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

Special Permit Information:

Docket Number:	PHMSA-2008-0066
Requested By:	Columbia Gulf Transmission, LLC
Operator ID#:	2620
Original Issuance Date:	March 2, 2010
1st Renewal Issuance Date:	October 9, 2015
Date Renewal Requested:	September 04, 2019
2nd Renewal Issuance Date:	July 21, 2021
Renewal Effective Dates:	July 21, 2021 to July 21, 2031
Code Section(s):	49 CFR 192.611

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 Columbia Gulf Transmission, LLC (CGT)[2] for 11 existing ***special permit segments*** consisting of approximately 9.15 miles of 30-inch and 36-inch diameter gas transmission pipelines and grants an additional 30 ***special permit segments*** consisting of approximately 18.51 miles of 30-inch and 36-inch diameter gas transmission pipelines in Williamson, Davidson, Trousdale, and Wilson Counties, Tennessee. This permit includes the renewal of a previous special permit granted to CGT that covered many of the same segments with updated conditions, extensions of ***special permit segments*** that were included in the previous permit and includes

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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 CGT is a wholly-owned subsidiary of TC Energy.

new segments to the permit. Within this special permit, PHMSA is proposing to waive compliance from 49 Code of Federal Regulations (CFR) 192.611 for 41 pipeline ***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:

CGT sought this special permit for Class 1 to Class 3 location changes occurring on the 30-inch diameter Mainline 100 (Mainline 100), 30-inch diameter Mainline 200 (Mainline 200), and 36-inch diameter Mainline 300 (Mainline 300) Pipelines. On the condition that CGT complies with the terms and conditions set forth below, the special permit waives compliance from 49 CFR 192.611[3] for approximately 27.66 miles of 30-inch and 36-inch diameter natural gas transmission pipeline, where the class location of the pipelines changed from a Class 1 to Class 3 location and from a Class 2 to Class 3 location in Williamson, Davidson, Trousdale, and Wilson Counties, Tennessee. This special permit allows CGT to maintain the current MAOP of 935 pounds per square inch gauge (psig) for the Mainline 100 Pipeline and 1,007 psig for Mainlines 200 and 300 Pipelines in the ***special permit segments***.

II. Special Permit Segments and Special Permit Inspection Areas:

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

1) **Special Permit Segments**:

   This special permit applies to the ***special permit segments*** located in Williamson, Davidson, Trousdale, and Wilson Counties, Tennessee, that are identified using the CGT survey station (SS) references. Each ***special permit segment*** is defined as follows:

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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**.

- ***Special permit segment 1*** – Active[4] – 30-inch diameter Mainline 100 – 704[5] feet, SS 1584+69 to SS 1591+59; Williamson County, Tennessee, Year Constructed: 1954;
- ***Special permit segment 2*** – Active – 30-inch diameter Mainline 200 – 1,081 feet, SS 1584+58 to SS 1595+39; Williamson County, Tennessee, Year Constructed: 1958;
- ***Special permit segment 3*** – Active, Extended[6] – 36-inch diameter Mainline 300 – 796 feet, SS 1584+74 to SS 1592+70 (extension of 262 feet, from SS 1590+08 to SS 1592+70); Williamson County, Tennessee, Year Constructed: 1969;
- ***Special permit segment 4*** – Active, Extended – 30-inch diameter Mainline 100 - 21,115 feet, SS 1783+03 to SS 1994+18 (extension of 10,318 feet, from SS 1891+00 to SS 1994+18); Williamson County, Tennessee, Year Constructed: 1954;
- ***Special permit segment 5*** – Active, Extended – 30-inch diameter Mainline 200 – 10,664 feet, SS 1785+75 to SS 1892+39 (extension of 139 feet, from SS 1891+00 to SS 1892+39); Williamson County, Tennessee, Year Constructed: 1954;
- ***Special permit segment 6*** – Active, Extended – 36-inch diameter Mainline 300 – 20,472 feet, SS 1790+85 to SS 1995+57 (extension of 199 feet, from SS 1790+85 to SS 1792+84, and extension of 10,457 feet from SS 1891+00 to SS 1995+57); Williamson County, Tennessee, Year Constructed: 1968/1969;
- ***Special permit segment 7*** – Active – 30-inch diameter Mainline 100 – 5,578[7] feet, SS 2210+36 to SS 2266+03; Davidson County, Tennessee, Year Constructed: 1953/1954;
- ***Special permit segment 8*** – Active – 30-inch diameter Mainline 200 – 5,487 feet, SS 2212+41 to SS 2267+28; Davidson County, Tennessee, Year Constructed: 1962;
- ***Special permit segment 9*** – Active – 36-inch diameter Mainline 300 – 603 feet, SS 2208+45 to SS 2214+48; Davidson County, Tennessee, Year Constructed: 1968;

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[4] An "Active" ***special permit segment*** is "currently managed" by a special permit and is to be renewed with the grant of this special permit.

[5] This footage does not match stationing due to a station equation within the ***special permit segment***.

[6] An "Active, Extended" ***special permit segment*** is currently managed by a special permit that has some amount of footage added to an endpoint of the existing "active segment" through issuance of this special permit renewal.

[7] This footage does not match stationing due to a station equation within the ***special permit segment***.

- ***Special permit segment 10*** – Active, Extended – 30-inch diameter Mainline 200 – 6,038 feet, SS 2986+05 to SS 3046+43 (extension of 4,438 feet, from SS 2986+05 to SS 3030+43); Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 11*** – Active, Extended – 36-inch diameter Mainline 300 – 5,986 feet, SS 2981+69 to SS 3041+55 (extension of 4,386 feet, from SS 2981+69 to SS 3025+55); Wilson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 12*** – New[8] – 30-inch diameter Mainline 100 – 46 feet, SS 1570+84 to SS 1571+30; Williamson County, Tennessee, Year Constructed: 1954;
- ***Special permit segment 13*** – New – 30-inch diameter Mainline 100 – 2,323 feet, SS 2016+69 to SS 2039+92; Williamson County, Tennessee, Year Constructed: 1954;
- ***Special permit segment 14*** – New – 30-inch diameter Mainline 100 – 7,219 feet, SS 2305+73 to SS 2377+92; Davidson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 15*** – New – 30-inch diameter Mainline 100 – 1,982 feet, SS 2509+43 to SS 2529+25; Davidson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 16*** – New – 30-inch diameter Mainline 100 – 1,377 feet, SS 3142+96 to SS 3156+73; Wilson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 17*** – New – 30-inch diameter Mainline 100 – 922 feet, SS 3366+03 to SS 3375+25; Wilson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 18*** – New – 30-inch diameter Mainline 100 – 1,292 feet, SS 3376+55 to SS 3389+48; Wilson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 19*** – New – 30-inch diameter Mainline 100 – 5,894 feet, SS 3399+47 to SS 3458+42; Wilson County, Tennessee, Year Constructed: 1953;
- ***Special permit segment 20*** – New – 30-inch diameter Mainline 200 – 9,352 feet, SS 1902+21 to SS 1995+73; Williamson County, Tennessee, Years Constructed: 1958, 1962 and 1963;
- ***Special permit segment 21*** – New – 30-inch diameter Mainline 200 - 2,309 feet, SS 2018+69 to SS 2041+78; Williamson County, Tennessee, Year Constructed: 1962;

[8] A "New" ***special permit segment*** is a pipeline segment that is being added to the special permit through the renewal process which includes a Federal Register notice and the issuance of a Final Environmental Assessment and Finding of No Significant Impact.

- ***Special permit segment 22*** – New – 30-inch diameter Mainline 200 – 7,237 feet, SS 2306+66 to SS 2379+03; Davidson County, Tennessee, Year Constructed: 1962;
- ***Special permit segment 23*** – New – 30-inch diameter Mainline 200 – 298 feet, SS 2654+25 to SS 2657+23; Davidson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 24*** – New – 30-inch diameter Mainline 200 – 743 feet, SS 2927+84 to SS 2935+27; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 25*** – New – 30-inch diameter Mainline 200 – 1,065 feet, SS 2943+83 to SS 2954+48; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 26*** – New – 30-inch diameter Mainline 200 – 1,404 feet, SS 3140+40 to SS 3154+44; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 27*** – New – 30-inch diameter Mainline 200 – 1,004 feet, SS 3361+66 to SS 3371+70; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 28*** – New – 30-inch diameter Mainline 200 – 1,280 feet, SS 3373+04 to SS 3385+85; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 29*** – New – 30-inch diameter Mainline 200 – 6,296 feet, SS 3395+18 to SS 3458+14; Wilson County, Tennessee, Year Constructed: 1963;
- ***Special permit segment 30*** – New – 30-inch diameter Mainline 200 – 7 feet, SS 4142+90 to SS 4142+97; Trousdale County, Tennessee, Year Constructed: 1965;
- ***Special permit segment 31*** – New – 36-inch diameter Mainline 300 – 621 feet, SS 1568+48 to SS 1574+69; Williamson County, Tennessee, Year Constructed: 1969;
- ***Special permit segment 32*** – New – 36-inch diameter Mainline 300 – 2,168 feet, SS 2017+32 to SS 2039+00; Williamson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 33*** – New – 36-inch diameter Mainline 300 – 9 feet, SS 2197+72 to SS 2197+81; Williamson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 34*** – New – 36-inch diameter Mainline 300 – 10 feet, SS 2205+72 to SS 2205+82; Davidson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 35*** – New – 36-inch diameter Mainline 300 – 46 feet, SS 3057+71 to SS 3058+17; Wilson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 36*** – New – 36-inch diameter Mainline 300 – 687 feet, SS 3062+97 to SS 3069+84; Wilson County, Tennessee, Year Constructed: 1968;

- ***Special permit segment 37*** – New – 36-inch diameter Mainline 300 – 1,315 feet, SS 3136+89 to SS 3150+04; Wilson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 38*** – New – 36-inch diameter Mainline 300 – 867 feet, SS 3358+02 to SS 3366+69; Wilson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 39*** – New – 36-inch diameter Mainline 300 – 1,326 feet, SS 3368+06 to SS 3381+32; Wilson County, Tennessee, Year Constructed: 1968;
- ***Special permit segment 40*** – New – 36-inch diameter Mainline 300 – 5,824 feet, SS 3391+59 to SS 3449+83; Wilson County, Tennessee, Year Constructed: 1968; and
- ***Special permit segment 41*** – New – 36-inch diameter Mainline 300 – 2,580 feet, SS 3647+69 to SS 3673+49; Wilson County, Tennessee, Year Constructed: 1970.

2) **Special Permit Inspection Area**:

The ***special permit inspection area*** is defined as the area that extends 220 yards on each side of the centerline along approximately 218.2 miles of the 30-inch diameter Mainline 100, 30-inch diameter Mainline 200, and 36-inch diameter Mainline 300 Pipelines as follows:[9]

- ***Special Permit Inspection Area 1*** – 30-inch diameter Mainline 100, SS 264+69 to SS 3586+03 (62.9 miles);
- ***Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200, SS 264+58 to SS 4366+43 (77.7 miles); and
- ***Special Permit Inspection Area 3*** – 36-inch diameter Mainline 300, SS 264+74 to SS 4361+55 (77.6 miles).

The ***special permit inspection areas*** are located in Maury, Williamson, Davidson, Sumner, Trousdale, and Wilson Counties, Tennessee.

3) **Extended Special Permit Segment**: The ***extended special permit segment*** is defined as the ***special permit segment*** and the five (5) contiguous miles past each endpoint.

Attachments B and C-1 through C-10 are maps showing the ***special permit segments***, ***special permit inspection areas***, and class locations.

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9 The ***special permit inspection area*** includes the ***special permit segment(s)***.

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 its entirety in Docket No. PHMSA-2008-0066 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

III. Conditions:

PHMSA grants this special permit subject to CGT implementing the following conditions on the ***special permit segment(s)*** and ***special permit inspection area(s)***. Each condition detailed in this section is applicable to the ***special permit inspection area(s)*** and the corresponding ***special permit segment(s)*** unless otherwise noted in the condition.

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

   a) **Maximum Allowable Operating Pressure**: CGT must continue to operate each ***special permit segment*** and each ***special permit inspection area*** at or below the existing MAOP of 935 psig for Mainline 100 Pipeline and 1,007 psig for Mainline 200 and Mainline 300 Pipelines.

   b) **Pressure Test**: CGT must identify all previously completed hydrotests. If CGT does not have a 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[10] 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.

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

[10] For all in-service and pressure test failures, CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern 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.

2) **<u>Condition 2 - Procedure Updates</u>**

Within 90 days of the grant of the special permit, CGT 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) **<u>Operations and Maintenance Manual</u>**: CGT must amend the applicable sections of its Operations and Maintenance (O&M) manual(s) and procedures to incorporate the special permit conditions.

b) **<u>Integrity Management Program</u>**:

i) CGT must incorporate each ***special permit segment*** into its written integrity management program (IMP) procedures as if the ***special permit segment*** was a "covered segment" as defined in 49 CFR 192.903, except for the reporting requirements contained in 49 CFR 192.945.[11] A ***special permit inspection area*** outside of a ***special permit segment*** is not required to be included as a "covered segments" in accordance with 49 CFR 192.903.

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

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

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

v) All special permit conditions that are applicable to a ***special permit inspection area*** are also applicable to a ***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.

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

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**: CGT must incorporate within a ***special permit inspection area*** the applicable best practices of the Common Ground Alliance (CGA)[12] in its damage prevention program.

3) **Condition 3 - Corrosion Control**

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

a) **Cathodic Protection Test Station Spacing**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each ***special permit segment***, with a spacing not to exceed ½ mile between CP pipe-to-soil test stations. In cases where obstructions or restricted areas prevent such test station placement, the test station must be placed in the closest practical location, not to exceed a 3,000-foot spacing. CP pipe-to-soil test stations must be installed within 12 months of the grant of this special permit.

b) **Annual Monitoring of Test Station Potential Measurements**: At least once every calendar year, not to exceed 15 months, CGT must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for each ***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).

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

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

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

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

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

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

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

4) **<u>Condition 4 - Close Interval Surveys</u>**

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

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

ii) CGT 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)**, CGT 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.

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

b) **Survey Intervals**: CGT must perform the CIS assessments 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 assessment 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. CGT 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)), or (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, CGT 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, CGT must apply for any necessary environmental permits (Federal or State).

iii) CGT must complete remediation of each ***special permit segment*** and confirm restoration of adequate CP over the entire area where inadequate CP levels were

[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."

detected within 12 months of the survey or as soon as practicable after obtaining the necessary permits.[16]

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

a) **<u>Threat Identification</u>**: CGT 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 IBR edition of the American Society of Mechanical Engineers Standard B31.8S, "Managing System Integrity of Gas Pipelines" (ASME B31.8S) Appendix A3 and NACE SP 0204-2008, "Stress Corrosion Cracking Direct Assessment Methodology," Sections 1.2.1.1 and 1.2.2.

b) **<u>Inline Inspection Methodology</u>**: CGT 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, CGT 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), CGT must use an ILI tool[18] that will identify tight cracks.[19]

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[16] If remediation based upon the findings of the CIS is not practicable within 12 months of the CIS survey, CGT must submit a schedule and justify the delay 60 days prior to the 12-month completion requirement to the Director, PHMSA Eastern Region. CGT must receive a “no objection” letter from the Director, PHMSA Eastern 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] CGT may propose an alternative assessment method for SCC (such as spike hydrostatic testing in accordance with 49 CFR 192.506) to the Director, PHMSA Eastern Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. CGT must receive a “no objection” letter from the Director, PHMSA Eastern Region, prior to implementing any alternative assessment methods for SCC.

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

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

c) <u>**Inline Inspection Assessment Intervals**</u>: CGT 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 electric flash-welded (EFW) pipe, it must be assessed for hard spots within 18 months of special permit issuance.

(2) CGT must assess for the cracking threat in each ***extended special permit segment*** within 18 months of special permit issuance.

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

(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 shorter of the following:

(1) Intervals of five (5) calendar years not to exceed 66 months, or

(2) Engineering critical assessment (ECA)-determined interval, if applicable.

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

iv) If factors beyond CGT's control prevent the completion of an assessment within the required timeframe or reassessment interval, CGT must perform the assessment as soon as practicable, and CGT must submit a letter justifying the delay and provide the anticipated date of completion to the Director, PHMSA Eastern Region, no later than two (2) months prior to the end the timeframe or interval. CGT must receive a "no objection" letter from the Director, PHMSA Eastern 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**: CGT 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. CGT must demonstrate these welds were excavated, NDT inspected, and repaired, if the welds do not meet Federal pipeline safety regulations at the time the pipelines were constructed.

b) **Missing Records**: If CGT cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, CGT 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;[20] and

iii) Excavate,[21] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance using 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 incorporated by reference (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, CGT 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***. CGT must submit the inspection and remediation plan for girth welds to the Director, PHMSA Eastern Region, and must receive a "no objection" letter, for the girth weld remediation plan prior to its implementation.[22] CGT 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.[23]

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[20] If the ***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.

[21] CGT 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***.

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

[23] CGT must include any plan requirements received from the Director, PHMSA Eastern Region, into the remediation plan.

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

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

a) **<u>Threat Assessments</u>**: CGT 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***[24] is susceptible to either near-neutral or high-pH SCC, CGT 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.[25]

c) **<u>Examination of Pipe</u>**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, CGT 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) and (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), CGT 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. CGT must use appropriate methods for crack detection, such as phased array ultrasonics (PAUT)), inverse wavefield extrapolation (IWEX), or magnetic

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

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

particle inspection (MPI),[26] 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." CGT must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe and/or shields the cathodic protection. CGT must keep coating records[27] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **Discovery of SCC**: If CGT discovers SCC[28] 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,[29] 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[30] based upon the evaluated growth of the SCC, using one of the following methods:

i) Spike hydrostatic test program:

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[26] 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.

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

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

[29] For all in-service and pressure test failures, CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern 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.

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

(1) CGT 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, CGT must replace the pipe joint that does not meet 49 CFR 192.611 in the ***extended special permit segment*** with new pipe. CGT must complete a successful SCC hydrostatic test prior to returning the ***extended special permit segment*** to operational service;

ii) **<u>Crack detection tool assessment</u>**: CGT 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>**: CGT must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

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

f) **<u>SCC Remediation Plan</u>**: If CGT discovers any SCC activity in the ***extended special permit segment***, CGT must submit an SCC remediation plan to the Director, PHMSA Eastern Region, and send a copy to the Director, PHMSA Engineering and Research Division, no later than 90 days after the finding of SCC. [31] The plan must:

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

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

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

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

a) **<u>General</u>**: CGT must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. CGT 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>**: CGT 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).[32, 33, 34] CGT must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to CGT. CGT 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.

[32] 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. CGT can propose alternative EMAT ILI Tool evaluation procedures to the Director, PHMSA Eastern Region, but must receive a “no objection” letter prior to usage of these procedures.

[33] ILI tool 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. 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, <u>if</u> the continuous ILI segment is longer than the ***special permit inspection area***. A minimum of four (4) calibration excavations must be used for unity plots.

[34] 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, CGT must complete the following: (1) submit a plan for using known and documented pipeline features such as calibration excavation data, to the Director, PHMSA Eastern 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 Eastern Region, prior to performing the ILI tool calibration using pipeline features; (3) submit a report to the Director, PHMSA Eastern 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.

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

iv) **Discovery Date**: The discovery date[36] 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*"**: CGT must remediate the ***special permit inspection area***[37] as follows:

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

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

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

(3) Metal loss preferentially affecting a detected pipe weld seam, and the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than or equal to 1.25 times the MAOP or the metal loss is greater than 50% of pipe wall thickness.[38]

(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

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[35] "6t" means pipe wall thickness times six.

[36] Discovery date is the day, month, and year that CGT receives the ILI tool run results from the ILI tool service provider.

[37] 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.

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

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 CGT, requires immediate action.

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

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

(2) A dent with a depth greater than 2% of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with 49 CFR 192.712 and **Attachment A**

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

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

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

(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. For Class 1 pipe within the ***special permit segment***, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(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. For Class 1 pipe within the ***special permit segment***, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.[39]

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

iv) **Two-year condition for crack repairs for a "*special permit inspection area*"**: CGT must remediate the following conditions within two (2) years of discovery that are in a ***special permit inspection area*** and are outside a ***special permit segment***:

(1) A crack or crack-like anomaly that has a crack depth greater than 40% of the pipe wall thickness.

v) **Monitored conditions for a "*special permit inspection area*"**: CGT 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

[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 engineering critical assessment methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

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

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

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

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

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than 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. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of greater than or equal to 1.39 times the MAOP. [40]

(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 1.39 times the

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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 engineering critical assessment methodology for cracking anomalies in accordance with 49 CFR 192.712(d).

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. For Class 1 pipe within the ***special permit segment***, a crack or crack-like anomaly with a predicted failure pressure greater than 1.39 times the MAOP.[41] The crack depth is less than 40% of the pipe wall thickness.

c) **Remediation schedule for a "*special permit segment*"**: In addition to the requirements in paragraphs (a) and (b) of **Condition 8** for a ***special permit inspection area***, CGT must remediate conditions in a ***special permit segment*** as follows:[42]

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

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

(2) **Weld Metal**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[43]

(3) **Class 1 or Class 1 to 3**: Any anomaly within a ***special permit segment*** that meets either: (l) a predicted failure pressure less than or equal to 1.39 for Class 1 or Class 1 location pipe in a Class 3 location operating up to 72% of SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

(4) **Class 2 or Class 2 to 3**: Any anomaly that meets either: (l) a predicted failure pressure less than or equal to 1.67 times the MAOP for Class 2 or Class 2

[41] 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.

[42] 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.

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

location pipe in a Class 3 location operating up to 60% of SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

(5) **<u>Class 3</u>**: Any anomaly that meets either: (l) a predicted failure pressure less than or equal to 2.0 times the MAOP for Class 3 location pipe in a Class 3 location operating up to 50% of SMYS; or (2) an anomaly depth greater than 40% of pipe wall thickness.

ii) **<u>One-year crack repair conditions for a "*special permit segment*"</u>**: CGT 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>**: CGT 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>**: CGT 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) **<u>Class 1 or Class 1 to 3</u>**: Any anomaly within a ***special permit segment*** with Class 1 or Class 1 location pipe in a Class 3 location operating up to 72% of SMYS that meets both: (1) a predicted failure pressure greater than 1.39 times the MAOP; and (2) an anomaly depth less than 40% wall thickness loss.

(2) **<u>Class 2 or Class 2 to 3</u>**: Any anomaly within a ***special permit segment*** with Class 2 or Class 2 location pipe in a Class 3 location operating up to 60% of SMYS that meets both: (1) a predicted failure pressure greater than 1.67 times the MAOP; and (2) an anomaly depth less than 40% wall thickness loss.

(3) **<u>Class 3</u>**: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 60% of SMYS that meets both: (1) a predicted failure pressure greater than 2.0 times the MAOP; and (2) an anomaly depth less than 40% wall thickness loss.

9) **Condition 9 - Pipe Casings**

CGT 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.[44]

a) **Clear Shorted Casings**: Where practical, CGT 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**: CGT 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**: CGT 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 CGT identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

   iii) **All Shorted Casings**: CGT 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. CGT 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 CGT completed an assessment and all necessary repairs.

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

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[44] As of the date of the grant of this special permit, CGT reported they identified five (5) shorted casings within the ***special permit segments***.

the Director, PHMSA Eastern Region, to use ILI assessments instead of clearing the short.[45, 46] In addition to the notification, CGT 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) CGT must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

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

CGT 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 issuance, CGT 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

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

[46] CGT 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.

Seam Evaluation," by Michael Baker Jr. and Kiefner and Associates, et. al. under PHMSA Contract DTRS56-02-D-70036.

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

b) **Seam Leak or Failure**:

i) If the pipeline experienced a seam leak or failure in the last five (5) years and CGT 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 CGT 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) CGT must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern Region, within 90 days of the failure.[48]

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

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

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;

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

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

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

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

d) **Girth Weld or Seam Weld Repairs**: Within a ***special permit segment***, CGT 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**: CGT must remediate all weld seam leaks, failures, or ruptures[49] discovered in the ***special permit segment***. CGT must submit a seam remediation plan for the ***special permit segment*** to the Director, PHMSA Eastern Region, no later than 30 days after finding a seam leak, seam failure, or seam rupture in the ***special permit segment*** containing one 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**

CGT 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

[49] For all in-service and pressure test failures, CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern 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.

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

b) **Analysis of Results**: CGT 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, CGT must develop a remediation procedure and apply for any necessary permits to conduct remediation. CGT 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 CGT's control prevent the completion of any remediation within six (6) months of completing the interference engineering analysis of the survey results, CGT 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 Eastern 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 CGT must receive a "no objection" letter from the Director, PHMSA Eastern Region.

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

CGT must automate mainline valves[50] 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 automated shutdown valves (ASVs) or remote-controlled valves (RCVs) so that the distance between the valves is no greater than 20 miles.[51] CGT must automate mainline valves to close in accordance with the requirements in **Condition 12** within 12 months of the grant of this special permit. The ***special permit segment*** must have procedures for rupture isolation as follows:

a) **Valve Locations**: ASVs or RCVs must be installed as follows:

i) ***Special permit segments 4, 7, and 13**: **Special Permit Inspection Area 1*** – 30-inch diameter Mainline 100 Pipeline:

(1) Upstream: Cane Ridge Compressor Station/Mainline Valve 410.5-1 at MP 43.6 (Survey Station 2302+90);

(2) Downstream: Mainline Valve 410-1 at MP 37.1 (Survey Station 1956+40); and

(3) A supervisory control and data acquisition (SCADA) system connection for pressure monitoring, communication, and control must be installed at the Cane Ridge Compressor Station at MP 43.6.

ii) ***Special permit segments 1 and 12: Special Permit Inspection Area 1*** – 30-inch diameter Mainline 100 Pipeline:

(1) Upstream: Mainline Valve 410-1 at MP 37.1 (Survey Station 1956+40);

(2) Downstream: Mainline Valve 409-1 at MP 26 (Survey Station 1374+71); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 409-1 at MP 26.

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

[51] The location of a ***special permit segment*** with regards to each upstream and downstream valve is detailed in **Figure 1 - Location of Special Permit Segments Between ASVs** on page 70.

iii) ***Special permit segments 14 and 15: Special Permit Inspection Area 1*** – 30-inch diameter Mainline 100 Pipeline:

(1) Upstream: Mainline Valve 411-1 at MP 48.7 (Survey Station 2573+23);
(2) Downstream: Cane Ridge Compressor Station/Mainline Valve 410.5-1 at MP 43.6 (Survey Station 2302+90); and
(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Cane Ridge Compressor Station at MP 43.6.

iv) ***Special permit segments 16, 17, 18, and 19: Special Permit Inspection Area 1*** – 30-inch diameter Mainline 100 Pipeline:

(1) Upstream: Mainline Valve 413-1 at MP 71.1 (Survey Station 3752+29);
(2) Downstream: Mainline Valve 412-1 at MP 58.8 (Survey Station 3103+11); and
(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 412-1 at MP 58.8.

v) ***Special permit segments 8, 20, and 21: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Cane Ridge Compressor Station/Mainline Valve 410.5-2 at MP 43.6 (Survey Station 2303+89);
(2) Downstream: Mainline Valve 410-2 at MP 37.1 (Survey Station 1956+40); and
(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Cane Ridge Compressor Station at MP 43.6.

vi) ***Special permit segments 2 and 5: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Mainline Valve 410-2 at MP 37.1 (Survey Station 1956+40);
(2) Downstream: Mainline Valve 409-2 at MP 26.1 (Survey Station 1376+95); and
(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 409-2 at MP 26.1.

vii) ***Special permit segments 10, 23, 24, and 25: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Mainline Valve 412-2 at MP 58.7 (Survey Station 3101+35);
(2) Downstream: Mainline Valve 411-2 at MP 48.7 (Survey Station 2573+39); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 412-2 at MP 58.7.

viii) ***Special permit segment 22: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Mainline Valve 411-2 at MP 48.7 (Survey Station 2573+39);

(2) Downstream: Cane Ridge Compressor Station/Mainline Valve 410.5-2 at MP 43.6 (Survey Station 2303+89); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Cane Ridge Compressor Station at MP 43.6.

ix) ***Special permit segments 26, 27, 28, and 29: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Mainline Valve 413-2 at MP 71.1 (Survey Station 3752+29);

(2) Downstream: Mainline Valve 412-2 at MP 58.7 (Survey Station 3101+35); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 412-2 at MP 58.7.

x) ***Special permit segment 30: Special Permit Inspection Area 2*** – 30-inch diameter Mainline 200 Pipeline:

(1) Upstream: Hartsville Compressor Station at MP 85.7 (Survey Station 4527+51);

(2) Downstream: Mainline Valve 413-2 at MP 71.1 (Survey Station 3752+29); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Hartsville Compressor Station at MP 85.7.

xi) ***Special permit segments 9, 32, 33, and 34: Special Permit Inspection Area 3*** – 36-inch diameter Mainline 300 Pipeline:

(1) Upstream: Cane Ridge Compressor Station/Mainline Valve 410.5-3 at MP 43.6 (Survey Station 2301+15);

(2) Downstream: Mainline Valve 410-3 at MP 37.1 (Survey Station 1956+07); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Cane Ridge Compressor Station at MP 43.6.

xii) ***Special permit segments 3, 6, and 31: Special Permit Inspection Area 3*** – 36-inch diameter Mainline 300 Pipeline:

(1) Upstream: Mainline Valve 410-3 at MP 37.1 (Survey Station 1956+07);

(2) Downstream: Mainline Valve 409-3 at MP 26 (Survey Station 1374+71); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 409-3 at MP 26.

xiii) ***Special permit segments 11, 35, and 36: Special Permit Inspection Area 3*** – 36-inch diameter Mainline 300 Pipeline:

(1) Upstream: Mainline Valve 412-3 at MP 58.7 (Survey Station 3096+88);

(2) Downstream: Mainline Valve 411-3 at MP 48.7 (Survey Station 2569+71); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 412-3 at MP 58.7.

xiv) ***Special permit segments 37, 38, 39, 40, and 41: Special Permit Inspection Area 3*** – 36-inch diameter Mainline 300 Pipeline

(1) Upstream: Mainline Valve 413-3 at MP 71.3 (Survey Station 3762+16);

(2) Downstream: Mainline Valve 412-3 at MP 58.7 (Survey Station 3096+88); and

(3) A SCADA system connection for pressure monitoring, communication, and control must be installed at the Mainline Valve 412-3 at MP 58.7.

b) **Automatic Shutoff Valve Requirements**:

i) If an ASV is used, CGT must confirm the 30-minute ASV shut-in pressure for a ***special permit segment*** after "notification of potential rupture" by flow modeling of the ***special permit inspection area*** and any looped pipelines or gas receipt tie-ins between the ASV or RCV valves. Flow modeling must include anticipated maximum, normal, or any other flow volumes, pressures, or any other operating conditions that may be encountered during the calendar year. The flow model detection for a rupture must be based upon 0.500 times the pipe diameter area or smaller pipe area (partial pipe opening) for rupture sizing to account for pressure drop. If operating conditions change that could affect the ASV set pressures and the 30-minute isolation time after "notification of potential rupture," a new flow model must be conducted and ASV set pressures must be reset prior to the next review for ASV set pressures. If the ***special permit segment*** cannot be isolated within 30 minutes of a "notification of potential rupture" by usage of ASVs, then RCVs must be installed. **Table 2 – ASV Closure Settings for Isolation of Special Permit Segment** has the ASV shutoff pressures and shut-off times for isolation of the ***special permit segment*** after "notification of potential rupture."

ii) ASVs must be equipped with rupture sensing equipment to detect the s***pecial permit segment*** "rate of pressure drop" with a set-point of 40 psig/minute or less unless CGT submits a request for a "rate of pressure drop" set-point change and receives a "no objection" letter from the Director, PHMSA Eastern Region, for any revised shut-in pressures prior to their implementation.

iii) ASV shut-in pressures must be confirmed and reset on a calendar year basis not to exceed 15 months. CGT must submit initial and annual ASV shut-in pressures to the Director, PHMSA Eastern Region, as detailed in **Condition 15(f)**, and receive a "no objection" letter from the Director, PHMSA Eastern Region, for any revised shut-in pressures prior to their implementation. The Director, PHMSA Eastern Region, must respond to CGT's submittal letter within 90 days with a decision letter, or either give CGT a request for additional information or additional time for PHMSA to review the request.

iv) If the pipeline is impacted by extreme weather or other emergency conditions that reduce pipeline operating pressures in the ***special permit segment*** to operating pressures where the ASV shut-in pressures require emergency resetting, CGT may reset ASV shut-in pressures below the operating pressure requirements for a maximum period of seven (7) days, but must notify the Director, PHMSA Eastern Region within two (2) days of the pressure reset.

c) **Remote Monitoring and Control**: 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) **Crossover or Lateral Pipe Connection Isolation**: If any crossover or lateral pipe[52] connects to the isolated segment between the upstream and downstream mainline valves,

[52] **Table 3 – Laterals Connecting Between Isolation Valves** has a listing of laterals.

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 used.[53, 54] Crossover valves that are in the CGT O&M Procedures as locked closed and that are only opened when manned by CGT operating personnel do not require RCVs or ASVs for closure.

e) **Remote-Control and Automatic-Shutoff Valve Status**:

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

ii) A ***special permit segment*** with ASVs must have a minimum of one (1) pressure monitoring point within the segment when the mainline valve locations do not have pressure monitoring. If an ASV is used, CGT must determine the set pressure used in **Condition 12(b)** on a calendar year basis not to exceed 15 months and must report the set pressure to PHMSA each year in the **Condition 15 – Annual Report**. ASV pressure settings must be determined by flow modeling of the ***special permit segment***, ***special permit inspection area*** and all looped, delivery, or receipt pipelines tied into the ***special permit inspection area*** that could affect pressures in the ***special permit segment***. If the ASV pressure settings cannot be accurately determined, RCVs must be installed for the ***special permit segment***. The shutdown time for ASVs must be within 30 minutes of the "notification of potential rupture."

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[53] Gas delivery or receipt pipelines must have a shutoff valve (gate or ball valve) either at the connection to the Mainline 100, Mainline 200, and Mainline 300 Pipelines or at the delivery or receipt meter station. Any gas delivery or receipt station over 5-miles in length that is connected to the Mainline 100, Mainline 200, or Mainline 300 Pipelines must have a RCV, ASV or check valve within 5-miles of the Mainline 100, Mainline 200, or Mainline 300 Pipelines. For gas delivery or receipt pipelines a manual shutoff valves can be used for isolation but must be closed within 30-minutes from pipeline leak or rupture confirmation. Check valves cannot be used for pipelines over 8-inch nominal diameter.

[54] Should a significant release occur on the mainline the check valves at the point of delivery to the customer will ensure isolation between the laterals and the mainline. CGT Mainline 200 and Mainline 300 Pipelines have thirteen laterals in the ***special permit inspection area*** and Mainline 100 Pipeline has twelve laterals within the ***special permit inspection area***. RCV, ASV, and check valves are installed on each lateral which will enable isolation. Check valves cannot be used for pipelines over 8-inch nominal diameter.

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

   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 CGT (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) CGT observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in CGT's written procedures. If CGT 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, CGT 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) CGT observes an unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication that may be representative of an event meeting paragraph (2) of this definition.

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

ii) CGT must evaluate and identify a rupture,[55] as defined above, as being either an actual leak event, rupture event, or non-rupture event in accordance with operating procedures and 49 CFR 192.615.

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

h) **Remote Monitoring**: CGT 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 CGT Gas Control Center during power outages.

i) **Point-to-Point Verification**: CGT 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) **Valve Maintenance**: CGT must maintain all valves used to isolate a leak or rupture in accordance with this special permit and 49 CFR 192.745.

k) **Inoperable Valves**: CGT 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 shut-off, 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

[55] For all in-service and pressure test failures, CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern 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.

iii) If valve repair or replacement cannot be met due to circumstances beyond CGT's control, CGT must notify, in writing, the Director, PHMSA Eastern 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) CGT 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) CGT 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;[56] and

iii) In accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631, CGT 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) **<u>Condition 13 - Special Permit Specific Conditions</u>**

CGT must comply with the following requirements:

a) **<u>Line-of-Sight Markers</u>**: CGT 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 CGT within 30 days after identification of line-of-sight marker removal.

[56] CGT 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.

b) **<u>Depth of Cover Survey</u>**:

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

ii) CGT 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 CGT 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, CGT must submit these procedures to the Director, PHMSA Eastern Region, for a "no objection" letter prior to usage. The Director, PHMSA Eastern Region, must respond to CGT's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify CGT of PHMSA's need for additional time to provide a decision.

c) **<u>Data Integration</u>**: CGT must develop and maintain data integration[57] 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: <u>(1)</u> Pipe diameter, wall thickness, grade, and seam type; <u>(2)</u> pipe coating; <u>(3)</u> MAOP; <u>(4)</u> class location, including boundaries on aerial photography; <u>(5)</u> HCAs, including boundaries on aerial photography; <u>(6)</u> hydrostatic test pressure, including any known test failures; <u>(7)</u> casings; <u>(8)</u> any in-service ruptures or leaks; <u>(9)</u> ILI survey results, including HR-MFL, HR-geometry/caliper, or deformation tools; <u>(10)</u> the most recent CIS results; <u>(11)</u> depth-of-cover surveys; <u>(12)</u> rectifier readings for the past five (5) years; <u>(13)</u> cathodic protection test point survey readings for the past five (5) years; <u>(14)</u> AC/DC

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[57] 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 conduct assessments and remediation for those threats.

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.[58] 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, CGT 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) CGT 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),** CGT must test the pipe in a ***special permit segment*** as follows:

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or 192.105 for determining MAOP.

ii) CGT must perform a minimum of two (2) destructive or non-destructive test methods at an excavation site. CGT must conduct non-destructive strength test assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[59] If non-destructive testing 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 CGT

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[58] Hydrostatic test failures, in-service ruptures, rectifier readings, cathodic protection 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 are not required to be on a drawing.

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

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, CGT must submit an assessment procedure to the Director, PHMSA Eastern Region, for a "no objection" letter prior to its usage.[60] The Director, PHMSA Eastern Region, must respond to CGT's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify CGT of PHMSA's need for additional time to provide a decision.

iii) CGT 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% 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).

iv) CGT cannot use the material properties determined from either destructive or non-destructive tests required by this condition to raise the original grade or specification of the pipeline material. CGT must use the applicable standard referenced in 49 CFR 192.7.

v) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, CGT must use the above methodology, or CGT may elect to remove pipe joints for destructive testing.[61]

e) **<u>Pipeline System Flow Reversals</u>**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49

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

[61] CGT must prepare a procedure in accordance with **Condition 13(d)** for material documentation and submit to the Director, PHMSA Eastern Region, and receive a "no objection" letter prior to usage of the procedure. The Director, PHMSA Eastern Region, must respond to CGT's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify CGT 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.

CFR 192.619(a)(1) or 192.611[62] in a ***special permit segment***, CGT 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). CGT must submit the written flow reversal procedure to the Director, PHMSA Eastern Region, and submit a copy of the plan to the FDMS for this special permit at www.regulations.gov.[63] CGT must receive a "no objection" letter from the Director, PHMSA Eastern Region, prior to implementing the pipeline system flow reversal through a ***special permit segment***.

f) **Environmental Assessments and Permits**: CGT must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings needed to implement the special permit conditions for a ***special permit segment*** or ***special permit inspection area*** prior to the disturbance. If a land disturbance or water body crossing is required, CGT must obtain and adhere to all applicable Federal, State, and local environmental permit requirements when conducting the special permit conditions activity.

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

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

i) **Notifications**: For any special permit condition that requires CGT to provide a notice for a "no objection" response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Eastern Region, CGT must also send a copy to the "State

[62] 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.

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

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. CGT must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. CGT must submit soil stress and strain evaluation and remediation procedures to the Director, PHMSA Eastern 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) CGT must conduct gas leakage surveys using instrumented gas leakage detection equipment along the ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in the ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. CGT 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 is an existing, probable, or future hazard to the public, operating personnel, property, or the environment. 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*** must be graded and remediated 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 regarding 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 where gas would likely migrate to an outside wall of a building;

(e) Any reading 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 under a street 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 a ***special permit inspection area***, CGT 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. CGT cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by CGT from the Director, PHMSA Eastern Region.

iv) CGT may request an extension of the remediation time interval requirements by writing a request to the Director, PHMSA Eastern Region, but must receive a "no objection" letter from the Director, PHMSA Eastern Region prior to extending the leak remediation timing or continuous monitoring requirements in **Condition 13(k)**.[64]

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

CGT must give a minimum 14-day notice to the Director, PHMSA Eastern 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 CGT should notify the Director, PHMSA Eastern Region, no later than two (2) business days after the immediate condition is discovered. The Director, PHMSA Eastern Region, may elect not to require a notification for some activities.

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[64] Any CGT 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.

15) **Condition 15 - Annual Report**

Annually[65] after the grant of this special permit, CGT must report the following to the Director, PHMSA Eastern Region, with copies to the Director, PHMSA Engineering and Research Division:[66]

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. CGT must include a summary of the results of the study conducted to meet **Condition 13(h) – Annual Class Location Study** in the annual report.

b) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any un-remediated anomalies over 30% wall loss; cracking found in the pipe body, weld seam, or girth welds; and dents with metal loss, cracking, or stress riser) and any soil movement (lateral or subsidence) that affects pipeline integrity[67] 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) 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***. CGT must include the location by mile post, county 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**.

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65 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.

66 CGT must post the annual report on the special permit docket PHMSA-2008-0066 at www.regulations.gov.

67 CGT 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.

d) Any on-going damage prevention initiatives affecting a ***special permit inspection area*** and a discussion of the success of the initiatives, including findings and remediation actions.

e) CGT 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, CGT must submit a full information package of the requested pipeline attribute and integrity items outlined in the condition.

f) If CGT uses ASVs for **Condition 12 – Mainline Valve**, CGT must report the set pressure and how it was determined for each year to meet "as soon as practicable but 30 minutes or less."

g) CGT must report the diameter and location of the lateral, if any laterals are installed between isolation valves for the ***special permit segment***.

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

i) A senior executive officer, vice president, or higher executive of CGT must review for correctness, date, and sign the annual report prior to posting it to the FDMS (PHMSA-2008-0066) at www.regulations.gov and submitting a copy to the Director, PHMSA Eastern Region and the Director, PHMSA Engineering and Research Division.

j) CGT must schedule a review meeting regarding **Condition 15 - Annual Report** with the Director, PHMSA Eastern Region, prior to or within one (1) month of the filing of each year.[68] During the annual review meeting, CGT must review the status of implementing the special permit conditions with the Director, PHMSA Eastern Region.

16) **<u>Condition 16 – Documentation</u>**

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

[68] The Director, PHMSA Eastern Region, has the authority to waive this meeting.

a) CGT 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 mill test reports or does not meet **Condition 13(d) – Pipe Properties Testing** and 49 CFR 192.607 for the pipe cannot be authorized per this special permit.

17) **Condition 17 - Extension of the *Special Permit Segment***

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

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

    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) CGT must update the Final Environmental Assessment (FEA) to reflect the ***special permit segment extension*** and Section IX of the FEA, "Affected Resources and Environmental Consequences" as necessary. CGT 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 CGT 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) CGT must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**, and

ii) CGT must have hydrostatically tested[69] a ***special permit segment extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable.

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

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

18) **Condition 18 – Certification**

CGT must meet the following conditions for certification:

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

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

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[69] For all in-service and pressure test failures, CGT 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. CGT must provide the written results of this root cause analysis to the Director, PHMSA Eastern 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.

b) CGT 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 with copies to the Director, PHMSA Eastern Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2008-0066) at www.regulations.gov within one (1) year of the grant 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 CGT 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 CGT 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 CGT sells, merges, transfers, or otherwise disposes of all or part of the assets known as a ***special permit segment*** or ***special permit inspection area***, CGT 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 to limit it to a term of no more than 10 years from the date of issuance. If CGT elects to seek renewal of this special permit, CGT 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 Eastern 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 CGT 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 July 21, 2021.

ALAN KRAMER MAYBERRY Digitally signed by ALAN KRAMER MAYBERRY Date: 2021.07.21 08:29:47 -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 1** below, CGT 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) CGT 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 Eastern 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, CGT must estimate the fatigue life of the dent in accordance with API 1156 (1997 Edition), API RP1183 (1^{st} 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 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 CGT uses other technologies or techniques to comply with failure pressure determinations, CGT must submit advance notification to Director, PHMSA Eastern Region, and must receive a "no objection" letter from the Director, PHMSA Eastern 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 Eastern Region.
13) CGT must remediate dents and mechanical damage that do not pass the criteria defined in **Table 1 – Dent Criteria**, or CGT must conduct an acceptable ECA as described in this **Attachment A, Items 1 through 12**.
14) CGT must submit the dent ECA procedure to the Director, PHMSA Eastern Region, for a "no objection" letter prior to conducting the anomaly evaluation.[70] The Director, PHMSA Eastern Region, must respond to CGT's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify CGT of PHMSA's need for additional time to provide a decision.

[70] CGT must submit a copy of the dent ECA procedure to the Director, PHMSA Engineering and Research Division.

Table 1 – 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 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 CGT or ILI vendor such as skewed dent, two or multi-peak deformations.	YES

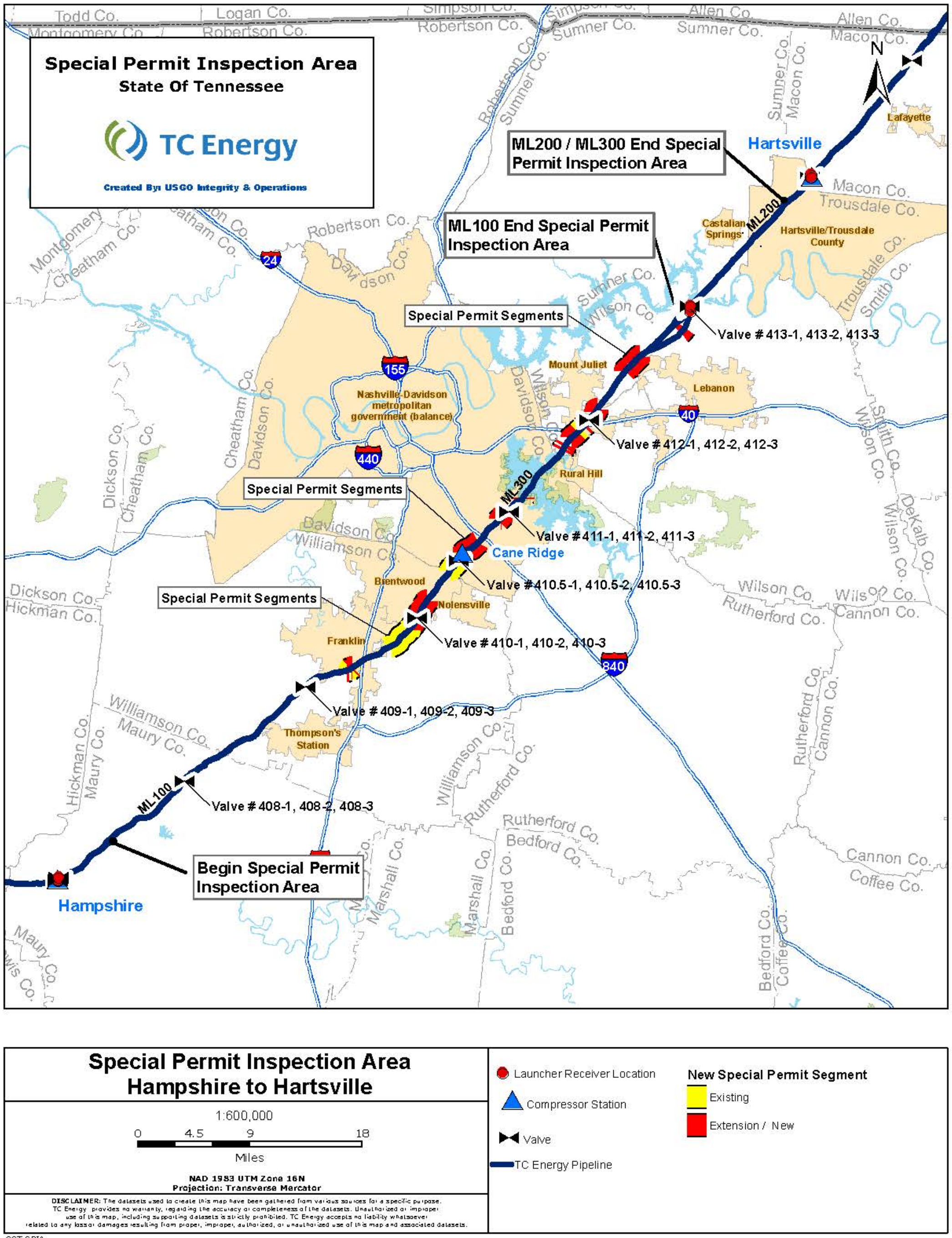
* Lack of ductility must be integrated into the ECA.

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

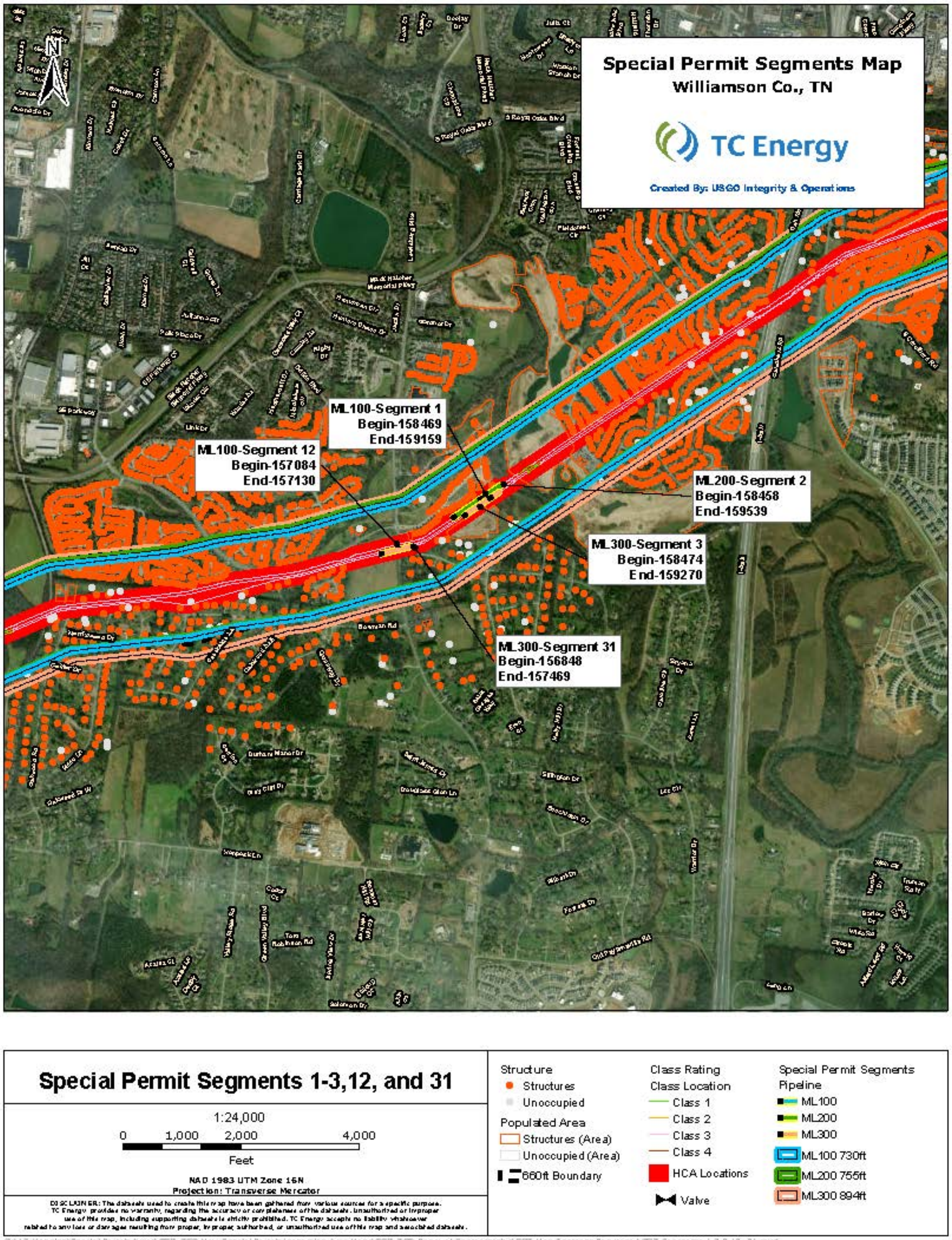
<u>**Note**</u>: An operator may use their normal dent remediation procedures, 49 CFR Part 192 compliant, for the evaluation and remediation for dents as follows:

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

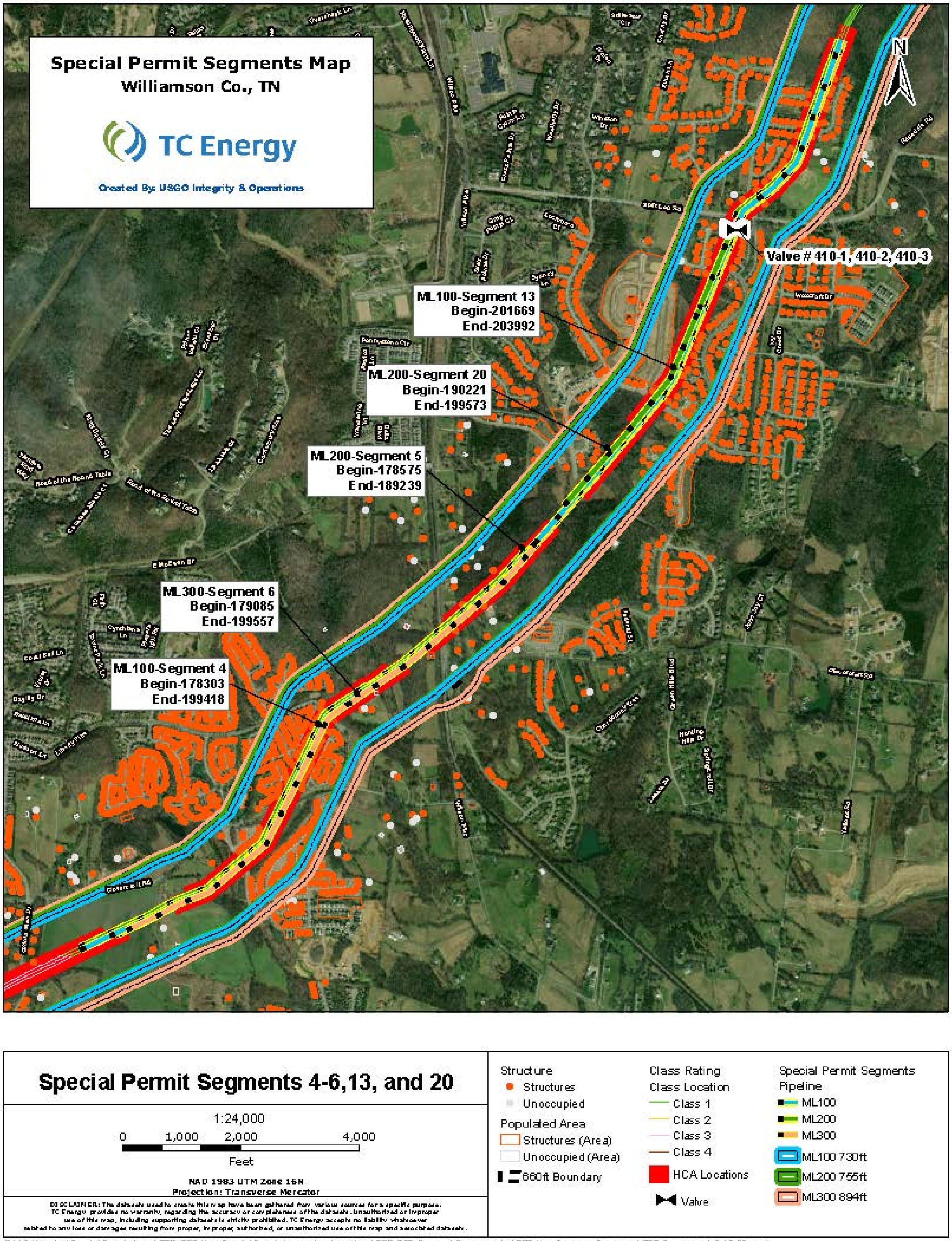
Attachment B – CGT Mainline 100, Mainline 200, and Mainline 300 Route Map Special Permit Segments and Inspection Areas



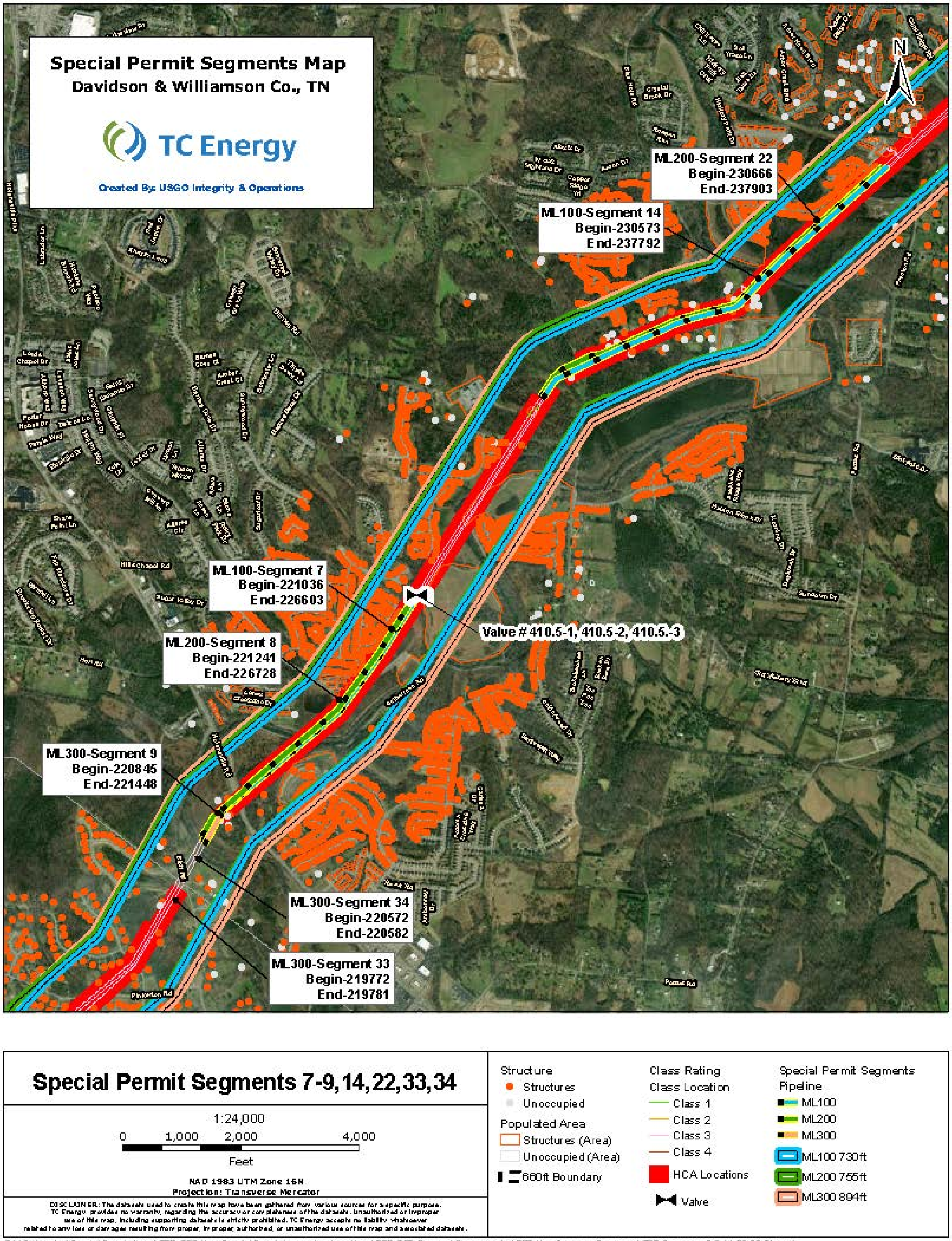
Attachment C-1 – CGT Mainline 100, Mainline 200, and Mainline 300 Route Map – Special Permit Segments



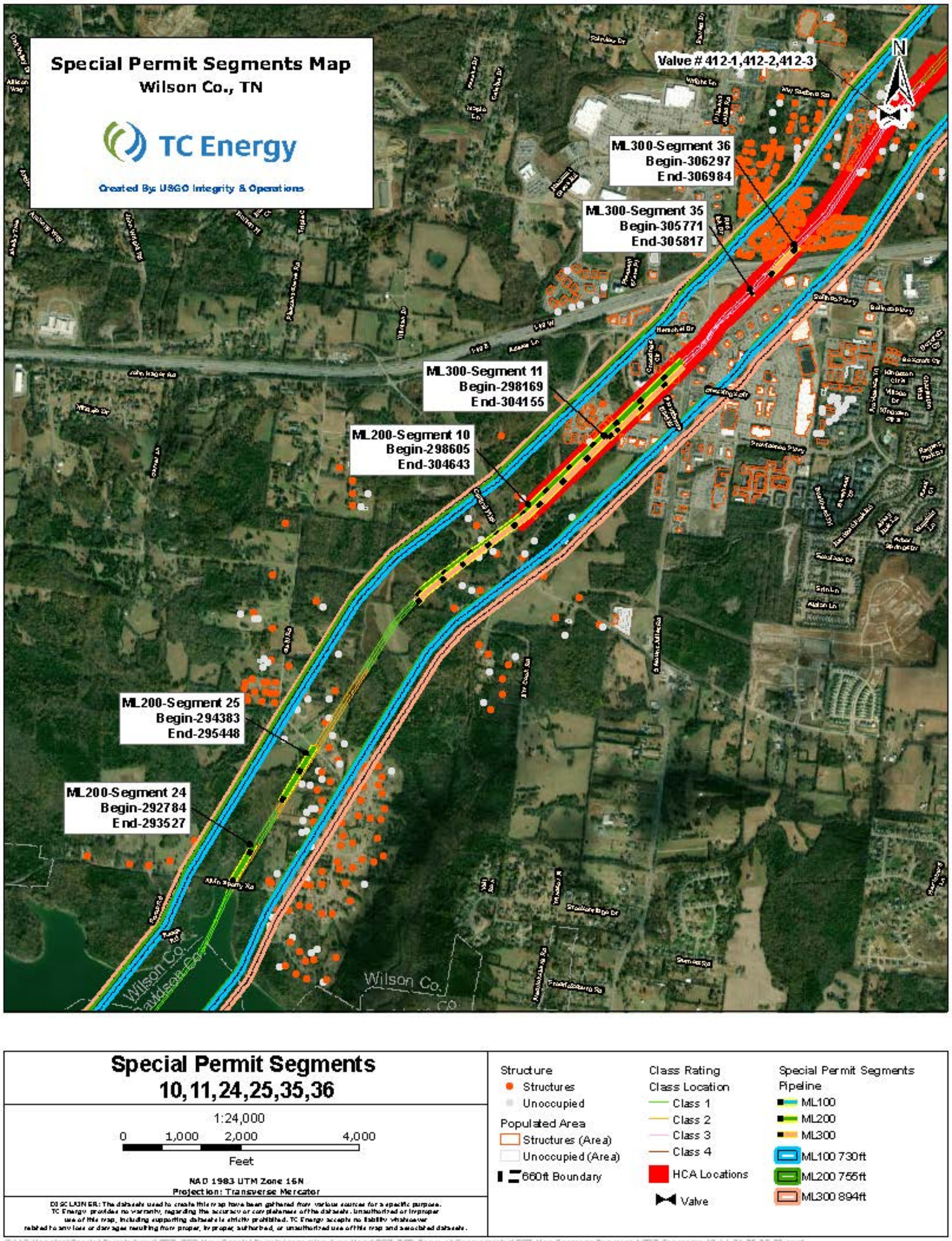
Attachment C-2 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



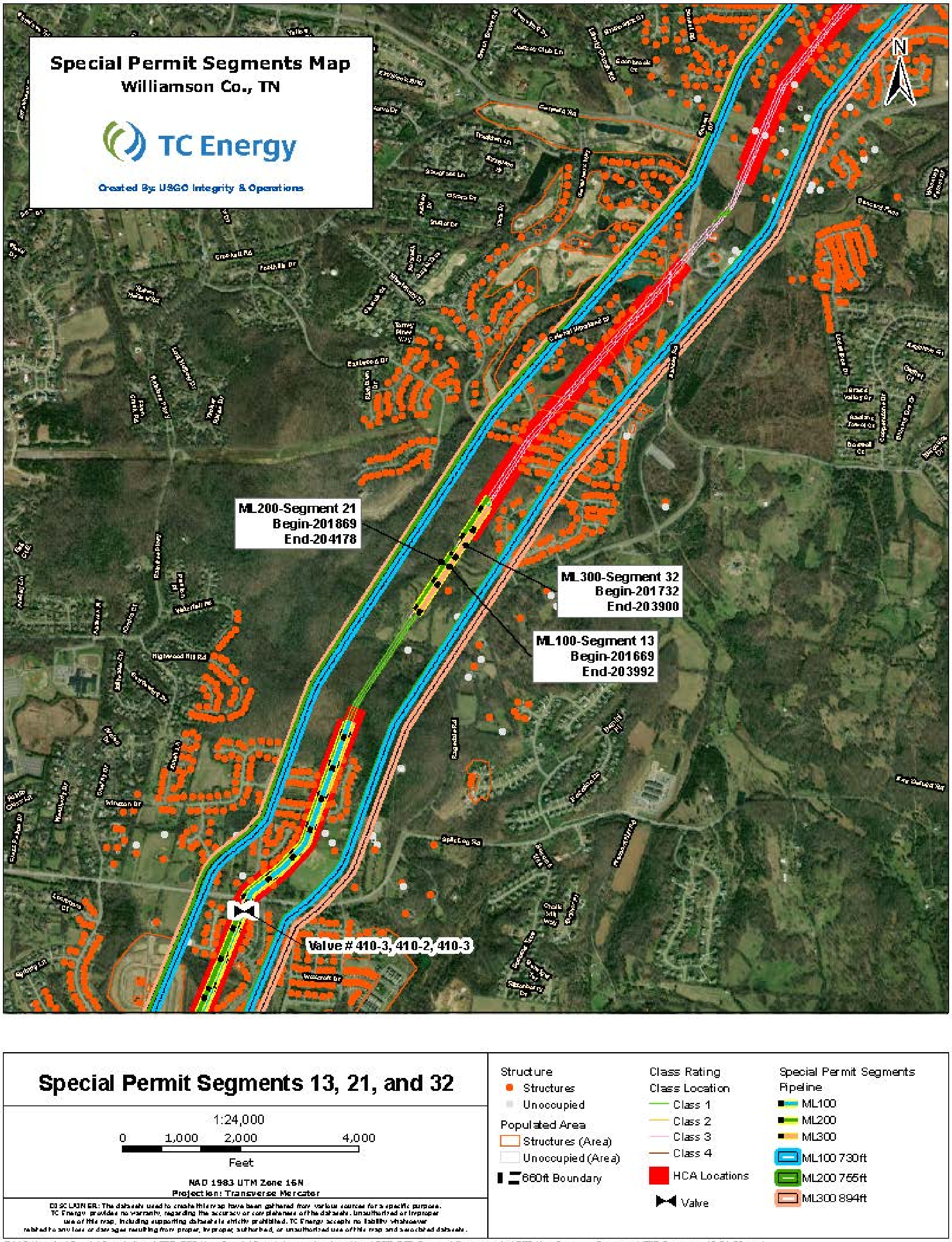
Attachment C-3 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



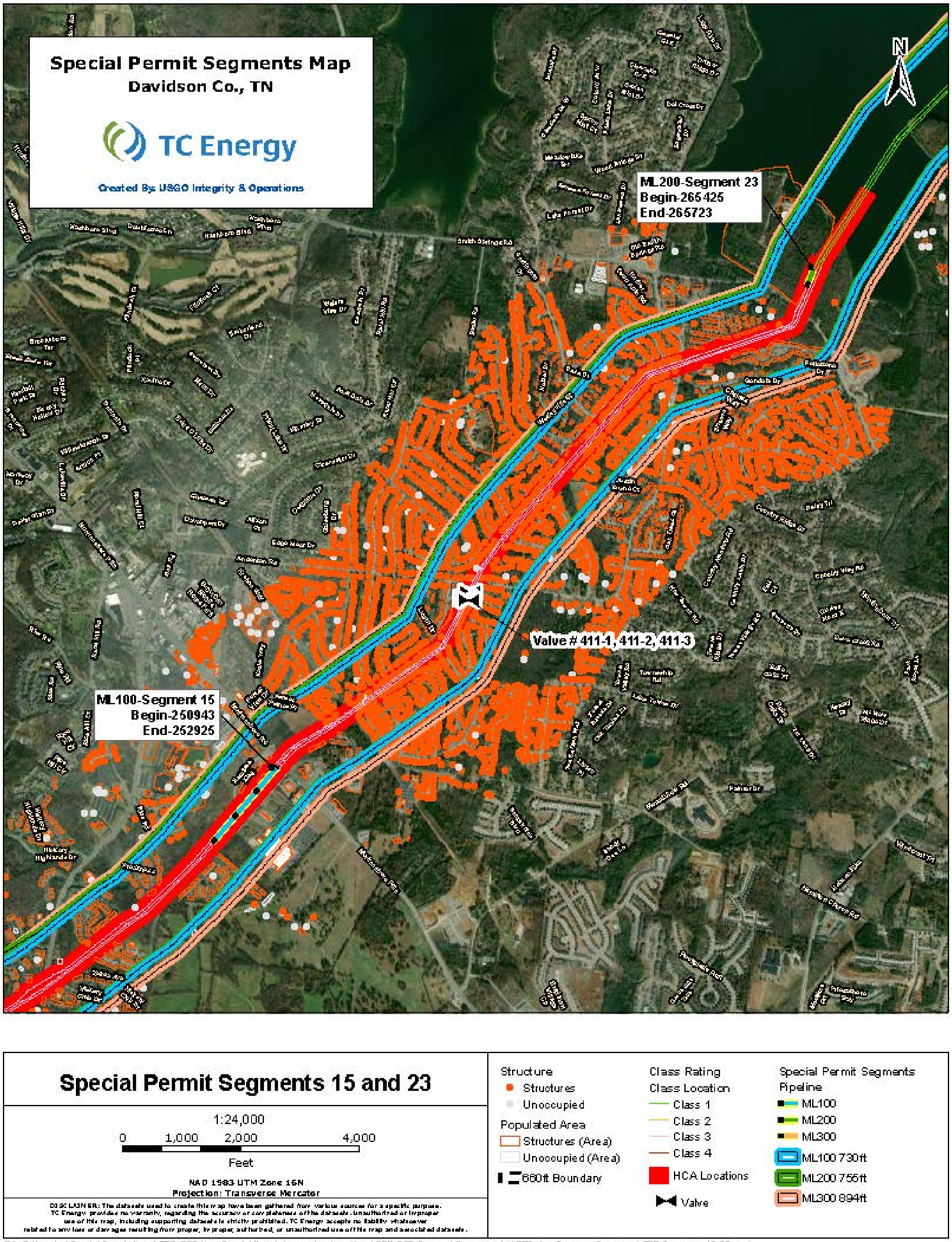
Attachment C-4 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map – Special Permit Segments



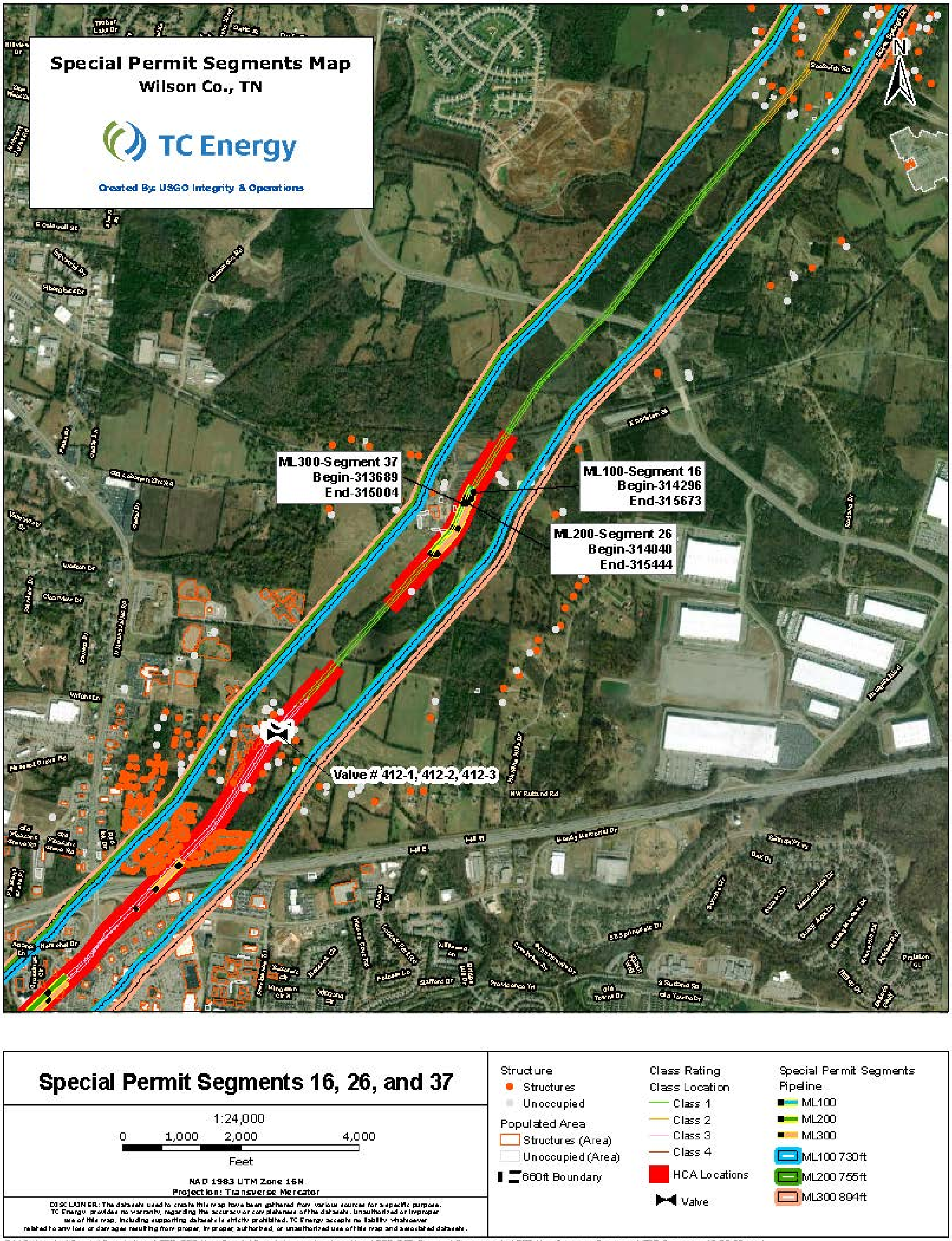
Attachment C-5 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



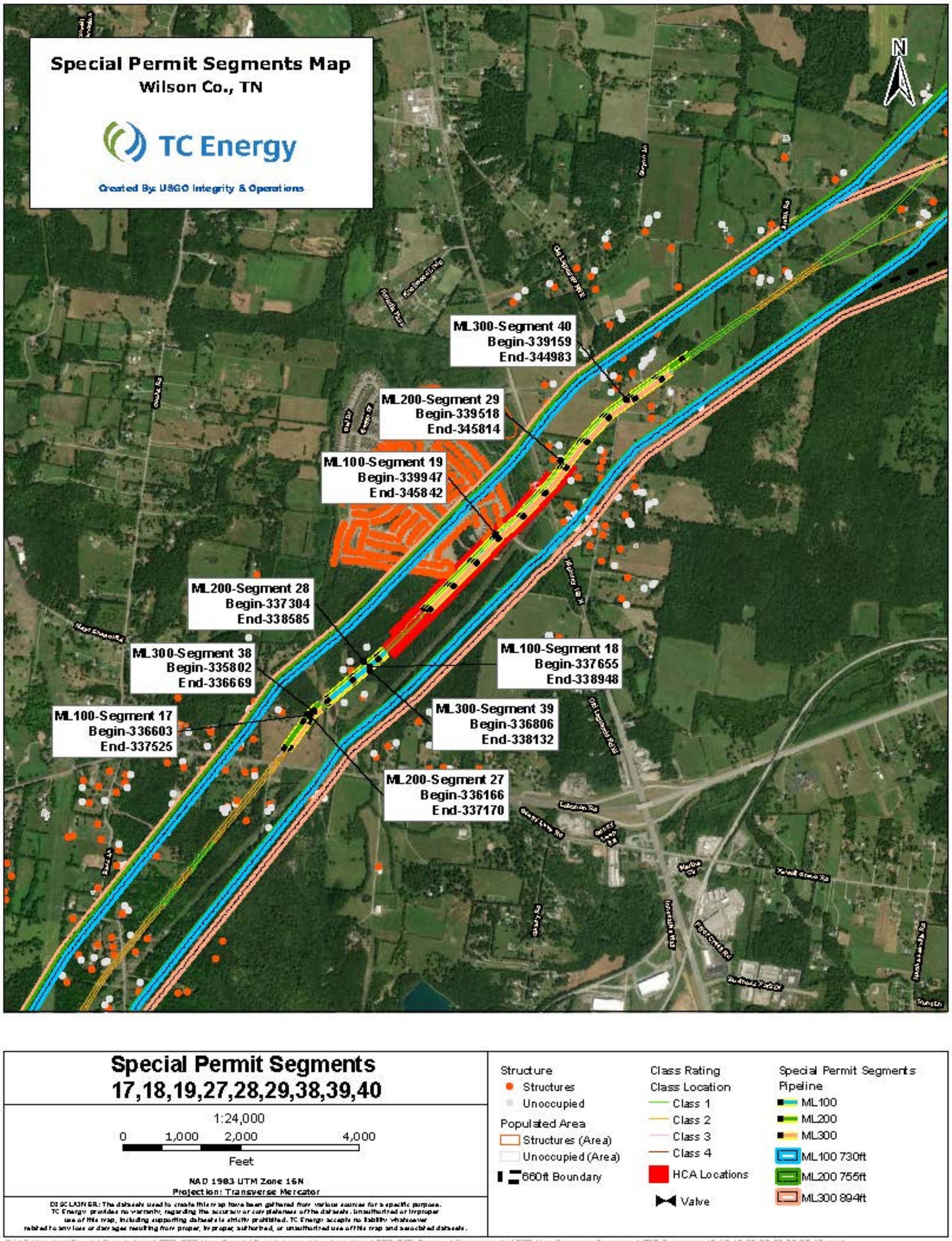
Attachment C-6 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



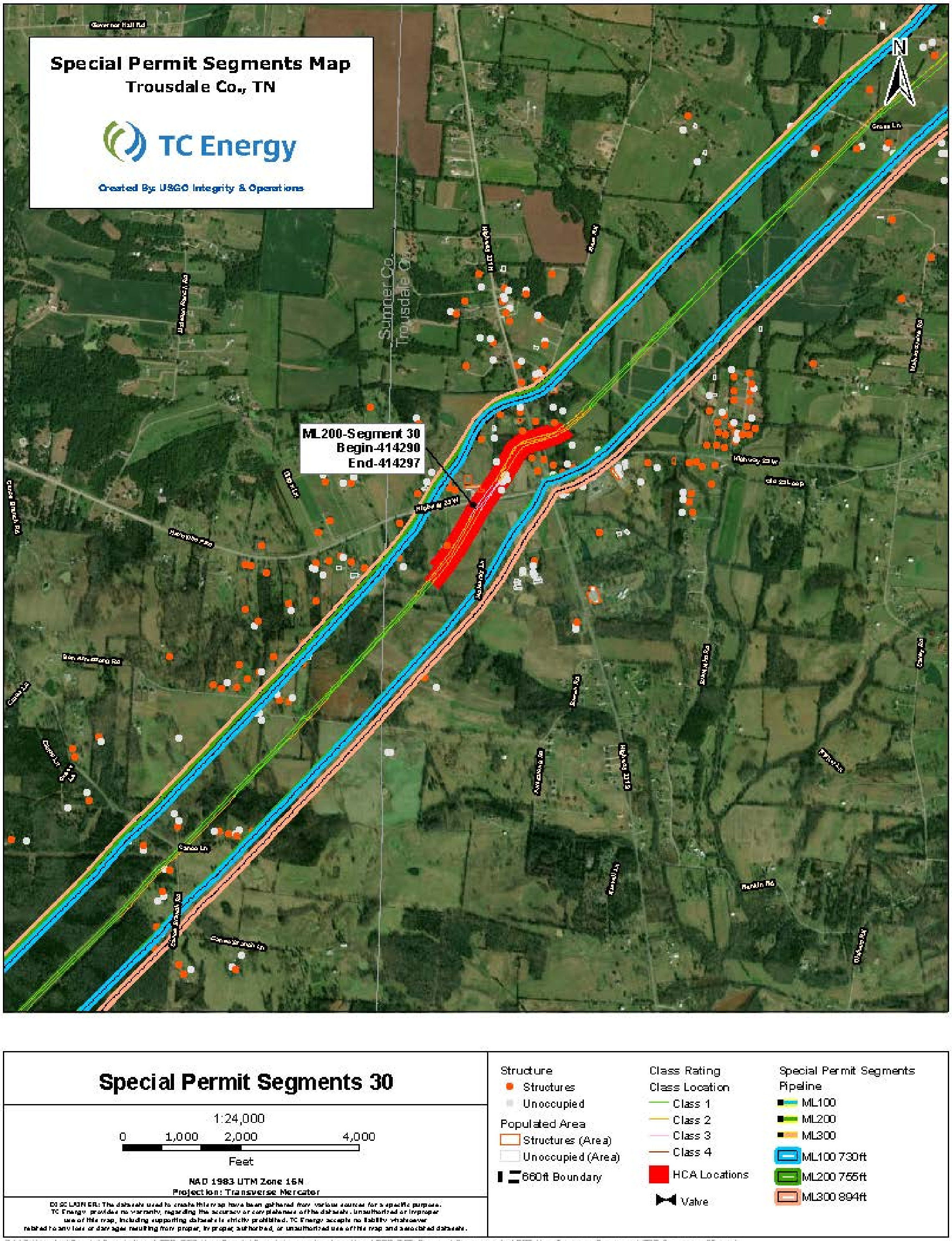
Attachment C-7 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments -



Attachment C-8 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



Attachment C-9 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments



Attachment C-10 - CGT Mainline 100, Mainline 200, and Mainline 300 Route Map - Special Permit Segments

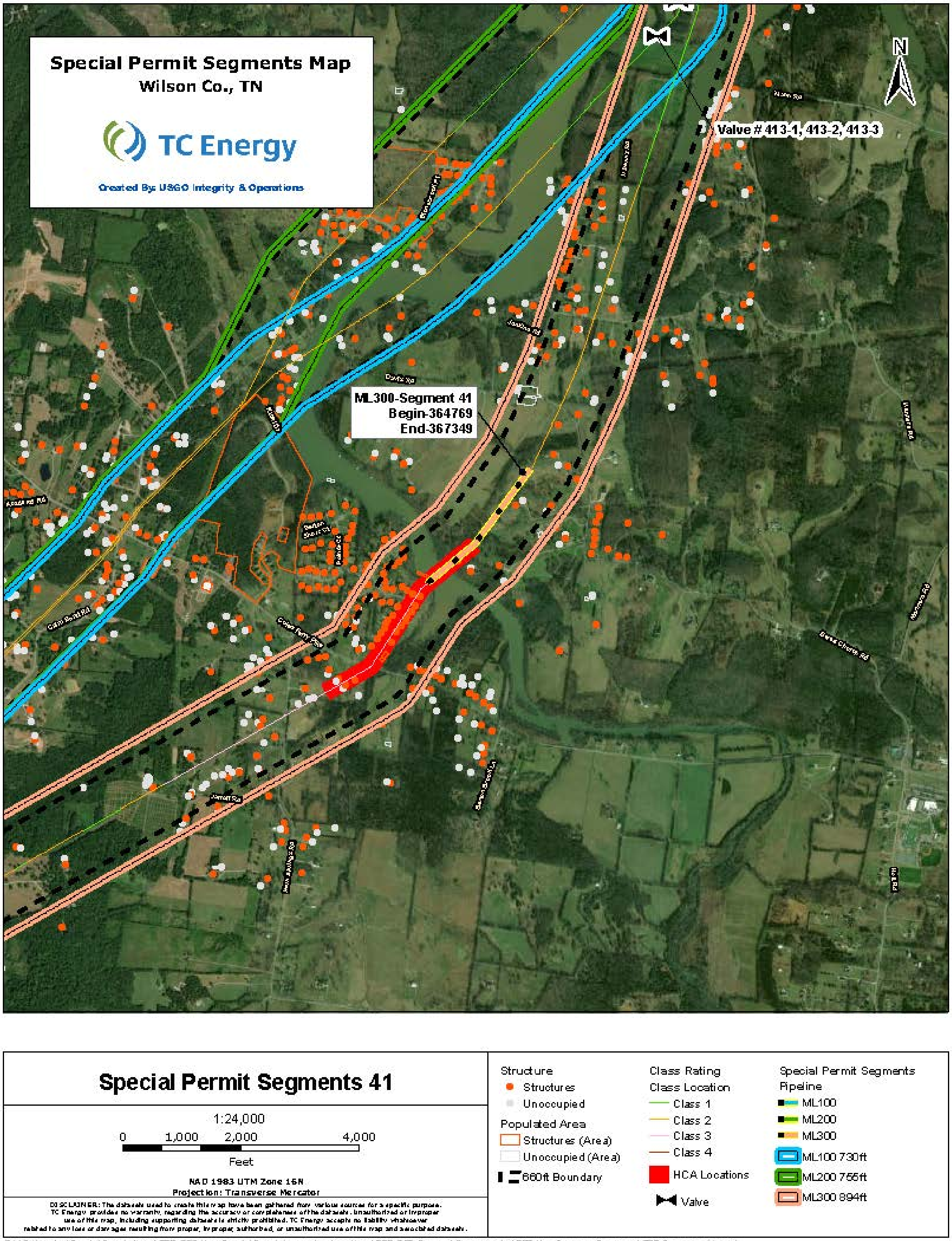


Table 2 – ASV Closure Settings for Isolation of Special Permit Segments								
Special Permit Segment Nos. (upstream)	**Valve**	**Special Permit Segment Nos.** (downstream)	**MAOP (psig)**	**Valve Automation Methodology**	**ASV Low Pressure Set-point (psig)**	**ASV Rate of Pressure Drop Set-point (psig/min)**	**Rupture - Rate of Change Timing (mins)**	**Rupture - Low Pressure Timing (min)**
	V413-1	19, 18, 17, 16	935	ASV	500	40	< 2	< 20
19, 18, 17, 16	**V412-1**		935	ASV	500	40	< 2	~ 10
	V411-1	15, 14	935	ASV	500	40	< 2	< 5
15, 14	**Cane Ridge – Suction 1**		935	RCV/ASV	500	n/a	n/a	< 5
	Hartsville Discharge 2	30	1007	RCV/ASV	550	n/a	n/a	< 5
30	**V413-2**	29, 28, 27, 26	1007	ASV	550	40	< 2	~ 20
29, 28, 27, 26	**V412-2**	10, 25, 24, 23	1007	RCV/ASV	550	40	< 2	~ 10
10, 25, 24, 23	**V411-2**	22	1007	ASV	550	40	< 2	~ 10
22	**Cane Ridge – Suction 2**		1007	RCV/ASV	550	n/a	n/a	< 5
	V413-3	41, 40, 39, 38, 37	1007	ASV	550	40	< 2	< 5
41, 40, 39, 38, 37	**V412-3**	36, 35, 11	1007	RCV/ASV	550	40	< 2	< 20
36, 35, 11	**V411-3**		1007	ASV	550	40	< 2	~ 10
	Cane Ridge Discharge 1	7, 13, 4	935	RCV/ASV	550	n/a	n/a	< 5
7, 13, 4	**V410-1**	1, 12	935	ASV	550	30	< 2	< 20
1, 12	**V409-1**		935	ASV	550	40	< 2	~ 10
	Cane Ridge – Discharge 2	8, 21, 20	935	RCV/ASV	550	n/a	n/a	< 5

Table 2 – ASV Closure Settings for Isolation of Special Permit Segments								
Special Permit Segment Nos. (upstream)	**Valve**	**Special Permit Segment Nos. (downstream)**	**MAOP (psig)**	**Valve Automation Methodology**	**ASV Low Pressure Set-point (psig)**	**ASV Rate of Pressure Drop Set-point (psig/min)**	**Rupture - Rate of Change Timing (mins)**	**Rupture - Low Pressure Timing (min)**
8, 21, 20	**V410-2**	2, 5	1007	ASV	550	40	< 2	< 10
2, 5	**V409-2**		1007	ASV	550	30	< 2	~ 20
	Cane Ridge – Discharge 3	9, 32, 33, 34	1007	RCV/ASV	550	n/a	n/a	< 5
9, 32, 33, 34	**V410-3**	6, 3, 31	1007	ASV	550	40	< 2	< 20
6, 3, 31	**V409-3**		1007	ASV	550	30	< 2	~ 10

Not applicable (n/a) due to valve being at or near compressor station.

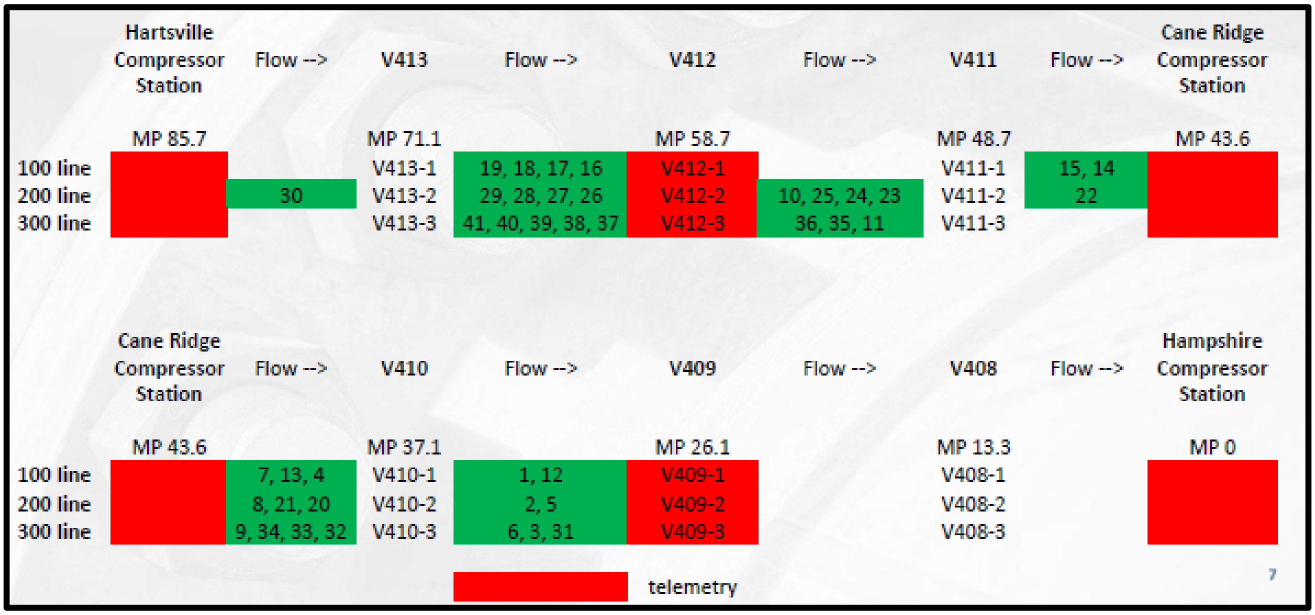
ASV low pressure set-point (psig) must be and is based upon a maximum pipe area as required in **Condition 12(a)(xv).**

Software Package – PIPESAFE - DNV GL manages the actual development.

PIPESAFE includes a number of mathematic models to model:
- Gas outflow
- Gas dispersion
- Fire model (fire ball and jet file)
- Thermal effects
- Risk summation
- Gas outflow model from rupture

Gas Outflow Model - BRAM model – is a transient outflow model developed by Gasunie and can model gas outflow from pipeline networks in case of ruptures, vents or leaks. Validated by full scale testing (British Gas WGGR/93/S8).

Figure 1 - Location of Special Permit Segments Between ASVs



<u>Note</u>: All ***special permit segments*** must have telemetry connections to the CGT SCADA System at the locations noted in red above in **Figure 1**.

Table 3 – Laterals Connecting Between Isolation Valves				
Special Permit Inspection Area	**Station Name**	**Diameter Nominal (in)**	**Mile Post**	**Isolation Method**[71]
ML100 Hampshire to Cumberland River	MS: 4117	12	35.3	ASV/RCV
	MS: 4126	4	64.9	Check Valve
	MS: 4088	16	58.8	ASV/RCV
	MS: 4182	4	39.5	Check Valve
	MS: 4183	6	39.7	Check Valve
ML200 Hampshire to Hartsville	MS: 4049	6	29.8	Check Valve
	MS: 4126	4	64.8	Check Valve
	MS: 4153	12	69.4	ASV/RCV
	MS: 4088	16	58.7	ASV/RCV
	MS: 4182	4	39.6	Check Valve
	MS: 4241	12	45.1	ASV/RCV
ML300 Hampshire to Hartsville	MS: 4016	6	47.8	Check Valve
	MS: 4049	6	29.8	Check Valve
	MS: 4088	16	58.7	ASV/RCV
	MS: 4117	12	35.3	ASV/RCV
	MS: 4183	6	39.7	Check Valve
	MS: 4241	12	45.1	ASV/RCV

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[71] To be determined (TBD). CGT must complete determination of type of rupture mitigation isolation method within 30 days of the grant of this special permit and the isolation method must meet **Condition 12** – **Mainline Valve** requirements.