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-2019-0150
Requested By:	Natural Gas Pipeline Company of America, LLC
Operator ID#:	13120
Original Date Requested:	December 19, 2018
Issuance Date:	May 17, 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 impacts that would result from granting or denying the special permit. PHMSA developed this assessment to determine what effects, if any, our decision would have on the

---

1 References to PHMSA in this document means PHMSA OPS.

environment.

Pursuant to 49 United States Code (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 would 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 National Environmental Policy Act (NEPA) for the Natural Gas Pipeline Company of America, LLC (NGPL)[2] application for a special permit request to waive compliance from 49 CFR 192.611 for the two (2) ***special permit segments*** and two (2) ***special permit inspection areas*** along 861.78 feet (approximately 0.163 miles) of the natural gas transmission pipeline system in Iowa and Louisiana. This FEA and Finding of No Significant Impact is 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). This FEA assesses 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 certain Federal pipeline safety regulations found in 49 CFR 192.611(a) and (d) and 192.619.

II. Introduction

Pursuant to 49 U.S.C. 60118(b) and 49 CFR 190.341, NGPL submitted a special permit application to PHMSA on December 19, 2018, requesting that PHMSA waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) to permit NGPL to maintain the maximum allowable operating pressure (MAOP) to the Pipeline segment where the class location has changed from Class 1 to Class 3 located in Muscatine County, Iowa, and Vermilion Parish, Louisiana.

PHMSA is granting a special permit to waive certain regulatory requirements where it is not inconsistent with pipeline safety. A special permit is typically conditioned on the performance of additional measures beyond minimum Federal pipeline safety regulations, in accordance with 49 CFR 190.341.

[2] Natural Gas Pipeline Company of America LLC is owned by Kinder Morgan, Inc.

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. Below is the relevant text of 49 CFR 192.611(a):

49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(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.

(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 **Table 1 – Maximum Allowable Operating Pressure for Steel or Plastic Pipelines**. Which requires Class 3 location pipe to be pressure tested to 1.5 times MAOP.

Table 1 - Maximum Allowable Operating Pressure for Steel or Plastic Pipelines

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

Class location	Installed before (Nov. 12, 1970)	Factors, [1] segment - 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:

IV. Purpose and Need

NGPL has requested a special permit, and PHMSA has reviewed the special permit application. The special permit would require NGPL implement increased integrity management (IM) activities in lieu of pressure reduction or replacing pipe within the ***special permit segments*** located on NGPL's Amarillo Line #4 located in Muscatine County, Iowa, and Louisiana Line #1 located in Vermilion Parish, Louisiana, where the class location has changed from a Class 1 to a Class 3 location. The special permit would allow contiguous ***special permit segment*** extensions to increase in length that experience further development and class change in the future.

If PHMSA grants a special permit it would have conditions for the 0.163 miles of ***special permit segments*** and the 158.82 miles of ***special permit inspection areas***. The special permit would also include future class changes within the ***special permit inspection area*** (***special permit segment extensions***) under the special permit, providing the ***special permit segment extensions*** meet the special permit conditions applicable to ***special permit segment***.

This special permit consists of two (2) ***special permit segments*** and would waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) with implementation of the special permit conditions. The class location in the ***special permit segment*** originally changed from Class 1 to Class 3 in 2018.

V. Site Description

The NGPL Amarillo Line #4 located in Muscatine County, Iowa; and Louisiana Line #1 located in Vermilion Parish, Louisiana, are natural gas transmission pipelines. The ***special permit inspection***

areas extend approximately 158.82 miles of the pipeline located Muscatine, Louisa, Washington, and Keokuk Counties, Iowa, and Vermilion and Cameron Parishes, Louisiana.

Special permit segments 2 and 3 consists of 0.163 miles 36-inch diameter Amarillo Line #4 located in Muscatine County, Iowa; and 30-inch diameter Louisiana Line #1 located in Vermilion Parish, Louisiana. The ***special permit segments*** were constructed between 1958 and 1973. The ***special permit inspection areas*** contain no high consequences areas (HCA), which are calculated by Method 2 (49 CFR 192.903).

VI. Special Permit Segments and Special Permit Inspection Areas

1) **Special Permit Segments:**

This special permit applies to the ***special permit segments*** located in Muscatine County, Iowa; and Vermillion Parish, Louisiana, that is identified using the NGPL survey station (SS) references. Each special permit segment is defined in **Table 2 – Special Permit Segment**.

Table 2 – Special Permit Segments

Special Permit Segment Number[3]	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County or Parish, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)
2 (KM 502)	36	Amarillo Line 4	206.26	109 – 3884222	109 – 3884428	Muscatine, IA	1	1973	DSAW	712
3 (KM 503)	30	Louisiana Line 1	655.52	342 – 1068074	342 – 1068730	Vermillion, LA	8	1967	DSAW	1100

Note: **DSAW** is double submerged arc welded pipe longitudinal seam.

2) **Special Permit Inspection Areas:**

The ***special permit inspection areas*** are defined as the area that extends 220 yards on each side of the centerline as listed in **Table 3 – Special Permit Inspection Areas**.

Table 3 – Special Permit Inspection Areas

Special Permit Inspection Area Number	Special Permit Segment(s) Included	Outside Diameter (inches)	Line Name	Start Survey Station (SS)	End Survey Station (SS)	Length[4] (miles)
2	2 (KM 502)	36	Amarillo Line #4	109 – 3615906	E Mississippi – 3892993.06	52.93
3	3 (KM 503)	30	Louisiana Line #1	342 – 525391	342 – 1084483.4	105.89

---

[3] On February 3, 2022, NGPL rescinded requested special permit segment number 1 (KM 501).

[4] If the ***special permit inspection area*** footage does not extend from launcher to receiver, the ***special permit inspection area*** would need to be extended.

Attachments A1 through A6 consist of maps that includes the pipeline route map and more detailed maps showing the area near the ***special permit segments***.

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-2019-0150 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

VII. Alternatives

Alternative 1: "No Action" Alternative

If PHMSA were to select the "no action" alternative, PHMSA would deny NGPL's special permit request, NGPL would be required to fully comply with 49 CFR 192.611(a) and (d) and 192.619(a) and replace the 0.163 miles of pipe with a higher grade pipe in the ***special permit segments***, or alternatively, NGPL would be required to reduce pressure on the segment. NGPL states that it would choose to replace the segments to maintain MAOP.

Alternative 2: "Selected" Alternative

The Proposed Action in the DEA was to grant to NGPL a special permit for two (2) segments in its request, where class change had occurred due to population growth. Following the comment period, PHMSA evaluated the file, public comments, incident history, and tool data. As a result of follow up discussion and information requests, NGPL withdrew its request for one (1) of the three (3) segments. Thus, the Selected Alternative only includes the remaining two (2) segments.

PHMSA is granting a special permit with conditions to maintain pipeline integrity. The special permit segment must be treated as a high consequence area (HCA) under an IM 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 IM program (IMP) (49 CFR Part 192, Subpart O). 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 segment is located.

VIII. Overview of Special Permit Conditions

The special permit conditions are designed to prevent leaks and ruptures such that the Special Permit is not inconsistent with pipeline safety. This section provides an overview of the special permit conditions. For NGPL specific technical requirements, see **Attachment B - Special Permit Conditions**.

1) **Current Status of Pipe in the Ground**

   To ensure that key characteristics of the pipe currently installed in each ***special permit segment*** is 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) **Operating Conditions**

   The ***special permit inspection areas*** 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, the NGPL'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 would impact the ***special permit segments***.

3) **Threat Management**

   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.** NGPL 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 inline inspection 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 cathodic protection (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, NGPL 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 and.

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

e) **Pipe seam requirements.** NGPL must perform an engineering integrity analysis to determine susceptibility to seam threats. NGPL must re-pressure test any ***special permit segments*** with an identified seam 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), NGPL 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, NGPL must install and maintain line-of-site markers for the pipeline. NGPL 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). NGPL 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.

5) **Post Leak or Failure**

If the ***special permit inspection area*** experiences an in-service or pressure test leak/failure, NGPL must conduct a root cause analysis to determine the cause. If the cause is determined to be systemic in nature, NGPL must implement a remediation plan or the ***special permit segment*** must be replaced, as determined by the special permit specific conditions.

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

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

7) **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.

8) **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, inline inspection (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 operator. The special permit will require a three-step grading process with a time interval for remediation based upon the type of leak.

9) **Documentation**

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

IX. Affected Resources and Environmental Consequences

A. Affected Resources and Environmental Consequences of the Granted Action and the "No Action" Alternative

NGPL is granted a special permit that waives compliance with 49 CFR 192.611(a) and (d) and 192.619(a) for two (2) ***special permit segments*** totaling 821.21 feet (approximately 0.156 miles) located within two (2) ***special permit inspection area*** totaling approximately 158.82 miles. NGPL must comply with the special permit conditions within the ***special permit segment***.

Potential risks from the waiver to pipeline integrity was 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**

Aesthetics: PHMSA grants the special permit and NGPL will avoid replacement of two (2) ***special permit segments*** totaling approximately 0.163 miles of the NGPL Amarillo Line #4 and Louisiana Line #1. The "Selected" alternative will require increased monitoring, maintenance, and repair requirements (i.e., special permit conditions) along the ***special permit inspection areas***, potentially increasing the presence of personnel and equipment along the right of way. The special permit conditions could require increased excavations, but the impacts associated with these activities will be sporadic and temporary along the ***special permit inspection areas***. These maintenance activities are intended to reduce the likelihood of a pipeline incident or failure. The aim of the special permit is to avoid construction in the right-of-way in the ***special permit segments***. The special permit will also require the installation of line of site markers. While these markers are intended to improve safety to reduce risks from third party damage, the markers pose some permanent aesthetic impacts.

Agricultural Resources: The area surrounding the ***special permit segments*** contains cultivated crops. The issuance of the special permit will reduce impact to agricultural resources in the ***special permit segments***. Increased monitoring and maintenance requirements imposed by the special permit conditions could increase these activities causing temporary and isolated impacts to the ***special permit inspection areas***. The aim of the special permit is to avoid the higher impact construction activities associated with pipeline replacement in the right-of-way along the ***special permit segments***.

Air Quality: Under the "No Action" alternative, pipe replacement of the ***special permit segments*** will be required, which will necessitate blowing down the pipeline to release unburned natural gas, which is a powerful greenhouse gas. The "Selected" alternative will have minimal impacts on air quality in the ***special permit inspection segments*** due to combustion emissions resulting from surveillance, assessment, and maintenance activities required by the permit. The "No Action" alternative will have a more substantial, though still minimal effect on air quality, with additional emissions that are temporary caused by equipment use during excavation, pipe removal, pipe replacement, and pipe installation.

Biological Resources: ***Special permit segment 2*** is dominated by grasslands/herbaceous land cover and developed open space. Federally listed species that may occur within the project vicinity include Indiana bat, northern long-eared bat, eastern massasauga, Higgins eye pearly mussel, sheep nose mussel, spectacle case mussel, prairie bus-clover, and western prairie fringed orchid. No critical habitat occurs within the project area.

The ***special permit segment 3*** is dominated by cultivated crops. Federally listed species that may occur within the project vicinity include West Indian manatee, loggerhead sea turtle, and Atlantic sturgeon. No critical habitat occurs within the project area.

Any potential impacts to wildlife will be temporary in nature and may include disturbance from increased human presence, vehicle access, vegetation clearing, and use of mechanized equipment within the project area. Some avian species may occasionally fly over or forage within the project location or stop over during migration.

Table 4. Federally Listed Threatened and Endangered Species with the Potential to Occur along the *Special Permit Segments* and Preliminary Effect Determination for the "Selected" Alternative, Muscatine County, Iowa and Vermilion Parish, Louisiana					
Common Name	**Scientific Name**	**Federal**	**Habitat Description**	**Occurrence**	**Effect**
Birds					
Piping Plover	*Charadrius melodus*	T	This species inhabits beaches, sandflats, and dunes along Gulf Coast beaches and adjacent offshore islands. Algal flats appear to be the highest quality habitat. Optimal site characteristics appear to be large in area, sparsely vegetated, continuously available or in close proximity to secondary habitat, and with limited human disturbance (USFWS 2021).	Not likely to occur.	No effect
Red Knot	*Calidris canutus rufa*	T	Migrating and wintering knots use marine habitats including sandy beaches, saltmarshes, lagoons, mudflats of estuaries and bays, and mangrove swamps that contain an abundance of invertebrate prey (USFWS 2021).	Not likely to occur.	No effect
Clams					
Higgins Eye (pearlymussel)	*Lampsilis higginsii*	E	This species is a freshwater mussel of larger rivers where it is usually found in deep water with moderate currents. The animals bury themselves in sand and gravel river bottoms with just the edge of their partially opened shells exposed (USFWS 2021).	Not likely to occur.	No effect
Sheepnose Mussel	*Plethobasus*	E	This species lives in larger rivers and streams where they are usually found in shallow areas with moderate to swift currents that flow over coarse sand and gravel. However, they have also been found in areas of mud, cobble and boulders, and in large rivers they may be found in deep runs (USFWS 2021).	Not likely to occur.	No effect
Spectaclecase (mussel)	*Cumberlandia monodonta*	E	This species of mussels are found in large rivers where they live in areas sheltered from the main force of the river current. This species often clusters in firm mud and in sheltered areas, such as beneath rock slabs, between boulders and even under tree roots (USFWS 2021).	Not likely to occur.	No effect
Flowering Plants					
Prairie Bush-clover	*Lespedeza leptostachya*	T	This species prefers dry to mesic prairies with gravelly soils (USFWS 2021).	Not likely to occur.	No effect

Table 4. Federally Listed Threatened and Endangered Species with the Potential to Occur along the *Special Permit Segments* and Preliminary Effect Determination for the "Selected" Alternative, Muscatine County, Iowa and Vermilion Parish, Louisiana					
Common Name	**Scientific Name**	**Federal**	**Habitat Description**	**Occurrence**	**Effect**
Western Prairie Fringed Orchid	*Platanthera praeclara*	T	This species occurs most often in mesic to wet unplowed tallgrass prairies and meadows but have been found in old fields and roadside ditches (USFWS 2021).	Not likely to occur.	No effect
Mammals					
Indiana Bat	*Mytosis sodalis*	E	Indiana bats hibernate in tight clusters on the ceilings and sides of caves and mines. Their Summer habitat includes small to medium river and stream corridors with well developed riparian woods; woodlots within 1 to 3 miles of small to medium rivers and streams; and upland forests (USFWS 2021).	Not likely to occur.	No effect
Northern Long-eared Bat	*Mytosis septentrionalis*	T	Northern long-eared bats spend winter hibernating in caves and mines, called hibernacula. During the summer, northern long-eared bats roost singly or in colonies underneath bark, in cavities or in crevices of both live trees and snags (dead trees) (USFWS 2021).	Not likely to occur.	No effect
West Indian Manatee	*Trichechus manatus*	T	Manatees live in marine, brackish, and freshwater systems in coastal and riverine areas throughout their range. Preferred habitats include areas near the shore featuring underwater vegetation like seagrass and eelgrass (USFWS 2021).	Not likely to occur.	No effect
Reptiles					
Eastern Massasauga	*Sistrurus catenatus*	T	This species lives in wet areas including wet prairies, marshes and low areas along rivers and lakes. They also use adjacent uplands during part of the year. They often hibernate in crayfish burrows but may also be found under logs and tree roots or in small mammal burrows (USFWS 2021).	Not likely to occur.	No effect
Hawksbill Sea Turtle	*Eretmochelys imbricate*	E	This species is found throughout the tropical waters of the Atlantic, Pacific, and Indian Oceans (USFWS 2021).	Not likely to occur.	No effect

Table 4. Federally Listed Threatened and Endangered Species with the Potential to Occur along the *Special Permit Segments* and Preliminary Effect Determination for the "Selected" Alternative, Muscatine County, Iowa and Vermilion Parish, Louisiana					
Common Name	**Scientific Name**	**Federal**	**Habitat Description**	**Occurrence**	**Effect**
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*	E	The major habitat for Kemp's ridleys is the nearshore and inshore waters of the northern Gulf of Mexico. Adult and sub-adult Kemp's ridleys primarily occupy nearshore habitats that contain muddy or sandy bottoms where prey can be found (USFWS 2021).	Not likely to occur.	No effect
Leatherback Sea Turtle	*Dermochelys coriacea*	E	The leatherback is the most pelagic of the sea turtles. Adult females require sandy nesting beaches backed with vegetation and sloped sufficiently so the distance to dry sand is limited. Their preferred beaches have proximity to deep water and generally rough seas (USFWS 2021).	Not likely to occur.	No effect
Loggerhead Sea Turtle	*Caretta caretta*	T	Loggerhead turtles are found worldwide primarily in subtropical and temperate regions of the Atlantic, Pacific, and Indian Oceans, and in the Mediterranean Sea (USFWS 2021).	Not likely to occur.	No effect
T: Threatened E: Endangered					

Increased maintenance, monitoring, and repair activities in order to achieve compliance with this special permit in the ***special permit segments*** and ***special permit inspection areas*** will be conducted within the boundaries of the previously disturbed pipeline right-of-way. NGPL will request no effect concurrence from the United States Fish and Wildlife Service Twin Cities Ecological Services Field Office for any future work by NGPL to be undertaken within its existing, previously disturbed right-of-way to ensure compliance with Section 9 of the Endangered Species Act (ESA). Replacement of line pipe in the ***special permit segments*** will result in increased disturbance to wildlife habitat, though that disturbance will also be temporary and limited in nature.

Climate Change: The "No Action" alternative will require pipe replacement, which would necessitate blowing down the pipeline releasing unburned natural gas, a greenhouse gas more potent than carbon dioxide. Pipeline replacement will also result in increased emissions from manufacture of new pipe, transportation of materials, and construction activities related to pipeline replacement. The "Selected" alternative will require increased pipeline maintenance activities that could result in increased emissions from equipment and transportation utilized to perform those actions, but these emissions are likely substantially less than what will result from pipeline removal, manufacture, transportation, and replacement. The scope and duration of any activities associated with the ***special permit*** will have an insignificant impact on climate change.

Cultural Resources: There are no cultural, archaeological, or paleontological resources that will be impacted by this special permit request because the right of way was disturbed during initial construction of the pipeline.

Environmental Justice: According to U.S. Census data for 2019, the local zip code within which the ***special permit segment 2*** is located contains a slightly higher proportion of individuals identified as minority, low-income, or limited English proficiency than Muscatine County, Iowa, as a whole.[5] In any event, PHMSA designed the special permit conditions so that there is no reduction in safety for the ***special permit segments***, in comparison with operation in full compliance with 49 CFR Part 192. Thus, the "Selected" alternative will not have an adverse impact on the local population near the ***special permit segment***. A summary of the demographics for the local zip code area for Muscatine City, Muscatine County, Iowa, where the ***special permit segment 2*** is located are highlighted below.

According to U.S. Census data for 2019, the local zip code within which the ***special permit segment 3*** is located contains a higher proportion of individuals identified as minority, low-income, or limited English proficiency than Vermilion Parish, Louisiana as a whole.[6] In any event, PHMSA designed the special permit conditions so that there is no reduction in safety for the ***special permit segments***, in comparison with operation in full compliance with 49 CFR Part 192. Thus, the special permit alternative will not have an adverse impact on the local population near the ***special permit segments***. A summary of the demographics for the local zip code area for Vermilion Parish, Louisiana, and the local zip code near ***special permit segment 3*** is located are highlighted below.

---

[5] https://www.census.gov/quickfacts/fact/table/muscatinecountyiowa,US/PST045219

[6] https://www.census.gov/quickfacts/fact/table/vermilionparishlouisiana,US/PST045219

TABLE 5 - Demographic Information for Special Permit Segments – Using EPA EJScreen								
Special Permit Segment	Latitude & Longitude (Begin)	Latitude & Longitude (End)	State	County	Total Population (Along Special Permit Segment)	People of Color Population (%)	Low Income Population (%)	Linguistically Isolated (%)
2 (KM 502)	On File	On File	IA	Muscatine	7	7	18	1
3 (KM 503)	On File	On File	LA	Vermillion	23	3	32	0

Minority*: The term minority is used in the currently active DOT Environmental Justice Order 5610.2(a), available at: https://www.fhwa.dot.gov/environment/environmental_justice/ej at dot/orders/order_56102a/index.cfm

People of Color**: The term people of color is used in EPA's Environmental Justice Screening and mapping tool (EJSCREEN). An overview of demographic indicators through EJSCREEN is available at: https://www.epa.gov/ejscreen/overview-demographic-indicators-ejscreen.

Geology, Soils, and Mineral Resources: The project area for ***special permit segment 2*** is located within the Cedar Valley Geologic Formation, which is characterized by limestone and dolomite exposures. The dominant soils are the Toolesboro sandy loam. Soils in this group have moderately low runoff potential when thoroughly wet and are poorly drained. These soils are not highly erodible and are classified as prime farmland if drained.

There have been no historical earthquakes in a 62-mile radius from ***special permit segment 2***.

The project area for ***special permit segment 3*** is located within the Alluvium Coastal Deposits Geologic Formation. The soils are gray to brownish gray clay and silty clay, some sand and gravel locally. The dominant soils are the Troutville silt loam. Soils in this group have moderately high runoff potential when thoroughly wet and are somewhat poorly drained. These soils are potentially highly erodible and are classified as prime farmland in all areas.

There have been no historical earthquakes in a 62-mile radius from ***special permit segment 3***.

Earthquake activity impact analysis for NGPL's pipelines is based upon magnitude, location, intensity extents, and analytical information provided by the USGS quantifying ground shaking and strength at our pipelines. The Modified Mercalli Intensity (MMI scale) provides an understanding of the intensity decrease with distance. For NGPL, conditions of initial interest would not be expected until an earthquake magnitude reaches M4.5 (referenced and explained in chart below) and greater with the epicenter directly at the pipeline or when the local ground shaking at the pipeline resulting from a remotely located event reaches an assigned MMI value of at least VI.[7]

Indian Trust Assets: There are no Indian Trust Assets in the ***special permit segments***. This special permit request does not impact a Federally-recognized Tribal Reservation thus Tribal coordination is not required.

Land Use: Minimal ground disturbance or modifications could occur along the ***special permit segments*** and ***special permit inspection areas*** will occur as part of the special permit from increased maintenance activities. The special permit will not impact land use or planning and does not require permits from local governments.

Noise: The scope and duration of any maintenance or repair activities required for compliance with the special permit along the ***special permit segments*** and ***special permit inspection areas*** will cause minimal localized and temporary increases in noise levels in the vicinity of the pipeline. These noise impacts could occur throughout the duration of the special permit, which could be many years. A denial of the special permit or the "no action" alternative will likely result in more significant and concentrated, though temporary increases in noise during the replacement of the existing pipe.

Recreation: The request could have minimal impacts on recreational resources in the ***special permit segments*** and ***special permit inspection areas*** due to compliance with increased maintenance, monitoring, and repair activities required for compliance with the special permits. The impacts will be temporary and sporadic throughout the applicability of the special permit.

A denial of the special permit or the "no action" alternative will result in temporary increases in disturbances to recreational activities during the replacement of the existing pipe.

Safety: 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

[7] The Modified Mercalli Intensity (MMI) value assigned to a specific site after an earthquake has a more meaningful measure of severity to nonscientist than the magnitude because intensity refers to the effects actually experienced at that place. The MMI is provided by the USGS (United Stated Geological Service) after earthquake. See chart below for more information.

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. Pipeline operators 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 pipeline segment with the higher population: a reduced MAOP, a new pressure test at a higher pressure, or installation of new pipe with either or both heavier walled or higher grade pipe with new, modern coating to protect against integrity risks to occupants along the pipeline segment.

This FEA incorporates the special permit analysis and findings document (SPAF), which is available under this docket on regulations.gov. The SPAF does not describe any integrity issue that would affect the approval of the special permit or the development of the special permit conditions.

The special permit conditions are designed to identify and mitigate integrity issues that could threaten the pipeline segment and cause failure. Compliance with the monitoring and maintenance requirements in the special permit by NGPL will ensure the integrity of the pipe and protection of the population living near the ***special permit segments*** to a similar degree of a lower MAOP, new pressure test, or a thicker walled or higher grade pipe without the special permit IM protections. Populations living near the ***special permit inspection areas*** will benefit from a higher level of safety.

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

PHMSA will require IM inspections for pipeline segment adjacent to the ***special permit segments***, which will lower the risk in areas beyond the special permit. The special permit will require that NGPL conduct the IM type procedures required by the special permit conditions in ***special permit segments*** and ***special permit inspection areas*** for the duration of the special permit. NGPL will implement the special permit conditions in ***special permit inspection areas*** for the duration of the special permit.

The special permit also includes a number of conditions that address potential safety risks, and their assessment and remediation requirements. Among these are incorporation of these segments into the Kinder Morgan Integrity Management Program, additional close interval corrosion surveys, implementation of a cathodic protection reliability improvement plan, a more comprehensive stress corrosion cracking direct assessment program, an ILI program with intervals not to exceed seven years, anomaly evaluation and repair meeting more stringent 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 special permit conditions is intended to provide for a significant added level of safety for the existing pipeline segment because it maintains safety in the areas surrounding the ***special permit segments*** and improves safety in the ***special permit inspection areas***.

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

Operation under the special permit is expected to reduce the risk of failure due to the addition of extensive special permit conditions requiring additional maintenance, monitoring, inspection, and repair conditions. The special permit segment must be inspected at intervals similar to IMP intervals, which will maintain the integrity of the pipe segment over the life of the special permit.

(b) If a failure occurred, would consequences and spill or release volumes be different if PHMSA granted the permit? Will granting this permit increase, decrease, or have no change on the risk of failure?

PHMSA's granting of the special permit will not increase the risk of failure with implementation of the special permit conditions. The implementation of these practices, in conjunction with increased mitigative measures that are required as per the special permit will meet or exceed safety and reliability standards of 49 CFR 192.611(a) and (d) in the requested ***special permit segments*** and ***special permit inspection areas***.

However, if PHMSA denies the special permit and NGPL opted to reduce pressure instead of replacing the pipe, a failure on a reduced-pressure pipeline could result in a smaller volume of natural gas released. NGPL contends that it would not opt to reduce pressure due to ongoing contractual obligations. If PHMSA were to deny the special permit application, PHMSA would have no input into whether NGPL reduced pressure or preformed a pipeline segment replacement. Either option could achieve compliance with § 192.611(a) and (d).

(c) 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 Potential Impact Radius (PIR) as calculated in accordance with 49 CFR 192.903 will not change under the special permit since maximum operating pressure and pipe diameter will not change, thus there will be no additional impact on the public. The PIR for each ***special permit segment*** is calculated below.

PIR = 0.69 * (MAOP * NOMINAL DIAMETER^2)$^{0.5}$

For ***special permit segment 2***, calculated PIR = 0.69 * (712 * 36^2)$^{0.5}$ = 663 feet

For ***special permit segment 3***, calculated PIR = 0.69 * (1100 * 30^2)$^{0.5}$ = 687 feet

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

The implementation of increased pipeline assessment within the ***special permit inspection areas*** as per required in the special permit will improve pipeline reliability and safety. Continued operation of the ***special permit segments*** will not be expected to have an effect on the pipeline longevity and reliability or cause any life cycle or maintenance issues.

Operation under the Conditions that provide an additional level of safety is expected to have a positive impact on pipeline longevity and reliability. NGPL does not anticipate any deleterious life cycle or maintenance.

Socioeconomics: The scope and duration of any activities associated with the ***special permit segment*** will have no impact on the socioeconomics in the vicinity of the Muscatine County, Iowa, and Vermilion parish, Louisiana. Approximately 10.5% of individuals in Muscatine County, Iowa, are living below the poverty level, and 15.1% of individuals are living below 125% of the poverty level. Approximately 17.9% of families in Vermilion Parish, Louisiana, are living below the poverty level, and 24.1% of families are living below 125% of the poverty level. The project is not situated in, or disproportionately impacts, any predominantly low-income populations.

In any event, the special permit will be designed to maintain pipeline safety for the ***special permit segment*** and increase pipeline safety for the ***special permit inspection areas.***

Topography: The topography of the area surrounding the requested ***special permit segment*** is flat open and forested land. The aim of the special permit is to avoid construction and other ground disturbing activities in the right-of-way.

No construction-related activities will occur in the "Selected" alternative; therefore, the topography in the area will not be affected.

Transportation: The ***special permit segments*** will be accessed by existing roads and right-of-way crossings. No construction-related activities will occur as part of the special permit request; therefore, traffic will not increase, and construction of additional roads will not be required.

Water Resources: ***Special Permit Segment 2***: The ***special permit segment*** is located in the Muscatine Slough-Mississippi River watershed and does not cross any wetland or surface waterbody features; the ***special permit segment*** is not located within the FEMA mapped 100-year floodplain. The ***special permit segment*** does not cross any sole source aquifers.

Special Permit Segment 3: The ***special permit segment*** is located in the Lower Vermilion River-Frontal Vermilion Bay watershed and does not cross any wetland or surface waterbody features; however, the ***special permit segment*** is directly adjacent to the Vermilion River. The ***special permit segment*** is located within the FEMA mapped 100-year floodplain and is located within the Chicot Sole Source Aquifer System.

Minor additional yet temporary waterbody impacts could result from runoff or siltation from additional maintenance and repair activities that occur along the ***special permit inspection areas***. These minor impacts could occur for as long as the special permit remains in effect. In the event that the special permit had been denied, more significant, yet temporary runoff or siltation impacts could affect water bodies in the vicinity of the ***special permit segments***. Siltation can decrease oxygen levels and visibility, affecting the feeding and reproduction of benthic macroinvertebrates, fish, reptiles, amphibians, and water fowl. In each case, NGPL is required to follow Federal, state, and local law to minimize impacts to these resources.

2) Comparative Environmental Impacts of Alternatives

As PHMSA recognized in its June 29, 2004, Criteria for Class Location Change Waivers, implementing additional preventative and mitigative measures enables a pipeline to improve its knowledge and understanding of the pipeline's integrity, accelerate the identification and repair of actionable anomalies, and better manage and mitigate threats to the public and environment. Implementing enhanced inspection and assessment practices throughout the ***special permit segments*** and ***special permit inspection areas***, in lieu of replacing small segments of pipe experiencing the class location change, extends pipeline safety benefits to a much greater area along the pipeline. In addition, avoiding pipe excavation and replacement will minimize costs to the operator, will avoid delivery interruptions and supply shortages, and avert environmental disturbance. All of these benefits will be realized under NGPL's requested ***special permit segments***.

In the "No Action" alternative, 49 CFR 192.611(a) and (d) requires pipe replacement. However, the monitoring conditions associated with the special permit would not be applicable if the special permit was denied because those conditions are not mandated by applicable regulations. Accordingly, both alternatives are anticipated to lead to a similar safety result.

Because NGPL's contractual obligations will not allow the operating pressure of the pipe to be lowered, the mode of pipeline failure will be the same whether the pipe operates under a special permit or is replaced.

The natural environment will be temporarily disturbed if the pipe is replaced; a special permit will have no impact on the environment.

X. Consultation and Coordination

NGPL and PHMSA personnel involved in preparation of this document include:

Personnel from NGPL

- Jaime Hernandez - Director of Codes and Standards
- Charlie Childs - Manager, IC Pipeline Integrity
- Justin Durham - Manager, Engineering
- Gary Taylor - Manager, Pipeline Compliance Systems
- Johnson Samuel - Project Management Specialist Compliance systems

- Megan Mater - Specialist SR 1, Project Permitting – Minor Project

PHMSA

- Amelia Samaras, PHMSA, US DOT
- Steve Nanney, PHMSA, US DOT

XI. Response to Public Comments Placed on Docket PHMSA-2019-0150

PHMSA published the special permit request in the Federal Register (86 FR 13016) for a 30-day public comment period from March 5, 2021, through April 5, 2021. The special permit application from NGPL, draft environmental assessment, and draft special permit conditions were available in Docket No. PHMSA-2019-0150 at: www.regulations.gov for public review. PHMSA received one anonymous public comment concerning this special permit request. The anonymous comment strongly opposed PHMSA entertaining any more special permits as the process is ineffective and unable to approve or deny special permits in a timely manner.

XII. Finding of No Significant Impact

In consideration of the analysis and special permit conditions explained above, PHMSA finds that no significant negative impact will result from the issuance and full implementation of the above-described special permit to waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) for two (2) ***special permit segments***, which consists of approximately 0.163 miles of 30-inch and 36-inch diameter Pipelines located in Muscatine County, Iowa, and Vermilion Parish, Louisiana. This special permit will require NGPL to implement the special permit conditions that apply to the operations, maintenance, and IM of the ***special permit segments*** and ***special permit inspection areas***.

XIII. Bibliography

U.S. Fish and Wildlife Service (USFWS). 2020. Information for Planning and Consultation (IPaC). Species by county report. Available at: https://ecos.fws.gov/ipac/. Accessed January 5, 2021.

U.S. Census Bureau (USCB). Available at: https://data.census.gov/cedsci/table?q=Muscatine%20county,%20iowa&tid=ACSDP5Y2019.DP05&hidePreview=false. Accessed January 2021.

U.S. Geological Survey 2020. Earthquake Hazards Program. https://www.usgs.gov/natural-hazards/earthquake-hazards/science/2014-united-states-lower-48-seismic-hazard-long-term?qt-

Attachments:

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

Attachment B – Copy of the Special Permit Conditions issued to NGPL without referenced attachments

Completed by PHMSA in Washington, DC on: May 17, 2022

Modified Mercalli Intensity Scale

Intensity	Shaking	Description/Damage
I	Not felt	Not felt except by a very few under especially favorable conditions.
II	Weak	Felt only by a few persons at rest,especially on upper floors of buildings.
III	Weak	Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a truck. Duration estimated.
IV	Light	Felt indoors by many, outdoors by few during the day. At night, some awakened. Dishes, windows, doors disturbed; walls make cracking sound. Sensation like heavy truck striking building. Standing motor cars rocked noticeably.
V	Moderate	Felt by nearly everyone; many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop.
VI	Strong	Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.
VII	Very strong	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.
VIII	Severe	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.
IX	Violent	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.
X	Extreme	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.

(Public domain.)

Earthquake Magnitude Scale

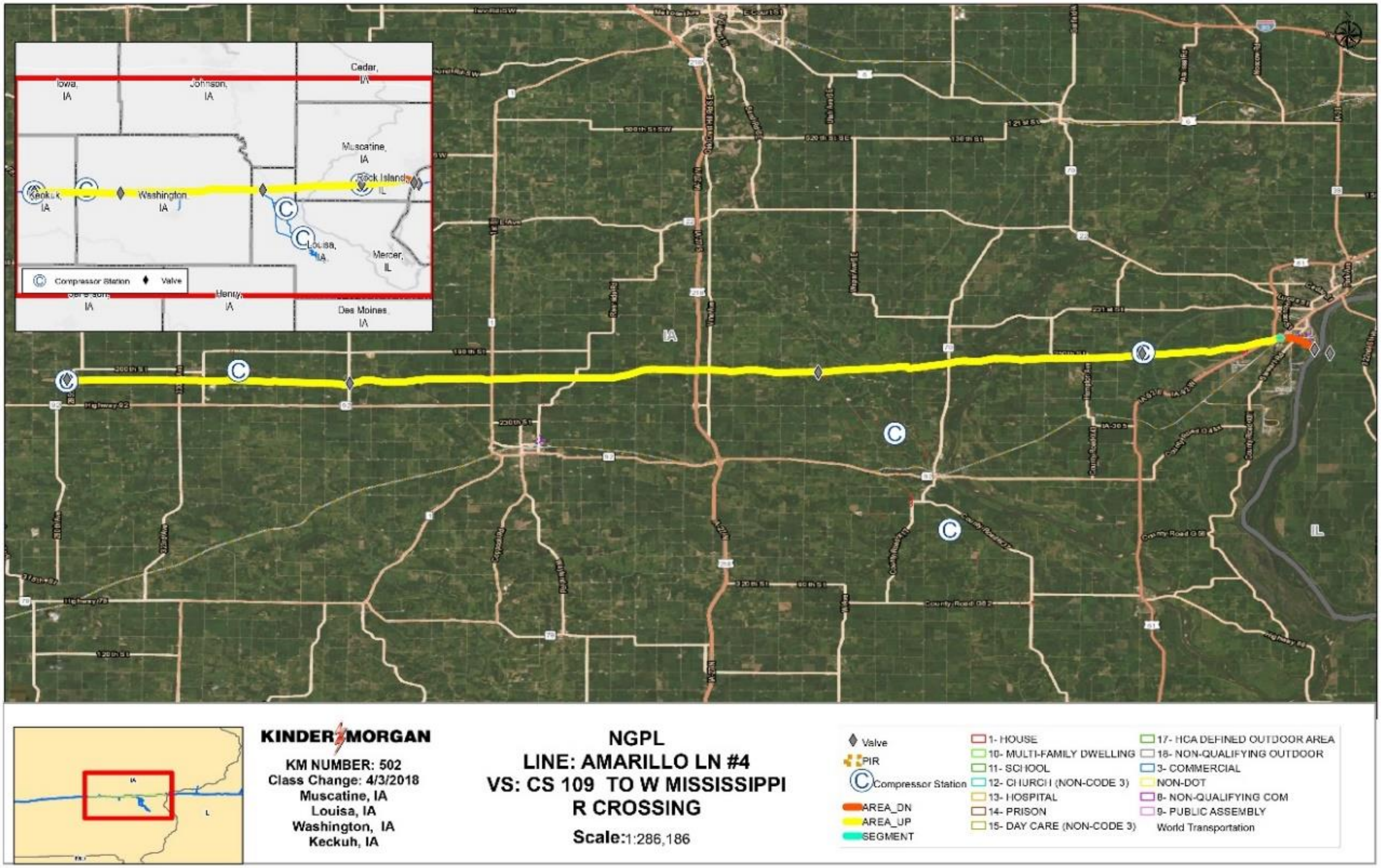
Richter Magnitudes	Description	Earthquake Effects	Frequency of Occurrence
Less than 2.0	Micro	Micro-earthquakes, not felt.	About 8,000 per day
2.0 - 2.9	Minor	Generally not felt, but recorded.	About 1,000 per day
3.0 - 3.9	Minor	Often felt, but rarely causes damage.	49,000 per year (est.)
4.0 - 4.9	Light	Noticeable shaking of indoor items, rattling noises. Significant damage unlikely.	6,200 per year (est.)
5.0 - 5.9	Moderate	Can cause major damage to poorly constructed buildings over small regions. At most slight damage to well-designed buildings.	800 per year
6.0 - 6.9	Strong	Can be destructive in areas up to about 160 kilometers (100 mi) across in populated areas.	120 per year
7.0 - 7.9	Major	Can cause serious damage over larger areas.	18 per year
8.0 - 8.9	Great	Can cause serious damage in areas several hundred miles across.	1 per year
9.0 - 9.9	Great	Devastating in areas several thousand miles across.	1 per 20 years
10.0+	Epic	Never recorded	Extremely rare (Unknown)

(Based on U.S. Geological Survey documents.)[2]

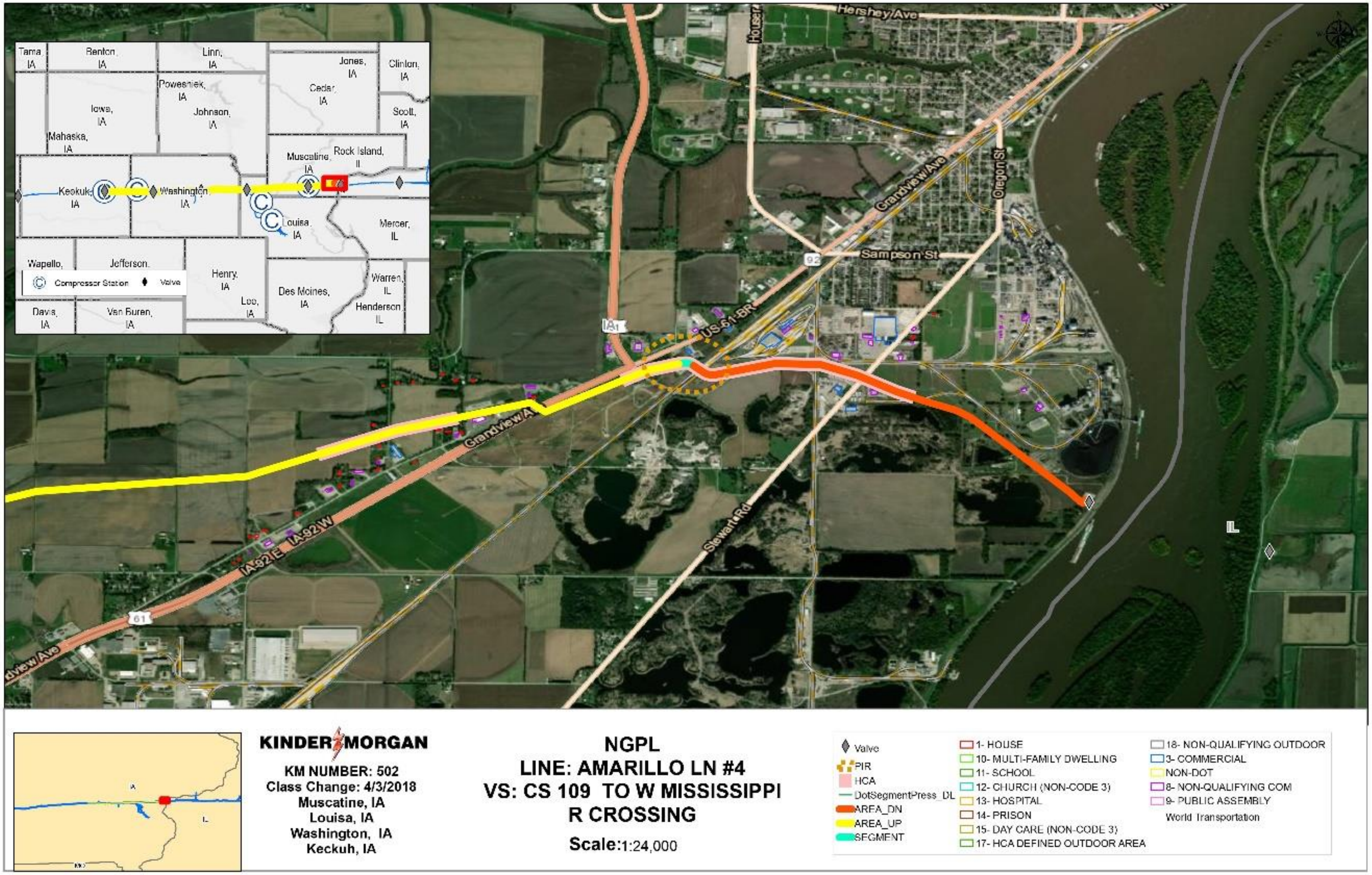
Note: An operator may use their normal dent remediation procedures, 49 CFR Part 192 compliant, for the evaluation and remediation for dents as follows:

- Dent ≤ 6% OD with a corrosion depth < 15% of the pipe wall and corrosion failure pressure with safety factor must meet the MAOP requirements in **Special Permit Condition 8**.

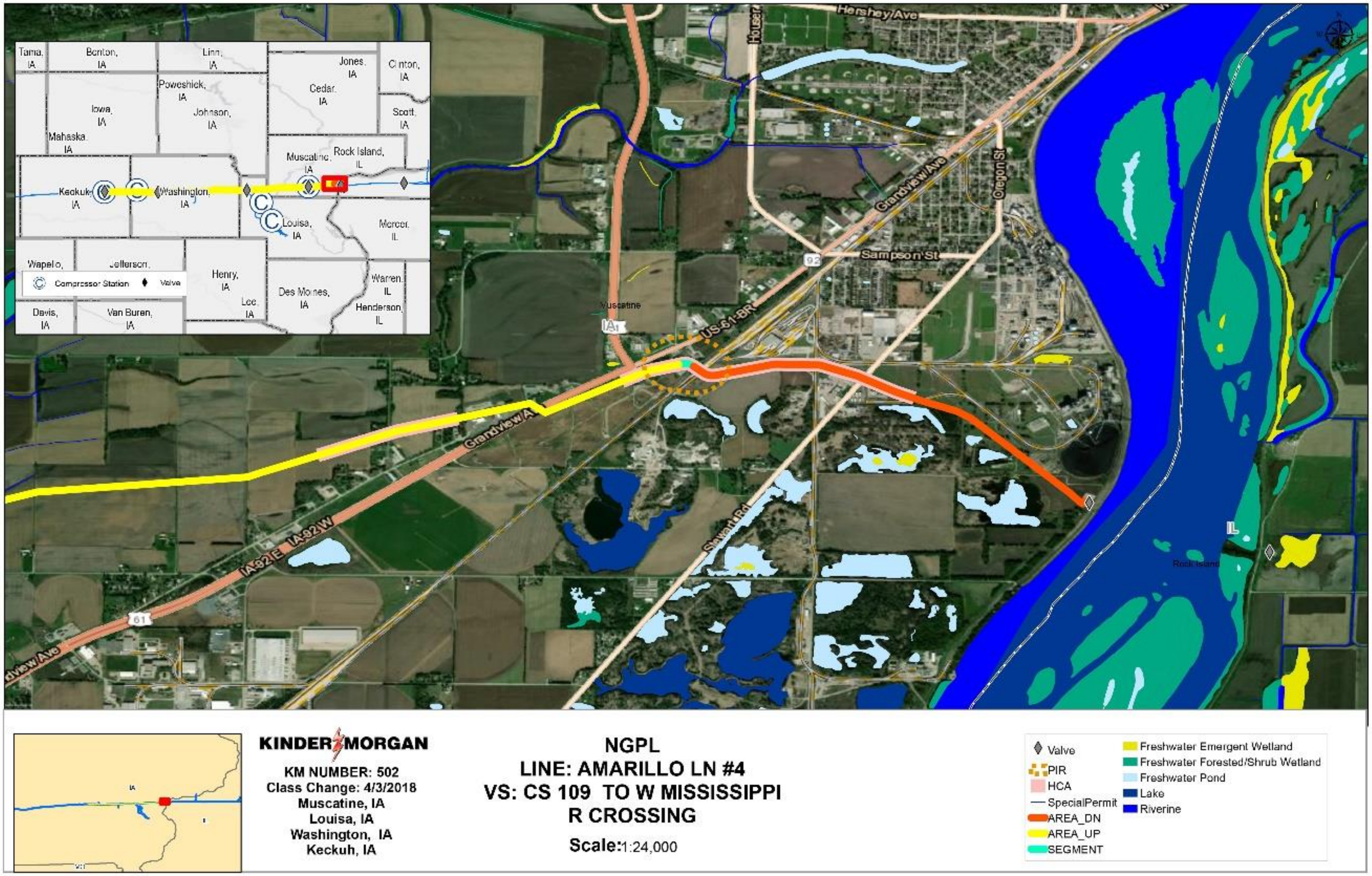
Attachment A-1. Project Location and Special Permit Segment 2 Map



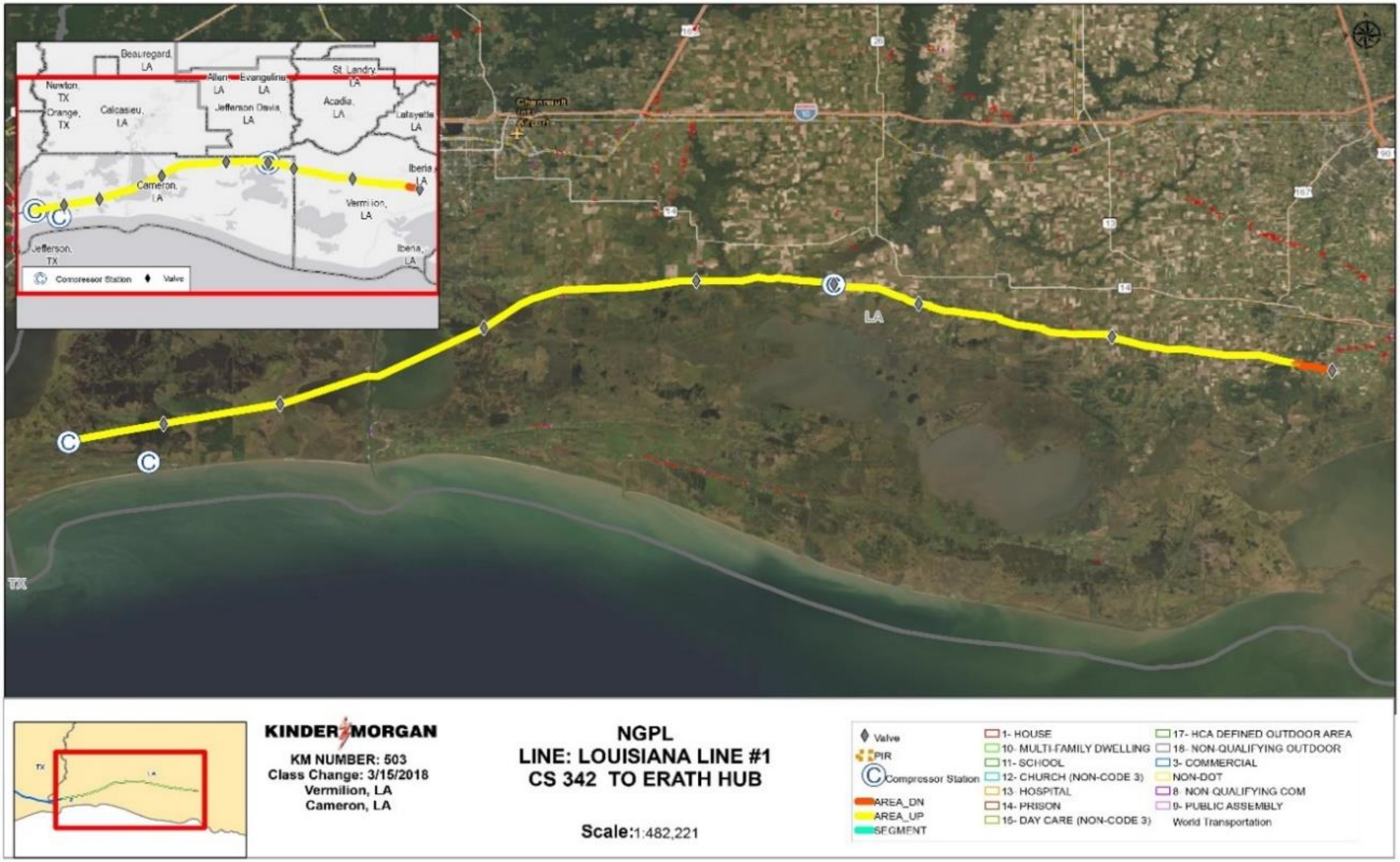
Attachment A-2. Special Permit Segment 2



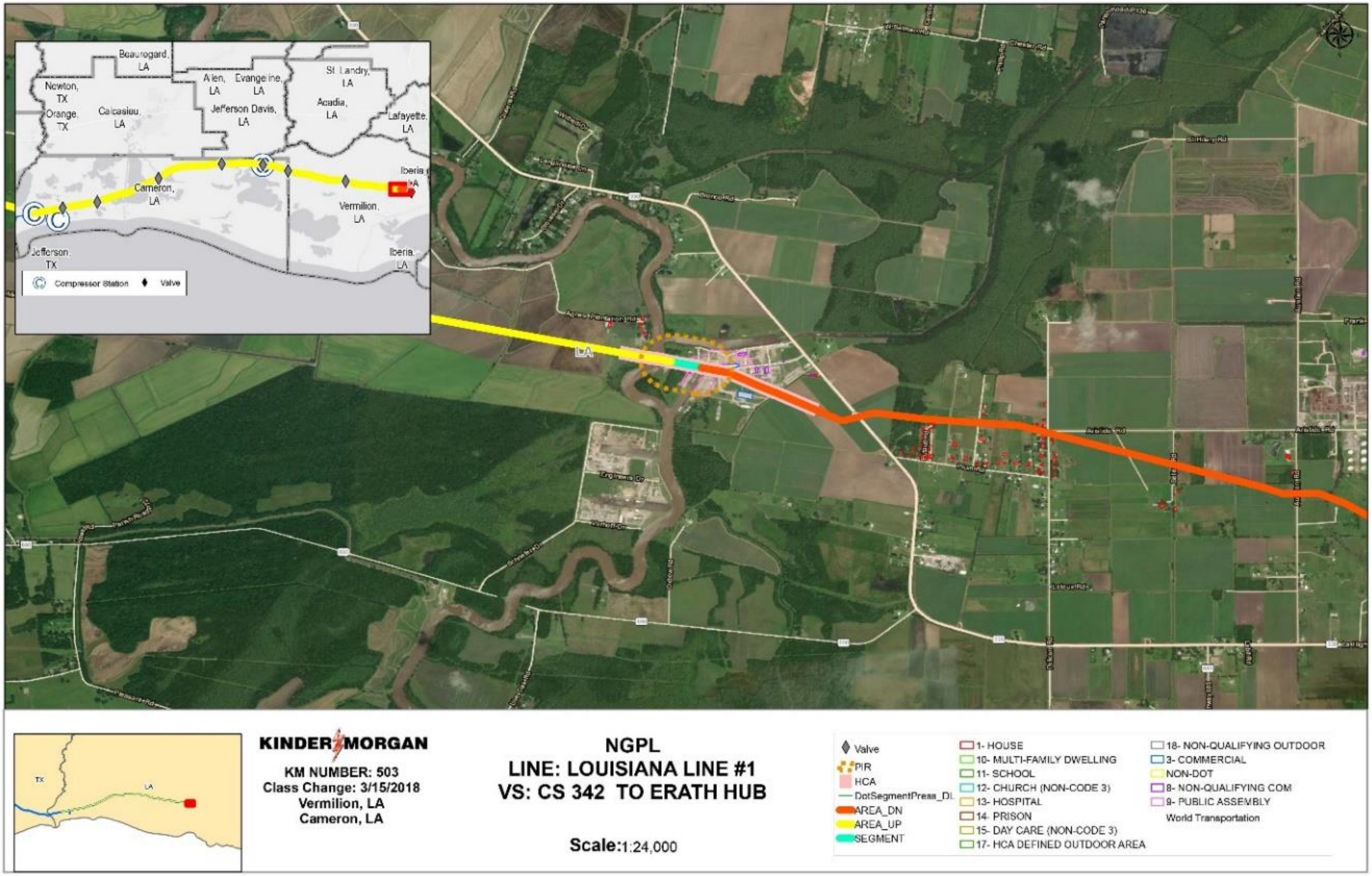
Attachment A-3. Special Permit Segment 2 Wetlands and Waterbody Map



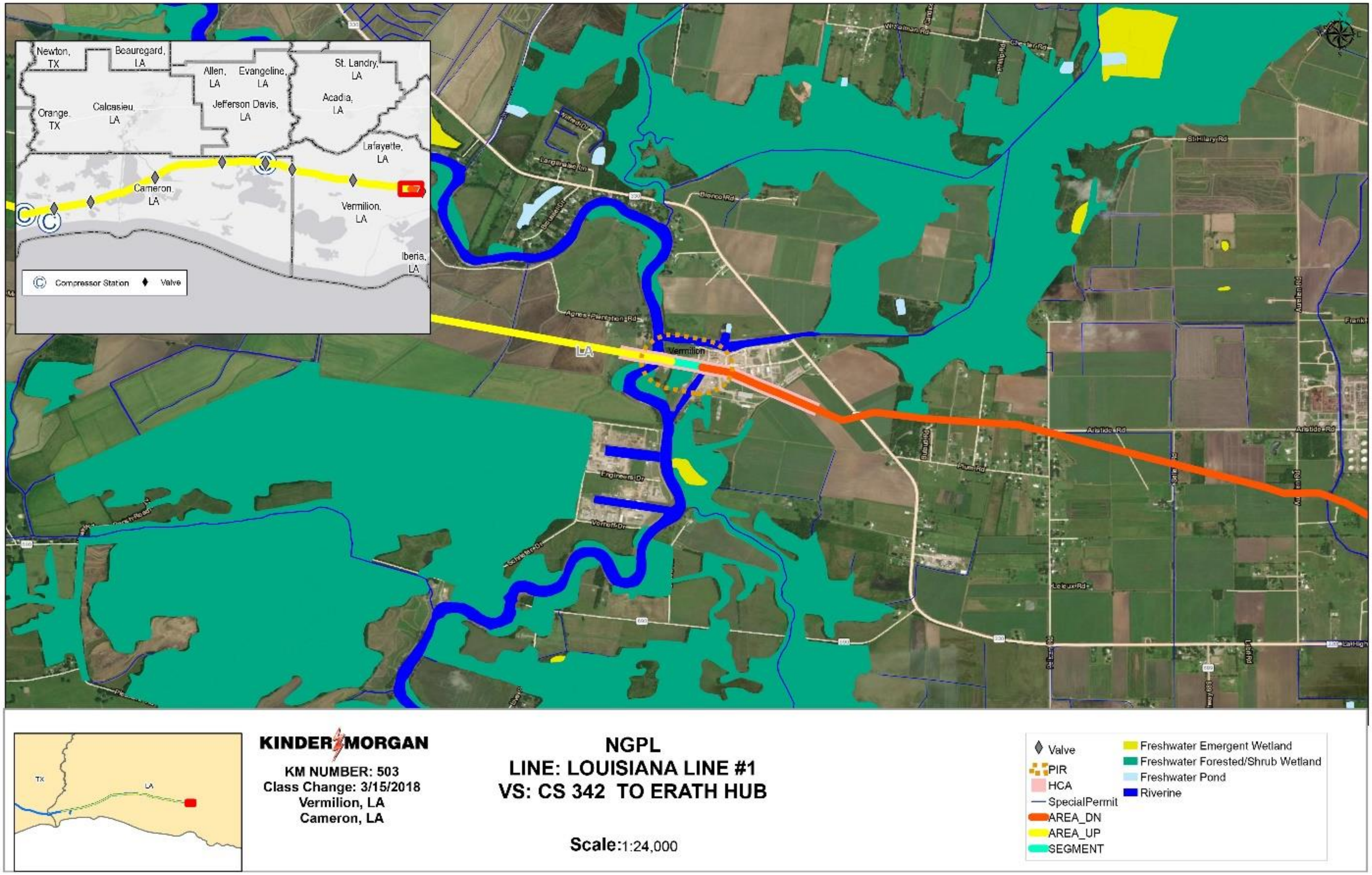
Attachment A-4. Project Location and Special Permit Segment 3 Map



Attachment A-5. Special Permit Segment 3



Attachment A-6. Special Permit Segment 3 Wetlands and Waterbody Map



Attachment B – Special Permit Conditions

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

   a) **Maximum Allowable Operating Pressure**: NGPL must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP of 712 pounds per square inch gauge (psig) (Amarillo Line #4) and 1,100 psig (Louisiana Line #1).

   b) **Pressure Test**: NGPL 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)[8] as required in 49 CFR 192.624(a)(1).[9]

      i) NGPL 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)**.[10] NGPL 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 NGPL must pressure test the ***special permit segment*** in accordance with **Condition 1(b)(ii)**.

      ii) If NGPL 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 pressure test, the ***special permit segment*** must be hydrostatically tested[11] 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

---

[8] 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.

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

[10] 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.

[11] For all in-service and pressure test failures, NGPL 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. NGPL 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.

months of the grant of this special permit.[12]

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, NGPL 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**: NGPL 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) NGPL must incorporate each ***special permit segment*** into its written integrity management program (IMP) 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.[13] 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.

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

---

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

[13] NGPL must follow the reporting requirements in **Condition 15 – Annual Report** as well as those noted throughout the conditions contained herein.

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) **Damage Prevention Program**: NGPL must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[14] in its damage prevention (DP) program.

3) **Condition 3 – Corrosion Control**

NGPL 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) **Cathodic Protection Test Station Spacing**: 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 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) **Annual Monitoring of Test Station Potential Measurements**: At least once every calendar year, not to exceed 15 months, NGPL 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

---

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

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, NGPL 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, NGPL must develop a remedial action plan to restore CP to meet 49 CFR 192.463. Within two (2) months of the finding, NGPL must apply for any necessary environmental permits (Federal or state).

ii) NGPL 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) **<u>Condition 4 – Close Interval Surveys</u>**

a) **<u>Survey Methodology and Boundaries</u>**:

i) NGPL must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***special permit segment***.[15]

ii) NGPL 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)**, NGPL 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.

---

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

b) **Survey Intervals**: NGPL 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.[16]

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[17] or the installation of linear anodes along the ***special permit segment*** to meet the CP requirements of 49 CFR 192.463, it is not eligible to operate with a Class 1 pipe in a Class 3 location. NGPL 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, NGPL 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, NGPL must apply for any necessary environmental permits (Federal or state).

iii) NGPL 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.[18]

---

16 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.

17 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."

18 If remediation based upon the findings of the CIS is not practicable within 12 months of the CIS survey, NGPL must submit a schedule and justify the delay 60 days prior to the 12-month completion requirement to the Director, PHMSA

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

a) **<u>Threat Identification</u>**: NGPL 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***,[19] 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.

b) **<u>Inline Inspection Methodology</u>**: NGPL 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, NGPL 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), NGPL must use an ILI tool[20] that will identify tight cracks.[21]

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

---

Southern Region. NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to a pipe coating remediation schedule extension.

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

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

[21] NGPL 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. NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

due to soil movement or the threat has been identified, NGPL 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) **Inline Inspection Assessment Intervals**: NGPL 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.[22]

(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,

[22] NGPL identified ***special permit segment 2 (KM 502)*** as having FBE coating. ***Special permit segment 2 (KM 502)*** will only require a cracking assessment to be completed within 18 months of special permit issuance, should cracking be identified as a threat.

(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, NGPL may request reassessment intervals up to seven (7) years for that threat assessment. NGPL must submit for and receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing this change.

iv) If factors beyond NGPL's control prevent the completion of an assessment within the required timeframe or reassessment interval, NGPL must perform the assessment as soon as practicable, and NGPL 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. NGPL 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**: NGPL 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. NGPL 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) **<u>Missing Records</u>**: If NGPL cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, NGPL 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;[23] and

iii) Excavate,[24] 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) **<u>Defective Girth Welds</u>**: 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, NGPL 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***. NGPL 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.[25] NGPL must remediate girth welds in

---

[23] 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.

[24] NGPL 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***.

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

the ***special permit segment*** in accordance with the inspection and remediation plan within 90 days of the "no-objection" letter receipt.[26]

7) **<u>Condition 7 - Stress Corrosion Cracking Threat</u>**

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

a) **<u>Threat Assessments</u>**: NGPL must complete the SCC threat assessment as detailed in **Condition 5(a) – Threat Assessment**.

b) **<u>SCC Integrity Assessment</u>**: If the threat assessment required under **Condition 7(a)** indicates the ***extended special permit segment***[27] is susceptible to either near-neutral or high-pH SCC, NGPL 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.[28]

c) **<u>Examination of Pipe</u>**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, NGPL 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) **<u>Inspection of Pipe at Excavations</u>**: 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), NGPL must directly examine the pipe for SCC using non-destructive examination methods appropriate for the type of pipe and integrity threat conditions in the ditch. NGPL must

---

26 NGPL must include any plan requirements or comments received from the Director, PHMSA Southern Region, into the remediation plan.

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

28 NGPL 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. NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[29] 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." NGPL 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. NGPL must keep coating records[30] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **<u>Discovery of SCC</u>**: If NGPL discovers SCC[31] 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,[32] 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[33] based upon the evaluated growth of the SCC, using <u>one (1) of the following methods</u>:

---

[29] 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.

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

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

[32] For all in-service and pressure test failures, NGPL 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. NGPL 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.

[33] NGPL 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. NGPL 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>**:[34]

(1) NGPL 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, NGPL must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended special permit segment*** with new pipe. NGPL 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>**: NGPL 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>**: NGPL must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

iv) **<u>Pipe Replacement</u>**: NGPL 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>**: NGPL must lower the operating pressure of the ***special permit segment*** to 20% below the maximum pressure during the preceding 90-day operating interval until NGPL conducts an ECA and remediates the ***special permit segment***.

f) **<u>SCC Remediation Plan</u>**: If NGPL discovers any SCC activity in the ***extended special permit segment***, NGPL must submit an SCC remediation plan to the Director, PHMSA Southern Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later

---

[34] NGPL 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. NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing any alternative assessment methods for SCC.

than 90 days after the finding of SCC.[35] 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 NGPL is addressing the threat for SCC in the ***special permit segment***.

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

a) **General**: NGPL must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. NGPL 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**: NGPL 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). NGPL 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 NGPL. NGPL 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 known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and

[35] For NGPL to go forward with the technical justification for addressing the SCC threat, NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region.

documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[36]

(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. NGPL 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, NGPL must provide the following to the Director, PHMSA Southern Region:

(1) EMAT ILI service provider report with any NGPL 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 - 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) NGPL must receive a "no objection" letter from the Director, PHMSA Southern

[36] 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, NGPL 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.

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"[37] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[38] 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"**: NGPL must remediate the ***special permit inspection area***[39] as follows:

i) **Immediate repair conditions for a "*special permit inspection area*"**: NGPL 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.

(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.[40]

(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

---

37 "6t" means pipe wall thickness times six (6).

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

39 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.

40 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).

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 NGPL, requires immediate action.

ii) **<u>One-year conditions – Hard Spots for a "special permit inspection area"</u>**: NGPL 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 HB scale of either (1) 300 HB or greater and 2-inches in length or width; (2) 300 HB or greater 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>**: NGPL 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, NGPL 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.[41]

---

[41] 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).

(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"**: NGPL 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"**: NGPL 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 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.[42]

(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.[43] The crack depth is less than 40% of the pipe wall thickness.

c) **Remediation schedule for a "special permit segment"**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, NGPL must remediate conditions in a ***special permit segment*** as follows:[44]

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

---

[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).

[43] 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.

[44] 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.

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

(2) **Weld Metal**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[45]

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

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

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

ii) **One-year crack repair conditions for a "special permit segment"**: NGPL 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) **Un-cleared shorted casing for a "special permit segment"**: NGPL 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) **Monitored conditions for a "special permit segment"**: NGPL 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) **Class 1 pipe**: 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.

---

[45] 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).

(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>**

NGPL 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, NGPL 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>**: NGPL 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>**: NGPL 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 NGPL identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

iii) **<u>All Shorted Casings</u>**: NGPL 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. NGPL 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 NGPL completed an assessment and all necessary repairs.

b) **<u>Remediation of Un-cleared Casing Shorts</u>**: If it is impractical for NGPL to clear a shorted casing within a ***special permit segment***, NGPL 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.[46, 47] In addition to the notification, NGPL must conduct the following:

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

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

10) **Condition 10 - Pipe - Seam Evaluations**

NGPL 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) **Identify and Test Pipe Seam Issues**:

i) Within 12 months of the special permit grant, NGPL must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended special permit segment***.[48] 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

---

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

47 NGPL must send a copy of the actions taken to clear the shorted casing to the Director, PHMSA Engineering and Research Division.

48 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, NGPL must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, NGPL must complete a hydrostatic test to a minimum of 1.39 times the MAOP for any identified ***special permit segment***.

b) **Seam Leak or Failure**:

i) If the pipeline experienced a seam leak or failure in the last five (5) years and NGPL 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 NGPL 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) NGPL must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. NGPL 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. NGPL must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure.[49]

c) **Pipe Replacement**: 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;

[49] NGPL 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;[50]

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[51]

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***, NGPL 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**: NGPL must remediate all weld seam leaks, failures, or ruptures[52] discovered in the ***special permit segment***. NGPL 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:

---

[50] As of the date of the grant of this special permit, NGPL reported no LF-ERW or EFW seam pipe in a ***special permit segment***.

[51] As of the date of the grant of this special permit, NGPL reported no pipe manufactured prior to 1954 with seam integrity issues in a ***special permit segment***.

[52] For all in-service and pressure test failures, NGPL 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. NGPL 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>**

NGPL 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***. NGPL 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>**: NGPL 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>**: NGPL 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, NGPL must develop a remediation procedure and apply for any necessary permits to conduct remediation. NGPL must complete all remediation within six (6) months, or as soon as practicable, after obtaining the necessary permits for the remediation.

d) **<u>Completion Schedules</u>**: If environmental permitting or right-of-way factors beyond NGPL's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, NGPL 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 NGPL must receive a "no objection" letter from the Director, PHMSA Southern Region.

12) **<u>Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures</u>**

NGPL must automate mainline valves[53] 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.[54] NGPL 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) **<u>Valve Locations</u>**: 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 NGPL supervisory control and data acquisition (SCADA) system installed.

b) **<u>Automatic Shutoff Valve Requirements</u>**: This special permit does not allow the use of automatic shutoff valves (ASVs).

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**.

---

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

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

d) **<u>Crossover or Lateral Pipe Connection Isolation</u>**: If any crossover or lateral pipe[55] 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.[56] Valves that are in the NGPL O&M procedures as locked closed and that are only opened when manned by NGPL 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:[57]

   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:

---

[55] **Table 4 - Valves and Lateral Locations with Isolations Methods** has a listing of all lateral valves. NGPL 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**.

[56] 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.

[57] The pipeline valve section location to be closed and isolated (if there should be a rupture) must be confirmed by NGPL 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.

(1) A release of gas observed by or reported to NGPL (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) NGPL observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in NGPL's written procedures. If NGPL 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, NGPL 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) NGPL 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.

Note: 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 NGPL.

ii) NGPL must evaluate and identify a rupture,[58] 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.

g) **Gas Control Center Monitoring**: The NGPL 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 NGPL pipeline operating procedures.

h) **Remote Monitoring**: NGPL 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

[58] For all in-service and pressure test failures, NGPL 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. NGPL 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.

pressure sensors, must have backup power to maintain communications and control to the NGPL Gas Control Center during power outages.

i) **<u>Point-to-Point Verification</u>**: NGPL 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>**: NGPL 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>**: NGPL 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 NGPL's control, NGPL 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) NGPL 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) NGPL 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;[59] and

iii) In accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631, NGPL 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**

NGPL must comply with the following requirements:

a) **Line-of-Sight Markers**: NGPL 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 NGPL within 30 days after identification of line-of-sight marker removal.

b) **Depth of Cover Survey**:

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

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

iii) For NGPL 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, NGPL 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 NGPL's submittal

---

[59] NGPL 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.

letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify NGPL of PHMSA's need for additional time to provide a decision.

c) **Data Integration**: NGPL must develop and maintain data integration[60] 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 encroachments.[61] 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, NGPL 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) NGPL must maintain data integration as a composite of all applicable data elements in a comparable data viewer.

---

60 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.

61 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.

d) **<u>Pipe Properties Testing</u>**: If the pipe does not meet **Condition 16(b)**, NGPL must test the pipe in a ***special permit segment*** as follows: [62]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[63, 64] 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) NGPL 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.

iii) NGPL must perform a minimum of two (2) destructive or NDT methods at an excavation site. NGPL must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[65] 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 NGPL 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, NGPL must submit an assessment

---

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

[63] 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>.

[64] 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.

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

procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to its usage.[66] The Director, PHMSA Southern Region, must respond to NGPL's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify NGPL of PHMSA's need for additional time to provide a decision.

iv) NGPL 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) NGPL 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. NGPL must use the applicable standard referenced in 49 CFR 192.7.

vi) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, NGPL must use the above methodology, or NGPL may elect to remove pipe joints for destructive testing.[67]

e) **<u>Pipeline System Flow Reversals</u>**: 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[68] in a ***special permit segment***, NGPL 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). NGPL must submit the written flow reversal procedure to the Director, PHMSA

---

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

[67] NGPL 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 NGPL's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify NGPL 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.

[68] 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.

Southern Region, and submit a copy of the plan to the Federal Docket for this special permit at www.regulations.gov.[69] NGPL 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**: NGPL 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, NGPL must obtain and adhere to all applicable Federal, state, and local environmental permit requirements when conducting the special permit conditions activity.

g) **Gas Quality**: NGPL 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) **Annual Class Location Study**: NGPL 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) **Notifications**: For any special permit condition that requires NGPL to provide a notice for a “no objection” response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Southern Region, NGPL must also send a copy to the State Agency that has interstate agent agreements with PHMSA and to the Director, PHMSA State Programs.

j) **Pipe and Soil Movement**: 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. NGPL must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. NGPL must submit soil stress and strain

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

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) NGPL 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. NGPL 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. NGPL 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***, NGPL 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. NGPL cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by NGPL from the Director, PHMSA Southern Region.

iv) NGPL 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)**.[70]

l) **Right-of-Way Patrols**: In addition to the requirements of 49 CFR 192.705, NGPL 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 NGPL’s control, NGPL 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.

---

[70] Any NGPL 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.

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

i) NGPL must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. NGPL must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. NGPL must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that minimizes the release of gas to the environment and is consistent with pipeline safety.[71]

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) NGPL 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. NGPL 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.

[71] **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.

iii) NGPL 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**.

14) **Condition 14 - Field Activity Notices to PHMSA**

NGPL 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 NGPL 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) **Condition 15 - Annual Report**

Annually[72] after the grant of this special permit, NGPL must report the following to the Director, PHMSA Southern Region, with copies to the Director, PHMSA Engineering and Research Division:[73]

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. NGPL 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[74] during the

[72] 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.

[73] NGPL must post the annual report to the special permit docket PHMSA-2019-0150 at www.regulations.gov.

[74] NGPL 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.

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.

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

   i) A pressure test that meets **Condition 1(b)**. NGPL 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**. NGPL 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***. NGPL 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) NGPL 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, NGPL 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 NGPL 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) NGPL 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) NGPL 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 NGPL must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2019-0150) at www.regulations.gov and submitting a copy to the Director, PHMSA Southern Region, and the Director, PHMSA Engineering and Research Division.

l) NGPL 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.[75] During the annual review meeting, NGPL must review the status of implementing the special permit conditions with the Director, PHMSA Southern Region.

16) **Condition 16 – Documentation**

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

a) NGPL 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***

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

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.

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 NGPL implementing the following conditions:

a) Within six (6) months after the Class 1 to Class 3 location change, NGPL 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) NGPL 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. NGPL 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 NGPL 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) NGPL must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) NGPL must have hydrostatically tested[76] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

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

18) **Condition 18 – Certification**

NGPL must meet the following conditions for certification:

a) A senior executive officer, vice president, or higher executive of NGPL 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) NGPL has updated its O&M, IMP, 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) NGPL has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

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

b) NGPL 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 for Pipeline Safety with copies to the Director, PHMSA Southern Region; the Director, PHMSA Engineering and

[76] For all in-service and pressure test failures, NGPL 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. NGPL 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.

Research Division; and the Federal Register Docket (PHMSA-2019-0150) at www.regulations.gov within one (1) year of the issuance date of this special permit.

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 NGPL 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 NGPL 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 NGPL sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, NGPL 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 NGPL elects to seek renewal of this special permit, NGPL 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 NGPL 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 May 17, 2022.

A 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 special permit with conditions granted to NGPL for Docket No. PHMSA-2019-0150 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