methods listed in the methods (1) through (5) above.

ii) TGP must document the determination and justification for the reduction method(s) implemented and how the method(s) used minimized the release of natural gas to the environment and was consistent with pipeline safety. TGP must also document and justify, any substantial difference (over 10 percent additional release) between the actual amount of natural gas released and the estimated volume calculated before the replacement.

iii) TGP must report all mainline blowdowns between the mainline isolating valves for a ***special permit segment*** due to pipe replacement as detailed in the **Condition 15(i) - Annual Report**.

[73] **Condition 13(m)** would not be required for a blowdown due to an immediate repair, as detailed in **Condition 8 - Anomaly Evaluation and Remediation**, or where immediate action is required to ensure public safety.

14) **<u>Condition 14 - Field Activity Notices to PHMSA</u>**

TGP must give a minimum 14-day notice to the Director, PHMSA Southern Region, to enable PHMSA to observe the excavations relating to **Condition 8 – Anomaly Evaluation and Remediation** and **Condition 13(d) – Pipe Properties Testing** of field activities in the ***special permit inspection area***. Immediate response conditions do not require 14-day notice, but TGP should notify the Director, PHMSA Southern Region, no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Southern Region, may elect not to require a notification for some activities.

15) **<u>Condition 15 - Annual Report</u>**

Annually[74] after the grant of this special permit, TGP must report the following to the Director, PHMSA Southern Region, with copies to the Director, PHMSA Engineering and Research Division:[75]

a) The number of new residences, other structures intended for human occupancy, and public gathering areas built within each ***special permit segment*** during the previous year. TGP must include a summary of the results of the study conducted to meet **Condition 13(h) - Annual Class Location Study** in the annual report.

b) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any un-remediated anomalies over 30% wall loss; cracking found in the pipe body, weld seam, or girth welds; and dents with metal loss, cracking, or stress riser) and any soil movement (lateral or subsidence) that affects pipeline integrity[76] during the previous year in the ***special permit inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

---

[74] PHMSA must receive the annual report 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, 2020, must be received by PHMSA no later than January 31, each year beginning in 2021.

[75] TGP must post the annual report to the special permit docket PHMSA-2016-0158 at <u>www.regulations.gov</u>.

[76] TGP must develop and implement an O&M procedure to review soil movements that could damage the ***special permit segment*** on a periodic interval so the lateral stresses will not exceed 100% of SMYS (0.5% strain) on girth welds.

c) In the 1st, 2nd, and 3rd annual reports TGP must report all ***special permit segments*** that do not have the following complaint TVC records:

   i) A pressure test that meets **Condition 1(b)**. TGP must report the planned or actual completion dates for the ***special permit segment*** pressure test including test pressure.

   ii) Material pipe properties tests that meet **Condition 13(d) – Pipe Properties Testing**. TGP must report the planned or actual completion dates for the ***special permit segment*** material pipe property tests.

d) 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 a ***special permit inspection area***. TGP must include the location by mile post, county/parish and state, the date of discovery, date of repair, and estimated gas loss (cubic feet) per day and in total for any Grade 1, 2, or 3 gas leak as described in **Condition 13(k) - Gas Leakage Surveys and Remediation**.

e) Any ongoing DP initiatives affecting a ***special permit inspection area*** and a discussion of the success of the initiatives, including findings and remediation actions.

f) TGP must submit annual data integration information, as required in **Condition 13(c) - Data Integration,** beginning with the 2nd annual report, which must include an annual overview of any new threats. If requested by PHMSA, TGP must submit a full information package of the requested pipeline attribute and integrity items outlined in the condition.

g) This special permit does not allow the use of ASVs, since TGP did not comply with **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** requirements for flow modeling to determine shutoff pressures of ASVs.

h) TGP must report the diameter and location of the lateral, if any lateral or crossover piping is not included in **Table 4 – Valves and Lateral Locations with Isolation Methods** or installed between isolation valves for a ***special permit segment***.

i) TGP must report all mainline blowdowns between the mainline isolating valves for a ***special permit segment*** due to pipe replacement which includes the date of blowdown, location (milepost/stationing), and the amount of gas released to comply with **Condition 13(m) – Minimization of Gas Released to the Environment**.

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

k) A senior executive officer, vice president, or higher executive of TGP must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2016-0158) at www.regulations.gov and submitting a copy to the Director, PHMSA Southern Region, and the Director, PHMSA Engineering and Research Division.

l) TGP must schedule a review meeting regarding **Condition 15 - Annual Report** with the Director, PHMSA Southern Region, prior to or within one (1) month of the filing of each year.[77] During the annual review meeting, TGP must review the status of implementing the special permit conditions with the Director, PHMSA Southern Region.

16) **Condition 16 – Documentation**

TGP must maintain the following records for a ***special permit segment*** as follows:

a) TGP must keep documentation of compliance with all conditions of this special permit for the life of the pipe.

b) Documentation of the mechanical and chemical properties (e.g., mill test reports) that show the pipe in a ***special permit segment*** meets the wall thickness, yield strength, tensile strength, and chemical composition requirements of API Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) incorporated by reference into the 49 CFR Part 192 code at the time of manufacturing, or, if the pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192, the API 5L standard in use at that time. Any pipe in a ***special permit segment*** that does not have TVC mill test reports or does not meet **Condition 13(d) – Pipe Properties Testing** and 49 CFR 192.607 cannot be authorized per this special permit.

[77] The Director, PHMSA Southern Region, has the authority to waive this meeting.

17) **<u>Condition 17 - Extension of the Special Permit Segment</u>**

PHMSA may extend a ***special permit segment*** to include contiguous segments up to the limits of the ***special permit inspection area*** pursuant to TGP implementing the following conditions:

a) Within six (6) months after the Class 1 to Class 3 location change, TGP must provide notice to the Director, PHMSA Southern Region, and Director, PHMSA Engineering and Research Division, of the request for a ***special permit segment <u>extension</u>***.

i) The notice must include the ***special permit segment extension*** survey stations, mile posts, additional pipeline footage, pipe attributes (wall thickness, grade, seam type, external coating, and latest pressure test), predicted failure pressure of any anomalies over 30% wall loss, schedule of inspections, and of any anticipated remedial actions.

ii) TGP must update the Final Environmental Assessment (FEA) to reflect the ***special permit segment*** extension and Section IX of the FEA, "Affected Resources and Environmental Consequences" as necessary. TGP must submit the updated FEA with its request for an extension to PHMSA for review and consideration.

iii) Any request for a ***special permit segment*** extension does not become effective until TGP receives a "no objection" response from the Director, PHMSA Engineering and Research Division.

b) Any proposed ***special permit segment extension*** must meet the following requirements prior to the class location change or within 12 months of the class location change:

i) TGP must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) TGP must have hydrostatically tested[78] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

iii) TGP must complete all required special permit conditions, except **Condition 17(b)** above, for each ***special permit segment extension*** within two (2) years of the Class 1 to Class 3 location change, unless specified otherwise.

c) TGP must apply all the special permit conditions and limitations included herein to all future ***special permit segment extensions***.

18) **<u>Condition 18 – Certification</u>**

TGP must meet the following conditions for certification:

a) A senior executive officer, vice president, or higher executive of TGP must certify in writing the following:

i) Each ***special permit inspection area*** and ***special permit segment*** meet the conditions described in this special permit;

ii) TGP has updated its O&M, IM program, and DP procedures required by **Condition 2 – Procedure Updates** to require the implementation of the special permit conditions for each ***special permit segment*** and ***special permit inspection area***;

iii) TGP has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

iv) TGP has implemented all conditions as required by this special permit.

b) TGP must send the certifications required in **Condition 18(a)**, with special permit condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator

---

[78] For all in-service and pressure test failures, TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure and must submit a copy of the root cause analysis to the Director, PHMSA Engineering and Research Division.

for Pipeline Safety with copies to the Director, PHMSA Southern Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2016-0158) at www.regulations.gov within one (1) year of the issuance date of this special permit.

IV. Limitations

This special permit is subject to the limitations set forth in 49 CFR 190.341, as well as the following limitations:

1) PHMSA has the sole authority to make all determinations on whether TGP has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.
2) Any work plans and associated schedules for a ***special permit segment*** and ***special permit inspection area*** are automatically incorporated into this special permit and are enforceable in the same manner.
3) Failure by TGP to submit the certifications required by **Condition 18 - Certification** within the time frames specified may result in revocation of this special permit.
4) As provided in 49 CFR 190.341, PHMSA may issue an enforcement action for failure to comply with this special permit. 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.
5) If TGP sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, TGP must provide PHMSA with written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances underlying the permit.
6) PHMSA grants this special permit limited to a term of no more than 10 years from the date of issuance. If TGP elects to seek renewal of this special permit, TGP must submit its renewal request at least 180 days prior to expiration of the 10-year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern Region, and to the Director, PHMSA Engineering and Research Division. All requests for

a renewal must include a summary report in accordance with the requirements in **Condition 15 - Annual Report** above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from TGP prior to granting any request for special permit renewal.

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR 1.97.

Issued in Washington, DC on __________________.

Signed copy of the special permit with tables, figures, and attachments is available as noted below.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

The granted special permit with conditions granted to TGP for Docket No. PHMSA-2016-0158 can be found the Federal Dockets Management System located on the internet at www.regulations.gov or on the PHMSA website for special permits issued at https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued.

Last Page of the FEA and FONSI