U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

SEP 23 2009

Mr. Jeryl L. Mohn
Senior Vice President, Operations and Engineering
Florida Gas Transmission
5444 Westheimer Road
Houston, TX 77056-5306

Docket No. PHMSA-2008-0077

Dear Mr. Mohn:

On March 31, 2008, you wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) on behalf of Florida Gas Transmission (FGT), a subsidiary of Panhandle Energy, requesting a special permit to waive compliance from certain PHMSA pipeline safety regulations to operate existing facilities from Mobile County, Alabama, eastward to Suwannee County, Florida, then south to Lee County, Florida at a pressure up to and commensurate with 80% of the Specified Minimum Yield Strength (SMYS) of the pipeline.

PHMSA is granting the special permit (enclosed) to FGT. The waived sections in the Pipeline Safety Regulations are 49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(c)(2), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), and 192.620(d)(11). The special permit has conditions and limitations and provides some relief from the Federal pipeline safety regulations for Florida Gas Transmission, while ensuring that pipeline safety is not compromised.

My staff would be pleased to discuss this special permit or any other regulatory matter with you. Please call John Gale, Director of Regulations at 202-366-0434, for regulatory matters or Alan Mayberry, Director of Engineering and Emergency Support at 202-366-5124, for technical matters specific to this special permit.

Sincerely,

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Enclosure: Special Permit

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

Special Permit

Docket Number:	PHMSA-2008-0077
Requested By:	Florida Gas Transmission Company
Date Requested:	March 31, 2008
Code Sections:	49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), 192.620(d)(11), and 192.620(c)(2)

Grant of Special Permit:

By this order, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to the Florida Gas Transmission Company (FGT) subject to the conditions and limitations set forth below, waiving compliance from 49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), 192.620(d)(11), and 192.620(c)(2) for the 741.2 miles interstate natural gas transmission pipeline operated by FGT. The FGT pipeline system subject to this special permit was constructed from 1992 to 2007. It originates in Mobile County, Alabama, crosses through Baldwin and Escambia Counties in Alabama, and then crosses into the State of Florida through the Counties of Santa Rosa, Okaloosa, Walton, Washington, Jackson, Bay, Calhoun, Liberty, Gadsden, Leon, Jefferson, Taylor Lafayette, Suwannee, Gilchrist, Levy, Citrus, Hernando, Pasco, Hillsborough, Polk, Hardee, De Soto, Charlotte, and ends in Lee County, Florida.

The pipeline ***special permit segment(s)*** are comprised of 16", 18", 20", 26", 30", and 36-inch diameter pipelines with an existing maximum allowable operating pressure (MAOP) of 1200 pounds per square inch gauge (psig) at 72% specified minimum yield strength (SMYS). The alternative MAOP of the FGT pipeline ***special permit segments*** at 80% SMYS would be 1333 psig.

This special permit allows FGT to raise the existing maximum allowable operating pressure (MAOP) of the FGT pipeline facility (pipeline, compressor station and meter/regulating station) ***special permit segments*** from 1200 psig to an alternative MAOP of 1333 psig.

The Federal pipeline safety regulations in § 192.111 limit the design factors[1] for steel natural gas transmission pipelines for Class locations 1, 2 and 3 to the values in the following table:

	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor
General	1	0.72	2	0.60	3	0.50
Un-cased road crossings	1	0.60	2	0.50	3	0.50
Fabricated Assembly	1	0.60	2	0.60	3	0.50
Supported on Bridge	1	0.60	2	0.60	3	0.50
Stations	1	0.50	2	0.50	3	0.50

Accordingly, this special permit allows FGT to operate the existing FGT pipeline ***special permit segments*** in Class locations[2] 1, 2 and 3 using the § 192.620(a) design factors in the following table:

	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor
General	1	0.80	2	0.67	3	0.56
Un-cased road crossings	1	0.67	2	0.56	3	0.56
Fabricated Assembly	1	0.67	2	0.67	3	0.56
Supported on Bridge	1	0.67	2	0.67	3	0.56
Stations	1	0.56	2	0.56	3	0.56

[1] Design factors limit the hoop stress in a pipeline due to the operating pressure to a percentage of the specified minimum yield strength (SMYS) of the pipe. For example, a design factor of 0.72 would limit the pipeline pressure to a value that results in a hoop stress level of 72% SMYS.

[2] The FGT pipeline ***special permit segments*** do not have Class 4 locations. This special permit does not apply to any future Class 4 locations on the FGT system.

Special Permit Segments:

For the purpose of this special permit, the FGT ***special permit segments*** are the pipeline areas consisting of the entire pipeline right-of-way for those pipeline sections along the applicable segment of the FGT pipeline that will operate above 72% SMYS in Class 1 locations, above 60% SMYS in Class 2 locations, above 50% SMYS in Class 3 locations, compressor stations and meter/regulating stations.

The ***special permit segments*** along the FGT pipeline facilities, including 8 compressor stations and 17 meter/regulating stations are listed below:

Pipeline – *Special Permit Segments*

Pipeline – *Special Permit Segments* - Description	Pipe Diameter (in)	Milepost Start	Milepost End	Length (Miles)
Mainline, Sta. 11A to Florida State Line	36	190.8	238.6	47.8
Mainline Loop, Beginning at Sta. 11A	36	190.8	202.0	11.2
Mainline Loop, Beginning at Sta. 11A	36	190.8	202.0	11.2
Mainline Loop Extension	36	202.0	205.1	3.1
Mainline, Florida State Line M.P. 245.6	36	238.6	245.6	7.0
Mainline, M.P. 245.6 to Sta. 12A	36	245.6	260.2	14.6
Mainline, Sta. 12A to Sta. 13A	36	260.2	324.5	64.3
Mainline, Sta. 13A to M.P. 355.2	36	324.5	355.2	30.7
Mainline, M.P. 355.2 to Sta. 14A	36	355.2	394.7	39.5
Mainline, Sta. 14A to M.P. 468.7A	36	394.7	438.7A	43.7
Mainline, M.P. 468.7A to Sta. 15A	36	438.7A	468.7	34.9
Mainline, Sta. 15A to West Leg Junction	36	468.7	515.3	46.6
West Leg, Mainline Junction to Sta. 24	30	0.0	25.4	25.4
West Leg Loop	36	17.8	25.4	7.6
West Leg Loop	36	12.8	17.8	5.0
West Leg, Sta. 24 to Sta. 26	30	25.4	90.6	65.2
West Leg Loop, Beginning at Sta. 24	36	25.4	38.5	13.1
West Leg Loop Extension	36	38.5	44.5	6.0
West Leg, Sta. 26 to Sta. 27	30	90.6	160.2	69.6
Bayside Lateral	26	0.0	13.8	13.8

Pipeline – *Special Permit Segments* - Description	Pipe Diameter (in)	Milepost Start	Milepost End	Length (Miles)
West Leg Loop, Beginning at Sta. 26	36	90.6	104.8	14.2
West Leg Loop Extension	36	104.8	110.9	6.5
West Leg, Sta. 27 to S.P./Sarasota Connector	30	160.2	165.0	4.8
West Leg, S.P./Sarasota Connector to Arcadia	30	165.0	240.8	75.8
Fort Myers Lateral	26	0.0	36.1	36.1
St. Pete/Sarasota Connector	18	0.0	36.9	36.9
Agricola Lateral	20	0.0	6.4	6.4
Agricola Lateral Extension	20	6.4	7.2	0.8
Sarasota Loop	16	0.0	10.6	10.6

Compressor Station # - *Special Permit Segments*

Compressor Station # - *Special Permit Segments*	Station Name	Location (MP)	State
Station 11	Mount Vernon	190.8	Alabama
Station 12	Munson	260.2	Florida
Station 13	Caryville	324.5	Florida
Station 14	Quincy	394.7	Florida
Station 15	Perry	468.7	Florida
Station 24	Trenton	West Leg 25.4	Florida
Station 26	Lecanto	West Leg 90.6	Florida
Station 27	Thonotosassa	West Leg 160.2	Florida

Measurement/Regulator Stations – *Special Permit Segments*

Special Permit Segments Description	Meter #	Station Type	Milepost	State
Alabama Electric	94450	Measurement & Regulator	238.6	Alabama
Tallahassee Hopkins #3	37055	Measurement & Regulator	415.5A	Florida
Shady Hills	88512	Measurement & Regulator	125.4	Florida
PGS Hudson	87140	Measurement & Regulator	126.3	Florida

Special Permit Segments Description	Meter #	Station Type	Milepost	State
Progress Energy Anclote	37697	Measurement & Regulator	128.6	Florida
Progress Energy Hines	59791	Measurement & Regulator	7.2 on Hines Lateral	Florida
North Star Vandolah	88513	Measurement & Regulator	213.5	Florida
DeSoto County Generating	88514	Measurement & Regulator	239.1	Florida
Panama City Lateral	n/a	Regulator	350.7	Florida
Purdom Lateral	n/a	Regulator	428.6A	Florida
Inglis Lateral	n/a	Regulator	62.8 on West Leg	Florida
Tampa East	n/a	Regulator	156.6 on West leg	Florida
Thonotosassa	n/a	Regulator	0.0 on St. Pete Connector	Florida
Manatee	n/a	Regulator	55.3 on St. Pete Connector	Florida
Brewster	n/a	Regulator	10.6 on Sarasota Loop	Florida
Bradley Jct.	n/a	Regulator	193.6 on West Leg	Florida
Ft. Myers	n/a	Regulator	36.1 Ft. Myers Lateral	Florida

After issuance of this special permit, all new pipe installed (example, relocated pipe, new pipe installed for class location changes), and all Operations and Maintenance (O&M) on the FGT pipeline ***special permit segments,*** must meet all sections of 49 CFR § 192 unless waived per the conditions of this special permit.

PHMSA grants this special permit based on the findings set forth in the *"Special Permit Analysis and Findings"* document, which can be read in its entirety in Docket No. PHMSA-2008-0077 in the Federal Docket Management System (FDMS) located on the Internet at www.Regulations.gov.

Conditions:

The grant of this special permit is subject to the following conditions:

1) **Design, Construction and Operations per 49 CFR 192**:

After issuance of this special permit, all new pipe installed (example, relocated pipe, new pipe installed for class location changes), and all Operations and Maintenance (O&M) on the FGT pipeline ***special permit segments,*** must meet all sections of 49 CFR § 192. All existing pipeline ***special permit segments*** must meet 49 CFR § 192 with the exception 49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), 192.620(d)(11), and 192.620(c)(2) which are waived on the existing pipe in the ***special permit segments*** when **Conditions 2 through 13** below have been implemented prior to operating at the alternative MAOP.

2) **Design Factor – Existing Pipelines:** Existing pipe installed in ***special permit segments*** in Class 1 locations may use a design factor of 0.80, in Class 2 locations may use a design factor of 0.67 and in Class 3 locations may use a design factor of 0.56.
   a) Existing road and railroad crossing pipe in Class 1, 2, and 3 locations may use a design factor of 0.67, 0.56, and 0.56, respectively. Existing compressor stations and meter/regulator stations may use a design factor of 0.56. Existing fabricated assemblies in Class 1, 2, and 3 locations may use a design factor of 0.67, 0.67, and 0.56, respectively.
   b) New road crossings, railroad crossings, fabricated assemblies, meter stations and compressor stations must be designed using the existing design factors in §§ 192.111(b), (c) and (d).
3) **Depth of Cover**: Existing FGT pipeline ***special permit segments*** must have depth of cover surveys conducted and remediation measures completed prior to operating at the alternative MAOP to ensure that pipeline cover meets the requirements of § 192.328(c). Remediation measures must be submitted to the Director, PHMSA Southern Region fourteen (14) days prior to implementation.
4) **Field Coating:** The coatings used on the existing pipeline in ***special permit segments*** and girth weld joints in the ***special permit segments*** must be non-shielding to cathodic protection (CP). In the event that the coating type is unknown or is known to shield CP for girth weld joints, FGT must take special care to conduct evaluations per **Condition 4 a), b), c), and d) below:**
   a) Prior to increasing operating pressures to the alternative MAOP in accordance with the conditions of this special permit, a minimum of 25% of the girth welds with a coating type that shields CP must be excavated and evaluated for external corrosion and stress corrosion cracking (SCC). These girth weld coatings must then be replaced with a non-

shielding coating, based upon proximity to compressor stations with higher operating temperatures and pressures and upon the likelihood that these areas are the most prone to external corrosion and/or SCC. These results must be analyzed to determine if additional girth welds should be examined for external corrosion and SCC. The findings and recommendations must be reviewed with PHMSA Director, Southern Region. If any of the excavated girth welds exhibit external corrosion in excess of 20% of wall loss and/or any SCC cracking, an additional 25% of the girth welds (with CP shielding coatings) must be excavated and evaluated. If any of the additional excavated girth welds exhibit external corrosion in excess of 20% of wall loss and/or any SCC cracking, all of the girth welds with shielding material must be replaced.

b) ILI logs in the areas of girth welds must be analyzed for potential corrosion indications.

c) For any ILI corrosion indications above 20% wall loss at girth welds where the coating type is unknown, or is known to shield CP, the girth weld joints must be exposed and evaluated. This must be repeated each time the ILI is run or until the girth weld coating is replaced.

d) A minimum of two girth weld joints at locations most likely to have shielding and corrosion shall be exposed and evaluated each time ILI is run. If any corrosion of greater than 20% wall loss is found on future ILI evaluations, all girth weld pipe joints with these coatings must be exposed and evaluated until no corrosion is found.

5) **Cased Crossings:** FGT must identify all shorted casings within the ***special permit segments*** and classify any shorted casings (a.k.a. coupled casing) 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, DCVG, ACVG, or AC Attenuation.

a) Metallic Shorts: FGT must clear any metallic short on a casing in the ***special permit segments*** after the short is identified and prior to operating at the alternative MAOP.

b) Electrolytic Shorts: FGT must remove the electrolyte from the casing/pipe annular space on any casing in the ***special permit segments*** that has an electrolytic short after the short is identified and prior to operating at the alternative MAOP.

c) All Shorted Casings: FGT must install external corrosion control test leads on both the carrier pipe and the casing in accordance with § 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 associated repairs were completed.

If FGT identifies any shorted casings within the ***special permit segments***, they must monitor 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 consecutive calendar quarters after the grant 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. FGT 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 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.

6) **Temperature Control**: The compressor station discharge temperature must be limited to 120° Fahrenheit. A temperature above this maximum temperature of 120° Fahrenheit may be approved up to 150° Fahrenheit if FGT's technical coating long-term operating tests show that the pipe coating will properly withstand the higher operating temperature for long-term operations. If the temperature exceeds 120° Fahrenheit, FGT must also institute a coating monitoring program in these areas, using ongoing Direct Current Voltage Gradient (DCVG) surveys or Alternating Current Voltage Gradient (ACVG) surveys, or other testing to demonstrate the integrity of the coating. This program and results must be provided to the PHMSA Director, Southern Region at least 60 days prior to implementation of the increased temperature or special permit operations.

a) FGT must monitor coating performance in areas where operating temperatures have exceeded or will exceed 120° F to provide additional data on the long-term durability and integrity of FBE coatings at these temperatures. CP current requirements and coating surveys with DCVG (soil cover) and ACVG (pavement cover) will indicate if there is deterioration in the coating at the higher temperatures.

b) DCVG and ACVG coating evaluation survey results will be addressed as follows:

i) The threshold survey indication values are 15% IR for DCVG and 35 dBμV for ACVG. These values represent the mid range of the "Minor" category in the severity classification used to characterize survey indications in an ECDA program.

c) FGT will excavate and remediate all indications found above the threshold values of 15% IR for DCVG and 35 dBμV for ACVG – Minor, Moderate and Severe categories.

d) FGT will conduct a calibration dig on at least two anomalies of each classification that are classified as minor, moderate and severe to ensure findings that are not in the remediation plan are not detrimental to the pipeline.

e) Holiday voltage tests (jeep) and coating adhesion tests will be performed at excavations.

f) Disbonded or blistered coating (with cracking and other damage that will compromise cathodic protection) found during excavations will be removed, and new coating applied.

g) Schedule – baseline, one year, three years, and in concert with ILI and CIS survey, both initial and second ILI Tool runs.

h) Surface temperatures of the pipe will be monitored during winter and summer operating conditions at '0' miles and at a downstream mileage to assure that the surface temperatures do not exceed 120° F. If it is determined that the temperature at this point exceeds 120° F, the survey distance will be increased to the point where the temperature is below 120° F.

i) FGT will submit to PHMSA Director, Southern Region a summary report of coating evaluation surveys and excavation/remediation results.

j) Repairs to fusion bond epoxy coatings must be with a compatible coating system that will bond together, be resistant to soil stresses, and not shield cathodic protection.

7) **Uprating Existing Pipeline Segments:** FGT must meet one or more of the following Conditions 7 a), 7 b), or 7 c), prior to uprating any existing pipeline ***special permit segment*** to an alternative MAOP above 72% SMYS in Class 1 locations, above 60% SMYS in Class 2 locations, or above 50% SMYS in Class 3 locations. FGT may elect to use a combination of Conditions 7 a), 7 b), or 7 c) as long as the entire ***special permit segment*** is operated in accordance with one or more of the below options of Condition 7. The O&M plan to meet Condition 7 for each ***special permit segment*** must be reviewed with PHMSA Director, Southern Region, prior to uprating to the alternative MAOP:

a) Class 1, 2, and 3 locations in the ***special permit segment*** must have been hydrostatically tested prior to the grant of this special permit, as follows:

   i) Class 1 and Class 2 locations containing a high consequence area (HCA) per 49 CFR Part 192, Subpart O - the pipeline segment must be hydrostatically pressure tested to at least 1.25 X alternative MAOP.

   ii) All existing pipeline ***special permit segments*** in Class 1 and 2 locations, not containing a HCA, must be hydrostatically tested to meet the requirements of § 192.620(a)(2)(ii) if previous hydrostatic testing was performed to less than 1.20 times the alternative MAOP. The alternative test factor for existing Class 3 locations, prior to issuance of this special permit, is a minimum of 1.40 times the alternative MAOP. When hydrostatic testing of Class 1 and 2 locations is required in accordance with Condition 7, the test must be to a minimum of 1.25 times the alternative MAOP, in accordance with § 192.620(a)(2)(ii).

   iii) All pipeline ***special permit segments*** that have a change in class location from a Class 1 to Class 2 location, must meet the operating hoop stress of § 192.611(a)(3) for the alternative MAOP. The alternative test factor for pipeline ***special permit segments*** that have a change in class location from a Class 2 to Class 3 location, prior to issuance of this special permit, is a minimum of 1.40 times the alternative MAOP.

   iv) The following table summarizes the minimum test factors that must be used, multiplied by the alternative MAOP, when hydrostatic testing per Condition 7 a) of this special permit:

Summary of Minimum Hydrostatic Test Factors for Alternative MAOP			
HCA		**non-HCA**	
Class 1 prior	1.25	Class 1 prior	1.20
Class 1 forward	1.25	Class 1 forward	1.25
Class 2 prior	1.25	Class 2 prior	1.20
Class 2 forward	1.50[1]	Class 2 forward	1.50[1]
Class 1->2 prior	1.25	Class 1->2 prior	1.25
Class 1->2 forward	1.25	Class 1->2 forward	1.25
Class 3 prior	1.40	Class 3 prior	1.40
Class 3 forward	1.50	Class 3 forward	1.50
Class 2->3 prior	1.40	Class 2->3 prior	1.40
Class 2->3 forward	1.50	Class 2->3 forward	1.50

"Prior" is the requirement before the grant of this special permit.
"Forward" is the requirement after the grant of this special permit.

[1]For Class 2 forward, alternative maximum allowable operating pressure segments installed prior to November 17, 2008, the alternative test factor is 1.25.

b) Overpressure Protection: Class 1, Class 2 and Class 3 locations - in lieu of hydrostatically pressure testing a ***special permit segment*** in accordance with Condition 7 a) above, FGT may operate the ***special permit segment*** taking into account the pressure gradient provided FGT installs control devices (regulator and monitor station, including SCADA control) to protect against accidental overpressure in accordance with the existing requirements in §§192.195, 192.199, 192.201, and 192.620(e). All ***special permit segments*** that have a change in class location from a Class 1 to Class 2 location or Class 2 to Class 3 location must meet the operating hoop stress of § 192.611(a)(3) for the alternative MAOP.

c) Pressure Gradient Monitoring: Class 1, Class 2 and Class 3 locations - in lieu of hydrostatically pressure testing a pipeline segment in accordance with Condition 7 a) and providing overpressure protection equipment in accordance with Condition 7 b) above, FGT may operate the pipeline segment taking into account the pipeline pressure gradient provided they provide overpressure protection equipment and use operating procedures designed to prevent accidental overpressure of the pipeline in accordance with the following requirements:

i) The written operating procedures must include pressure gradient monitoring along the pipeline at mainline valves as operating conditions change with updated gas flow models,

ii) Two operational pressure sensors must be installed at each mainline valve upstream and downstream (total of four each – two on each side of the mainline valve) of pipeline ***special permit segments*** that do not meet the criteria of Conditions 7 a) and 7 b) above, and must be tied into the SCADA system and set-up to limit and control compressor discharge pressures based upon the gas flow gradient model (including steady state flow conditions, upset conditions, and line-pack conditions) and pressure of the gas along the pipeline so as not to exceed the limits of Conditions 7 a) and 7 b),

iii) The SCADA system must document the maximum and minimum pressures, the entire range of flow conditions and pressures, of the pressure sensors for each mainline valve in Condition 7(b) above, and the pressure data must be kept for the applicable life of the special permit.

iv) A review and training of written operating procedures and gas gradient flow models must be conducted with gas controllers and compressor station personnel responsible for these operating procedures at least once each calendar quarter and documented,

v) Pressure sensors must be calibrated once each calendar year at intervals not to exceed 15 months,

vi) FGT must limit operations to 72% SMYS in Class 1 locations within 12 hours of the loss of SCADA or both pressure sensors at any mainline valve in a ***special permit segment***, and

vii) All ***special permit segments*** that have a change in class location from a Class 1 to Class 2 location or Class 2 to Class 3 location must meet the operating hoop stress of § 192.611(a)(3) for the alternative MAOP.

8) **Interference Currents Control:** Control of induced AC from parallel electric transmission lines and other interference issues in the ***special permit segments***, that may affect the pipeline must be incorporated into the operations of the pipeline and must be addressed. An induced AC program to protect the pipeline ***special permit segments*** from corrosion caused by stray currents must be in place prior to operating at the alternative MAOP.

9) **Initial Close Interval Survey (CIS):** FGT must have performed a CIS on the pipeline in the ***special permit segments*** within the two years immediately prior to the increase in operating pressure above the existing MAOP to the alternative MAOP, or a CIS must be completed prior to operating at the alternative MAOP. The CIS results must be integrated with the In-Line Inspection (ILI) Tool results to determine whether any further action is needed.

10) **Coating Assessment:** To verify the pipeline coating conditions and to remediate any integrity issues, FGT must perform a DCVG survey or an ACVG survey of all piping in the ***special permit segments,*** not later than one year after the grant of this special permit, and prior to operating at the alternative MAOP. A DCVG or ACVG survey and remediation need not be performed if FGT has performed a DCVG or ACVG and remediation survey of the above and completed the remediation of any integrity issue within the two years prior to the grant of this special permit. FGT must remediate any damaged coating indications found during these assessments that are classified as minor (i.e., 15% IR and above for DCVG or 35 dBμV and above for ACVG) moderate or severe, based on NACE International Recommended Practice 0502-2002, Pipeline External Corrosion Direct Assessment Methodology, (NACE RP 0502-2002). A minimum of two coating survey assessment classifications must be excavated, classified, and/or remediated per each survey crew and compressor station discharge section. If factors beyond FGT's control prevent the completion of the DCVG or ACVG survey and remediation within one year, 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 PHMSA Director, Southern Region, not later than one year after the grant of this special permit.

11) **Initial In-Line Inspection**: FGT must have performed an initial In-Line Inspection (ILI) of the pipeline in the ***special permit segments*** within the two years immediately prior to operating at the alternative MAOP using a high-resolution magnetic flux leakage (MFL) tool and a deformation and/or geometry tool(s) (with sensing multi-finger calipers which contact the pipe internally, with a tolerance of +/- 1% accuracy for deformation tools, to find expanded pipe and dents). The results of the initial ILI must be integrated with the initial CIS and DCVG/ACVG surveys required in accordance with § 192.620(d) and **Conditions 9 and 10** of this special permit. FGT must evaluate and repair all "Repair Immediately" and "Repair within One Year" anomalies in accordance with **Condition 12 below** prior to increasing the pressure above the existing MAOP to the alternative MAOP.
   a) The results of all deformation and geometry tool run results for expanded pipe and dents must be analyzed and submitted to the PHMSA Director, Southern Region. All pipes exhibiting an indicated diameter greater than 0.75% above the nominal pipe diameter must be noted on the report of potential deformations.
   b) FGT must review with PHMSA Director, Southern Region, the deformation and/or geometry tool reports. Indications of diameter greater than 0.75% above the nominal pipe diameter will be analyzed by FGT. This analysis will consider pipe properties and property distributions, hydrostatic test pressures and reported test behavior, and pipe end to center variations. Based on local pressure and expected behavior, any pipe expansion exceeding 1.00% shall be investigated by excavation to determine actual expansion and, if necessary, to verify pipeline ***special permit segments*** yield and ultimate tensile strengths, elongation, chemistry, hardness and charpy impact toughness. This requirement may be modified by PHMSA if initial verification reviews by PHMSA Director, Southern Region shows negligible integrity risk.

12) **Anomaly Evaluation and Repair:** All anomaly evaluations and repairs in the ***special permit segments*** for the life of this special permit, regardless of HCA status, must be performed,

based upon the following:

a) Anomaly Response Time: **Repair Immediately**

- Any anomaly within a ***special permit segment*** operating up to 80% SMYS with either: (1) a failure pressure ratio (FPR) equal to or less than 1.1; (2) an anomaly depth equal to or greater than 60% wall thickness loss.
- Any anomaly within a ***special permit segment*** operating up to 67% SMYS with either: (1) an FPR equal to or less than 1.25; (2) an anomaly depth equal to or greater than 60% wall thickness loss.
- Any anomaly within a ***special permit segment*** operating up to 56% SMYS with either: (1) an FPR equal to or less than 1.4; (2) an anomaly depth equal to or greater than 60% wall thickness loss.

b) Anomaly Response Time: **Repair Within One Year**

- Any anomaly within a ***special permit segment*** operating at up to 80% SMYS with either: (1) an FPR equal to or less than 1.25; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** operating at up to 67% SMYS with either: (1) an FPR equal to or less than 1.5; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a ***special permit segment*** operating at up 56% SMYS with either: (1) an FPR equal to or less than 1.8; (2) an anomaly depth equal to or greater than 40% wall thickness loss.

c) Anomaly Response Time: **Monitored Conditions**

- Anomalies not requiring immediate or one year repairs **in accordance with Condition 12 a) and b) above** must be reassessed according to 49 CFR Part 192, Subpart O reassessment intervals.
- Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per FGT's Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

d) Anomaly Assessment Methods

- FGT must confirm the remaining strength (R-STRENG) effective area method, R-STRENG - 0.85dL, and ASME B31G assessment methods are valid for the pipe diameter, wall, thickness, grade, operating pressure, operating stress level, and operating temperature. FGT must use the most conservative method until confirmation of the proper method is made to PHMSA Headquarters and the PHMSA Director, Southern Region.

- Dents in the pipe in the ***special permit segments*** must be evaluated and repaired in accordance with § 192.309(b) for the baseline ILI tool run and in accordance with § 192.933(d) for future ILI.

13) **Construction Tasks:** If the performance of a construction task associated with implementing the alternative MAOP, including the performance of construction tasks required by conditions in this MAOP special permit, can affect the integrity of the pipeline segment, FGT must treat that task as a "covered task", notwithstanding the definition in § 192.801(b), and implement the requirements of Subpart N as appropriate. FGT must have qualification records available for each individual performing covered construction tasks during and after the construction of the pipeline, whether company or contract employee.

a) A construction quality assurance plan, to ensure quality standards and controls of the pipeline, must be followed throughout the construction phase with respect to the following: surveying, locating foreign lines, one call notifications, grading, pipe hauling and stringing, ditching, rock blasting, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, hydrostatic testing, dewatering, alternating current (AC) interference mitigation, cathodic protection (CP) system surveys and installation, directional drills, anomaly evaluations and repairs, right of way clean up, and quality assurance monitoring.

b) A Construction Operator Qualification (COQ) Plan, in accordance with § 192.801(b), must be followed throughout the construction process for the qualification of individuals performing tasks on an alternative MAOP special permit pipeline. This includes:

   i) Tasks performed on an alternative MAOP pipeline facility construction project,

ii) Tasks performed to meet the conditions of this special permit during field construction,

iii) Tasks which may affect the in-service operation or integrity of the pipeline, or parallel pipelines or utilities, with respect to: surveying, locating foreign lines, one call notifications, grading, pipe hauling and stringing, ditching, rock blasting, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, hydrostatic testing, dewatering, alternating current (AC) interference mitigation, cathodic protection (CP) system surveys and installation, directional drills, anomaly evaluations and repairs, right of way clean up, and quality assurance monitoring. Likewise, other tasks performed directly on the pipe affecting its integrity, but not listed here, are to be considered covered tasks.

c) Issues with Qualifications

i) Abnormal Operating Condition (AOC) – Construction personnel must be able to recognize and react to AOCs. AOCs will vary during construction.

ii) Evaluation Methods – FGT must develop and implement evaluation methods to ensure that FGT employees, and all contractor employees, have the required knowledge, skills, and abilities for all construction tasks.

14) **Certification:** A senior executive officer of FGT must certify in writing the following:

a) That the FGT pipeline meets the conditions described in this special permit and 49 CFR § 192 for the ***special permit segments.***

b) FGT has maintained the following records for each ***special permit segment***:

i) Documents showing that each ***special permit segment*** has received a § 192.505, Subpart J, hydrostatic test for 8 continuous hours and at a minimum pressure as required by **Condition 7** of this special permit. If FGT does not have hydrostatic test documentation, then the ***special permit segment*** must be hydrostatically tested to meet this requirement within one year of receipt of this special permit in accordance with 49 CFR § 192 and prior to operating at the alternative MAOP.

ii) Documents (mill test reports) certifying that the pipe in each ***special permit segment*** meets the requirements for wall thickness, yield strength, ultimate tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, "Specification for Line Pipe" (API 5L) approved by the 49 CFR § 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR § 192, that the pipe meets the API 5L standard in use at that time. Any special permit segment that does not have mill test reports for the pipe cannot be authorized per this special permit.

iii) Documentation of compliance with all conditions of this special permit must be retained for the applicable life of this special permit for the referenced ***special permit segments***.

c) FGT must notify the PHMSA Director, Southern Region, 14 days prior to conducting all field activities for **Conditions 3, 4, 5, 6, 7, 8, 9, 10, 11, 12 and 13** of this special permit in the ***special permit segments***.

d) That the written manual of O&M procedures for the FGT pipeline has been updated to include all additional operating and maintenance requirements of this special permit and 49CFR § 192 applicable sections; and

e) That FGT has reviewed and modified its damage prevention program relative to the FGT pipeline to include any additional elements required by special permit.

FGT must send a copy of the certification, with the required senior executive signature, and date of signature to the PHMSA Director, Southern Region at least 90 days prior to operating the FGT pipeline ***special permit segments*** at the alternative MAOP. FGT must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement.

Limitations:

PHMSA grants this special permit subject to the following limitations:

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

2) Should FGT fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require FGT to comply with the regulatory requirements in 49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), 192.620(d)(11), and 192.620(c)(2).
3) PHMSA may revoke, suspend, or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require FGT to comply with the regulatory requirements in 49 CFR §§ 192.112(c), 192.112(f)(1), 192.112(h), 192.328(a)(2), 192.620(a)(2)(ii), 192.620(d)(7)(i), 192.620(d)(7)(ii), 192.620(d)(9)(ii), 192.620(d)(11), and 192.620(c)(2).
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 FGT in writing of the proposed action and provide FGT an opportunity to show cause why the action should not be taken unless PHMSA determines that taking such action is immediately necessary to avoid the risk of significant harm to persons, property or the environment (see 49 CFR § 190.341(h)(2)).
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).

AUTHORITY: 49 U.S.C. 60118(c) and 49 CFR § 1.53.

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Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety