U.S. Department
of Transportation

Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Avenue SE
Washington, DC 20590

JUL 23 2013

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gregory L. Ebel
President and Chief Executive Officer
Spectra Energy Transmission, LLC
5400 Westheimer Court
Houston, TX 77056-5310

Re: Docket No. PHMSA-2004-18858

Dear Mr. Ebel:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is reviewing existing special permits issued under the Risk Management Demonstration Program (RMDP) to determine whether these special permits remain consistent with pipeline safety in light of significant changes to the Part 192 regulations and PHMSA's experience with class location special permits over the last ten years which has resulted in updated conditions and requirements to ensure safety.

Among the RMDP special permits under review is a special permit issued to Duke Energy Gas Transmission Company (DEGT), predecessor to Spectra Energy Transmission, LLC (SET), on March 16, 2006, (Special Permit PHMSA-2004-18858). Special Permit PHMSA-2004-18858 waived DEGT's obligation to comply with the requirement in 49 CFR § 192.611 to confirm or revise maximum allowable operating pressure (MAOP) following a change in class location for twenty-one segments of its Texas Eastern Gas Pipeline located on parallel Line 10, Line 15, and Line 25 pipelines within Maury and Williamson Counties, Tennessee and Fleming and Lewis Counties, Kentucky (the "special permit segments"). The special permit segments include a total of approximately 17.75 miles of pipeline.

The conditions in Special Permit PHMSA-2004-18858 were developed at the beginning of implementation of the Gas Integrity Management Rule and development of class location criteria for special permits which included the use of pressure testing standards, effective coating, ongoing integrity management processes (such as close interval surveys, in-line inspections, hydrostatic testing, stress corrosion cracking mitigation, selective seam corrosion mitigation, and data integration) and prior to Advisory Bulletin ADB-11-01 for MAOP records validation. Additionally, current requirements for ongoing integrity assessments are not integrated into the conditions of Special Permit PHMSA-2004-18858 since it was issued in 2006.

PHMSA is considering initiating steps to modify Special Permit PHMSA-2004-18858 to ensure it is consistent with current safety standards. I am requesting that SET review the enclosed proposed special permit conditions and provide any comments to us by August 30, 2013. We recognize that SET may already have implemented many of these measures on the special permit segments. PHMSA will consider your input in determining whether formal modifications of this special permit under § 190.341(h) are needed. If so, SET will receive prior notice and will be provided with an opportunity to show why such modification, in whole or in part, is not needed.

Thank you for your cooperation in this matter and we look forward to your response.

Sincerely,

for Alan K Mayberry

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Enclosure

cc: Mr. J. A. Drake, Vice President, Gas Transmission Services, SET
Mr. Wayne Lemoi, Director, Southern Region, OPS
Mr. Alan Mayberry, Deputy Associate Administrator for Field Operations, OPS
Mr. John Gale, Director of Standards and Rulemaking, OPS

Proposed Special Permit Modifications - PHMSA-2004-18858

The Federal pipeline safety regulations in 49 CFR § 192.611(a) require natural gas pipeline operators to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline segment after a change in class location.

Special Permit PHMSA-2004-18858 as issued in 2006 waives compliance from 49 CFR § 192.611(a) for twenty-one (21) segments of natural gas transmission pipeline on Texas Eastern Gas Pipeline (Texas Eastern) Line 10, Line 15, and Line 25 pipelines, where a change has occurred from a Class 1 location to a Class 2[1] located in Maury and Williamson Counties, Tennessee and Fleming and Lewis Counties, Kentucky. The special permit segments total approximately 17.75 miles of pipeline.

In reviewing Special Permit PHMSA-2004-18858 and its conditions, PHMSA proposes to modify this special permit as set forth below. On the condition that Spectra Energy Transmission, LLC (SET) complies with the terms and conditions set forth below, this special permit, as modified, allows SET to continue to operate each ***special permit segment*** at its current maximum allowable operating pressure (MAOP) of 1000 pounds per square inch gauge (psig) for the 30-inch Line 10, 30-inch Line 15, and 36-inch Line 25 pipelines.

Special Permit Segments and Special Permit Inspection Areas:

Mt. Pleasant Compressor Station Discharge, Maury and Williamson Counties, Tennessee

Special Permit PHMSA-2004-18858 is modified to include the following ***special permit segments, inspection areas, and conditions***:

This special permit applies to the ***special permit segment(s)*** defined as follows using the SET mile post (MP) or survey station (Sta.) references:

- ***Special permit segment 1*** – Line 10, 30-inch, MP 226.88 to MP 227.35

[1] SET's Texas Eastern Gas Pipeline 30-inch Line 10, 30-inch Line 15, and 36-inch Line 25 pipelines all operate above 72% of specified minimum yield strength (SMYS) in accordance with 49 CFR § 192.619 (c) – Grandfather Clause. The Class 2 location ***special permit segments*** were originally a Class 1 location that could not be upgraded to a Class 2 location and operate above 72% SMYS in accordance with 49 CFR § 192.611 (a) hydrostatic test without a special permit.

- *Special permit segment 2* – Line 15, 30-inch, MP 226.90 to MP 227.50
- *Special permit segment 3* – Line 25, 36-inch, MP 227.05 to MP 227.50
- *Special permit segment 4* – Line 10, 30-inch, MP 228.49 to MP 229.07
- *Special permit segment 5* – Line 15, 30-inch, MP 228.65 to MP 229.21
- *Special permit segment 6* – Line 25, 36-inch, MP 228.63 to MP 229.22
- *Special permit segment 7* – Line 10, 30-inch, MP 238.01 to MP 239.19
- *Special permit segment 8* – Line 15, 30-inch, MP 238.17 to MP 239.34
- *Special permit segment 9* – Line 25, 36-inch, MP 238.17 to MP 239.36
- *Special permit segment 10* – Line 25, 36-inch, MP 241.69 to MP 241.72
- *Special permit segment 11* – Line 10, 30-inch, MP 247.79 to MP 247.88
- *Special permit segment 12* – Line 15, 30-inch, MP 247.94 to MP 248.04
- *Special permit segment 13* – Line 25, 36-inch, MP 247.94 to MP 248.03
- *Special permit segment 14* – Line 10, 30-inch, MP 264.03 to MP 265.31
- *Special permit segment 15* – Line 15, 30-inch, MP 264.19 to MP 265.49
- *Special permit segment 16* – Line 25, 36-inch, MP 264.24 to MP 265.48

- **Owingsville Compressor Station Discharge, Fleming and Lewis Counties, Kentucky**[2]
  - *Special permit segment 17* – Line 10, 30-inch, MP 514.78 to MP 514.98
  - *Special permit segment 18* – Line 25, 36-inch, MP 515.25 to MP 515.28
  - *Special permit segment 19* – Line 10, 30-inch, MP 531.10 to MP 533.33
  - *Special permit segment 20* – Line 15, 30-inch, MP 531.54 to MP 533.75
  - *Special permit segment 21* – Line 25, 36-inch, MP 531.54 to MP 533.76

This special permit applies to the ***special permit inspection areas*** defined as follows using the Line 10, Line 15, and Line 25 pipelines stationing as a reference.

Special permit inspection areas – are defined as the area that extends 220 yards on each side of the centerline along the entire length of the Line 10, Line 15, and Line 25 pipelines from:

[2] SET begin reporting in annual report dated June 15, 2009, special permit segments on 30-inch Line 15 in Fleming County, Kentucky from MP 513.11 to MP 513.25 and from MP 513.32 to MP 513.50. This ***special permit segment*** is not included in this listing.

- *Special permit inspection area A* - Line 10, Line 15, and Line 25 pipelines – **Mt. Pleasant Compressor Station Discharge – MP 223.50**[3] **to MP 287.08**:
  - Includes ***special permit segments 1 through 16;***
  - Located in Maury and Williamson Counties, Tennessee.
  - Starts downstream of the Mt. Pleasant Compressor Station and ends at the Gladeville Compressor Station along the pipeline.
- *Special permit inspection area B* - Line 10, Line 15, and Line 25 pipelines – **Owingsville Compressor Station Discharge – MP 502.11 to MP 563.72:**
  - Includes ***special permit segments*** *17 through 21;*
  - Located in Fleming and Lewis Counties, Kentucky.
  - Starts downstream of the Owingsville Compressor Station and ends at the Wheelersburg, Ohio Compressor Station along the pipeline.

Conditions:

PHMSA proposes to modify this special permit by adding the following conditions:

1) **Maximum Allowable Operating Pressure (MAOP)**: SET must continue to operate the pipelines ***special permit segments*** at or below their existing MAOP as follows: 30-inch Line 10, 30-inch Line 15, and 36-inch Line 25 pipelines - MAOP 1000[4] psig.

2) **Integrity Management Program**: SET must incorporate the ***special permit segments*** into its written integrity management program (IMP) as a "*covered segment*" in a "*high consequence area (HCA)*" in accordance with 49 Code of Federal Regulations (CFR) § 192.903, except for the reporting requirements contained in 49 CFR § 192.945. SET need not include the ***special permit segments*** described in this special permit in its IMP baseline assessment plan unless those areas meet the conditions of an HCA in accordance with 49 CFR § 192.905.

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[3] SET in an annual report dated June 15, 2009, to PHMSA's Southern Region on Attachment 2 noted a previous error for the beginning MP for Mt. Pleasant Compressor Station Discharge from prior MP 223.44 to MP 223.50.
[4] SET's Line 10, Line 15 and Line 25 pipelines all operate above 72% of SMYS in accordance with 49 CFR § 192.619 (c) – Grandfather Clause.

3) **Close Interval Surveys**: SET must perform a close interval survey (CIS) of the Line 10, Line 15 and Line 25 pipelines along the entire length of all ***special permit inspection areas***[5] and remediate any areas of inadequate cathodic protection no later than one (1) year after the modification of this special permit. However, a CIS need not be performed if SET has performed a CIS and completed remediation[6] including damaged coating repair on the Line 10, Line 15 and Line 25 pipelines along the entire length of all ***special permit inspection areas*** less than four (4) years prior to the modification of this special permit. If factors beyond SET control prevent the completion of the CIS and remediation activities within the one (1) year from the modification of this special permit, a CIS and subsequent remediation including coating repair must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) year after the modification of this special permit.

4) **Close Interval Surveys – Reassessment Interval**: SET must perform a periodic CIS of the ***special permit segments*** at the applicable reassessment interval(s) for a "covered segments" determined in concert and data integrated with in-line inspection (ILI) in accordance with 49 CFR 192 Subpart O reassessment intervals as contained in 49 CFR §§ 192.937(a) and (b) and 192.939, not to exceed a seven (7) year reassessment interval. Condition 24 (d) – Data Integration – gives a complete description of data integration information that an operator must maintain for a special permit in the ***special permit segments*** and ***special permit inspection areas***.

5) **Coating Condition Surveys**: Within one (1) year of the modification of this special permit SET must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey of each ***special permit segment*** to determine the pipeline coating conditions and must then remediate any integrity issues including external

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[5] Each condition that requires SET to perform an action with respect to the ***special permit inspection areas*** shall also require SET to perform that action on all ***special permit segments*** within such areas.

[6] The terms "remediate" or "remediation" of pipe coating shall include repair of damaged external pipe coating.

coating repairs in each ***special permit segment***. However, a DCVG or ACVG survey and subsequent remediation need not be performed on the ***special permit segment*** if SET has performed a DCVG or ACVG and remediation on the Line 10, Line 15 and Line 25 pipelines along the entire length of all ***special permit inspection areas*** less than four (4) years prior to the modification of this special permit. SET must remediate any damaged coating indications found during these assessments that are classified as moderate (i.e. 35% IR and above for DCVG or 50 dBμV and above for ACVG) or severe based on NACE International Standard Practice 0502-2008, "*Pipeline External Corrosion Direct Assessment Methodology*", (NACE SP 0502-2008[7]). A minimum of two (2) coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew per each time the survey is performed. If factors beyond SET control prevent the completion of the DCVG or ACVG survey and remediation within the one (1) year from the modification of this special permit, a DCVG or ACVG survey and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) year after the modification of this special permit.

6) **<u>Stress Corrosion Cracking Direct Assessment</u>**: SET must evaluate the Line 10, Line 15 and Line 25 pipelines for stress corrosion cracking (SCC) as follows:
   a) SET must perform a stress corrosion cracking direct assessment (SCCDA) or other appropriate assessment method for SCC [such as pressure test or in-line inspection (ILI) with a crack detection tool] of the Line 10, Line 15 and Line 25 pipelines along the entire length of all ***special permit inspection areas*** according to the requirements of 49 CFR § 192.929 and/or NACE SP 0204-2008 no later than one (1) year after of the modification of this special permit. The SCCDA or other approved method must address both high pH SCC and near neutral pH SCC.
      i) If factors beyond SET control prevent the completion of the SCCDA survey and remediation within the one (1) year from the modification of this special

[7] When PHMSA adopts a revised edition of a referenced standard such as NACE International (NACE) or ASME standard into 49 CFR Part 192, the referenced requirements of those revised standards are automatically incorporated into these special permit conditions.

permit, a SCCDA and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than one (1) year after the modification of this special permit.

ii) SET may eliminate this Condition 6 (a), provided SET provides an engineering assessment showing that the pipeline does not meet the criteria for either near neutral or high pH SCC in accordance with the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, "*Managing System Integrity of Gas Pipelines*" (ASME B31.8S), Appendix A3, or NACE SP 0204-2008, "*Stress Corrosion Cracking (SCC) Direct Assessment Methodology*", Section 1.2.1.1 and 1.2.2.

iii) A SCCDA need not be performed if SET has performed a SCCDA of the Line 10, Line 15 and Line 25 pipelines along the entire length of the ***special permit inspection areas*** less than four (4) years prior to the modification of this special permit.

b) If the threat of SCC exists as determined in Condition 6 (a) and when SET's Line 10, Line 15 and Line 25 pipelines are exposed for any reason, including damage prevention activities, in the ***special permit inspection areas*** and the coating has been identified as poor during the pipeline examination, then SET must directly examine the pipe for SCC using an accepted industry detection practice such as dry or wet magnetic particle tests. Poor coating is a coating that is damaged, is losing adhesion to the pipe which is shown by falling off the pipe, is porous, has pin holes, and/or shields the cathodic protection. In addition to visual inspection, holiday detection testing at the proper voltage must also be performed. SET must keep coating records[8] of all excavation locations for the ***special permit inspection areas*** to demonstrate the coating condition.

c) If SCC[9] activity is discovered by any means within the ***special permit inspection area*** in similar pipe and pipe coating vintage [in accordance with 49 CFR § 192.917(e)], or has had an in service or hydrostatic test SCC failure or leak; the ***special permit segment*** must

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

[9] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

be further assessed and mitigated, using one of the following methods, within six (6) months of finding SCC:

- i) Hydrostatic test program
  - A. The SCC hydrostatic test program must be performed at an interval no greater than seven (7) years (but may be at a lesser interval in accordance with the results of an engineering critical assessment) in the ***special permit segment***.
  - B. If pipe in the ***special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, all pipe in the ***special permit segment*** must be replaced with new pipe.
- ii) Crack detection tool assessment
  - A. SCC detection tool must be run in the ***special permit inspection area***.
  - B. All SCC[10] cracking found in the ***special permit segment*** must be replaced with new pipe.
- iii) Operating pressure lowered to 60% specified minimum yield strength (SMYS).
- iv) Replace all affected pipe to meet 49 CFR § 192.611 in the ***special permit segment***.

d) If any SCC activity is discovered in the ***special permit inspection area***, SET must submit a SCC remediation plan to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division no later than 30 days after the finding of SCC:

- i) That meets Condition 6 (c), including a SCC remediation/repair plan with SCC characterization and timing, or
- ii) Technical justification that shows that the ***special permit segment*** is not at risk for SCC.

7) **<u>Reporting of Pipe and Coating Remediation</u>**: SET must submit the DCVG or ACVG, CIS, and SCCDA [or other PHMSA-approved methods of determining SCC] findings, including

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[10] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

remediation actions, in a written report to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division, no later than one (1) year after the modification of this special permit.

8) **<u>O&M Manual – In-Line Inspection and Reassessment Intervals</u>**: SET must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the inspection and reassessment intervals by ILI, including both metal loss and geometry tools of the Line 10, Line 15 and Line 25 pipelines along the entire length of the ***special permit inspection areas*** at a frequency consistent with 49 CFR Part 192, Subpart O, but not to exceed a seven (7) year reassessment interval. [Deformation tools with up to +/- 1% accuracy may be considered as a replacement for geometry tools.]

9) **<u>O&M Manual - CIS Inspection and Reassessment Intervals</u>**: SET must amend applicable sections of its O&M manual(s) to require the CIS inspection and reassessment intervals of the Line 10, Line 15 and Line 25 pipelines ***special permit segments*** at a frequency consistent with 49 CFR Part 192, Subpart O, but not to exceed a seven (7) year reassessment interval.

10) **<u>In-Line Inspection Initial Assessment</u>**: SET must perform ILI assessment along the entire length of the ***special permit inspection area*** using ILI Tools (both high resolution magnetic flux leakage (HR-MFL) and either HR-geometry or HR-deformation tools) and must remediate discovered conditions in accordance with Condition 20 of this permit. If ILI assessments have not been run within four (4) years of the modification of this special permit using both HR-MFL and either HR-geometry or HR-deformation tools, SET must complete initial ILI Tool inspections on the Line 10, Line 15 and Line 25 pipelines within six (6) months of the modification of this special permit. Subsequent ILI assessments of the Line 10, Line 15 and Line 25 pipelines pipeline along the entire length of the ***special permit inspection areas*** using ILI must conform to the required maximum reassessment intervals specified in 49 CFR § 192.939, but may not to exceed a seven (7) year reassessment interval.

11) **<u>In-Line Inspection Reassessment Intervals</u>**: SET must schedule ILI reassessment dates for the Line 10, Line 15 and Line 25 pipelines along the entire length of the ***special permit***

inspection areas according to 49 CFR § 192.939 by adding the required time interval to the previous assessment date, but may not to exceed a seven (7) year reassessment interval.

12) **<u>Damage Prevention Best Practices</u>**: SET must incorporate the applicable best practices of the Common Ground Alliance (CGA) into its damage prevention program within the ***special permit inspection areas***.

13) **<u>Field Activity Advance Notice to PHMSA</u>**: SET must give a minimum of 14 days advance notice to the Director, PHMSA Southern Region to enable PHMSA to observe the excavations relating to Conditions 5, 6 (b), 19, 20, 21, 22, 23, 24 (f), and 24 (g) of field activities in the ***special permit inspection areas***. Immediate response conditions do not require a 14-day advance notice, but the Director, PHMSA Southern Region should be notified by SET no later than two (2) business days after the immediate condition is discovered.

14) **<u>High Consequence Area Assessments</u>**: SET must not let this special permit be a basis for deferring any of its assessments for HCAs in accordance with 49 CFR Part 192, Subpart O.

15) **<u>Annual Reports to PHMSA</u>**: Within three (3) months following the modification of this special permit and annually[11] thereafter, SET must report the following to the Director, PHMSA Southern Region with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Engineering and Research Division; and Director, PHMSA Standards and Rulemaking Division:

a) In the first annual report, SET must describe the economic benefits of the special permit including both the costs avoided from not replacing the pipe and the added costs of the inspection program. Subsequent annual reports should address any changes to these economic benefits.

b) In the first annual report, fully describe how the public benefits from energy availability. This should address the benefits of avoided disruptions as a consequence

[11] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a modified Special Permit dated November, 2012, must be received by PHMSA no later than November 30, each year beginning in 2013.

of pipe replacement and the benefits of maintaining system capacity. Subsequent reports must indicate any changes to this initial assessment.

c) The number of new residences, other structures intended for human occupancy and public gathering areas built within the ***special permit inspection areas***.

d) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year in the ***special permit inspection areas***.

e) Any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the ***special permit inspection areas***.

f) Any on-going damage prevention initiatives affecting the ***special permit inspection areas*** and a discussion of the success of the initiatives.

g) Annual data integration information, as required in Condition 24 (d) - Data Integration.

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

16) **Cathodic Protection Test Station – Location**: At least one (1) cathodic protection (CP) pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. This requirement applies to any HCA within the ***special permit inspection areas***.

17) **Cathodic Protection Test Station - Remediation**: If any annual CP test station readings on Line 10, Line 15, or Line 25 pipelines within the ***special permit inspection areas*** fall below 49 CFR Part 192, Subpart I requirements, remediation must occur within six (6) months and include a CIS on each side of the affected test station to the next test station and any identified corrosion system modifications to ensure corrosion control. If factors beyond SET control prevent the completion of remediation including coating repairs within six (6) months, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the Director.

PHMSA Southern Region no later than the end of the six (6) months completion date.

18) **Interference Currents Control**: SET must address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) in the ***special permit inspection areas*** that may affect the pipeline. An induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents must be in place within one (1) year of the date of this special permit.

   a) At least once every seven (7) calendar years not exceeding 90 months, SET must perform an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate any AC interference between 20 and 50 Amps per meter squared. In evaluating such interference, SET must integrate AC interference data with the most recent ILI results to determine remediation measures. If SET does not remediate AC interference between 20 and 50 Amps per meter squared, SET must provide an engineering justification for not remediating such interference to the Director, PHMSA Southern Region, who may accept or reject the justification and require remediation.

   b) SET must take interference readings (continuous 24 hour recordings) during the calendar quarter of the known or anticipated highest voltage reading. If there are any changes to the amount of electricity/current flowing in any co-located high voltage alternating current (HVAC) power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, SET must perform an AC mitigation survey along the entire co-located pipeline ***special permit inspection areas*** right of way within six (6) months of any such change.

   c) Within three (3) months of the engineering analysis, SET must remediate any AC interference greater than 50 Amps per meter squared. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference that results in CP levels that do not meet the requirements of 49 CFR Part 192, Subpart I, must be remediated within three (3) months of this evaluation.

19) **Field Coating**: The coatings used on the pipeline and girth weld joints in the ***special permit***

segments must be non-shielding to CP. In the event that the coating type is unknown or is known to shield CP for girth weld joints then SET must take special care to:

a) Remove all shielding coatings such as shrink sleeves and replace them with a non-shielding coating in the ***special permit segment*** within six (6) months of receipt of this permit.

b) Analyze ILI logs in the areas of girth welds for potential corrosion indications.

c) Any ILI corrosion indications above 30% wall loss at girth welds where the coating type is unknown, the girth weld joints must be exposed and evaluated each time the ILI is run or until the unknown girth weld coating is replaced.

d) If any SCC[12] activity is found on girth welds or pipe in the ***special permit segment***, the pipe and girth welds in the ***special permit segment*** must be remediated in accordance with Condition 6 within six (6) months of finding the SCC.

20) **<u>Anomaly Evaluation and Repair</u>**:

a) **<u>General</u>**: SET must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. SET must demonstrate ILI Tool tolerance accuracy for each ILI Tool run by usage of calibration excavations and unity plots that demonstrate ILI Tool accuracy for depth within ±10% accuracy for 80% of the time. The unity plots must show: a) actual anomaly depth versus predicted depth and b) actual failure pressure/MAOP versus predicted failure pressure/MAOP. Discovery date must be within 60 days of an ILI Tool run for each type ILI Tool (HR-geometry, HR-deformation or high resolution HR-MFL).

i) ILI tool evaluations for metal loss must use "6t x 6t" interaction criteria (or more conservative criteria) for determining anomaly failure pressures and remediation response timing with *"6t" being pipe wall thickness times six.*

b) **<u>Dents</u>**: SET must repair dents to the Line 10, Line 15 and Line 25 pipelines in the ***special permit inspection areas*** in accordance with 49 CFR § 192.933 repair criteria. ***Special permit inspection areas*** must have a geometry or deformation tool inspection as part of the initial ILI, if no geometry or deformation tool has been completed it

[12] "SCC" activity shall be defined as over both a 10 percent wall thickness depth and 2-inches in length.

must be completed and all dent repairs made in accordance with 49 CFR § 192.933 repair criteria. The geometry tool can be from past ILI inspections. The timing for these dent repairs should follow SET's O&M Manual but must not be longer than one (1) year after discovery.

c) **Investigation and Repair Criteria**: Investigation , evaluation, and repair criteria applies to all anomalies located on the Line 10, Line 15 and Line 25 pipelines within the ***special permit segments*** and ***special permit inspection area*** when they have been excavated, investigated, and remediated in accordance with 49 CFR §§ 192.485 and 192.933 incorporating appropriate class location design factors in the anomaly repair criteria, including HCAs[13] as follows:

- ***Special permit segments***[14]- Repair any anomaly within a ***special permit segment*** that meets either: (1) a failure pressure ratio[15] (FPR) less than or equal to 1.39 for original Class 1 location pipe in a Class 3 location operating up to 72% of the specified minimum yield strength (SMYS); or (2) an anomaly depth greater than or equal to 40% of pipe wall thickness.
- ***Special permit inspection areas***[16]– Repair any anomaly within a ***special permit inspection area*** that meets either: (1) an FPR less than design factor – for Class 1 location – FPR equal to or less than 1.39; for Class 2 location – FPR equal to or less than 1.67; and for Class 3 location – FPR equal to or less than 2.0; or (2) an anomaly depth equal to or greater than 60% wall thickness loss.

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[13] HCAs in the ***special permit inspection area*** and ***special permit segment*** must have anomalies evaluated and repaired based upon the most stringent requirements of either: this special permit, 49 CFR Part 192, Subpart O, or SET's Texas Eastern Integrity Management Plan.

[14] Any ***special permit segment or area*** that operates above 72% SMYS to up 80% SMYS may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

[15] Failure pressure ratio (FPR) is based upon the class location where the ***special permit segment*** or ***special permit inspection area*** pipe is located in accordance with 49 CFR § 192.5 and is the reciprocal of the class location design factor in 49 CFR § 192.111(a).

[16] Any ***special permit segment or area*** operates above 72% SMYS to up 80% SMYS may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

- Repair anomalies in original Class 1 location pipe that are now in a Class 2 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets either: (1) is equal to or less than the Class 1 location FPR of 1.39; or (2) an anomaly depth equal to or greater than 50% wall thickness loss for anomaly repairs.
- Repair anomalies in original Class 2 location pipe that is now in a Class 3 location in accordance with § 192.611 that meets either: (1) is equal to or less than the Class 2 location FPR of 1.67; or (2) an anomaly depth equal to or greater than 50% wall thickness loss for anomaly repairs.

d) **Response Time for ILI Results**: The following section provides the required timing for excavation, investigation, and remediation of anomalies based on ILI data results in accordance with 49 CFR §§ 192.485 and 192.933, and must incorporate appropriate class location design factors in the anomaly repair criteria for ***special permit segments*** and ***special permit inspection areas*** including all HCAs. Reassessment by ILI will reset the timing for anomalies not already investigated and/or repaired. SET must evaluate ILI data by using either the ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines*" (ASME B31G), the modified B31G (0.85dL) or R-STRENG for calculating the predicted FPR to determine anomaly responses.

- *Special permit segments*:
  - Immediate response: Any anomaly within a ***special permit segment*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; or (2) an anomaly depth equal to or greater than 80% wall thickness loss.
  - One-year response[17]: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.39; or (2) an anomaly depth equal to or greater than 40% wall thickness loss.

[17] Any ***special permit segment or area*** **operates** above 72% SMYS to up 80% SMYS may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

- Monitored response[18]: Any anomaly within a ***special permit segment*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets both: (1) an FPR greater than 1.39; or (2) an anomaly depth less than 40% wall thickness loss. The schedule for the response must take tool tolerance and corrosion growth rates into account.

▪ ***Special permit inspection area:***

- Immediate response: Any anomaly within a ***special permit inspection area*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; (2) an anomaly depth equal to or greater than 80% wall thickness loss.
- One-year response[19]: Any anomaly within a ***special permit inspection area*** that meets either: (1) an FPR less than design factor – for Class 1 location- FPR equal to or less than 1.39; Class 2 location – FPR equal to or less than 1.67; and for Class 3 location – FPR equal to or less than 2.0; or (2) an anomaly depth equal to or greater than 60% wall thickness loss.

  Any anomaly for Class location changes from original Class 1 to 2 location or original Class 2 to 3 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets either: (1) an anomaly FPR equal to or less than the FPR of the original Class location; or (2) an anomaly depth equal to or greater than 50% wall thickness loss.
- Monitored response[20]: Any anomaly within a ***special permit inspection area*** that meets both: (1) an FPR less than design factor – for Class 1 location – FPR greater than 1.39; Class 2 location – FPR greater than 1.67; and for Class 3 location – FPR greater than 2.0; or (2) an anomaly depth less than 60% wall

[18] Any ***special permit segment or area*** operates above 72% SMYS to up 80% SMYS may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

[19] Any ***special permit segment or area*** operates above 72% SMYS to up 80% SMYS may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

[20] Any ***special permit segment or area*** operates above 72% SMYS to up 80% SMYS, may have the FPR modified between a FPR of 1.32 for 80% SMYS to a FPR of 1.39 for 72% SMYS. A pipeline ***special permit segment and area*** that operates at 1000 psig and 76.9% SMYS would have an interpolated FPR of 1.35 (rounded to next highest .01 number).

thickness loss.

Any anomaly repairs for Class location changes from original Class 1 to 2 location or original Class 2 to 3 location in accordance with 49 CFR §§ 192.5 and 192.611 that meets both: (1) an anomaly FPR greater than the FPR of the original Class location; or (2) an anomaly depth less than 50% wall thickness loss.

- The schedule for the response must take tool tolerance and corrosion growth rates into account.

e) ***Special permit segments*** and ***special permit inspection area:*** Upon modification of this special permit, SET must implement the repair and remediation of any pipe anomalies or dents that does not meet Condition 20 based upon existing ILI assessments results from the high resolution MFL and geometry/deformation tools used to previously assess the Line 10, Line 15 and Line 25 pipelines in the ***special permit segments*** and ***special permit inspection areas***. Remediation of anomalies and dents must be completed in accordance with Condition 20 timing requirements and completed within 12 months from modification of this special permit.

21) **Girth Welds**: SET must provide records to PHMSA to demonstrate the girth welds on the Line 10, Line 15 and Line 25 pipelines were nondestructively tested at the time of construction in accordance with:

a) The Federal pipeline safety regulations at the time the pipelines were constructed. If not, show that at least 10% of the girth welds in each ***special permit segment*** were non-destructively tested (NDT) after construction but prior to the application for this special permit provided at least two (2) girth welds in each ***special permit segment*** were excavated and NDT inspected.

b) If SET cannot provide girth weld records to PHMSA to demonstrate either of the above in Condition 21 (a), SET must accomplish either (i); or (ii) and (iii) of the following:

i) Certify to PHMSA in writing that there have been no in-service leaks or breaks in the girth welds on the Line 10, Line 15 and Line 25 pipelines within the entire ***special permit inspection areas*** for the entire life of the pipelines, or

ii) Evaluate the terrain along each ***special permit segment*** for threats to girth weld integrity from soil types, soil settlement, soil movement, terrain, or heavy loads across the pipeline; and

iii) Excavate[21], visually inspect and nondestructively test at least two (2) girth welds on the Line 10, Line 15 and Line 25 pipelines in each ***special permit segment*** in accordance with the American Petroleum Institute Standard 1104, "*Welding of Pipelines and Related Facilities*" (API 1104) as follows:

   A. Use the edition of API 1104 current at the time the pipelines were constructed; or

   B. Use the edition of API 1104 recognized in the Federal pipeline safety regulations at the time the pipelines were constructed; or

   C. Use the edition of API 1104 currently recognized in the Federal pipeline safety regulations.

c) If any girth weld in any of the ***special permit segments*** is found unacceptable in accordance with API 1104, SET must repair the girth weld immediately and then prepare an inspection and remediation plan for all remaining girth welds in the ***special permit segments*** based upon the repair findings and the threat to the ***special permit segments***. SET must submit the inspection and remediation plan for these remaining girth welds to the Director, PHMSA Southern Region and remediate girth welds in the ***special permit segments*** in accordance with the inspection and remediation plan within 60 days of finding girth welds that do not meet this Condition 21(c).

d) Additionally, all oxy-acetylene girth welds, mechanical couplings and wrinkle bends in any ***special permit segment*** must be removed.

e) SET must complete the girth weld testing, and the girth weld inspection and remediation plan, within six (6) months after the modification of this special permit. If factors beyond SET control prevent the completion of these tasks within six (6) months, the tasks must be completed as soon as practicable and a letter justifying the

[21] SET must evaluate for SCC any time the Line 10, Line 15 and Line 25 pipelines are uncovered in accordance with Condition 6 (b) of this special permit.

delay and providing the anticipated date of completion must be submitted to the Director, PHMSA Southern Region no later than six (6) months after the modification of this special permit.

22) **Casings**: SET must identify all shorted casings (metallic or electrolytic) within each ***special permit segment*** no later than six (6) months after the modification 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 Southern, Pearson, DCVG, ACVG or AC Attenuation.

a) **Metallic Shorts**: SET must clear any metallic short on a casing in the ***special permit segments*** no later than six (6) months after the short is identified.

b) **Electrolytic Shorts**: SET must remove the electrolyte from the casing/pipe annular space on any casing in the ***special permit segments*** that has an electrolytic short no later than six (6) months after the short is identified.

c) **All Shorted Casings**: SET 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 and may then choose to fill the casing/pipe annular space with a high dielectric casing filler or other material which provides a corrosion inhibiting environment provided an assessment and all repairs were completed.

If SET identifies any shorted casings within the ***special permit segments***, they must monitor[22] all casings within the ***special permit segments*** for shorts at least once each calendar quarter, but at intervals not to exceed 100 days, for four (4) consecutive calendar quarters after the modification of this special permit. The intent is to identify through monitoring the calendar quarter(s) when electrolytic casing shorts are most likely to be identified. Thereafter, SET must then monitor all casings for shorts within the ***special permit segments*** at least once each calendar year during the calendar quarter(s) when electrolytic

[22] Monitoring of casings in this situation means an acceptable test method in accordance with 49 CFR Part 192 to determine if the casing and carrier pipe have either a metallic or electrolytic short (connection or contact).

casing shorts are most likely to be identified. Any casing shorts found in the ***special permit segments*** at any time must be classified and cleared as explained above.

23) **Pipe Seam Evaluations**: SET must identify any pipe in the ***special permit inspection area*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacturing process of the pipe, or other issues. Once SET has identified such issues, SET must complete Condition 23 (a). If the engineering analysis required in Condition 23 (a) reveals that there is a threat to the pipeline, then SET must complete all of the applicable condition requirements in Condition 23 (b), (c), (d), (e), (f), and (g):

a) SET must perform an engineering analysis to determine if there are any pipe seam threats on the Line 10, Line 15 and Line 25 pipelines located in the ***special permit inspection area***. This analysis must include the documentation that the processes in '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-C0SP02120 and 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 were utilized along with other relevant materials. If the engineering analysis shows that the pipe seam issues on the Line 10, Line 15 and Line 25 pipelines pipeline located in the ***special permit inspection area*** are not a threat to the integrity of the pipeline, SET does not have to complete Conditions 23 (b) through 23 (e). Condition 23 (f) and (g) must be completed.

b) If a 49 CFR Part 192, Subpart J hydrostatic test has not been performed since 1971, the ***special permit segments*** must be hydrostatically tested to a minimum pressure of 100 percent SMYS, in accordance with 49 CFR Part 192, Subpart J requirements for eight (8) continuous hours, within one (1) year of issuance of this special permit. The hydrostatic test must confirm no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic issue. The results of this root cause analysis must be reported to the Director.

PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division, within 60 days of the failure; or

c) If the pipeline in the ***special permit inspection area*** has experienced a seam leak or failure in the last five (5) years and no hydrostatic test meeting the conditions of 49 CFR Part 192, Subpart J was performed after the seam leak or failure, then a hydrostatic test must be performed within one (1) year after the modification of this special permit on the ***special permit segment*** pipeline; or

d) If the pipeline in any ***special permit segment*** has seam conditions as noted below in (i), (ii), (iii), or (iv), such ***special permit segment*** pipeline shall not be eligible for this special permit:

    i) was constructed or manufactured prior to 1980 or has had any pipe seam leaks or ruptures in the ***special permit inspection area***, or

    ii) has unknown manufacturing processes, or

    iii) has low fracture toughness pipe that will not ensure ductile fracture and arrest, or

    iv) 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, have had past leak and rupture issues, or any other systemic issues].

e) If the pipeline in any ***special permit segment*** has a reduced longitudinal joint seam factor, below 1.0, as defined in 49 CFR § 192.113 the ***special permit segment*** pipeline must be replaced.

f) Pipe in the ***special permit segments*** must have 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 removed and replaced with pipe in accordance with 49 CFR Part 192 requirements.

g) SET must submit a seam remediation plan for the ***special permit segments*** to the Director, PHMSA Southern Region no later than 30 days after the finding a seam leak in the ***special permit segment***:

    i) Longitudinal weld seam remediation/repair plan that meets Condition 23 (a) and includes either replacement, hydrostatic testing, or in-line inspection

(ILI), and timing of the plan not to exceed six (6) months, or

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

24) ***Special Permit Segment*** **Specific Conditions**: SET must comply with the following requirements.

a) **Depth of Cover Survey**: SET must complete within six (6) months of the modification of this special permit a depth of cover survey of the ***special permit segments***. Any pipe in the ***special permit segments*** that does not meet 49 CFR § 192.327(a) must have additional safety measures implemented in areas with reduced depth of cover. SET must submit to the Director, PHMSA Southern Region for PHMSA approval remedial measures to implement based upon the threat, such as lowering the pipeline, increased pipeline patrols and/or additional line markers.

b) **Line-of-Sight Markers**: SET must install and maintain line-of-sight markings on the pipeline in the ***special permit segments*** and ***special permit inspection areas*** except in agricultural areas or large water crossings such as lakes where line-of-sight signage is not practical.

c) **Right-of-Way Patrols**: SET must perform ground or aerial right-of-way patrols, monthly not to exceed 45 days, in the ***special permit segments*** and ***special permit inspection areas***. Each calendar year not to exceed 15 months, one of these right-of-way patrols must be a ground patrol in the ***special permit segments*** and ***special permit inspection areas***. All patrols must document compliance with Condition 12 and Condition 24 (b).

d) **Data Integration**: SET must maintain data integration of special permit condition findings and remediation in the ***special permit segments*** and ***special permit inspection areas***. Data integration must include the following information: Pipe diameter, wall thickness, grade, and seam type; pipe coating including girth weld coating; maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography); high consequence areas (HCAs) (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; in-line inspection (ILI) survey results including HR-MFL, HR-geometry/caliper or deformation tools; close interval survey (CIS) surveys – all; depth of cover surveys; rectifier readings – past five (5) years; test point survey readings – past five (5) years; AC/DC interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC) excavations and findings; and pipe exposures from encroachments. Data integration must be outlined on pipeline route sheets (scale of 1-inch = 100 up to 500-feet on "D (24"x36") or E (36"x42")" size drawings or similar size drawings[23]), with parallel sections for each integrity category and recent aerial photography (recent photography, within 24 months of permit modification and every three (3) years thereafter). Data integration must be updated on a continuing basis and with at least a semi-annual review of integrity issues to be remediated.

e) **<u>Root Cause Analysis for Failure or Leak</u>**: SET must notify PHMSA's Southern Regional Director within five (5) days, if a leak or rupture (incident) occurs in any of the ***special permit inspection areas*** and ***special permit segments.*** A 'root cause analysis' must be performed to determine the cause of the failure and must be sent to PHMSA's Southern Regional Director and Director of Engineering and Research Division within 60-days of the incident. PHMSA will review the 'root cause analysis' report to determine if revocation, suspension, or modification of the special permit is warranted based upon incident findings.

f) **<u>Pipe Properties Records</u>**: SET must mechanically and hydrostatically test pipe in each ***special permit segment*** that does not meet Condition 25 (b) as follows***:***

i) Test a minimum of 10% of pipe lengths/joints, or at least two (2) pipe lengths/joints when percentage is less than two (2) pipe lengths/joints, must be tested in accordance with 49 CFR §§ 192.109 and 192.107 (b).

ii) ***Special permit segments*** pipe must meet the requirements of 49 CFR § 192.107 (b).

iii) ***Special permit segments*** pipe must be tested for mechanical and chemical properties (properties) as required in 49 CFR Part 192, Appendix B, Section

[23] SET must obtain written approval from Director, PHMSA Southern Region, if a different drawing size is used for 'data integration'.

III (B) and (C).

iv) Pipe that is tested for properties in accordance with Condition 24 (f) (i), (f) (ii) and (f) (iii), must meet the hydrostatic test requirements of 49 CFR Part 192, Appendix B, Section III (C)(2). Original Class 1 location pipe that is approved for Class 3 locations per this special permit must be tested to a minimum of 100% SMYS for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J.

v) The requirements in Condition 24 (f) must be completed within one (1) year of issuance of this special permit and must meet pipe properties requirements for the pipe designed class location factor in accordance with 49 CFR § § 192.103. 192.105, 192.107, 192.109, 192.111 and 192.113.

g) **Pipe Hard Spots:** If SET has pipe that is susceptible to hard spots based upon the manufacturing vintage[24] or has had a leak or failure due to a pipe hard spot in the ***special permit inspection area***, SET must perform in-line inspection (ILI), evaluation, and remediation in the ***special permit inspection area*** of the pipelines (Line 10, Line 15 and Line 25 pipelines) susceptible to hard spots as soon as practicable but not later than one (1) year after the grant of this special permit. The results of the hard spot ILI tool must be assessed using the following criteria:

i) Brinnel hardness equal to or greater than 300 HB: Check for cracks by excavation, nondestructive examination (NDE), repair by an acceptable repair technique, and recoat.

ii) Brinnel hardness equal to or greater than 300 HB with the presence of cracking: Check for cracks by NDE, repair with Type B sleeve or replace pipe, and re-coat.

iii) Brinnel hardness equal to or greater than 300 HB with mill or mechanical deformation: Check for cracks by NDE, repair by an acceptable repair technique or replace and recoat.

iv) Brinnel hardness equal to or greater than 300 HB: Establish a monitoring program with an inspection frequency in accordance with 49 CFR § 192.465(b)

[24] Pipe manufacturing vintage is defined as the manufacturers and decades shown on Table 5 – Hard spot incident summary, page 21 of the "Integrity Characteristics of Vintage Pipelines" prepared on October, 2004, by E. B. Clark and B. N. Leis of Battelle Memorial Institute and R. J. Eiber of R .J. Eiber Consultants Inc. for the INGAA Foundation, Inc. in conjunction with American Gas Foundation.

to maintain CP voltage levels below minus 1.2 volts DC on the ***special permit inspection area***.

v) Brinnel hardness equal to or greater than 400 HB: Repair with Type B sleeve or replace pipe and recoat.

vi) SET must amend applicable sections of its O&M manual(s) to incorporate the monitoring required to maintain CP voltage levels below minus 1.2 volts DC on the special permit inspection areas with any pipe areas with a Brinnel Hardness equal to or greater than 300 HB.

vii) SET must inspect, evaluate, remediate, recoat and monitor the ***special permit inspection area*** for hard spots. SET must submit a hard spot remediation plan for the ***special permit inspection area*** to the Director, PHMSA Southern Region with a copy to the Director, PHMSA Engineering and Research Division no later than 30 days prior to the inspection, evaluation or remediation:

A) Hard spot ILI inspection, evaluation, remediation, recoating, and monitoring plans and procedures that meets Condition 24 (g) – Pipe Hard Spots, or

B) Technical justification that shows that the ***special permit segment*** and ***special permit inspection area*** are not at risk for future hard spot leaks or failures.

h) **Pipeline System Flow Reversals** – This special permit is not applicable for any pipeline system flow reversals that would exceed 49 CFR § 192.611 approved MAOPs. SET must re-apply for a new special permit 180-days prior to any pipeline system long term flow reversals for a ***special permit segment*** or ***special permit inspection area*** that would exceed 49 CFR § 192.611 allowed MAOPs.

25) **Documentation**: SET must maintain the following records for each ***special permit segment***:

a) Documentation showing that each ***special permit segment*** has received a 49 CFR § 192.505, Subpart J, hydrostatic test for eight (8) continuous hours and at a minimum pressure of 1.25 times MAOP (1.25 x MAOP). If SET does not have hydrostatic test documentation, then the ***special permit segment*** must be hydrostatically tested to meet this requirement within one (1) year of the modification of this special permit.

b) Documentation of mechanical and chemical properties including pipe toughness (mill test reports) showing that the pipe in each ***special permit segments*** meets the wall thickness, yield strength, tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, "*Specification for Line Pipe*" (API 5L) referenced in the 49 CFR Part 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR § 192 then the pipe meets the API 5L standard in usage at that time. Any ***special permit segment*** that SET does not have mill test reports for the pipe cannot be authorized per this special permit.

c) Documentation of compliance with all the conditions of this special permit must be kept for the applicable life of this special permit for the referenced ***special permit segments*** and ***special permit inspection areas.***

26) **<u>Extension of Special Permit Segments</u>**: PHMSA may extend the original ***special permit segments*** to include contiguous segments of the Line 10, Line 15 and Line 25 pipelines up to the limits of the ***special permit inspection areas*** pursuant to the following conditions. SET must:

a) Provide notice to the Director, PHMSA Southern Region: Director, PHMSA Standards and Rulemaking Division: and Director, PHMSA Engineering and Research Division of a requested ***special permit segment or extension***[25] of the Line 10, Line 15 and Line 25 pipelines based on actual class location change and include a schedule of inspections, of any anticipated remedial actions and the location of the new request including survey stationing. All requests for a ***special permit segment or extension*** must be submitted in the first nine (9) months of the 49 CFR § 192.611(d) timing limits, and must include data integration (see Condition 24 (d)) and information on the potential environmental impacts of the extension.

b) Complete all inspections and remediation of the proposed ***special permit segments*** extension to the extent required of the original the Line 10, Line 15 and Line 25

[25] For a new ***special permit segment or extension*** to be considered by PHMSA, SET must notify PHMSA's Southern Region Director to determine the need for a draft environmental assessment.

pipelines ***special permit segments***.

c) Comply with all the special permit conditions and limitations included herein to all future ***special permit segments or extensions***.

d) Comply with all conditions of this special permit for the contiguous new ***special permit segments*** required for implementation and certification in accordance with 49 CFR § 192.611(d) timing limits, including submittal of documents to PHMSA required in Condition 27.

27) **Certification**: A senior executive officer, vice president or higher, of SET must certify in writing the following:

a) SET pipeline ***special permit inspection areas*** and ***special permit segments*** meet the conditions described in this special permit,

b) The written manual of O&M procedures for the SET pipeline has been updated to include all additional requirements of this special permit: and

c) SET has implemented all conditions as required by this special permit.

SET must send the certifications required in Condition 27 (a) through (c) with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking Division: and Director, PHMSA Engineering and Research Division within one (1) year of the modification date of this special permit.

Limitations:

PHMSA modifies this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether SET has complied with the specified conditions of this special permit.

2) Failure to submit the certifications required by Condition 27 within the time frames specified may result in revocation of this special permit.

3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require SET to comply with the regulatory requirements in 49 CFR

§ 192.611. As provided in 49 U.S.C. § 60122, PHMSA may also issue an enforcement action for failure to comply with this Order.

4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify SET in writing of the proposed action and provide SET an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective.

5) 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 in accordance with 49 CFR § 190.341(h)(4).

6) If SET sells, merges, transfers, or otherwise disposes of the assets known as the ***special permit segments*** or the ***special permit segment extension***, SET must provide PHMSA with written notice of the transfer within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

7) PHMSA modifies this special permit to limit it to a term of no more than five (5) years from the modification date. If SET elects to seek renewal of this special permit, as modified, SET must submit its renewal request at least 180 days prior to expiration of the five (5) year period to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Field Operations; Director, PHMSA Southern Region; Director, PHMSA Standards and Rulemaking; and Director, PHMSA Engineering and Research Division. PHMSA will consider requests for a special permit renewal for up to an additional five (5) year period. All requests for a special permit renewal must include a summary report in accordance with the requirements in Condition 15 above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from SET prior to granting any request for special permit renewal.