U.S. Department
of Transportation
Pipeline and Hazardous
Materials Safety
Administration

1200 New Jersey Avenue, SE
Washington, DC 20590

Mr. Tony Rizk
Vice President, Technical Services
Gulf South Pipeline Company, LP
9 Greenway Plaza, Suite 2800
Houston, TX 77046

Docket No. PHMSA-2019-0174

Dear Mr. Rizk:

On September 4, 2019, pursuant to 49 Code of Federal Regulations § 190.341, Gulf South Pipeline Company, LP (GSPC) applied to the Pipeline and Hazardous Materials Safety Administration (PHMSA) for a special permit. GSPC requested to waive compliance with § 192.625 for the non-odorized operation of 1.31 miles of the 30-inch diameter Index 129-72 Pipeline (Pipeline) located near the city of Kay, Fort Bend County, Texas. The gas transported by a transmission pipeline is required by § 192.625 to be odorized in a Class 3 or 4 location as defined in § 192.5.

On December 13, 2019, PHMSA published a Federal Register notice (84 FR 68297), announcing the special permit request. The Special Permit Request letter, Final Environmental Assessment (FEA) and Finding of No Significant Impact (FONSI), Special Permit Analysis and Findings, and all other pertinent documents for this special permit are available in Docket No. PHMSA-2019-0174 in the Federal Docket Management System located at www.regulations.gov.

PHMSA grants this special permit (enclosed) based on the information provided by GSPC and the findings set forth in the Special Permit Analysis and Findings, FEA and FONSI. This special permit provides relief from the Federal Pipeline Safety Regulations for the 1.3-mile Pipeline and requires GSPC to comply with certain conditions and limitations designed to maintain pipeline safety for the period as defined in the special permit.

My staff would be pleased to discuss this special permit or any other regulatory matter with you. Sentho White, Director of PHMSA Engineering and Research Division, may be contacted at 202-366-2415, on technical matters; and Allan Beshore, Director, Office of Pipeline Safety, Central Region, may be contacted at 816-329-3811, for operational matters specific to this special permit.

Sincerely,

ALAN KRAMER MAYBERRY
Digitally signed by ALAN KRAMER MAYBERRY
Date: 2020.04.22 13:12:55 -04'00'

Alan K. Mayberry
Associate Administrator for Pipeline Safety

Enclosure: Special Permit – PHMSA-2019-0174

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT – Non-Odorization of Gas

Special Permit Information:

Docket Number:	PHMSA-2019-0174
Requested By:	Gulf South Pipeline Company, LP
Operator ID#:	31728
Date Requested:	September 4, 2019
Original Issuance Date:	April 22, 2020
Effective Dates:	April 22, 2020 to April 22, 2030
Code Section(s):	49 CFR 192.625

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] grants this special permit to Gulf South Pipeline Company, LP (GSPC)[2]. This special permit waives compliance with the 49 Code of Federal Regulations (CFR) 192.625 for odorization of GSPC's Index 129-72 Pipeline, which is a 30-inch diameter natural gas transmission pipeline, 1.31 miles in length, in Fort Bend County, Texas. This special permit requires that GSPC implement additional conditions on the operations, maintenance, and integrity management of the Index 129-72 Pipeline. The entire pipeline constitutes the ***special permit segment***.

I. Purpose and Need:

The Index 129-72 Pipeline is a 1.31-mile natural gas transmission pipeline in a Class 3 location and more than 50 percent of the downstream portion of the pipeline is not located in Class 1 or

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

[2] GSPC is a wholly-owned, subsidiary of Boardwalk Pipeline Partners, LP.

Class 2 locations as shown in Appendix A - GSPC Index 129-72 Pipeline – Overview Map. The Index 129-72 Pipeline transports unodorized natural gas to and from the Katy Storage. Katy Storage is an underground natural gas storage facility that cannot accept odorized gas. In addition, Katy Storage delivers gas to a number of pipelines that that do not transport odorized gas. Accepting odorized gas into the storage cavern would preclude customers at Katy Storage from delivering gas to some of these pipelines.

The Federal pipeline safety regulations in 49 CFR 192.625 require natural gas pipeline operators to odorize natural gas in a Class 3 or 4 location as defined by 49 CFR 192.5 unless at least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location. This special permit allows GSPC to operate the ***special permit segment*** transporting unodorized gas and at its maximum allowable operating pressure (MAOP) of 1,100 pound per square inch gauge (psig)[3] in accordance with the conditions of this special permit.

II. Special Permit Segments:

<u>Fort Bend County, Texas</u>

This special permit for the GSPC pipeline applies to the ***special permit segment*** defined as:

- 1.31 miles of the 30-inch diameter GSPC Index 129-72 Pipeline which connects GSPC's Index 129 Pipeline to Katy Storage in Fort Bend County, Texas. The Index 129-72 Pipeline total length is approximately 1.31 miles (6,929 feet) and is located in Fort Bend County, Texas.

PHMSA hereby grants this special permit for the ***special permit segment*** based on the findings set forth in the "*Final Environmental Assessment and Finding of No Significant Impact*" and the "*Special Permit Analysis and Findings*" documents, which can be read in their entirety in Docket No. PHMSA-2019-0174 in the Federal Docket Management System located on the internet at www.regulations.gov.

[3] The GSPC pipeline will have a potential impact radius of 942.6 feet as determined by 49 CFR 192.903 for gas transmission pipeline integrity management determination of high consequence areas.

III. Conditions:

PHMSA grants this special permit to GSPC subject to GSPC implementing the following conditions on the Index 129-72 Pipeline as detailed below:

1. **<u>General Conditions and Maximum Allowable Operating Pressure</u>**: GSPC can continue to operate the ***special permit segment*** at or below the existing MAOP of 1,100 psig, and within 180 days of the grant of this special permit, GSPC must ensure the following:
    a) The ***special permit segment*** must be hydrostatically tested to 1,650 psig (which is a minimum of 1.50 times the MAOP of 1,100 psig) for eight (8) continuous hours in accordance with 49 CFR Part 192, Subpart J.
    b) All material, design, construction, and operations and maintenance (O&M) procedures and specifications for the ***special permit segment*** must meet Class 3 or 4 location requirements in 49 CFR Part 192. A pipe design factor for either Class 3 or 4 locations as described in 49 CFR 192.111 must be used for the ***special permit segment***.
    c) All pipe and girth welds in the ***special permit segment*** must have an external coating that is non-shielding to cathodic protection (CP) current. Coatings that can shield CP, such as polyethylene coatings (shrink sleeves and tape coatings), must not be used within the ***special permit segment***.
    d) All road crossings must be non-cased in the ***special permit segment***.
    e) The ratio of the specified outside pipe diameter of the pipe to the specified wall thickness (d/t) must be less than 100 for the pipeline within the ***special permit segment***. The ***special permit segment*** has 30-inch diameter, API 5L X-60 grade steel pipe with a wall thickness of 0.550 inches and 0.625 inches**.** The pipe d/t ratio is between 48 to 63.64, which is below 100.
    f) The toughness properties for the pipeline within the ***special permit segment*** must be at least 99% probability of fracture arrest within eight pipe lengths with a probability of not less than 90% within five (5) pipe lengths as defined in 49 CFR 192.112(b)**.** The Battelle Two Curve Method, assuming conservative gas composition data and the application of a Leis Correction Factor (1.3x), is an acceptable method of confirming fracture control.

g) A direct current voltage gradient survey must have been conducted over the ***special permit segment*** either after pipeline construction occurred in 2017 or within 180-days of the grant of this special permit and coating anomalies must be remediated.

h) The ***special permit segment*** must be capable of internal inspection in accordance with 49 CFR 192.150 and must include either permanently or temporarily installed launchers and receivers capable of running in-line inspection (ILI) tools.

i) The ***special permit segment*** cannot be connected to directly deliver natural gas to any dwellings for human occupancy, except for GSPC operational buildings.

2. **<u>Integrity Management Program</u>**: GSPC must incorporate the requirements of this special permit into its written integrity management program and standard operating procedures (SOPs).[4]

   a) GSPC must treat the ***special permit segment*** as a *"covered segment"* in a *"high consequence area (HCA)"* in accordance with 49 CFR Part 192, Subpart O. Reassessments of the ***special permit segment*** using high resolution magnetic flux leakage (HR-MFL) and high resolution (HR) Deformation ILI must be conducted at the frequency specified for HCAs in 49 CFR 192, Subpart O.

   b) If GSPC identifies threats within the ***special permit segment*** that require running additional ILI tools, pursuant to 49 CFR Part 192, Subpart O, such as for crack detection[5] or pipe movement from soil or geologic stresses, GSPC must use the appropriate ILI tools or other evaluation methods for pipeline assessments.

   c) GSPC must conduct baseline assessments of the ***special permit segment*** using HR-MFL and HR-Deformation ILI tools within three (3) calendar years, not to exceed 42 months, of the grant of this special permit.

3. **<u>Anomaly Response and Repair</u>**:

   a) **<u>General</u>**: GSPC must account for ILI tool tolerance and corrosion growth rates within the scheduled response times and repairs, and must document and justify the values used.

      i) GSPC must demonstrate ILI tool tolerance accuracy for each ILI tool run

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[4] Pipeline operating procedures such as GSPC SOPs are required by 49 CFR 192.603(b) and 192.605.

[5] "Pipe Crack" activity shall be defined as over both 10% wall thickness depth and 2-inches in length.

by usage of calibration excavations[6, 7] and unity plots that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +/- 10% accuracy for 80% of the time). GSPC must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool and includes that tolerance in determining the size of each anomaly feature reported to GSPC. GSPC must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently overcalling or under-calling, the remaining ILI features must be re-graded accordingly.

ii) The unity plots must show actual anomaly depth versus predicted depth.

iii) ILI tool evaluations for metal loss must use "6t x 6t"[8] interaction criteria for determining anomaly failure pressures and response timing.

iv) Discovery date[9] must be within 150 days of any ILI tool run for each type

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[6] ILI tool calibration excavations may include previously excavated anomalies or recent anomaly excavations with known dimensions that were field measured for length, depth, and width, externally re-coated, CP maintained, and documented for ILI calibrations prior to the ILI tool run. ILI tool calibrations must use ILI tool run results and anomaly calibrations from either the ***special permit segment*** or from the complete ILI tool run segment, <u>if the continuous ILI segment is longer</u> than the ***special permit segment.*** A minimum of four (4) calibration excavations must be used for unity plots or as an alternative a minimum of one (1) calibration excavation and compliance with API 1163-2013, In-Line Inspection Systems Qualification Standard (API 1163), Level 1 criteria must be used. For API 1163, Level 1 criteria to be used, all anomalies greater than 20-percent wall loss must be excavated and remediated unless Director, PHMSA Central Region gives GSPC a "No Objection" to an alternative ILI tool calibration procedure (*see* Footnote 7).

[7] **Note:** Other known and documented pipeline features that are appropriate for the type ILI tool used may be used as calibration excavations for ILI tool calibration with technical documentation of their validity. To use other known and documented pipeline features as calibration excavations for ILI tool calibration GSPC must submit a plan for using known and documented pipeline features as calibration excavations to, and receive a "No Objection" from the Director, PHMSA Central Region, prior to performing the ILI tool calibration using pipeline features. PHMSA must reply to GSPC within 90-days of GSPC's request. The plan must include at least the following information: **(1)** reason that known and documented pipeline features will be used in place of anomalies on the pipelines; the pipeline features that will be used for the ILI tool calibration, and the technical justification for using the pipeline features for ILI tool calibration. **(2)** submit a report to the Director, PHMSA Central Region and to the Director, PHMSA Engineering and Research with the results of the use of pipeline features for the ILI tool calibration that includes technical documentation establishing the validity of using the pipeline features for the ILI tool calibration. GSPC must submit the report to PHMSA within 90-days after completion of the ILI tool calibration.

[8] "6t" means pipe wall thickness times six.

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

of ILI tool (e.g. HR-geometry, HR-deformation or HR-MFL tools).

b) **<u>Dents</u>**: GSPC must repair dents in the ***special permit segment*** in accordance with the 49 CFR 192.933 repair criteria. The ***special permit segment*** must have a HR deformation tool inspection as part of the initial ILI. The HR deformation tool can be from past ILI inspections. The timing for these dent repairs should follow the GSPC O&M Manual but must be no longer than one (1) year after discovery or the timing intervals in 49 CFR 192.933(d), whichever is shorter.

c) **<u>Repair Criteria and Response Time for ILI Results</u>**: The following is the required timing for excavation and investigation of anomalies based on ILI results. GSPC must evaluate ILI data by using either the ASME Standard B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines,"[10] the modified B31G (0.85dL) or R-STRENG[11] for calculating the predicted failure pressure ratio (FPR) to determine corrosion anomaly responses. Repair criteria applies to anomalies located within the ***special permit segment*** when they have been ILI assessed, excavated and investigated, or the timing intervals in 49 CFR 192.933(d), whichever is shorter as follows:

   i) **<u>Immediate response</u>**: Any anomaly within the ***special permit segment*** that meets either: (l) an FPR equal to or less than 1.25; or (2) an anomaly depth equal to or greater than 70% wall thickness loss.

   ii) **<u>One-year response</u>**: Repair any anomaly in the ***special permit segment*** that meets either: (l) a failure pressure ratio (FPR) less than or equal to 2.0; or (2) an anomaly depth greater than 40% of pipe wall thickness.

   iii) **<u>Monitored response</u>:** Any anomaly within the ***special permit segment*** that meets both: (1) an FPR equal to or greater than 2.00; or (2) an anomaly depth less than or equal to 40% wall thickness loss. The schedule for the response must take tool tolerance[12] and corrosion growth rates into account.

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[10] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

[11] The applicable edition incorporated by reference is listed in 49 CFR 192.7.

[12] Tool tolerance shall be applied only to FPR calculations, not to the anomaly depth criteria.

iv) ***<u>Special permit segment – Crack Type Anomalies</u>*** - All cracking exceeding 20% of the pipe wall thickness or having a FPR below 2.00 must be remediated within 180 days of discovery.[13, 14]

4. **<u>Close Interval Surveys</u>**: GSPC must perform a close-interval survey (CIS)[15] and remediate[16] any areas of inadequate cathodic protection in the ***special permit segment*** within one (1) year after the grant of this special permit. If environmental permitting or right-of-way factors beyond GSPC's control should prevent the completion of the CIS within one (1) year from the grant of this special permit, <u>(1)</u> GSPC must complete a CIS and perform subsequent remediation including coating repair as soon as practicable, <u>(2)</u> GSPC must submit a letter justifying the delay and providing the anticipated date of completion to the Director, PHMSA Central Region, no later than one (1) month prior to the end of one (1) year after the grant of this special permit, and <u>(3)</u> must receive a letter of "no objection" from the Director, PHMSA Central Region, for a delay.[17] CIS remediation activities must be completed within one (1) year of the finding. GSPC must submit a written request to the Director, PHMSA Central Region, for any extended evaluation and remediation schedules. GSPC must receive a letter of "no objection" from PHMSA prior to implementing an extended CIS and remediation interval.

5. **<u>Close Interval Surveys – Reassessment Interval</u>**:

   a) GSPC must perform periodic CIS of the ***special permit inspection area*** at the applicable reassessment interval(s) for a "covered segment" determined in concert

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[13] Should any cracking anomalies above 20% of the pipe wall thickness be found in the ***special permit segment***, GSPC must remediate the cracks or have a crack anomaly evaluation procedure submitted to the Director, PHMSA Central Region with a "no objection" reply prior to using the crack evaluation procedure for cracking anomalies left in the pipeline above 20% of the pipe wall thickness without remediation. If GSPC does not receive a "no objection" letter or request for additional review time from PHMSA within 90 days of the notification, GSPC may proceed.

[14] A fracture mechanics and pressure cycling evaluation is required where an un-remediated crack of 10% or more (of wall thickness) is detected by ILI or direct inspection tools. The pipe must have toughness tests (Charpy V-notch impact values) of the pipe body, seam, or girth weld so that fracture mechanics modeling can be used, if needed.

[15] CIS must be conducted at a maximum 5-foot spacing and with interrupted on/off current.

[16] The terms "remediate" or "remediation" of pipe coating must include repair of damaged external pipe coating, where required to maintain cathodic protection of the pipeline in accordance with 49 CFR 192.463.

[17] PHMSA has assigned this special permit to the Director, PHMSA Central Region, but upon notice to GSPC could assign this special permit to a different PHMSA Region.

and integrated with ILI in accordance with 49 CFR Part 192 Subpart O reassessment intervals as required in 49 CFR 192.937 (a) and (b) and 192.939, not to exceed the 7-calendar year reassessment interval in 49 CFR 192.939(a). CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

b) CIS data must be integrated with ILI data. **Condition 14 (Data Integration)** – gives a complete description of data integration information that an operator must maintain for ***special permit segment***, including CIS and ILI data.

c) Any areas of low CP levels as specified in 49 CFR 192, Subpart I, must be remediated in accordance with **Condition 7**.

6. **<u>Cathodic Protection Test Station – Location</u>**: Spacing between CP pipe-to-soil test stations within ***special permit segment*** cannot exceed 3200 feet. In cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. Within six (6) months of completing a close-interval survey, GSPC must utilize the data gained from this survey to place external corrosion control test stations at identifiable and significant dips in electric potential in accordance with 49 CFR 192.469, in conjunction to the previously agreed upon test stations placed at half-mile intervals. GSPC must utilize the data gained from the CIS to place external corrosion control test stations at identifiable and significant dips in CP potential[18] in accordance with 49 CFR 192.469. However, placement of a test station at areas of significant dips shall not be required if GSPC identifies and remediates the cause of the significant dip, and confirms successful remediation by a follow-up CP survey.

7. **<u>Cathodic Protection – Low Potential Remediation</u>**: Any areas of low CP potential within the ***special permit segment*** must be remediated within one (1) year of the finding unless it is impracticable to meet this schedule due to a permitting interval. Permit applications must be submitted within four (4) months of any low CP potential findings. If the schedule cannot be met due to circumstances beyond GSPC's control, GSPC must notify the Director, PHMSA Central Region, in writing explaining the reasons the schedule

[18] A significant dip is defined as a dip in a potential reading (either an "on" or "off" potential) that is greater in magnitude than 200 milli-volts, occurring within any 100-foot sample area.

cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing the schedule change.

8. **<u>Right-of-Way Patrols</u>:** In addition to the requirements of 49 CFR 192.705 and 192.706, GSPC must perform right-of-way patrols as follows:
    a) Ground patrols using instrumented leakage detection equipment that can detect gas leaks along the ***special permit segment*** at intervals between every five (5) months to seven and one-half (7½) months, not to exceed seven and one-half (7½) months, but at least two (2) times per calendar year.
    b) Aerial flyover patrols or ground patrols by walking or driving of the ***special permit segment*** right-of-way once a week, not to exceed 10 days, contingent on weather conditions. Should mechanical availability of the patrol aircraft or weather conditions become an extended issue, the ***special permit segment*** pipeline aerial flyover patrol must be completed within 21 days of the last patrol by other methods such as walking or driving the pipeline route, as feasible.
    c) If the schedule for either ground patrols or aerial flyover patrols cannot be met due to circumstances beyond GSPC's control, GSPC must notify the Director, PHMSA Central Region, in writing of the reasons the schedule cannot be met and obtain a letter of "no objection" within three (3) business days of the exceedance.

9. **<u>Line-of-Sight Markers</u>**: GSPC must install and maintain line-of-sight markers within the ***special permit segment*** in accordance with 49 CFR 192.620(d)(4)(iv) to the extent practicable. Any removed or missing line-of-sight markers must be replaced within 30 days of discovering the marker is removed or missing.

10. **<u>Mainline Valve – Monitoring and Remote Control for Leaks or Ruptures</u>**: All mainline valves for the ***special permit segment*** must be controlled by a supervisory control and data acquisition (SCADA) system and must be equipped for remote monitoring and control, or remote monitoring and automatic control in accordance with 49 CFR 192.620(d)(3)(iii) and the following requirements:
    a) If any crossover or lateral pipe for gas receipts or deliveries connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated, such that, when all

valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment);

b) Mainline valves must be continuously monitored for valve status (open, closed, or partial closed/open), upstream pressure, and downstream pressure;

c) Closure of the appropriate valves following a pipeline leak or rupture meeting the criteria of **Condition 10(c)(i)** must occur as soon as practicable from the time the pipeline leak or rupture location is confirmed, not to exceed 30 minutes from such confirmation;[19]

  i) "Rupture" means a significant breach of a pipeline that results in a large-volume, uncontrolled release of gas. For purposes of this special permit, GSPC must treat any of the following as ruptures unless and until determined otherwise:

    1. A release of gas observed or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition;
    2. An unanticipated or unplanned pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less; or
    3. An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined in paragraph (2) of this definition.

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

Note: Rupture identification occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel or a controller.

ii) Within five (5) minutes of the initial notification to GSPC, GSPC must evaluate and identify a rupture, as defined above, as being either an actual leak event, rupture event or non-rupture event in accordance with operating procedures and 49 CFR 192.615;

d) The GSPC Gas Control Center must monitor the pipeline 24 hours a day, 7 days a week in accordance with GSPC pipeline operating procedures and must confirm the existence of a leak or rupture in accordance with **Condition 10(c)** and as soon as practicable, in accordance with GSPC pipeline operating procedures;

e) GSPC must maintain remote monitoring and automatic control equipment, mainline valves, mainline valve operators, and pressure sensors in accordance with 49 CFR 192.631 and 192.745. All remote monitoring and automatic control equipment including pressure sensors must have backup power to maintain communications and control to the GSPC Gas Control Center during power outages;

f) GSPC must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with 49 CFR 192.631(c) and (e), or an equivalent verification;

g) All valves used to isolate a leak or rupture must be maintained in accordance with this special permit and 49 CFR 192.745;

h) GSPC must take remedial measures to correct any valve used to isolate a leak or rupture that is found to be inoperable or unable to maintain shut-off, as follows:

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

ii) Designate an alternative valve within seven (7) calendar days of the finding while repairs are being made. Repairs must be completed within six (6) months; and

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

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

j) GSPC must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated;[20] and

k) GSPC must establish actions required to be taken by a pipeline controller, or the appropriate emergency response coordinator, during an emergency in accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631.

11. **<u>Interference Currents Control</u>**: Within one (1) year of the grant of this permit, GSPC must perform surveys and remediation, with corrosion control implemented, for induced currents from electric transmission lines and other known sources of potential interference that may affect the ***special permit segment***. An induced alternating current (AC) or direct current (DC) program and remediation plan to protect the pipeline from corrosion caused by stray currents must be written and implemented within one (1) year of the grant date of this special permit.

a) At least once every seven (7) years not exceeding 90 months, GSPC must perform an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate and remediate any AC interference between 20 and 50 amperes (Amps) per meter squared. In evaluating such interference, GSPC must integrate AC interference data with the most recent ILI results to determine remediation measures. Any discovered AC interference between 20 and 50 Amps per meter

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

squared must be remediated within six (6) months of the finding. If GSPC decides not to remediate AC interference between 20 and 50 Amps per meter squared, GSPC must provide a written engineering justification for not remediating the interference to the Director, PHMSA Central Region and obtain a letter of “no objection” from PHMSA prior to implementing the change. If GSPC does not receive a “no objection” from PHMSA, GSPC must remediate the interference.

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

c) Within six (6) months of the engineering analysis, as required in **Condition 11(a)**, GSPC 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 six (6) months of the engineering analysis.

d) If environmental permitting or right-of-way factors beyond GSPC’s control prevent the completion of remediation within six (6) months of the completion of the engineering evaluation, GSPC must complete remediation as soon as practicable. GSPC must also submit a letter justifying the delay and provide the anticipated date of completion to the Director, PHMSA Central Region, no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from GSPC must receive a letter of “no objection” from the Director, PHMSA Central Region, prior to extending the evaluation or remediation schedule.

12. **Landowner Communications**: GSPC must provide pipeline safety awareness material to residents within the potential impact radius of the ***special permit segment*** each calendar year not to exceed 15 months.

13. **Annual Report to PHMSA**: Annually,[21] after the grant of this special permit, GSPC must submit an annual pipeline integrity report[22] to the Director, PHMSA Central Region summarizing any significant integrity threats and the following items:
    a) Any new integrity threats identified during the previous year in the ***special permit segment***, and the results of any ILI or direct assessments performed (including any remediated anomalies with the associated wall loss, length, and unrepaired failure pressure; any un-remediated anomalies over 30% pipe wall loss and the associated wall loss, length and failure pressure; cracking found in the pipe body; weld seam or girth welds; and dents with metal loss, cracking or stress riser) during the previous year in the ***special permit segment***;
    b) Summaries of any close interval surveys that resulted in low cathodic protection levels in the ***special permit segment*** and a remediation schedule;
    c) 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 segment***;
    d) Any pressure test leaks or failures with a description of the cause in the ***special permit segment***;
    e) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline;
    f) Any emergency events that cause closure of mainline valves as described in **Condition 10**, including the location (Mile Post) of valves and closure times.

14. **Data Integration**: GSPC must maintain data integration of special permit condition findings and remediation in the ***special permit segment.*** Data integration must include the

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[21] 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 Special Permit dated January, 2018, must be received by PHMSA no later than January 31, each year beginning in 2019.

[22] GSPC must place a copy of each GSPC annual pipeline integrity report on the PHMSA docket, PHMSA-2019-0174, at www.regulations.gov.

following information: pipe diameter, wall thickness, grade, and seam type; pipe coating; MAOP; class location (including boundaries on aerial photography); HCAs (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI survey results including HR-MFL, HR-Deformation tools; most recent CIS; rectifier readings; cathodic protection test point survey readings; 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.[23] Structures must be validated every three (3) years by obtaining new aerial imagery or by ground patrol.

a) Data integration documentation and drawings, with four (4) years of prior data, must be maintained and must be submitted, if requested by PHMSA, beginning with the 2nd annual report of this special permit.
b) Data integration must be updated on an annual basis. GSPC must conduct, at least, an annual review of integrity issues to be remediated.
c) GSPC must maintain data integration as a composite of all applicable data elements in a data viewer.

15. **<u>Environmental Assessments and Permits</u>**: GSPC must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings needed to implement the special permit conditions for the ***special permit segment*** prior to the disturbance. GSPC must obtain all applicable (Federal, state, and local) environmental permits and adhere to all applicable (Federal, state, and local) environmental permit requirements when conducting the special permit conditions activity.

16. **<u>Root Cause Analysis for Failure or Leak</u>**: If a leak or rupture (incident as defined by 49 CFR 191.3) occurs in any of the ***special permit segment,*** GSPC must notify the Director PHMSA Central Region, within five (5) days of the leak or rupture. A root cause analysis must be performed to determine the cause of the failure and must be sent to the Director, PHMSA Central Region and the Director, PHMSA Engineering and Research, within 90

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

days of the incident. If a root cause analysis cannot be performed within 90 days of the incident, GSPC must submit to the Director, PHMSA Central Region, a request for an extension of time. GSPC must receive a letter of "no objection" from the Director, PHMSA Central Region, prior to implementing an extended timeframe to perform the root cause analysis. 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.

17. **Documentation:** GSPC must maintain documentation for **Conditions 1 through 16 and 18** for the special permit segment for the life of this special permit.

18. **Certification**: A GSPC senior executive officer, vice president or higher, must certify in writing the following:
    a) The ***special permit segment*** meets the conditions described in this special permit;
    b) The written manual of O&M procedures required by 49 CFR 192.605 for the GSPC pipeline has been updated to include all additional operating and maintenance requirements of this special permit; and
    c) GSPC has implemented all conditions as required by this special permit.

    Within 12 months after the grant of this special permit, GSPC must send the certifications required in **Condition 18(a) through (c)** with special permit condition status and procedure completion date, compliance documentation summary, and the required senior executive signature and date of the signature to the PHMSA Associate Administrator for Pipeline Safety, with copies to Director, PHMSA Central Region; and to the Federal Register Docket (PHMSA-2019-0174) at www.Regulations.gov.

IV. Limitations:

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

1) PHMSA has the sole authority to make all determinations on whether GSPC has complied with the specified conditions of this special permit. Failure to comply with any condition of this special permit may result in revocation of the permit.
2) Any work plans and associated schedules for the ***special permit segment*** are automatically incorporated into this special permit and are enforceable in the same manner.

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

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

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

6) PHMSA grants this special permit to limit it to a term of no more than ten (10) years from the date of issuance. If GSPC elects to seek renewal of this special permit, GSPC must submit its renewal request at least 180 days prior to expiration of the ten (10) year period to the PHMSA Associate Administrator for Pipeline Safety with copies to the Director, PHMSA Central Region and Director, PHMSA Engineering and Research. All requests for a renewal must include a summary report in accordance with the requirements in **Condition 13 (Annual Report to PHMSA)** and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from GSPC prior to granting any request for special permit renewal.

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

Issued in Washington, DC on April 22, 2020.

ALAN KRAMER MAYBERRY

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Date: 2020.04.22 13:14:17 -04'00'

Alan K. Mayberry,

Associate Administrator for Pipeline Safety

Attachment A: GSPC Index 129-72 Pipeline – Overview Map