U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
FINAL ENVIRONMENTAL ASSESSMENT
and
FINDING OF NO SIGNIFICANT IMPACT

SPECIAL PERMIT INFORMATION:

Docket Number:	PHMSA-2008-0331
Requested By:	Columbia Gas Transmission, LLC
Operator ID#:	2616
Date Requested:	October 15, 2019
Issuance Date:	March 31, 2022
Code Section(s):	49 CFR 192.611(a)

I. Background

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

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

denying the special permit. PHMSA developed this assessment to determine what effects, if any, our decision would have on the environment.

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

The purpose of this final environmental assessment (FEA) is to comply with NEPA for the Columbia Gas Transmission, LLC (TCO)[2] application for a special permit request to grant renewal of special permit PHMSA-2008-0331 waiving compliance with the requirements of 49 CFR 192.611(a) "Change in class location: Confirmation or revision of maximum allowable operating pressure" for approximately 2.863 miles of 30-inch diameter gas transmission pipelines located in West Virginia, and an additional approximately 1.119 miles of 30-inch diameter gas transmission pipelines located within the existing ***special permit inspection areas*** to the special permit PHMSA-2008-0331 in West Virginia. This FEA and finding of no significant impact (FONSI) is prepared by PHMSA to assess the pipeline special permit request, in accordance with 49 CFR 190.341, and is intended to specifically analyze any environmental impact associated with the waiver of 49 CFR 192.611(a). This special permit waives 49 CFR 192.611(a) and requires TCO to implement additional requirements for the operations, maintenance, and integrity management of the approximately 3.981 miles of 30-inch diameter pipelines located in Putnam and Kanawha Counties, West Virginia (***special permit segments***) and 107.2 miles of 30-inch diameter pipelines located in Putnam, Kanawha, Cabell, and Wayne Counties, West Virginia (***special permit inspection areas***).

II. Introduction

Pursuant to 49 United States Code 60118(b) and 49 CFR 190.341, TCO submitted an application for a special permit to PHMSA on October 15, 2019, requesting that PHMSA grant the renewal of waiving the requirements of 49 CFR 192.611(a) to permit TCO to maintain the maximum allowable operating

[2] TCO is a wholly-owned subsidiary of TC Energy.

pressure (MAOP) of four (4) pipe segments located in West Virginia, and waive the requirements of 49 CFR 192.611(a) for an additional four (4) pipe segments located in the same ***special permit inspection areas*** in West Virginia. A change of the class location of the eight (8) pipe segments has occurred from an original Class 1 location to a Class 3 location due to population density increase. Without the special permit, 49 CFR 192.611(a) would require TCO to replace the eight (8) pipe segments or to reduce pipeline MAOP. However, pressure reduction was not a viable option for TCO because reducing MAOP would prevent TCO from meeting its contractual gas delivery obligations to customers. Under the special permit, TCO would implement alternative risk control measures and integrity management procedures in the ***special permit inspection areas*** and the ***special permit segments***.

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

III. Regulatory Background

PHMSA regulations at 49 CFR 192.611(a) require that an operator confirm or revise the MAOP of a pipe segment that is in satisfactory condition when the hoop stress of the segment is no longer commensurate with class location. Under Section 192.611(a), an operator may be required to reduce the operating pressure of a pipe segment, or alternatively, may have to replace the pipe in order to maintain the MAOP. Below is the relevant text of 49 CFR 192.611(a):

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

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

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

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4

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

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

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

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

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

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

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

IV. Purpose and Need

TCO requests a special permit to avoid having to replace approximately 3.981 miles of eight (8) ***special permit segments*** located on the 30-inch diameter SM80 and 30-inch diameter SM80 Loop Pipelines in Putnam and Kanawha Counties, West Virginia, where the class location has changed from an original Class 1 location to a Class 3 location. This special permit consists of eight (8) ***special permit segments*** and would waive the requirements of 49 CFR 192.611(a) with implementation of the special permit conditions. The pipeline ***special permit segments*** and ***special permit inspection areas*** have an MAOP of 920 pounds per square inch gauge (psig) and 935 psig on the SM80 Pipeline and SM80 Loop Pipeline.[3] The ***special permit inspection areas*** are comprised of 30-inch diameter SM80 Pipeline constructed in 1955 and 30-inch diameter SM80 Loop Pipeline constructed between 1967 and 1969. **Attachments A and B** are pipeline route maps showing the ***special permit segments*** and ***special permit inspection areas***.

V. Site Description

The TCO system is a major interstate natural gas transmission system that serves millions of customers in the states of Maryland, New Jersey, New York, Pennsylvania, Virginia, and West Virginia, Ohio, Kentucky, and North Carolina. The system is comprised of approximately 12,000 miles of pipelines. The ***special permit segments*** are located in the 30-inch diameter SM80 and the 30-inch diameter SM80 Loop Pipelines in the TCO system in Putnam and Kanawha Counties, West Virginia, and were constructed between 1955 and 1969. The ***special permit inspection areas*** contain thirty-one (31) high consequences areas (HCA), which are calculated by Method 2 (49 CFR 192.903). There is a mix of residential and industrial areas, agricultural fields and deciduous forests within a one-mile radius of the ***special permit inspection areas***.

VI. Special Permit Segments and Special Permit Inspection Areas

On the condition that TCO complies with the terms and conditions set forth below, the granted special permit waives compliance from 49 CFR 192.611(a) for approximately 3.981 miles of natural gas

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[3] The MAOP of the SM80, and SM80 Loop Pipelines between the Hedric Valve Setting (SM80-215; SM80-LOOP-215) and the Lanham Compressor Station are 920 psig.

transmission pipeline on the 30-inch diameter pipelines, where the class location of the lines changed from Class 1 to Class 3 location in Putnam and Kanawha Counties, West Virginia. This special permit allows TCO to maintain the current MAOP of 920 psig and 935 psig in the ***special permit segments***.

Special Permit Segments:

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

Table 1 – Special Permit Segments

Special Permit Segment Number[4]	Segment Type[5, 6]	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (SS)	End Survey Station (SS)	County, State	Year Installed	Seam Type	MAOP (psig)
3	Active	30	SM80	4,577	1957+32	2003+09	Putnam, WV	1955	DSAW	920
4	Active	30	SM80	722	2530+34	2537+56	Putnam, WV	1955	DSAW	920
5	Active	30	SM80	4,768	2687+17	2734+85	Putnam, WV	1955	DSAW	920
6	Active	30	SM80 Loop	5,049	2762+58	2813+07	Putnam, WV	1968	DSAW	935
7	New	30	SM80	891	2773+23	2782+14	Putnam, WV	1955	DSAW	920
8	New	30	SM80	2,295	2813+61	2836+56	Putnam, WV	1955	DSAW	920
9	New	30	SM80	1,652	3013+82	3030+34	Kanawha, WV	1955	DSAW	920
10	New	30	SM80 Loop	1,068	2047+14	2057+82	Putnam, WV	1969	DSAW	935

Special Permit Inspection Areas:

The ***special permit inspection areas*** are defined as the areas that extends 220 yards on each side of the centerline as listed in **Table 2 – Special Permit Inspection Areas**. The ***special permit inspection areas*** are located in Putnam, Kanawha, Cabell, and Wayne Counties, West Virginia.

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4 ***Special permit segments 1 and 2*** in the original PHMSA-2008-0331 Special Permit have been replaced with Class 3 compliant pipe and have been removed from this special permit renewal.

5 "Active segments" are "currently managed" by a special permit and are to be renewed with the issuance of this special permit.

6 "New" ***special permit segments*** are pipeline segments that are 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.

Table 2 – Special Permit Inspection Areas						
Special Permit Inspection Area Number	Special Permit Segment(s) Included	Outside Diameter (inches)	Line Name	Start Survey Station (SS)	End Survey Station (SS)	Length[7] (miles)
1	3, 4, 5, 7, 8, 9	30	SM80	219+69	3030+88	53.4
2	6, 10	30	SM80 Loop	251+59	3094+43	53.8

High Consequence Areas:

HCAs located in the ***special permit inspection areas*** as detailed in **Table 3 – High Consequence Areas**

Table 3 – High Consequence Areas				
Special Permit Inspection Area	Line Name	End Survey Station (SS)	Start Survey Station (SS)	Length (feet)
1	SM80	218+30	246+02	2,772
1	SM80	258+56	292+10	3,354
1	SM80	470+89	492+81	2,192
1	SM80	755+29	791+51	3,622
1	SM80	912+34	937+00	2,466
1	SM80	1051+21	1077+72	2,651
1	SM80	1082+04	1114+19	3,215
1	SM80	1827+87	1880+43	5,256
1	SM80	1888+17	1961+86	7,369
1	SM80	1976+00	2009+13	3,313
1	SM80	2086+80	2105+70	1,890
1	SM80	2281+25	2308+59	2,734
1	SM80	2354+88	2371+15	1,627
1	SM80	2516+77	2531+71	1,494
1	SM80	2654+64	2709+46	5,482
1	SM80	2766+83	2809+89	4,306
2	SM80 Loop	244+14	275+04	3,090
2	SM80 Loop	299+02	329+33	3,031
2	SM80 Loop	504+71	525+46	2,075
2	SM80 Loop	793+96	826+98	3,302
2	SM80 Loop	950+23	977+10	2,687
2	SM80 Loop	1090+33	1114+14	2,381
2	SM80 Loop	1118+84	1149+55	3,071

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

Table 3 – High Consequence Areas				
Special Permit Inspection Area	Line Name	End Survey Station (SS)	Start Survey Station (SS)	Length (feet)
2	SM80 Loop	1851+16	1908+00	5,684
2	SM80 Loop	1935+82	1987+82	5,200
2	SM80 Loop	1989+38	2010+72	2,134
2	SM80 Loop	2022+58	2054+36	3,178
2	SM80 Loop	2332+84	2356+19	2,335
2	SM80 Loop	2399+29	2418+42	1,913
2	SM80 Loop	2558+28	2576+44	1,816
2	SM80 Loop	2727+16	2784+24	5,708

The purpose of the special permit is to waive the requirements of 49 CFR 192.611(a), allowing TCO to maintain the existing MAOP and implement special permit conditions for the 3.981 miles of pipelines without having to replace existing pipe in the ***special permit segments***.

PHMSA grants this special permit based on this document and the "Special Permit Analysis and Findings" document, which can be read in its entirety in Docket No. PHMSA- 2008-0331 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

VII. Additional Design, Construction, Operations, & Maintenance Requirements

To provide an equivalent level of safety in the absence of either lowering the pipeline operating pressure or upgrading the pipe, this special permit has additional operations and maintenance requirements (conditions) which are intended to decrease the likelihood of a release of gas. PHMSA believes that these additional measures designed to prevent leaks and ruptures will ensure that the Special Permit is not inconsistent with pipeline safety.

VIII. Alternatives

1) Alternative 1: "No Action" Alternative

If PHMSA were to select the "no action" alternative, PHMSA would deny TCO's special permit request, TCO would be required to fully comply with 49 CFR 192.611(a). In order to maintain the existing MAOP, TCO would be required to replace the 3.981 miles of pipe in the ***special permit segments*** or TCO would be required to reduce pressure on the segment. TCO states that it would choose to replace the segments to maintain MAOP because a pressure reduction would prevent it from meeting its contractual obligations to deliver natural gas to its customers. Nonetheless, TCO maintains that replacing the pipe would cause interruptions in customers' services and cause construction-related environmental disruption, including the release of methane, a known and greenhouse gas.

2) **<u>Alternative 2: Granted Alternative</u>**

PHMSA grants this alternative and will issue the special permit allowing TCO to continue to operate at the current 920 psig and 935 psig MAOP in the Class 3 location without replacing pipe while complying with the special permit conditions, as described in the Overview of Special Permit Conditions.

IX. Overview of the Special Permit Conditions for Granted Alternative 2:

This section provides an overview of the special permit conditions. For TCO specific technical requirements, see the complete special permit in **Attachment C – Special Permit Conditions**.

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

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

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

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

3) **Threat Management**

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

a) **General activities**

The special permit requires TCO to perform annual data integration and identification of threats to which the ***special permit inspection area*** is susceptible. These activities must include integrity assessments with specific inline inspection tools, strict anomaly repair criteria, and appropriate environmental assessment and permitting. Additional integrity assessment methodologies may be used if allowed by the special permit. Integrity assessments must then be conducted periodically at an interval determined in the special permit for each threat identified.

b) **External corrosion control requirements**

The special permit requires TCO to perform additional activities to monitor and mitigate external corrosion. These activities include installation and annual monitoring of cathodic protection (CP) test stations, periodic close interval surveys (CIS), and clearing or remediating shorted casings that may impede CP effectiveness. These activities ensure the appropriate level of CP is reaching the pipeline in areas where coating loss or damage has occurred in order to prevent or mitigate external corrosion. In addition, TCO is required to develop and implement procedures to identify and remediate interference from alternating current (AC) or direct current (DC) sources (such as high-voltage powerlines) that could adversely impact the effectiveness of CP.

c) **Internal corrosion control requirements**

The special permit includes gas quality specifications to mitigate internal corrosion because internal corrosion is highly dependent on the quality of the gas transported within the pipeline.

d) **Stress corrosion cracking (SCC) requirements**

To ensure that SCC is discovered and remediated, any time a pipe segment is exposed during an excavation TCO must examine coating to determine type and condition. If the coating is in poor condition, the permit holder must conduct additional SCC analysis. If

SCC is confirmed, TCO must implement additional special permit defined remediation and mitigation criteria to maintain safety.

e) **Pipe seam requirements**

TCO must perform an engineering integrity analysis to determine susceptibility to seam threats. The special holder must re-pressure test any ***special permit segment*** with any identified seam threats to ensure the issue is not systemic in nature.

f) **External pipe stress requirements.**

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

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

4) <u>Consequence Mitigation</u>

To ensure quick response and decreased adverse outcome in the event of a failure, each side (upstream and downstream) of a ***special permit segment*** must have and maintain operable automatic shutdown valves (ASV) or remote-controlled valves (RCV). The permit holder must monitor valves through a control room with a supervisory control and data acquisition (SCADA) system. In addition to the mainline valves, should a crossover or lateral connect between the valve locations, additional isolation valves are required, unless the valves are closed valves during normal operation.

5) <u>Post Leak or Failure</u>

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

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

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

7) PHMSA Oversight and Management

PHMSA maintains regulatory oversight and management of each special permit. This includes periodic inspections of the special permit implementation status, written certification of the special permit, special permit required notification of planned activities, notification of root cause analysis results, and notification prior to certain excavation activities so that PHMSA may observe.

8) Gas Leakage Surveys and Remediation for Gas Transmission Pipelines

TCO is required to conduct gas leakage surveys using instrumented gas leakage detection equipment along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins, ILI launcher, and ILI receiver facilities in each ***special permit inspection area*** at intervals that do not exceed 7½ months, but twice each calendar year. The type equipment used, survey findings, and remediation of all instrumented gas leakage survey findings must be documented. TCO is required to remediate Grade 1, 2, and 3 leaks as outlined in the special permit condition.

9) Documentation

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

X. Affected Resources and Environmental Consequences

1) Affected Resources and Environmental Consequences of the Granted Action and the No Action Alternatives

Aesthetics: The only permanent visual impact of the Granted Action would be the installation of line-of-sight markers that are placed to reduce the risk of third-party damage. Increased maintenance activities, including some that temporary excavations, could cause temporary visual impacts. These impacts are expected to be significantly shorter in duration than removal and replacement of the existing pipeline. Maintenance activities and line of sight markers have a minimal impact on the visual character of the ***special permit segments*** right-of-way. Pipe replacement under the No Action Alternative would require removal of the existing pipe and installation of a new pipe. This would result in the use of heavy equipment and ground disturbance. Therefore, the issuance of the special permit would result in less aesthetic impacts to the affected ***special permit segments***.

Agricultural Resources: The ***special permit segments*** are in rural areas which are dominated by agricultural fields, deciduous forests, and low intensity residential and low intensity industrial land use. The right-of-way of the ***special permit segments*** is currently not utilized for agriculture, but adjacent areas are utilized for agricultural fields or naturally contain deciduous forests. PHMSA's issuance of a special permit could result in increased maintenance activities due to more stringent maintenance requirements than what would otherwise be required under Part 192. However, these maintenance activities could potentially interfere with some agricultural activities, but these activities would have a significantly smaller footprint than a pipe removal and replacement and would be temporary in duration. The maintenance activities for the ***special permit segments*** would not impact any agricultural resources. If the permit is not granted and pipe replacement is required, it would cause disturbance to farm operations adjacent to the segment.

Air Quality: The special permit could potentially have minimal impacts on air quality in the ***special permit segments*** due to surveillance, assessment, and maintenance activities required by the permit. If the permit is not granted, pipe replacement would be required, which would necessitate blowing down the pipeline releasing natural gas, a greenhouse gas. The no action alternative would have a more substantial, though still minimal effects on air quality, with additional emissions that are temporary caused by equipment use during excavation, pipe removal, pipe replacement, and pipe installation.

Biological Resources: The primary wildlife habitat occurring within, and in the vicinity of the ***special permit segments*** is composed of various land cover types, including mixed and deciduous forests, residential areas, industrial areas, agricultural fields, and maintained utility right-of-way. Several waterbody features were observed in the vicinity of the ***special permit segments*** in

Putnam County, including three (3) intermittent streams, two (3) perennial streams, and one potential wetland. In addition, only one (1) waterbody, Pocatalico River, was observed in the vicinity of the ***special permit segments*** in Kanawha County. Granting the special permit could result in increased surveillance, assessment, and maintenance activities but would not result in permanent modifications to any habitat, or impact wetlands or waterbodies, and would have no significant effect on fishery resources or essential fish habitats (EFH). The special permit would not trigger any notification or permitting requirements from Coastal Zone Management.

According to the FWS Information for Planning and Conservation (IPaC) website[8], there are 10 types of federally listed threatened and endangered species may be present within the ***special permit segments***; however, there is no critical habitat for any species located within the ***special permit segments***. Biological resources would not be impacted by granting this special permit.

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

Climate Change: The scope and duration of any activities associated with the ***special permit segments*** would have an insignificant impact on climate change. If the permit is not granted, however, pipe replacement would be required, which would necessitate blowing down the pipeline, releasing unburned natural gas, which is a greenhouse gas that is more potent than carbon dioxide. Pipeline replacement would also result in increased emissions from manufacture of new pipe, transportation of materials, and construction activities related to pipeline replacement. Increased pipeline maintenance activities could result in increased emissions, but these emissions are likely substantially less than what would result from pipeline blowdown, pipeline removal, manufacture, transportation, and replacement.

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[8] Information for Planning and Conservation (IPaC). FWS website. Available at https://ecos.fws.gov/ipac/. Accessed September 2019.

Cultural Resources: Any activities associated with the ***special permit segments*** would be conducted within the boundaries of the previously disturbed pipeline right-of-way. A cultural resource survey completed in 2019 determined that one (1) National Register of Historical Places (NRHP) listed building is located within 1 mile of the ***special permit segments*** in Putnam County. The West Virginia State Historic Preservation Offices (SHPO) documents 85 resources within a 1-mile radius of the pipeline segments in Putnam and Kanawha Counties. The NRHP status of the 85 recorded properties has not been determined or is determined ineligible for listing in the NRHP (West Virginia SHPO 2019). No new ground disturbing activities would occur as part of the special permit request; therefore, this request will not impact cultural resources.

Environmental Justice: The special permit alternative associated with this special permit will not have an adverse human health impacts or disproportionately high impact on minority or low-income populations. According to U.S. Census data from 2019, the minority percentages of Putnam and Kanawha Counties are 3.6 percent and 11.0 percent, respectively. All the census block groups within the ***special permit segments*** in Putnam and Kanawha Counties have a minority population less than 50 percent and average per capita incomes above the national poverty threshold. Therefore, the areas immediately adjacent to the special permit segments have higher minority populations in comparison to Putnam and Kanawha Counties at large.[9] Nonetheless, the special permit conditions detailed in the special permit require more rigorous inspection, maintenance, and repair than would be required if the special permit was not issued. For this reason, the issuance of the special permit does not reduce safety. The special permit will not have a disparate impact on any minority, low income, or non-English language populations.

Geology, Soils, and Mineral Resources: The ***special permit segments*** are comprised of various rock types and mostly well-drained soils. The USGS Mineral Recourses Data System from 2019 identified no mineral resources in the vicinity of ***special permit segments*** mainly in Putnam and Kanawha Counties.

The topography across the ***special permit segments*** is generally and dominated by deciduous forests, residential areas, industrial areas, and agricultural fields. Several waterbody features and

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[9] U.S. Census Bureau (USCB). 2019. American Fact Finder. Available at: https://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml. Accessed August 2019.

one wetland were observed in the vicinity of ***special permit segments***. If the special permit is granted, no construction-related activities would occur; therefore, the topography in the area will not be affected.

Seismic hazards include earthquakes, surface faulting, and soil liquefaction. According to the USGS Seismic Hazards maps, there is a 2 percent probability in 50 years that a seismic event would occur with 0 to 8 percent ground acceleration, and projected earthquakes intensity is III or less in Putnam and Kanawha Counties. Therefore, granting the special permit will minimize the ground disturbance and existing conditions would remain undisturbed. As such, geologic, soil and mineral resources would not be impacted.

Indian Trust Assets: According to the U.S. Department of Interior, Bureau of Indian Affairs (2016), there are no federally recognized Indian tribes or tribal reservations in the counties with the ***special permit segments***. The scope and duration of any compliance work resulting from the special permit would have little to no effect or impact on the socioeconomics in the surrounding area.

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

Noise: The scope and duration of any maintenance or repair activities associated with the ***special permit segments*** and ***special permit inspection areas*** would cause minimal localized and temporary increases in noise levels in the vicinity of the pipeline. A denial of the special permit or the "no action" alternative would likely result in more significant temporary increases in noise during the replacement of the existing pipe in the ***special permit segments***.

Recreation: The scope and duration of any activities associated with the ***special permit segments*** and ***special permit inspection areas*** would have little to no impact on recreation in the vicinity of the pipeline. A denial of the special permit or the "no action" alternative would result in temporary increases in disturbances to recreational activities. during the replacement of the existing pipe.

Safety: The Pipeline Safety Regulations require pressure reduction or replacement of Class 1 and Class 2 location pipe in the event of certain population growth in order to better protect higher populations located along the pipeline. Within the current Class 3 location area, more than 46 dwellings located within a 660 feet class unit buffer around the ***special permit segments*** would benefit from increased safety associated with pipe replacement.

The special permit would waive the requirement to reduce pressure or replace the existing pipe with a stronger pipe. However, the special permit would include conditions intended to improve safety and environmental protection to equal or exceed that provided by the measures required under 49 CFR 192.611(a). The special permit conditions include: coating surveys and remediation, corrosion surveys and remediation, damage prevention activities, line of sight markers, inline-tool inspections for threats (corrosion, third party damage, and cracking – pipe body, seam and girth welds), remediation of pipe threats based upon design factor for class location, reassessments based upon integrity management program, procedures, and documentation.

Monthly patrols, weather permitting, are used to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, third party construction activity, exposed pipe, erosion, or other factors that affect the safety and operation of the pipeline.

CIS will be performed on the pipe within the ***special permit segments*** to ensure cathodic protection (CP) is acceptable. Areas of low CP potentials have been or will be remediated according to the special permit conditions if the special permit is granted.

TCO will continue to perform Damage Prevention measures as described in the best practices of the Common Ground Alliance (CGA) within the ***special permit inspection area***.

ILI tool inspections will be performed using high-resolution inspection at intervals as specified by 49 CFR Part 192, Subpart O reassessment intervals.

Any anomalies detected during in-line inspections will be remediated in accordance with 49 CFR Part 192, Subpart O, and the conditions of the special permit. These activities provide safety and environmental protection in the area of the ***special permit segments*** and the ***special permit inspection areas***.

The above-described monitoring conditions associated with the special permit would not be applicable if PHMSA denied the special permit request, because the safety requirements in 49 CFR Part 192, Subpart O only applies to 6.3 miles of HCAs within the ***special permit inspection areas***.

These monitoring conditions are intended to provide more information about the condition of the pipe so that any integrity issues can be remediated to avoid risk.

On the other hand, the "no action" alternative would require full compliance with 49 CFR 192.611(a). This provision would require the replacement of 3.981 total miles of 8 ***special permit segments*** of the existing pipeline with a thicker/stronger pipeline with new, high-quality coating that meets the requirements of 49 CFR 192.611(a). However, the monitoring conditions that would be applicable to approximately 107.2 miles of the pipeline that make up the ***special permit inspection areas*** associated with the special permit would not be applicable if the special permit were denied because those conditions are not mandated by the current 49 CFR Part 192. Accordingly, both alternatives are expected to lead to a similar safety result.

i) Would operation under a special permit change the risk of rupture or failure?

Since the safety risk with respect to the special permit focuses on the integrity of the pipeline and its effect on the increased population in the event of a catastrophic failure of this pipeline, the special permit contains conditions to ensure the safety level meets the requirement of 49 CFR Part 192 in the ***special permit inspection areas***. A number of pipeline safety measures that exceed the requirements of 49 CFR Part 192 have already been implemented in the ***special permit inspection areas***. The measures include conducting in-line inspection at least once in the last seven (7) years, conservatively repairing conditions that do not present a near-term risk to pipeline integrity in order to help ensure the integrity and safety of the pipeline, patrolling frequencies that exceed the requirements of 49 CFR 192.705, and performing annual system-wide risk assessment to identify the risk levels associated with pipeline segments both in HCAs and non-HCAs. In addition, TCO has determined the required preventive and mitigative measures to ensure an adequate safety level for the ***special permit segments*** and the ***special permit inspection areas***. These measures include but are not limited to performing a depth of cover survey during the CIS survey to confirm the presence of adequate cover in all the special permit segments and remediate appropriately, reviewing the existing pipeline markers and signage to ensure that the presence of a buried pipeline is visible in the special permit segments, continuing to investigate and remediate any identified soil instability sites within the ***special permit segments***. As a result of these measures, the pipeline is in good condition, and TCO's safety record is good. The permit would allow operation at the current pressure (MAOP), creating no additional risk. Additional inspections would lower the risk of rupture or failure.

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

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

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

iii) Would the Potential Impact Radius (PIR) of a rupture change under the Special Permit? Please calculate and provide the PIR data, if applicable. Would more people be affected by a failure if PHMSA granted the permit?

The PIR of a rupture would not change if a special permit was granted unless TCO opted to reduce pressure, which it has indicated it does not intend to do. Consequently, no more people would be affected by a failure if PHMSA granted the permit. The calculated 730 feet PIR and 718 feet PIR of SM80 and SM80 Loop Pipelines of the ***special permit segments*** are determined using the current MAOPs.

iv) Would operation under the Special Permit have any effect on pipeline longevity or reliability? Would there be any life cycle or maintenance issues?

The implementation of increased pipeline assessment within the ***special permit inspection areas*** as per required in the special permit will improve pipeline reliability and safety. Continued operation of the ***special permit segments*** would not be expected to have an effect on the pipeline longevity and reliability or cause any life cycle or maintenance issues. In addition, the pipe in ***special permit inspection areas*** has the same characteristics of the other pipe on TCO system along SM80 and SM80 Loop. This pipe operates as one system. The MAOPs and other factors would not change under the special permit; renewal of the special permit would not impact the overall pipeline longevity or reliability and would not cause any life cycle or maintenance issues.

Socioeconomics: The scope and duration of any activities associated with the ***special permit segments*** will have no impact on the socioeconomics in the vicinity of TCO SM80 and SM80 Loop Pipelines. According to US Census data, the minority population in Putnam and Kanawha Counties are 3.6 percent and 11.5 percent, respectively. Both counties have average per capita incomes above the national poverty threshold, although Kanawha County has a higher unemployment rate than the unemployment rate for West Virginia. The special permit will not disproportionately impact any predominantly low-income populations. In any event, the special permit would be designed to maintain pipeline safety for the ***special permit segments*** and increase pipeline safety for the ***special permit inspection areas.***

Topography: The ***special permit segments*** in Putnam County traverse a valley with rolling terrain and rolling hills surrounding the Kanawha River. The ***special permit segments*** in Kanawha County begins in the hills to the west of the Pocatalico River followed with a downward slope to the east. In the vicinity of the ***special permit segments*** in Putnam and Kanawha Counties, the area consists of deciduous forests, agricultural fields, residential areas, and industrial areas. The surrounding area contains waterbody features and a wetland. No construction-related activities would occur if the special permit is granted; therefore, the topography in the area will not be affected.

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

Water Resources: TC Energy sponsored field surveys for wetlands and waterbodies occurred in 2019. In the same year, TC Energy conducted field surveys for potential wetland areas by utilizing the Routine "Onsite" Determination Method contained in the Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Northcentral and Northeast Region for the 1987 Wetlands Delineation Manual Technical Report Y-87-1. The surveys concluded that no sole source aquifers or water wells were observed within the right-of-way boundary of ***special permit segments***. In addition, no federally designated Wild and Scenic Rivers were identified in the vicinity of ***special permit segments***. In Putnam County, Hurricane Creek, Kanawha River, and Pocatalico River are classified as impaired waterbodies, and in Kanawha County, Pocatalico River and Martin Branch are also classified as impaired waterbodies. The ***special permit segments*** directly cross Hurricane Creek and Pocatalico River. According to the West Virginia Department of Environmental Protection reports to the EPA[10], the designated uses of these rivers include fish and aquatic life, irrigation, livestock watering and wildlife, and recreation. There are four impaired waters identified near the ***special permit segments***. The impaired recourses are monitored for any additional degradation and authorization is required for discharge events. As a result, TCO does not anticipate any impact to any surface water, wetlands or drinking water aquifers, since if the special permit is granted, no construction-related activities would occur. Minor additional yet temporary waterbody impacts could result from runoff or siltation from additional maintenance and repair activities that occur along the ***special permit inspection areas.***

2) <u>Comparative Environmental Impacts of Alternatives</u>

As PHMSA recognized in its June 29, 2004, Criteria for Class Location Change Waivers,[17] implementing additional preventative and mitigative measures enables a pipeline to improve its knowledge and understanding of the pipeline's integrity, accelerate the identification and repair of actionable anomalies, and better manage and mitigate threats to the public and environment.

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[10] U.S. Environmental Protection Agency (EPA). 2014. West Virginia Water Quality Assessment Data for 2014. Available at: https://ofmpub.epa.gov/waters10/attains_state.control?p_state=WV. Accessed August 2019.

Implementing enhanced inspection and assessment practices throughout the ***special permit segments*** and ***special permit inspection areas***, in lieu of replacing small segments of pipe experiencing the class location change, extends pipeline safety benefits to a much greater area along the pipeline. In addition, avoiding pipe excavation and replacement will minimize costs to the operator, will avoid delivery interruptions and supply shortages, and avert environmental disturbance. All of these benefits will be realized under TCO's requested ***special permit segments***.

If the special permit is not granted, 49 CFR 192.611(a) would require a reduced MAOP and TCO would have to replace the pipe in order to maintain reliable transportation service. However, the monitoring conditions associated with the special permit would not be applicable if the special permit were denied because those conditions are not mandated. Accordingly, both alternatives are expected to lead to a similar safety result.

Because TCO contractual obligations would not allow the operating pressure of the pipe to be lowered, the mode of pipeline failure would be the same whether the pipe operates under a special permit or is replaced. Likewise, human safety would not be affected.

The natural environment would be temporarily disturbed if the pipe is replaced; a special permit would result in additional maintenance and monitoring activities that would have temporary and minimal impact to the environment in the ***special permit segments*** and the ***special permit inspection areas***.

XI. Consultation and Coordination

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

<u>TCO</u>

Scott Currier, Director Integrity, TC Energy

Lee Romack, Director Regulatory Compliance, TC Energy

<u>PHMSA</u>

Amelia Samaras, PHMSA, US DOT

Steve Nanney, PHMSA, US DOT

Joshua Johnson, PHMSA, US DOT

XII. Request for Public Comments Placed on Docket PHMSA-2008-0331

On November 5, 2020, PHMSA posted a notice of this special permit request in the Federal Register (85 FR 70710) with a closing date of December 7, 2020. PHMSA received no public comments concerning this special permit renewal request through December 7, 2020. PHMSA sought comments on any potential environmental impacts that could result from the selection of either alternative, including the special permit conditions.

PHMSA has reviewed this special permit application to ensure the special permit conditions address pipeline safety and integrity threats to the pipeline in the ***special permit segments*** and ***special permit inspection areas***. The special permit requires TCO's Operations and Maintenance Manual and Procedures to provide a systematic program to review and remediate the pipeline for safety concerns. Additional operational integrity reviews and remediation requirements are required by this special permit for these ***special permit segments*** for Class 1 to 3 location changes or Class 2 to 3 location changes.

The TCO special permit application letter, Federal Register notice, FEA and FONSI, special permit with conditions, special permit analysis and findings document, and all other pertinent documents are available for review in Docket No. PHMSA-2008-0331 in the FDMS located on the internet at www.Regulations.gov.

XIII. Finding of No Significant Impact

In consideration of the special permit conditions explained above, PHMSA find that no significant negative impact will result from the issuance and full implementation of the above-described special permit to waive the requirements of 49 CFR 192.611(a) for ***special permit segments***, approximately 3.981 miles of 30-inch diameter pipelines located in Putnam and Kanawha Counties. This permit will require TCO to implement additional conditions on the operations, maintenance, and integrity management of the ***special permit segments*** and ***special permit inspection areas***.

XIV. Bibliography

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3) US Geological Survey National Seismic Hazard Mapping Program. Horizontal Spectral Response Acceleration for 0.2-second Period with 2% Probability of Exceedance in 50 Years (2014). https://earthquake.usgs.gov/arcgis/rest/services/haz/US5hz250_2014/MapServer. Accessed August 2019.

4) FERC Federal Energy Regulatory Commission. 2015. Natural Gas Pipelines. https://www.ferc.gov/industries/gas/indus-act/pipelines.asp. Accessed August 2019.

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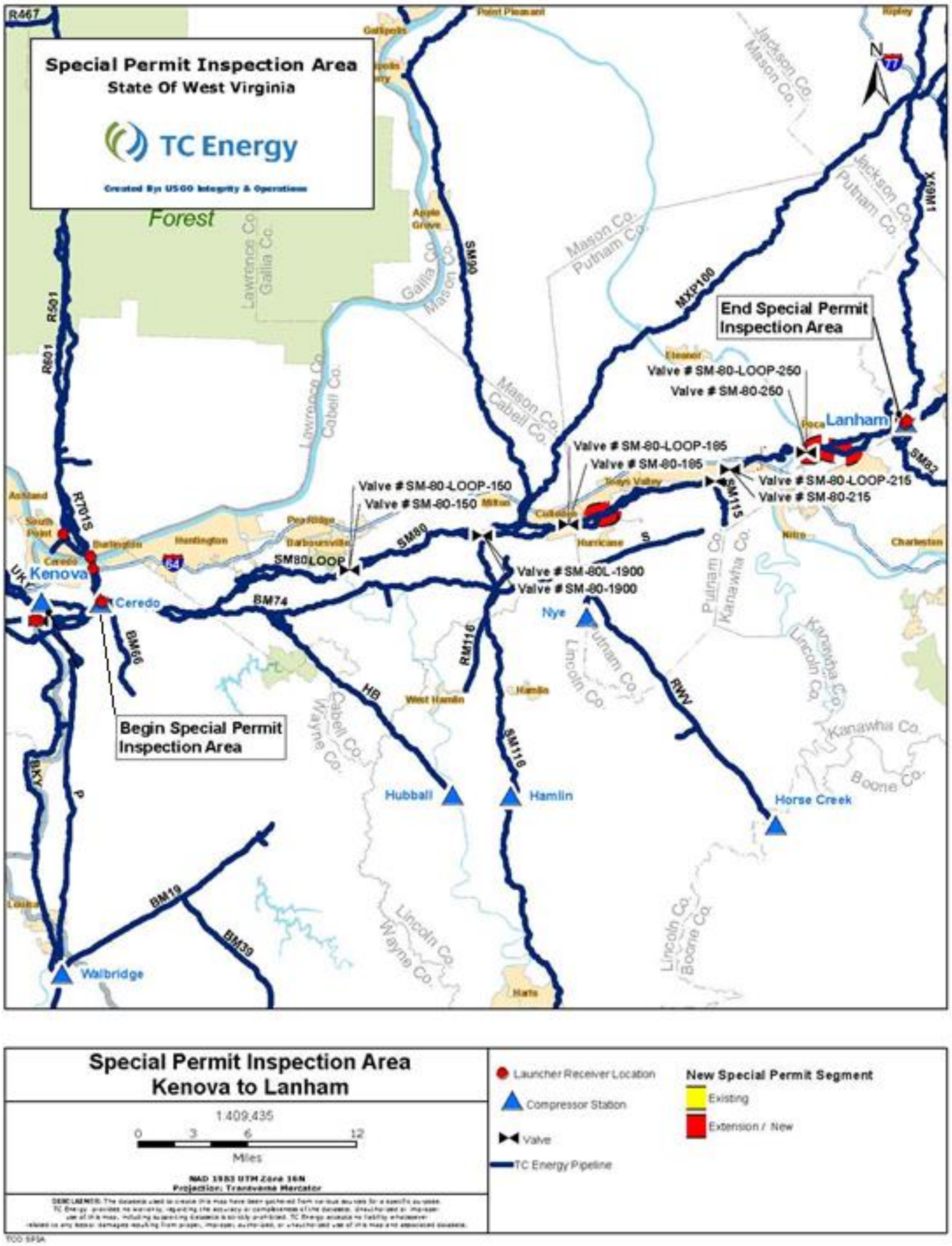
10) U.S. Fish and Wildlife Service (USFWS). 1984. Recovery plan for the orange-footed pearly mussel (Plethobasus cooperianus). Atlanta, Georgia: U.S. Fish and Wildlife Service, Region 4.

11) U.S. Geological Survey (USGS). 2013. Federal Standards and Procedures for the National Watershed Boundary Dataset (WBD). Chapter 3 of Section A, Federal Standards. Book 11 Collection and Delineation of Spatial Data. Techniques and Methods 11-A3. 4th. ed. Available at: https://pubs.usgs.gov/tm/11/a3/pdf/tm11-a3.pdf. Accessed August 2019.

Completed by PHMSA in Washington, DC on: March 31, 2022

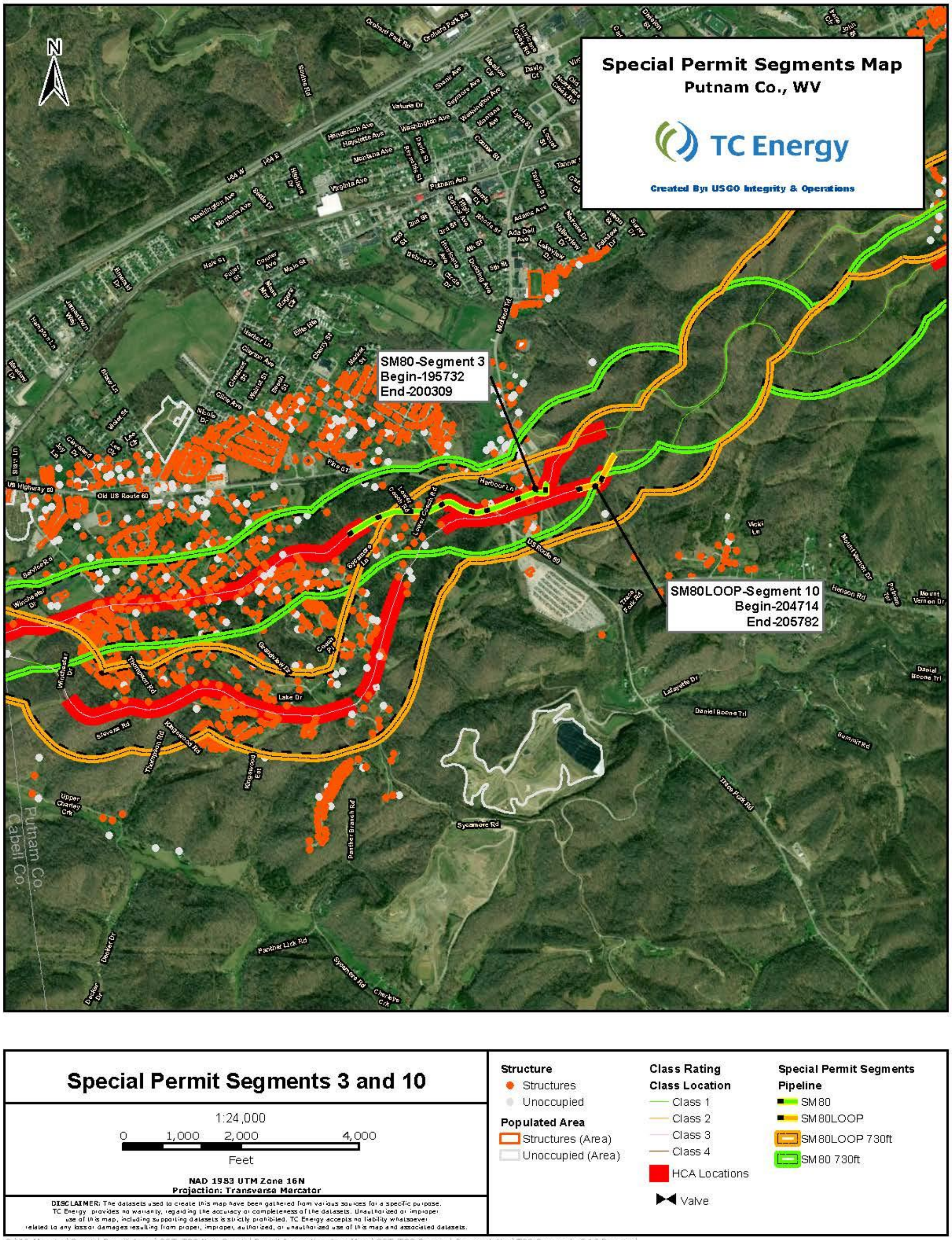
ATTACHMENT A – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments and Inspection Area



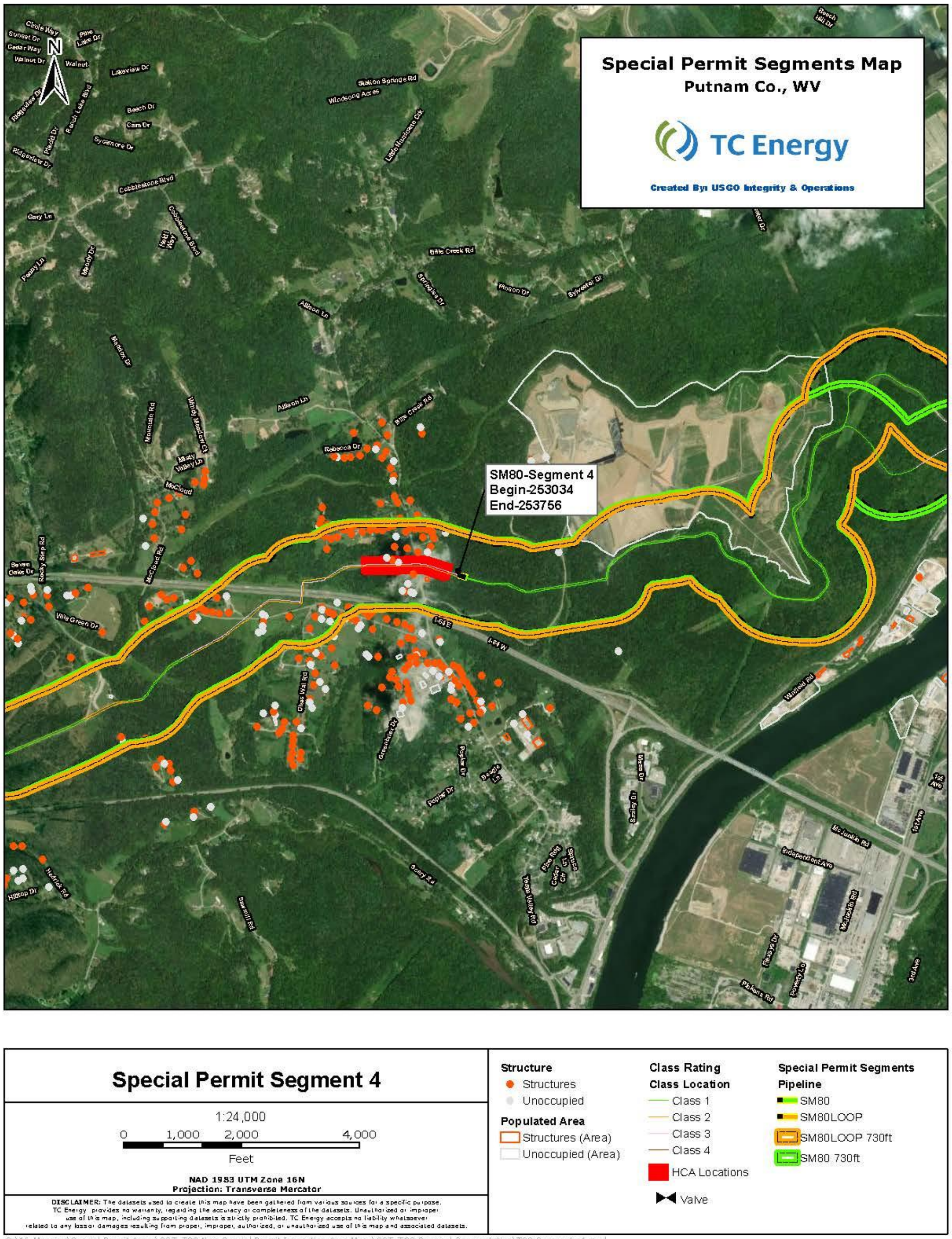
ATTACHMENT B.1 – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments



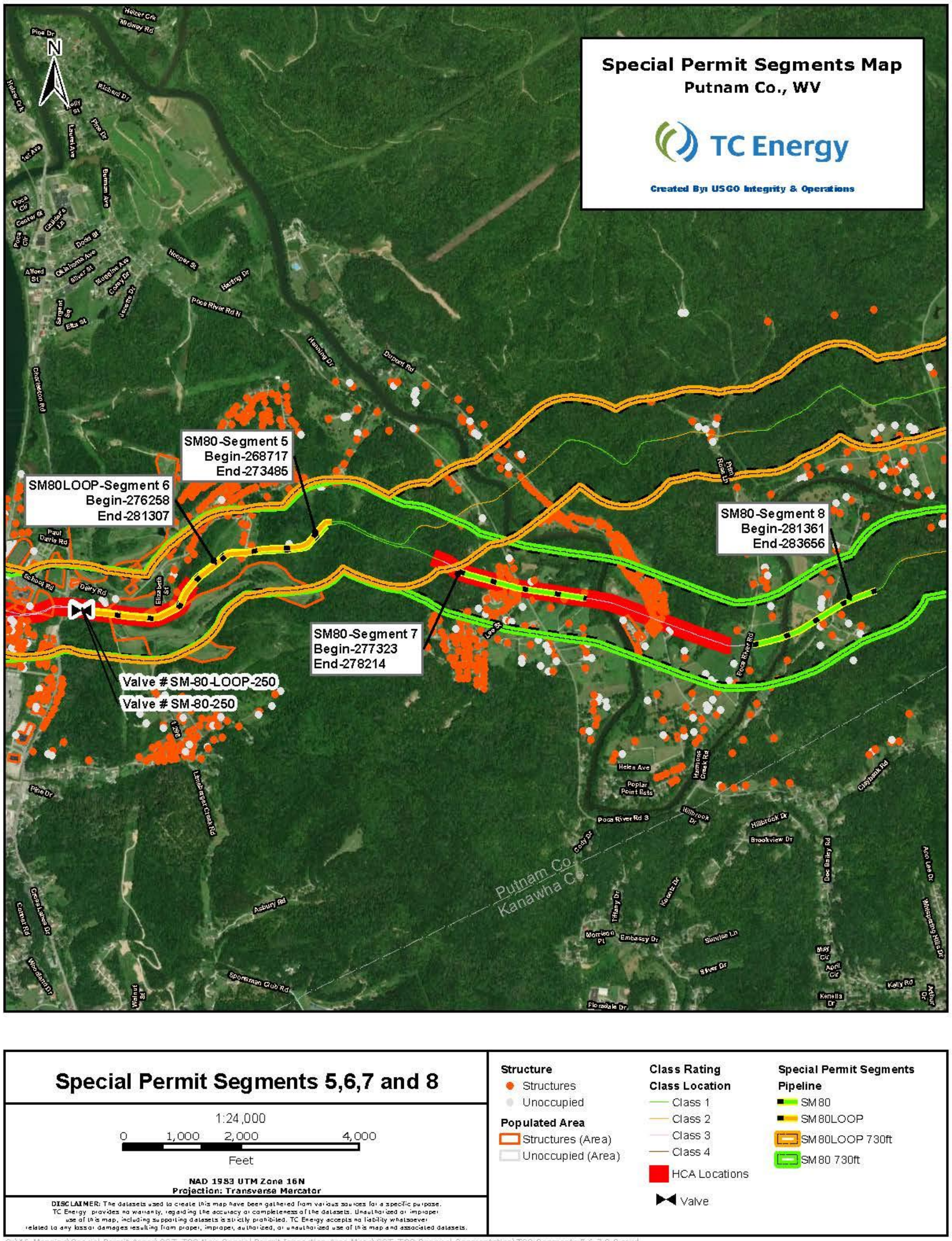
ATTACHMENT B.2 – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments



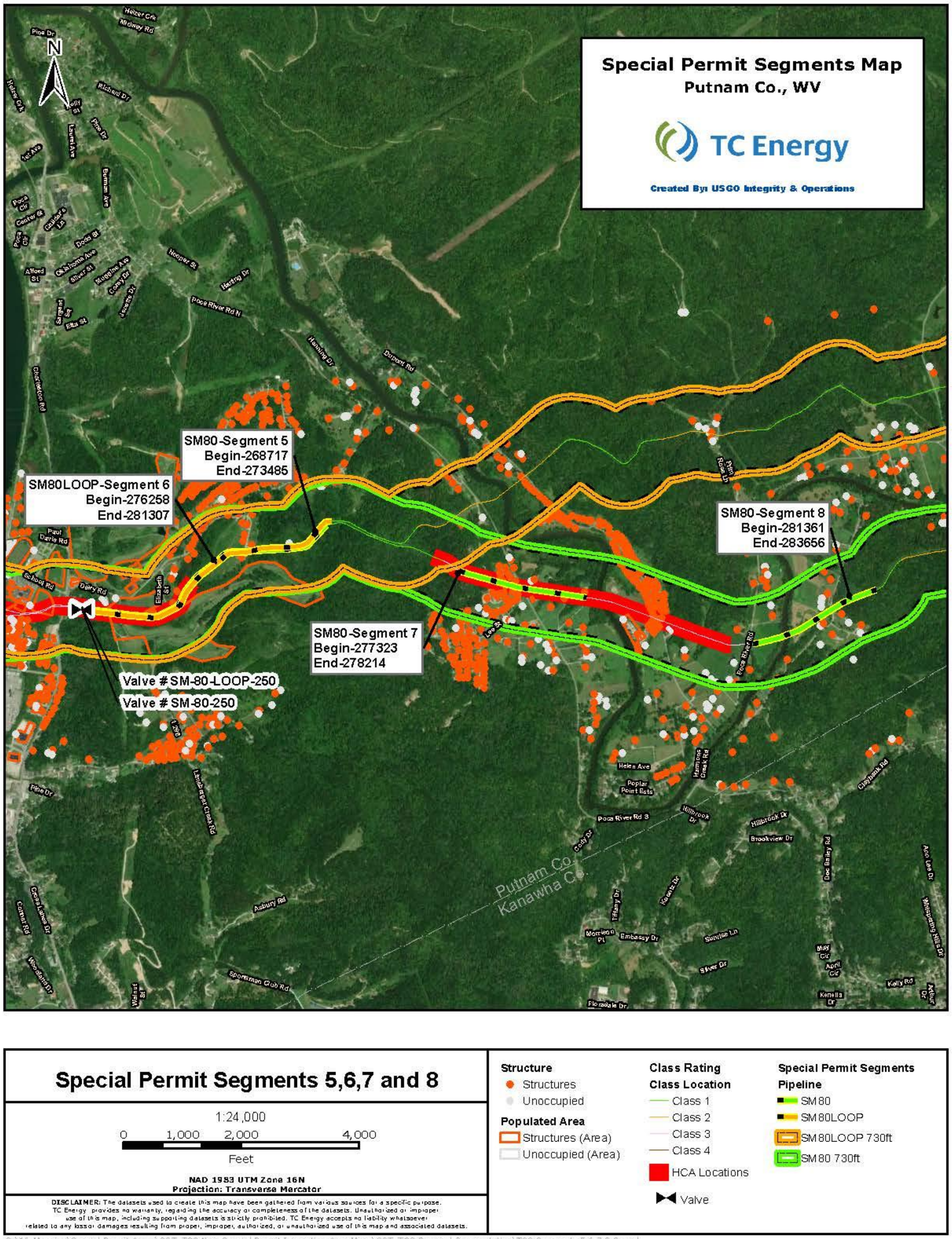
ATTACHMENT B.3 – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments



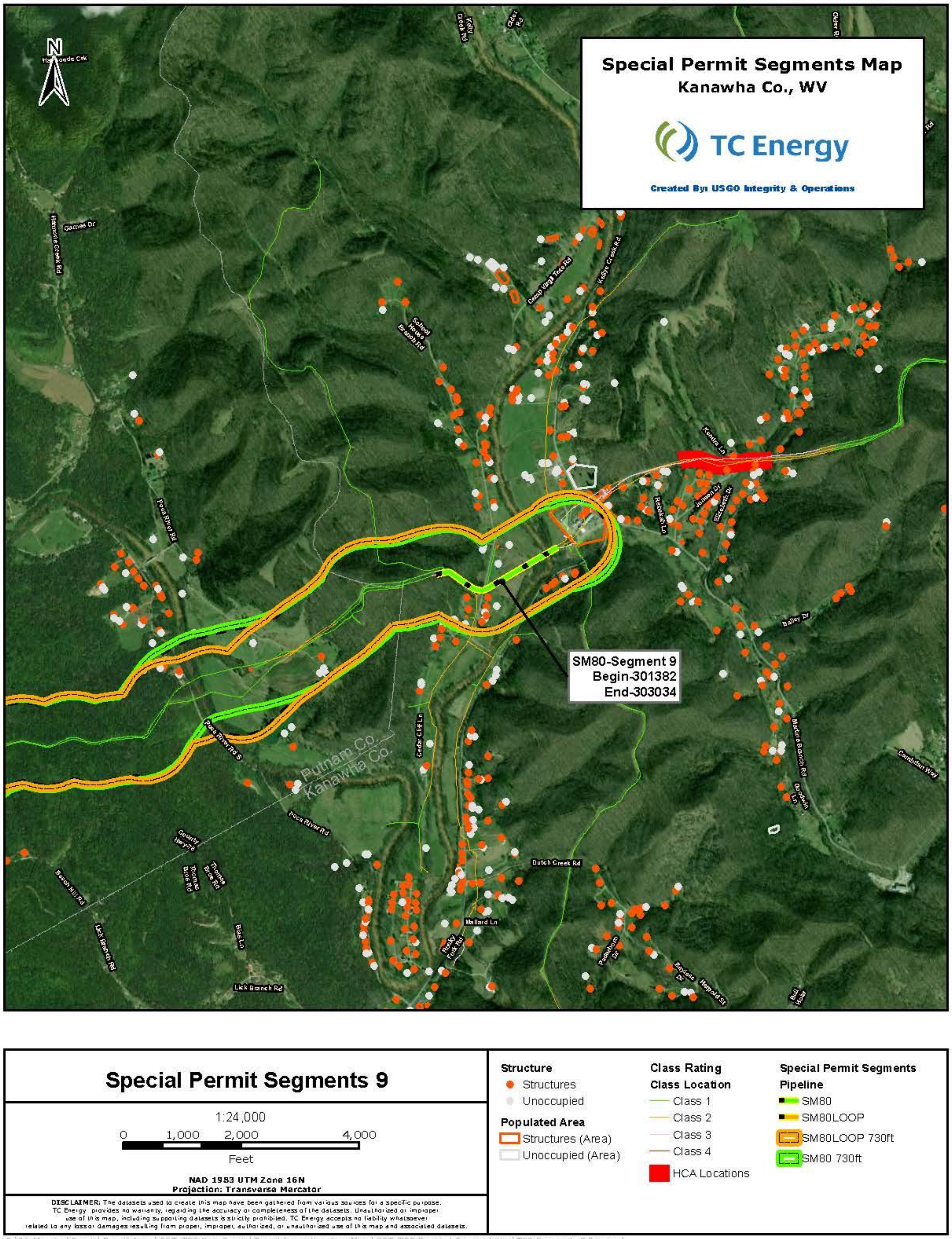
ATTACHMENT B.4 – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments



ATTACHMENT B.5 – TCO 30-INCH SM80 AND SM80 LOOP ROUTE MAP

Special Permit Segments



Attachment C – Special Permit Conditions

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

   a) **Maximum Allowable Operating Pressure**: TCO must continue to operate each ***special permit segment*** and ***special permit inspection area*** at or below the existing MAOPs. ***Special permit segments 3 and 10*** have MAOPs of 935 psig. ***Special permit segments 4, 5, 6, 7, 8, and 9*** have MAOPs of 920 psig.

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

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

      ii) If TCO does not have a TVC record of a 1.25 times the MAOP hydrotest in accordance with Subpart J, or the ***special permit segment*** requires an updated pressure test, the ***special permit segment*** must be hydrostatically tested[14] to a minimum of 1.39 times the MAOP for

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

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

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

14 For all in-service and pressure test failures, TCO 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. TCO 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.

eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J, within 18 months of the grant of this special permit.[15]

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

2) **Condition 2 - Procedure Updates**

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

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

b) **Integrity Management Program**:

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

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.

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

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

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

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

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

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

3) **Condition 3 – Corrosion Control**

TCO 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, TCO must monitor CP pipe-to-soil test stations to meet 49 CFR 192.463 and 192.465 for the ***special permit segment*** and must include "on and off" potential

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

measurements. Test station readings (pipe-to-soil potential measurements) must comply with Appendix D – Section I.A. (1) of 49 CFR Part 192 or remediation detailed in paragraph (c) of this condition is required. For hard spots identified with a Brinell Hardness (HB) of 300 HB or greater, CP voltage levels must be maintained more electro-positive than minus 1.2 volts direct current (DC).

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

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

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

d) **Remedial Action Plans**:

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

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

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

a) **Survey Methodology and Boundaries**:

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

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

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

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

b) **<u>Survey Intervals</u>**: TCO must perform the CIS within the following timeframes:

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

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

c) **<u>Survey Remediation and Remedial Action Plans</u>**:

i) If a ***special permit segment*** requires the use of 100 millivolt shift criteria[20] or the installation of linear anodes along the ***special permit segment*** to meet the CP requirements of 49 CFR 192.463, it is not eligible to operate with a Class 1 pipe in a Class 3 location. TCO must either: (1) replace the pipe in the ***special permit segment*** with Class 3 location standard (design factor) pipe (see 49 CFR 192.111(a)); (2) recoat the pipe with non-shielding external coating within 12 months of the finding; or (3) lower the MAOP to meet 49 CFR 192.611.

ii) Within four (4) months of identifying a deficiency, TCO 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, TCO must apply for any necessary environmental permits (federal or state).

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

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

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

5) **Condition 5 – Inline Inspection**

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

b) **Inline Inspection Methodology**: TCO 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, TCO 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.

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

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

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

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

iv) In a ***special permit inspection area*** that has experienced pipe or girth weld leaks or ruptures due to soil movement or the threat has been identified, TCO 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>**: TCO must conduct initial assessments and reassessments for the ***special permit inspection area*** in accordance with the following:

i) Initial ILI assessments must be conducted as follows:

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

(2) TCO <u>must</u> assess for the cracking threat in each ***extended special permit segment*** within 18 months of the special permit grant date.

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

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

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

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

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

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

(1) TCO must perform reassessments for all threats at 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 (1) of which must be after the grant of this special permit, TCO may request reassessment intervals up to seven (7) years for that threat assessment. TCO must submit for and receive a "no objection" letter from the Director, PHMSA Eastern Region, prior to implementing this change.

iv) If factors beyond TCO's control prevent the completion of an assessment within the required timeframe or reassessment interval, TCO must perform the assessment as soon as practicable, and TCO 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. TCO 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**: TCO 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.

TCO must demonstrate these welds were excavated, NDT, and repaired, if the welds do not meet federal pipeline safety regulations at the time the pipelines were constructed.

b) **<u>Missing Records</u>**: If TCO cannot provide girth weld records to PHMSA to demonstrate compliance with **Condition 6(a)**, TCO 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:[25]

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;[26] and

iii) Excavate,[27] visually inspect, and perform NDT on at least two (2) girth welds on each ***special permit segment*** in accordance with the applicable American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

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

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

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

c) **<u>Defective Girth Welds</u>**: If any girth weld in a ***special permit segment*** is found unacceptable in accordance with the API 1104 IBR Edition at the time of pipeline construction, TCO 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

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[25] TCO may propose an alternative method for obtaining missing records to the Director, PHMSA Eastern Region, with a copy of the proposal to the Director, PHMSA Engineering and Research Division. TCO must receive a "no objection" letter from the Director, PHMSA Eastern Region, prior to implementing the alternative method. An example of an alternative method could be usage of an appropriate ILI tool to identify girth weld(s) for excavation to determine overall girth weld integrity in the ***special permit segment***.

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

[27] TCO 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***.

threat to the ***special permit segment***. TCO 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.[28] TCO 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.[29]

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

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

a) **<u>Threat Assessments</u>**: TCO 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***[30] is susceptible to either near-neutral or high-pH SCC, TCO 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.[31]

c) **<u>Examination of Pipe</u>**: If the threat of SCC exists in the ***extended special permit segment*** as determined in **Condition 7(a)**, TCO must directly examine the pipe for SCC when the coating has been identified as poor during the pipeline examination. The examination must be conducted using an accepted crack detection practice in accordance with 49 CFR 192.710(c)(4), (d), and **Condition 7(d)** when the ***extended special permit segment*** is

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

[29] TCO must include any plan requirements or comments received from the Director, PHMSA Eastern Region, into the remediation plan.

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

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

uncovered for any reason to comply with the special permit and IM activities, not including One Call activities (49 CFR 192.614).

d) **Inspection of Pipe at Excavations**: Except for pipe coated with non-shielding coatings (fusion-bonded or liquid-applied epoxy coatings) and excavations performed in accordance with 49 CFR 192.614(c), TCO 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. TCO must use appropriate methods for crack detection, such as phased array ultrasonic testing (PAUT), inverse wavefield extrapolation (IWEX), or magnetic particle inspection (MPI),[32] 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." TCO must "jeep" the excavated segment to determine the coating condition. Examples of "poor coating" include, but are not limited to, a coating that has become damaged and is losing adhesion to the pipe which is shown by falling off the pipe and/or shields the CP. TCO must keep coating records[33] at all excavation locations in the ***special permit inspection area*** to demonstrate the coating condition.

e) **Discovery of SCC**: If TCO discovers SCC[34] 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,[35] the ***special permit segment*** must be further assessed and mitigated, within

[32] 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.

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

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

[35] For all in-service and pressure test failures, TCO 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. TCO 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.

18 months of finding SCC and reassessed every five (5) calendar years or less[36] based upon the evaluated growth of the SCC, using one (1) of the following methods:

i) **Spike Hydrostatic Test Program**:[37]

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

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

iii) **MAOP Lowered**: TCO must lower the MAOP of the ***special permit segment*** to 60% specified minimum yield strength (SMYS);

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

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

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[36] TCO 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 seven (7) years, as defined in 49 CFR 192.939(a), if the ECA shows that five (5) calendar year assessments are not required. TCO must receive a "no objection" letter from the Director, PHMSA Eastern Region, prior to extending the assessment interval to seven (7) calendar years.

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

f) **<u>SCC Remediation Plan</u>**: If TCO discovers any SCC activity in the ***extended special permit segment***, TCO 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.[38] The plan must:

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

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

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

a) **<u>General</u>**: TCO must use the procedures specified in the special permit conditions, 49 CFR 192.712, and **Attachment A** when evaluating anomalies. TCO 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>**: TCO 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). TCO 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 TCO. TCO must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly. ILI tools used must be calibrated as follows:

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

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38 For TCO to go forward with the technical justification for addressing the SCC threat, TCO must receive a “no objection” letter from the Director, PHMSA Eastern Region.

anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. A minimum of four (4) calibration excavations must be used for unity plots.[39]

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

(a) ILI calibration for EMAT ILI Tools must be based upon excavation results of a minimum of the two (2) most severe anomalies from a combined review of crack depth and length. If the EMAT tool identifies only one (1) anomaly, the anomaly must be excavated and assessed. TCO 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.

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

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

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

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

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[39] 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, TCO 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.

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

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

iii) **ILI Tool Evaluations**: ILI tool evaluations for metal loss must use "6t x 6t"[40] interaction criteria for determining anomaly failure pressures and response timing.

iv) **Discovery Date**: The discovery date[41] 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"**: TCO must remediate the ***special permit inspection area***[42] as follows:

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

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

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

(3) Metal loss preferentially affecting a detected pipe weld seam, and the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.25 times the MAOP or the metal loss is greater than 50% of pipe wall thickness.[43]

(4) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in

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40 "6t" means pipe wall thickness times six (6).

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

42 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.

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

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 TCO, requires immediate action.

ii) **<u>One-year conditions – Hard Spots for a "special permit inspection area"</u>**: TCO must repair by installation of a Type B sleeve or cut-out and recoat within 12 months of discovery, any hard spots found in the pipe body of EFW pipe discovered after the grant of the special permit with a hardness on the Brinell Hardness scale (HB) of either (1) 300 HB or greater and 2-inches in length or width; (2) 300 HB or greater 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>**: TCO 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, TCO must follow the remediation schedule specified in ASME/ANSI B31.8S, Section 7, Figure 4.

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

(6) Metal loss preferentially affecting a detected pipe weld seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0 (49 CFR 192.113), and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[44]

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

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

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

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

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

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

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

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

(5) Metal loss preferentially affecting a detected pipe weld seam and where the predicted failure pressure determined in accordance with 49 CFR 192.712(d) is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[45]

(6) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with 49 CFR 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and Class 3 and Class 4 locations.[46] 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***, TCO must remediate conditions in a ***special permit segment*** as follows:[47]

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

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

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

[46] 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.

[47] 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.

(2) **<u>Weld Metal</u>**: Girth weld metal loss greater than 30% of pipe wall thickness or pipe weld seam metal loss greater than 15% of pipe wall thickness.[48]

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

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

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

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

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

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

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

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

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

TCO 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.[49]

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

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

ii) **<u>Electrolytic Shorts</u>**: TCO 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 TCO identifies any shorts after uprating, they must be cleared no later than 12 months after identification.

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

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

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

Eastern Region, to use ILI assessments instead of clearing the short.[50, 51] In addition to the notification, TCO 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) TCO must remediate any identified corrosion, cracking, or other anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**.

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

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

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

i) Within 12 months of the special permit grant, TCO must perform an engineering integrity analysis to determine if the pipe seam is susceptible to seam threats located in the ***extended special permit segment***.[52] 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

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

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

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

(2) Figure 4.2, "Framework for Evaluation with Path for the Segment Analyzed Highlighted" from TTO-5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation," by Michael Baker Jr. and Kiefner and Associates, et. al. under PHMSA Contract DTRS56-02-D-70036.

ii) If the engineering integrity analysis identifies pipe seam issues in the ***extended special permit segment*** that are a threat to the integrity of the pipeline, TCO must confirm there are no systemic issues with the weld seam or pipe. Within 12 months of analysis completion, TCO 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 TCO 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 TCO 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) TCO must determine from the hydrostatic test whether there are systemic issues with the weld seam or pipe. TCO 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. TCO must provide the written results of this root cause analysis to the Director, PHMSA Eastern Region, within 90 days of the failure.[53]

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;

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

ii) The ***special permit segment*** pipe has any LF-ERW or EFW seam pipe joints that had pipe seam leaks or ruptures and the pipe has not been replaced with new pipe;[54]

iii) Pipe in the ***extended special permit segment*** was constructed or manufactured prior to 1954 and had pipe seam leaks or ruptures;[55]

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***, TCO 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**: TCO must remediate all weld seam leaks, failures, or ruptures[56] discovered in the ***special permit segment***. TCO 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 (1) of the following:

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

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

[56] For all in-service and pressure test failures, TCO 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. TCO 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.

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**

TCO must address induced alternating current (AC) from parallel electric transmission lines and other interference issues, such as direct current (DC), that may affect the pipeline in a ***special permit segment***. TCO 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**: TCO must perform periodic interference surveys to detect the presence and level of any electrical stray current, including when there are current flow increases over the ***special permit segment*** grounding design from any co-located pipelines, structures, or high voltage alternating current (HVAC) powerlines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures.

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

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

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

TCO must automate mainline valves[57] 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.[58] TCO must automate mainline valves to close in accordance with the requirements in **Condition 12** within 12 months of the grant of this special permit. The ***special permit segment*** must have procedures for rupture isolation as follows:

a) **<u>Valve Locations</u>**: ASVs or RCVs must be installed as shown in **Table 3 - ASV Closure Settings for Isolation of Special Permit Segment** and **Figure 1 - Location of Special Permit Segments Between ASVs**. All ***special permit segments*** must have telemetry connections to the TCO supervisory control and data acquisition (SCADA) system installed at locations shown in red in **Figure 1 - Location of Special Permit Segments Between ASVs**.[59]

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

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

[59] ***Special permit segment 5*** originates upstream of mainline valve SM80-250 and terminates downstream of mainline valve SM80-250.

b) **Automatic Shutoff Valve Requirements**:

i) If an ASV is used, TCO 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 ASVs or RCVs. 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 3 - ASV Closure Settings for Isolation of Special Permit Segment** has the ASV shutoff pressures and shutoff 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 TCO 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. TCO must submit initial and annual ASV shut-in pressures to the Director, PHMSA Eastern Region, as detailed in **Condition 15 – Annual Report**, 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 TCO's submittal letter within 90 days with a decision letter, or either give TCO 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, TCO 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[60] connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment). If the nearest valve for a gas receipt or delivery line to the ***special permit inspection area*** is not isolated, isolation valves must be installed within 12 months of the grant of this special permit.[61] Crossover valves that are in the TCO O&M procedures as locked closed and that are only opened when manned by TCO 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

[60] **Table 4 – Laterals Connecting between Isolation Valves** has a listing of all lateral valves.

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

monitoring. If an ASV is used, TCO 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."

f) **Mainline Valve Closure**: Closure of the appropriate valves following a pipeline leak or rupture must occur "as soon as practicable" and must not exceed 30 minutes from the "notification of potential rupture" as defined below:[62]

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 TCO (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) TCO observes an unanticipated or unplanned pressure loss outside of the pipeline's normal operating pressures, as defined in TCO's written procedures. If TCO 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, TCO 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

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

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

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

ii) TCO must evaluate and identify a rupture,[63] 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 TCO 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 TCO pipeline operating procedures.

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

i) **Point-to-Point Verification**: TCO 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**: TCO 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**: TCO must take remedial measures to correct any valve used to isolate a leak or rupture that is found to be inoperable or unable to maintain shutoff, as follows:

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[63] For all in-service and pressure test failures, TCO 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. TCO 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.

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

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

iii) If valve repair or replacement cannot be met due to circumstances beyond TCO's control, TCO 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) **Emergency Communications**:

i) TCO 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) TCO 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;[64] and

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

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

TCO must comply with the following requirements:

a) **Line-of-Sight Markers**: TCO 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

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[64] TCO 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.

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 TCO within 30 days after identification of line-of-sight marker removal.

b) **Depth of Cover Survey**:

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

ii) TCO 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 TCO 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, TCO 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 TCO's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify TCO of PHMSA's need for additional time to provide a decision.

c) **Data Integration**: TCO must develop and maintain data integration[65] in accordance with 49 CFR 192.917, of all special permit condition findings and remediation in a ***special permit segment*** and ***special permit inspection area***. Data integration must be completed at least once each calendar year, with intervals not to exceed 15 months.

i) Data integration must include the following information: (1) Pipe diameter, wall thickness, grade, and seam type; (2) pipe coating; (3) MAOP; (4) class location, including boundaries on aerial photography; (5) HCAs, including boundaries on aerial photography; (6)

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

hydrostatic test pressure, including any known test failures; (7) casings; (8) any in-service ruptures or leaks; (9) ILI survey results, including HR-MFL, HR-geometry/caliper, or deformation tools; (10) the most recent CIS results; (11) depth-of-cover surveys; (12) rectifier readings for the past five (5) years; (13) CP test point survey readings for the past five (5) years; (14) AC/DC interference surveys; (15) pipe coating surveys; (16) pipe coating and anomaly evaluations from pipe excavations; (17) SCC excavations and findings; and (18) pipe exposures from encroachments.[66] 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, TCO 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) TCO 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)**, TCO must test the pipe in a ***special permit segment*** as follows:[67]

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for any ***special permit segment***, without TVC[68, 69] pipe material properties records, in accordance with this condition and either 49 CFR 192.607 or

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

67 TCO must complete **Condition 13(d)** for the ***special permit segments*** flagged as required ("Yes") in ***Table 1 – Special Permit Segments***.

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

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

192.105 for determining MAOP. Non-destructive or destructive tests, examinations, and assessments must be completed within 18 months of the grant of this special permit.

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

iii) TCO must perform a minimum of two (2) destructive or NDT methods at an excavation site. TCO must conduct NDT assessments using test procedures, calibration pipe of similar confirmed properties for equipment testing, and ball indention methodology, or an equivalent method.[70] If NDT of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances, and the pipe grade is under the strength requirements of API 5L by 1,000 pounds per square inch (psi) or more, then TCO 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, TCO must submit an assessment procedure to the Director, PHMSA Eastern Region, for a "no objection" letter prior to its usage.[71] The Director, PHMSA Eastern Region, must respond to TCO's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify TCO of PHMSA's need for additional time to provide a decision.

iv) TCO must assess pipe in a ***special permit segment*** with missing mill test reports (MTRs) or missing mill inspection reports (i.e. Moody Engineering Reports) for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest

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

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

wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a 2-year interval), and construction dates (within a 2-year interval).

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

vi) For a future ***special permit segment*** with missing mill inspection reports for mechanical and chemical properties, TCO must use the above methodology, or TCO may elect to remove pipe joints for destructive testing.[72]

e) **Pipeline System Flow Reversals**: For pipeline system flow reversals lasting longer than 90 days and where the MAOP for class location changes are exceeded under either 49 CFR 192.619(a)(1) or 192.611[73] in a ***special permit segment***, TCO 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). TCO must submit the written flow reversal procedure to the Director, PHMSA Eastern Region, and submit a copy of the plan to the Federal Docket for this special permit at www.regulations.gov.[74] TCO 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**: TCO must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings, and pipeline natural gas emissions from implementation of the special permit conditions for a ***special permit segment*** or ***special permit inspection area*** prior to the disturbance or activity. If

[72] TCO must prepare a procedure in accordance with **Condition 13(d) – Pipe Properties Testing**, 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 TCO's submittal letter within 90 days. The Director, PHMSA Eastern Region, may provide a decision, request for additional information, or notify TCO 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.

[73] 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.

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

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

g) **Gas Quality**: TCO 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**: TCO 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 TCO to provide a notice for a "no objection" response from PHMSA, other notice, annual report, or documentation to the Director, PHMSA Eastern Region, TCO must also send a copy to the State Agency that has interstate agent agreements with PHMSA and to the Director, PHMSA State Programs.

j) **Pipe and Soil Movement**: Girth weld strain from soil movement exerted onto the pipeline in the ***special permit segment*** must not exceed 0.5 percent and must account for girth weld misalignment. TCO must develop procedures on how to evaluate and remediate soil stresses and strains on the pipeline including IMU intervals. TCO 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) **Gas Leakage Surveys and Remediation**:

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

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

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

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

(b) Escaping gas that has ignited;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

iii) When a pressure limiting device or relief valve allows a gas release to the atmosphere that is located along the ***special permit inspection area***, TCO 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. TCO cannot extend or change any remediation timing or continuous monitoring requirements in this paragraph without a "no objection" letter received by TCO from the Director, PHMSA Eastern Region.

iv) TCO may request an extension of the remediation time interval requirements by sending 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)**.[75]

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

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

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

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

   i) TCO must reduce the release of gas to the environment when replacing any pipe between the mainline isolating valves for a ***special permit segment***. TCO must use one (1) or more of following methods that will reduce the environmental effects of methane (gas) being released. TCO must calculate the volume of natural gas that will be released by each method or combination of methods and select an option(s) that minimizes the release of gas to the environment and is consistent with pipeline safety.[76]

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

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[75] Any TCO 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.

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

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

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

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

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

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

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

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

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

TCO 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 TCO 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.

15) **Condition 15 - Annual Report**

Annually[77] after the grant of this special permit, TCO must report the following to the Director, PHMSA Eastern Region, with copies to the Director, PHMSA Engineering and Research Division:[78]

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. TCO 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[79] during the previous year in the ***special permit inspection area***, including their survey station, predicted failure pressure, anomaly depth and length, class location, and whether these threats are in an HCA.

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

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

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

[77] 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.

[78] TCO must post the annual report to the special permit docket PHMSA-2008-0331 at www.regulations.gov.

[79] TCO 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 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***. TCO must include the location by mile post, County/Parish and State, the date of discovery, date of repair, and estimated gas loss (cubic feet) per day and in total for any Grade 1, 2, or 3 gas leak as described in **Condition 13(k) - Gas Leakage Surveys and Remediation**.

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

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

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

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

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

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

k) A senior executive officer, vice president, or higher executive of TCO must review for correctness, date, and sign the annual report prior to posting it to the Federal Docket (PHMSA-2008-0331) at www.regulations.gov and submitting a copy to the Director, PHMSA Eastern Region, and the Director, PHMSA Engineering and Research Division.

l) TCO 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.[80] During the annual review meeting, TCO must review the status of implementing the special permit conditions with the Director, PHMSA Eastern Region.

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

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

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

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

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

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

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

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

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

ii) TCO 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. TCO 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 TCO 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) TCO must remediate all anomalies in accordance with **Condition 8 – Anomaly Evaluation and Remediation**;

ii) TCO must have hydrostatically tested[81] a ***special permit segment*** and ***extension*** in accordance with **Condition 1 – Maximum Allowable Operating Pressure**, as applicable; and

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

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

TCO must meet the following conditions for certification:

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

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[81] For all in-service and pressure test failures, TCO 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. TCO 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.

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

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

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

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

b) TCO must send the certifications required in **Condition 18(a)**, with special permit condition status, completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Eastern Region; the Director, PHMSA Engineering and Research Division; and the Federal Register Docket (PHMSA-2008-0331) at www.regulations.gov within one (1) year of the issuance date of this special permit.

Limitations

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

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

6) PHMSA grants this special permit limited to a term of no more than 10 years from the date of issuance. If TCO elects to seek renewal of this special permit, TCO 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 TCO 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 March 31, 2022.

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

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

The granted special permit renewal with conditions granted to TCO for Docket No. PHMSA-2008-0331 can be found the Federal Dockets Management System located on the internet at www.regulations.gov or on the PHMSA website for special permits issued at https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued.

Last Page of the FEA and FONSI