U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT - Class 1 to 3 Location

Special Permit Information:

Docket Number:	PHMSA-2017-0161
Requested By:	Tennessee Gas Pipeline Company, LLC
Operator ID#:	19160
Original Date Requested:	December 7, 2017
Original Issuance Date:	August 11, 2022
Effective Dates:	August 11, 2022 to August 11, 2032
Code Section(s):	49 CFR 192.611(a) and (d), 192.619(a)

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] grants this special permit to the Tennessee Gas Pipeline Company, LLC (TGP)[2] for three (3) ***special permit segments*** consisting of approximately 1.050 miles of 20-inch diameter gas transmission pipeline located in Kanawha County, West Virginia. This special permit waives compliance from 49 Code of Federal Regulations (CFR) 192.611 for three (3) ***special permit segments*** that have undergone changes from Class 1 to Class 3. The Federal pipeline safety regulations in 49 CFR 192.611(a) require natural gas pipeline operators to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location.

I. Purpose and Need

TGP sought this special permit for Class 1 to Class 3 location changes occurring on the 20-inch diameter Line 100-1 Pipeline (Pipeline). On the condition that TGP complies with the terms and

[1] Throughout this special permit, the usage of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety.

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

conditions set forth below, the special permit waives compliance from 49 CFR 192.611[3] for approximately 1.050 miles of natural gas transmission pipeline. This special permit allows TGP to maintain the current MAOP as shown in **Table 1 – Special Permit Segments**.

II. Special Permit Segment and Special Permit Inspection Area

This permit pertains to the specified ***special permit segments*** and corresponding ***special permit inspection areas*** defined in this section.

Special Permit Segments:

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

Table 1 – Special Permit Segments

Special Permit Segment Number[4]	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County, State	No. Dwellings	Year Installed	Seam Type	MAOP (psig)
451	20	100-1	3,651.14	120-1 – 14932	120-1 – 18584	Kanawha, WV	13	1984	DSAW	936
452	20	100-1	1,177.32	120-1 – 20565	120-1 – 21742	Kanawha, WV	2	1984	DSAW	936
453	20	100-1	716.37	120-1 – 23420	120-1 – 24136	Kanawha, WV	1	1984	DSAW	936

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

Special Permit Inspection Area:

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

Table 2 – Special Permit Inspection Area

Special Permit Inspection Area Number	Special Permit Segment(s) Included	Outside Diameter (inches)	Line Name	Master Segment Name	Start Survey Station (SS)	End Survey Station (SS)	Length[5] (miles/feet)
1	451, 452, 453	20	100-1	118-1 (HWY 60) TO 121-1A (BROAD RUN)	118-1 – 18.79	121-1 – 27219.53	46.02/ 242,989.49

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[3] PHMSA is granting this special permit for Class 1 to Class 3 location changes where the pipeline has been pressure tested to 1.25 times MAOP or greater for eight (8) hours to meet 49 CFR 192.619(a)(2), 192.611(a), 192.517, and **Condition 1(b)**. Each ***special permit segment*** must meet the documentation requirements in **Condition 16 - Documentation**.

[4] On February 3, 2022, TGP rescinded requested ***special permit segment***s ***454, 455, 456, 457, 458, 459, 462,*** and ***463***.

[5] <u>If the ***special permit inspection area*** footage does not extent from launcher to receiver, then the ***special permit inspection area*** must be extended</u>.

Extended Special Permit Segments:

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

Attachments B-1 through B-3 are general maps that include the pipeline route map showing the ***special permit segments*** and ***special permit inspection area***.

PHMSA grants this special permit based on the findings set forth in the "Special Permit Analysis and Findings" and "Final Environmental Assessment and Finding of No Significant Impact" documents, which can be read in their entirety in Docket No. PHMSA-2017-0161 in the Federal Docket Management System located on the internet at www.regulations.gov.

III. Conditions

PHMSA grants this special permit subject to TGP implementing the following conditions on the ***special permit segments*** and ***special permit inspection area***. Each condition detailed in this section applies to the ***special permit inspection area*** and the corresponding ***special permit segments*** unless otherwise noted in the condition:

1) **Condition 1 - Maximum Allowable Operating Pressure**
   a) **Maximum Allowable Operating Pressure**: TGP must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOP of 936 pounds per square inch gauge (psig) (20-inch diameter Line 100-1).
   b) **Pressure Test**: TGP must identify previous pressure tests for each ***special permit segment***. Pressure test records for each ***special permit segment*** must meet 49 CFR 192.517(a) and be traceable, verifiable, and complete (TVC)[6] as required in 49 CFR 192.624(a)(1).[7]
      i) TGP must furnish TVC pressure test records to the Director, PHMSA Engineering and Research Division, and to the Director, PHMSA Southern Region, within 60 days of the grant of the special permit. The pressure test records must be compliant with **Condition**

[6] 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.

[7] TGP has furnished TVC pressure test records to PHMSA for each ***special permit segment*** that meet **Condition 1(b)**.

1(b).[8] TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, that the TVC pressure test records are compliant with 49 CFR 192.517(a), 192.624(a)(1), and 192.619(a)(1) through (a)(4) for a Class 1 location, or TGP must pressure test the ***special permit segment*** in accordance with **Condition 1(b)(ii)**.

ii) If TGP does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated pressure test, the ***special permit segment*** must be hydrostatically tested[9] to a minimum of 1.39 times the MAOP for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J, within 18 months of the grant of this special permit.[10]

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

2) **Condition 2 - Procedure Updates**

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

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

b) **Integrity Management Program**:

i) TGP must incorporate each ***special permit segment*** into its written integrity management 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

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8 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.

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

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

192.945.[11] A ***special permit inspection area*** outside of a ***special permit segment*** is not required to be included as a "covered segment" 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 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**: TGP must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[12] in its damage prevention (DP) program.

3) **Condition 3 – Corrosion Control**

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

a) **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

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

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

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, TGP must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for the ***special permit segment*** and must include "on and off" potential measurements. Test station readings (pipe-to-soil potential measurements) must comply with Appendix D – Section I.A. (1) of 49 CFR Part 192 or remediation detailed in paragraph (c) of this condition is required. For hard spots identified with a Brinell Hardness (HB) of 300 HB or greater, CP voltage levels must be maintained more electro-positive than minus 1.2 volts direct current (DC).

c) **Inadequate Cathodic Protection Level Determination**:

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

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

d) **Remedial Action Plans**:

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

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

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

a) **Survey Methodology and Boundaries**:

   i) TGP must perform an "on and off" current CIS at a maximum 5-foot spacing along the entire length of each ***special permit segment***.[13]

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

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

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

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

i) Initial assessment must be completed for each newly incorporated and extended ***special permit segment*** within 12 months after the grant of the special permit. For a ***special permit segment*** renewal, the CIS may be conducted at the next reassessment interval.[14]

ii) Reassessments must be conducted every five (5) years not to exceed 66 months. CIS assessments 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[15] 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. TGP must either: (1) replace the pipe in the ***special permit segment*** with Class 3 location standard (design factor) pipe (see 49 CFR 192.111(a)); (2) recoat the pipe with non-shielding external coating within 12 months of the finding; or (3) lower the MAOP to meet 49 CFR 192.611.

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

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[14] 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.

[15] 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."

iii) TGP must complete remediation of each ***special permit segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[16]

5) **Condition 5 – Inline Inspection**

a) **Threat Identification**: TGP must implement data integration and identify integrity threats in the ***special permit inspection area*** at least once each calendar year, with intervals not to exceed 15 months, in accordance with 49 CFR 192.917 and **Condition 13(c) – Data Integration**. The stress corrosion cracking (SCC) threat assessment for the ***extended special permit segment***,[17] 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) **Inline Inspection Methodology**: TGP must conduct instrumented ILI integrity assessments in accordance with 49 CFR 192.493, for each ***special permit inspection area*** for all threats identified in accordance with 49 CFR 192.919 and 192.921.

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

ii) For near-neutral or high-pH SCC (cracking threat), TGP must use an ILI tool[18] that will identify tight cracks.[19]

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.

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

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

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

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

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

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

i) Initial ILI assessments must be conducted as follows:

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

(2) If cracking has been identified as a threat for the ***extended special permit segment,*** it must be assessed within 18 months of the special permit grant date.[20]

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

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

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

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

(1) 49 CFR 192.939(a);

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

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

(b) hard spots,

(c) shorted carrier pipe to the casing,

[20] TGP identified ***special permit segments 451, 452, and 453*** as having FBE coating. These ***special permit segments*** will only require a cracking assessment to be completed within 18 months of special permit issuance, should cracking be identified as a threat.

(d) susceptible to SCC, or

(e) pipe or soil movement; or

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

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

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

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

6) **Condition 6 - Girth Welds**

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

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

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

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

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

ii) Evaluate the terrain along each ***special permit segment*** for threats to girth weld integrity from soil or settlement stresses, perform NDT, and remediate all such integrity threats;[21] and

iii) Excavate,[22] 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, TGP must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segment*** based upon the repair findings and the threat to the ***special permit segment***. TGP must submit the inspection and remediation plan for girth welds to the Director, PHMSA Southern Region, and must receive a "no objection" letter for the girth weld remediation plan prior to its implementation.[23] TGP must remediate girth welds in the ***special permit segment*** in accordance with the inspection and remediation plan within 90 days of the "no objection" letter receipt.[24]

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

TGP must evaluate the entire length of each ***special permit inspection area***[25] for SCC as follows:

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21 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.

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

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

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

25 TGP has no documented occurrences of SCC in the ***special permit inspection area***.

a) **<u>Threat Assessments</u>**: TGP 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***[26] is susceptible to either near-neutral or high-pH SCC, TGP must perform an SCC assessment on the ***extended special permit segment*** in accordance with **Condition 5 – Inline Inspection**. SCC integrity assessment using spike pressure testing is not approved for this special permit.[27]

c) **<u>Examination of Pipe</u>**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, TGP must directly examine the pipe for SCC when the coating has been identified as poor during the pipeline examination. The examination must be conducted using an accepted crack detection practice in accordance with 49 CFR 192.710(c)(4), (d), and **Condition 7(d)** when the ***extended special permit segment*** is uncovered for any reason to comply with the special permit and integrity management 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), TGP 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. TGP must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[28] when an ***extended special permit segment*** is uncovered, and the coating has been identified as poor during the pipeline examination. Visual inspection is not sufficient to determine "poor coating." TGP must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe

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

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

[28] 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.

and/or shields the CP. TGP must keep coating records[29] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **<u>Discovery of SCC</u>**: If TGP discovers SCC[30] 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,[31] 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[32] based upon the evaluated growth of the SCC, using <u>one (1) of the following methods</u>:

i) **<u>Spike Hydrostatic Test Program</u>**:[33]

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

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

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

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

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

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

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

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

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

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

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

f) **<u>SCC Remediation Plan</u>**: If TGP discovers any SCC activity in the ***extended special permit segment***, TGP must submit an SCC remediation plan to the Director, PHMSA Southern Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC.[34] The plan must:

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

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

8) **<u>Condition 8 - Anomaly Evaluation and Remediation</u>**

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

i) **<u>ILI Tool Accuracy</u>**: TGP must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration excavations and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). TGP must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that

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

tolerance in determining the size of each anomaly feature reported to TGP. TGP must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. ILI tools used must be calibrated as follows:

(1) **General ILI Tool Calibration**: ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***special permit inspection area*** or from the complete ILI tool run segment if the continuous ILI segment is longer than the ***special permit inspection area***. ILI calibration excavations may include previously excavated anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[35]

(2) **EMAT ILI Tool Calibration**:

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

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

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

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

(2) Calibration data showing the ILI tool meets API Standard 1163 IBR - *Sections 6 - Qualification of Performance Specifications*, *Section 7 - System Operational Verification*, and *Section 8 - System Results Validation*, as applicable; and

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

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

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

iii) **ILI Tool Evaluations**: ILI tool evaluations for metal loss must use "6t x 6t"[36] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[37] must be within 180 days of any ILI tool run for each type of ILI tool (e.g., HR-geometry, HR-deformation, HR-MFL, EMAT, IMU, or other equivalent ILI tools).

b) **Remediation schedule for "special permit inspection area"**: TGP must remediate the ***special permit inspection area***[38] as follows:

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

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

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

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36 "6t" means pipe wall thickness times six (6).

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

38 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.

(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.[39]

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

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

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

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

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

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

ii) **<u>One-year conditions – Hard Spots for a "special permit inspection area"</u>**: TGP must repair by installation of a Type B sleeve or cut-out and recoat within 12 months of discovery, any hard spots found in the pipe body of EFW pipe discovered after the grant of the special permit with a hardness on the 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>**: TGP must repair the following conditions within 12 months of discovery in a ***special permit inspection area***:

(1) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12), unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment**

[39] 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).

A demonstrates the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

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

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

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

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

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

locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[40]

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

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

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[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).

(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.[41]

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

c) **<u>Remediation schedule for a "special permit segment"</u>**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, TGP must remediate conditions in a ***special permit segment*** as follows:[43]

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[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).

[42] 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.

[43] 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.

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

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

(2) **<u>Weld Metal</u>**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[44]

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

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

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

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

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

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

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

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

(2) **Class 2 pipe**: 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) **Class 3 pipe**: 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) **Condition 9 - Pipe Casings**

TGP must identify all shorted casings within a ***special permit segment*** no later than six (6) months after the grant of this special permit and classify any shorted casings as either having a "metallic short" (the carrier pipe and the casing are in metallic contact) or an "electrolytic short" (the casing is filled with an electrolyte) using a commonly accepted method such as the Panhandle Eastern, Pearson, Direct Current Voltage Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), or AC Attenuation.

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

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

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

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

b) **Remediation of Un-cleared Casing Shorts**: If it is impractical for TGP to clear a shorted casing within a ***special permit segment***, TGP must document the actions taken to remediate the shorted casing and must receive a "no objection" letter from the Director, PHMSA Southern

Region, to use ILI assessments instead of clearing the short.[45, 46] In addition to the notification, TGP must conduct the following:

i) A ***special permit segment*** with shorted casings must be assessed with the appropriate ILI tools (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) TGP must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

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

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

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

i) Within 12 months of the special permit grant, TGP must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended special permit segment***.[47] 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

(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.

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

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

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

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

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

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

ii) TGP must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. TGP must perform a root cause analysis, including the metallurgical examination of the failed pipe, to determine if the failure is caused by a systemic or non-systemic issue. TGP must provide the written results of this root cause analysis to the Director, PHMSA Southern Region, within 90 days of the failure.[48]

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

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

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;[49]

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[50]

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

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

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

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

v) The ***special permit segment*** pipe has known manufacturing or construction issues that are unresolved, such as concentrated hard spots, hard heat-affected weld zones, selective seam corrosion, pipe movement that has led to buckling, past leak and rupture issues, or any other systemic issues.

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

e) **Remediation Plan**: TGP must remediate all weld seam leaks, failures, or ruptures[51] discovered in the ***special permit segment***. TGP must submit a seam remediation plan for the ***special permit segment*** to the Director, PHMSA Southern Region, no later than 30 days after finding a seam leak, seam failure, or seam rupture in the ***special permit segment*** containing one (1) of the following:

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) **Condition 11 - Control of Interference Currents**

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

a) **Surveys**: TGP must perform periodic interference surveys to detect the presence and level of any electrical stray current, including when there are current flow increases over the ***special***

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

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

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

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

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

TGP must automate mainline valves[52] 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.[53] TGP must automate mainline valves to

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

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

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**. Each ***special permit segment*** must have telemetry connections to the TGP 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**.

d) <u>**Crossover or Lateral Pipe Connection Isolation**</u>: If any crossover or lateral pipe[54] 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.[55] Valves that are in the TGP O&M procedures as <u>locked closed</u> and that are only opened when manned by TGP operating personnel do not require RCVs or ASVs for closure.

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

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

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

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

[55] 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.

f) **Mainline Valve Closure**: 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:[56]

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

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

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

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

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 TGP.

ii) TGP must evaluate and identify a rupture,[57] 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.

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

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

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

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

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

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

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

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

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

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

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

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

   ii) TGP must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other emergency management coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[58] and

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

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

TGP must comply with the following requirements:

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

b) **Depth of Cover Survey**:

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

ii) TGP must implement additional safety measures for any pipe in a ***special permit segment*** that does not meet 49 CFR 192.327(a) for a Class 1 location where there is a reduced depth of cover. A ***special permit segment*** with depth of cover less than 24-inches must be either lowered, have additional soil cover added, or have a concrete pad installed unless it is in consolidated rock.

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

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

c) **Data Integration**: TGP must develop and maintain data integration[59] 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.[60] Structures must be validated each calendar year by obtaining new aerial imagery or by ground patrol in accordance with **Condition 13(h)**.

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

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

d) **Pipe Properties Testing**: If the pipe does not meet **Condition 16(b)**, TGP must test the pipe in a ***special permit segment*** as follows: [61]

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[59] 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.

[60] 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.

[61] TGP has furnished TVC material records to PHMSA for each ***special permit segment*** that meet **Condition 16(b)**.

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[62, 63] pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or 192.105 for determining MAOP. Non-destructive or destructive tests, examinations, and assessments must be completed within 18 months of the grant of this special permit.

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

iii) TGP must perform a minimum of two (2) destructive or NDT methods at an excavation site. TGP must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[64] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then TGP will confirm the yield strength of that individual pipe using destructive test methods or remove the ***special permit segment*** pipe. If ILI tools are used to verify the pipeline materials, TGP must submit an assessment procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to its usage.[65] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

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[62] 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.

[63] 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.

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

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

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

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

vi) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, TGP must use the above methodology, or TGP may elect to remove pipe joints for destructive testing.[66]

e) **Pipeline System Flow Reversals**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49 CFR 192.619(a)(1) or 192.611[67] in a ***special permit segment***, TGP must prepare a written plan that corresponds to the applicable criteria identified in the PHMSA Advisory Bulletin, ADB-2014-04, "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" (79 FR 56121; Sept. 18, 2014). TGP must submit the written flow reversal procedure to the Director, PHMSA Southern Region, and submit a copy of the plan to the Federal Docket for this special permit at www.regulations.gov.[68] TGP must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to implementing the pipeline system flow reversal through a ***special permit segment***.

f) **Environmental Assessments and Permits**: TGP must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings, and pipeline natural gas emissions from implementation of the special permit conditions for a ***special permit segment*** or ***special permit inspection area*** prior to the disturbance or activity.

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

[67] 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.

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

If a land disturbance, water body crossing, or pipeline natural gas emission is required, TGP must obtain and adhere to all applicable Federal, state, and local environmental permit requirements when conducting the special permit conditions activity.

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

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

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

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

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

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

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

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

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

(b) Escaping gas that has ignited;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

iv) TGP may request an extension of the remediation time interval requirements by sending a request to the Director, PHMSA Southern Region, but must receive a “no objection” letter from the Director, PHMSA Southern Region, prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[69]

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

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

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

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

m) **Minimization of Gas Released to the Environment**:

i) TGP must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. TGP must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. TGP must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that minimizes the release of gas to the environment and is consistent with pipeline safety.[70]

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

[70] **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.

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

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

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

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

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

15) **Condition 15 - Annual Report**

Annually[71] after the grant of this special permit, TGP must report the following to the Director, PHMSA Southern Region, with copies to the Director, PHMSA Engineering and Research Division:[72]

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

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71 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.

72 TGP must post the annual report to the special permit docket PHMSA-2017-0161 at www.regulations.gov.

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[73] during the previous year in the ***special permit inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

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

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

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

d) Any reportable incident, any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in a ***special permit inspection area***. TGP must include the location by mile post, county/parish, and state, the date of discovery, date of repair, and estimated gas loss (cubic feet) per day and in total for any Grade 1, 2, or 3 gas leak as described in **Condition 13(k) - Gas Leakage Surveys and Remediation**.

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

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

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

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

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

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

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

k) A senior executive officer, vice president, or higher executive of TGP must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2017-0161) at www.regulations.gov and submitting a copy to the Director, PHMSA Southern Region, and the Director, PHMSA Engineering and Research Division.

l) TGP must schedule a review meeting regarding **Condition 15 - Annual Report** with the Director, PHMSA Southern Region, prior to or within one (1) month of the filing of each year.[74] During the annual review meeting, TGP must review the status of implementing the special permit conditions with the Director, PHMSA Southern Region.

16) **Condition 16 – Documentation**

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

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

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

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

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

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

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

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

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

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

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

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

   ii) TGP must have hydrostatically tested[75] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

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

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

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

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

TGP must meet the following conditions for certification:

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

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

   ii) TGP has updated its O&M, 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) TGP has prepared an uprating plan in accordance with **Condition 1(c)**, if applicable; and

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

b) TGP must send the certifications required in **Condition 18(a)**, with special permit condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2017-0161) at <u>www.regulations.gov</u> within one (1) year of the issuance date of this special permit.

IV. Limitations

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

1) PHMSA has the sole authority to make all determinations on whether TGP has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.

2) Any work plans and associated schedules for a ***special permit segment*** and ***special permit inspection area*** are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by TGP to submit the certifications required by **Condition 18 - Certification** within the time frames specified may result in revocation of this special permit.

4) As provided in 49 CFR 190.341, PHMSA may issue an enforcement action for failure to comply with this special permit. The terms and conditions of any corrective action order, compliance order, or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit.

5) If TGP sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, TGP must provide PHMSA with written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit if the transfer constitutes a material change in conditions or circumstances underlying the permit.

6) PHMSA grants this special permit limited to a term of no more than 10 years from the date of issuance. If TGP elects to seek renewal of this special permit, TGP must submit its renewal request at least 180 days prior to expiration of the 10-year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Southern Region, and to the Director, PHMSA Engineering and Research Division. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 15 - Annual Report** above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from TGP prior to granting any request for special permit renewal.

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

Issued in Washington, DC on August 11, 2022.

ALAN KRAMER MAYBERRY

Digitally signed by ALAN KRAMER MAYBERRY
Date: 2022.08.11 17:10:25 -04'00'

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Attachment A - Dent Anomalies – Engineering Critical Assessment

To evaluate dents and other mechanical damage anomalies that conform to the conditions described in **Table 3 – Dent Criteria** below, TGP must perform an engineering critical assessment (ECA) as follows:

1) Identify and assess all threats for the pipe segment such as ground movement, other external loading, cracking and corrosion that may be impacting the dent and mechanical damage.
2) Review all available high-resolution magnetic flux leakage (HR-MFL), high-resolution deformation, inertial mapping tool, and crack detection ILI data for damage in the dent area and any associated weld region.
3) If multiple ILI runs over time are available, the dent profile between the most recent and previous inline inspections should be compared to identify changes or significant changes in dent depth and shape and its possible impact to the integrity of the pipeline.
4) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.
5) Identify and quantify all significant loads acting on the dent.
6) TGP must use finite element analysis to quantify the dent strain, and then estimate the damage using either Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) at the dent. Finite element analysis modeling of the dent must include all associated anomalies, defects, and welds. Other methodologies and approaches that are supported by peer reviewed publications will also be considered as part of the ECA but will require a "no objection" letter from the Director, PHMSA Southern Region.
7) The analyses performed must account for material property uncertainties and model inaccuracies and ILI tool sizing tolerances.
8) Using operational pressure data, appropriate fatigue models, and assuming the appropriate safety factor, TGP must estimate the fatigue life of the dent in accordance with API 1156 (1997 Edition), API RP 1183 (1st Edition, 2020, or IBR Edition) or other published literature that is technically appropriate for dent assessment. Multiple dent or other fatigue models must be evaluated as part of the ECA.
9) If the dent is suspected to have cracks, then a crack growth rate assessment is required (or the dent needs to be remediated) to ensure adequate life for the dent with crack(s) and the crack(s) in the dent must be evaluated and remediated in accordance with the criteria in **Condition 8 – Anomaly Evaluation and Remediation**.

10) If TGP uses other technologies or techniques to comply with failure pressure determinations, TGP must submit advance notification to Director, PHMSA Southern Region, and must receive a "no objection" letter from the Director, PHMSA Southern Region, prior to usage.
11) The ECA process must be repeated following each assessment to ensure conformance to the original ECA conclusions.
12) To use ECA for dents with a depth greater than 6% up to 10% of the outside diameter (OD) requires a "no-objection" letter from the Director, PHMSA Southern Region.
13) TGP must remediate dents and mechanical damage that do not pass the criteria defined in **Table 3 – Dent Criteria**, or TGP must conduct an acceptable ECA as described in this **Attachment A, Items 1 through 12**.
14) TGP must submit the dent ECA procedure to the Director, PHMSA Southern Region, for a "no objection" letter prior to conducting the anomaly evaluation.[76] The Director, PHMSA Southern Region, must respond to TGP's submittal letter within 90 days. The Director, PHMSA Southern Region, may provide a decision, request for additional information, or notify TGP of PHMSA's need for additional time to provide a decision.

[76] A copy of the dent ECA procedure must be sent to the Director, PHMSA Engineering and Research Division.

Table 3 – Dent Criteria

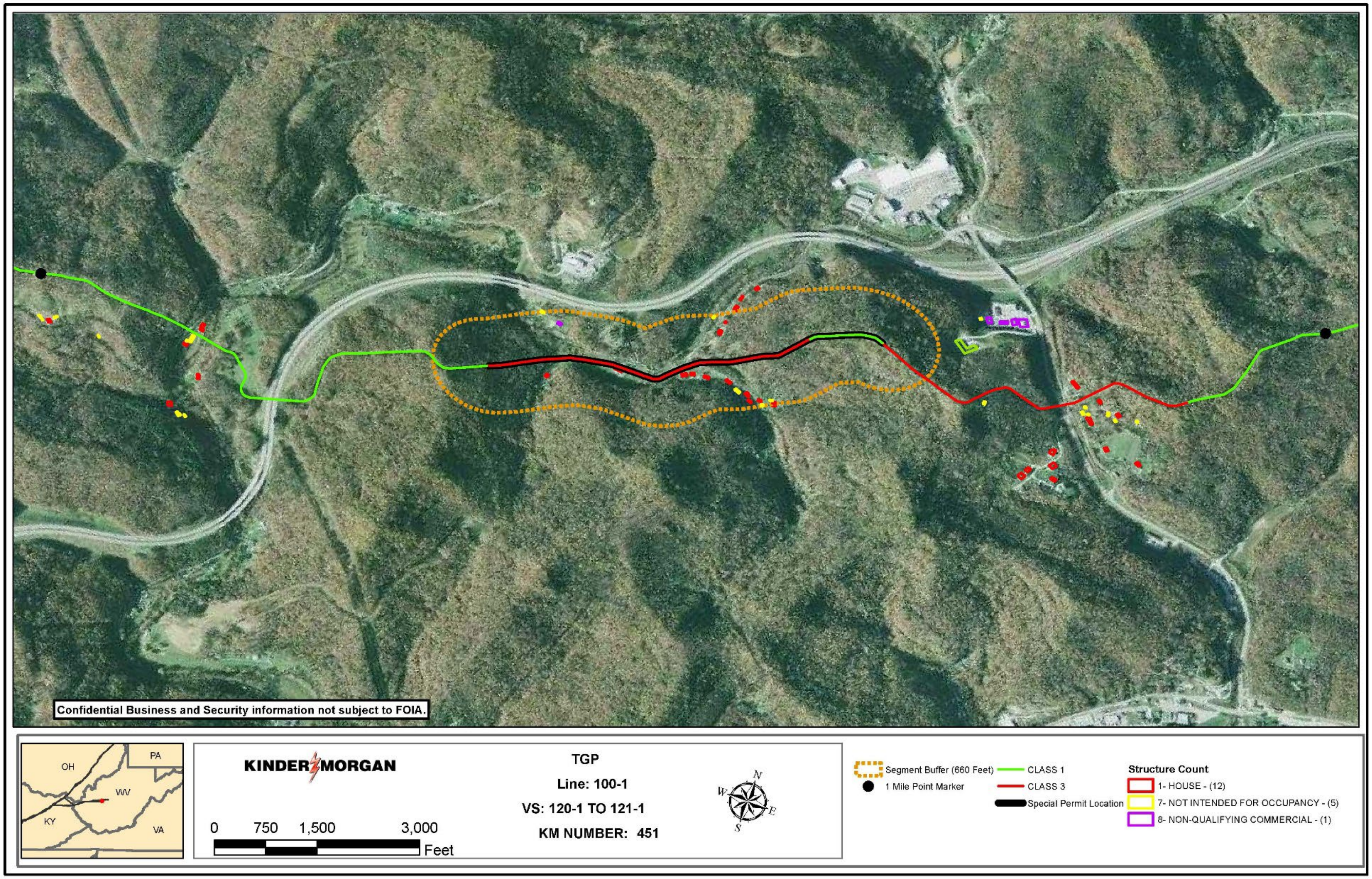
Dent type	Critical Dents that Require Action	ECA an Option
Plain Dent	Dent of depth > 6% Outside Diameter (OD) or dent strain level exceeding: i. Dent with strain > 6% limit (ASME B31.8, 2018 Edition) **or** ii. Strain Limit Damage (SLD) or Ductile Failure Damage Indicator (DFDI) > 0.6 (per API RP 1183, IBR Edition or 1st Edition, 2020, if not IBR)	YES
Dent Associated with Corrosion**	i. Dent depth of > 6% OD with corrosion of any depth **or** ii. Dent of depth ≤ 6% OD with corrosion depth that is more than 15% of the pipe wall thickness	YES
Dent Associated with Metal Loss other than Corrosion**	Dent associated with metal loss other than corrosion: Gouge, axial or circumferential groove, SCC, fatigue cracks, and/or other cracks.	YES
Dent Affecting Weld (Girth Weld, Longitudinal Seam Weld or Spiral Seam Weld)	Dent of any depth affecting pipe with: Low Frequency Electric Resistance Welded (LF-ERW), Electric Flash Welded (EFW), Lap Welded, or Longitudinal Joint Factor < 1.0	YES*
	Dent of depth > 2% OD affecting other types of weld seams, see above, or girth welds with strain level exceeding 4% (ASME B31.8, 2018 Edition)	YES
Skewed and/or Multiple Dent Peaks	Any complex dent geometry identified by TGP or ILI vendor such as skewed dent, two or multi-peak deformations	YES

* Lack of ductility must be integrated into the ECA.

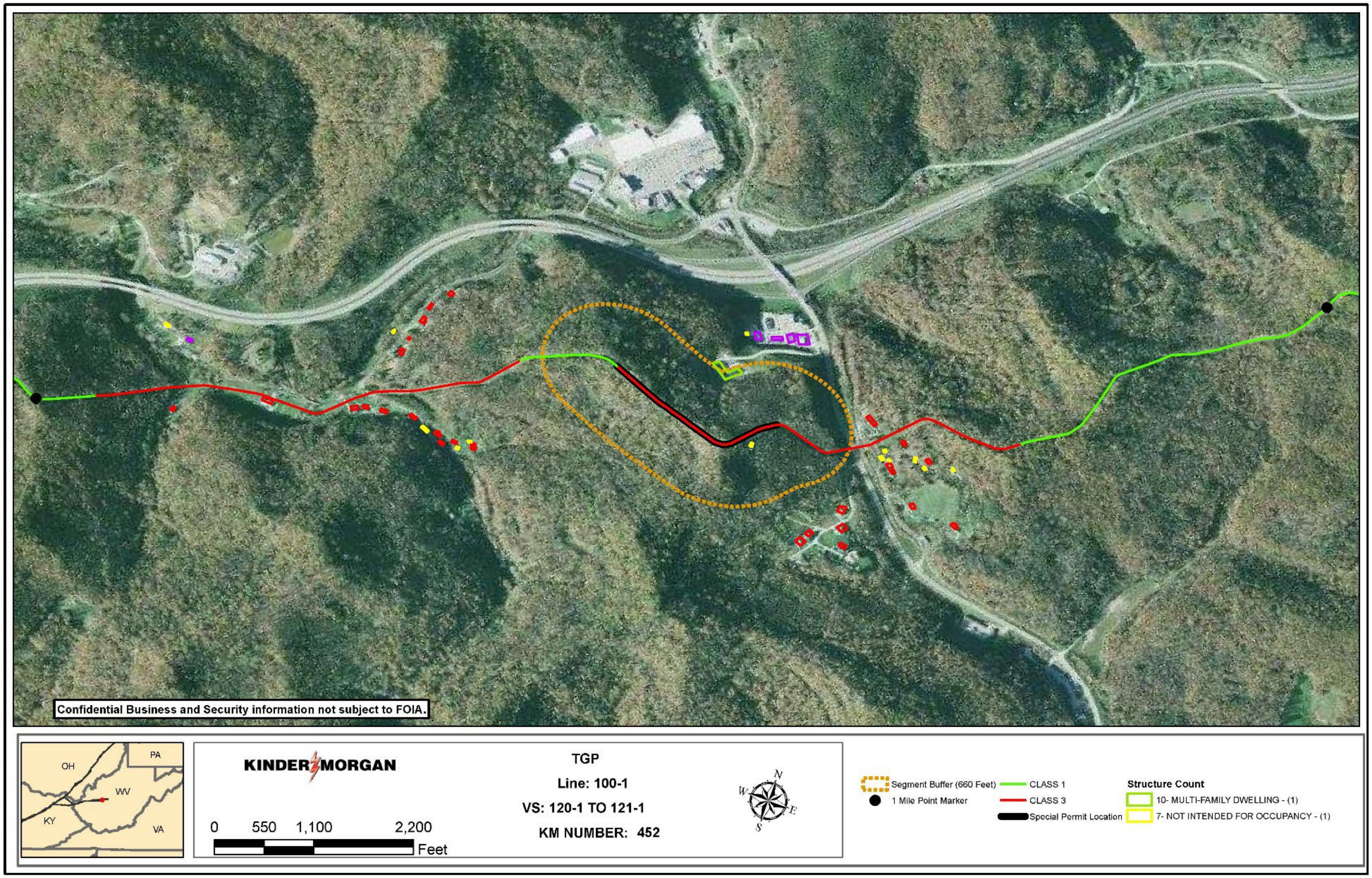
** Corrosion failure pressure with safety factor must meet the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation**.

Note: TGP may use 49 CFR Part 192 compliant dent remediation procedures for the evaluation and remediation of a dent ≤ 6% OD, with a corrosion depth < 15% of the pipe wall, and corrosion failure pressure with safety factor that meets the MAOP requirements in **Condition 8 - Anomaly Evaluation and Remediation**.

Attachment B-1 - Special Permit Segments and Inspection Area Route Maps
Special Permit Segment # 451



Attachment B-2 - Special Permit Segments and Inspection Area Route Maps
Special Permit Segment # 452



Attachment B-3 - Special Permit Segments and Inspection Area Route Maps
Special Permit Segment # 453

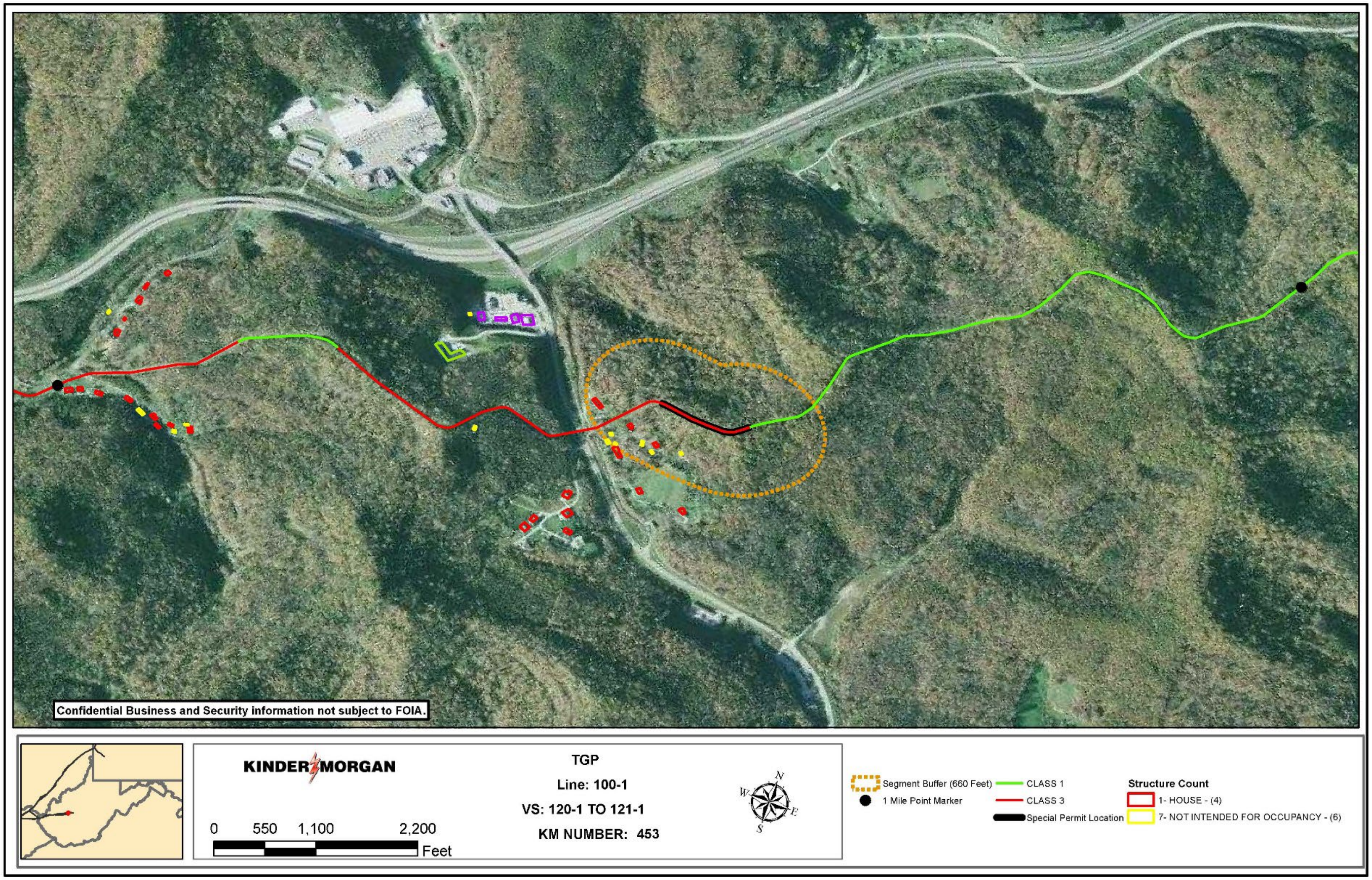


Table 4 – Valves and Lateral Locations with Isolations Methods						
Special Permit Segment Nos.	Mile Post (MP) / Stationing	Type	Valve / Lateral Name (If Applicable)	Nominal Diameter (inches)	Current Valve Automation Methodology	Required Automation Methodology for Special Permit[77]
451, 452, 453	MP 9.59/ 506+49 BACK 0+00 AHEAD	UPSTREAM VALVE	120-1	20	MANUAL BALL VALVE	RCV
	0+06.92	MLV BYPASS	120-1BD1	8	MANUAL CLOSED	CLOSED or RCV
	566+63.19	MLV BYPASS	121-1BD	8	MANUAL CLOSED	CLOSED or RCV
	MP 10.73/ 566+69	DOWNSTREAM VALVE	121-1	20	MANUAL BALL VALVE	RCV

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[77] Isolation valves shown as CLOSED, when opened, must be manned by TGP personnel. **Condition 12 - Mainline Valve – Monitoring and Remote Control for Ruptures** is applicable to all crossover valves, valve spacing, and lateral tie-ins. **Condition 12(d)** requires isolation valves shown as "closed or CLOSED" to be "locked close" when unmanned by TGP personnel.