U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

SPECIAL PERMIT – Three-Layer Polyethylene Coating

SEP 9 2019

Special Permit Information:

Docket Number:	PHMSA-2017-0046
Requested By:	Alaska Gasline Development Corporation
Operator ID#:	40015
Original Date Requested:	April 14, 2017
Original Issuance Date:	September 9, 2019
Effective Date:	September 9, 2019
Code Sections:	49 CFR 192.112(f)(1)

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] grants this special permit to Alaska Gasline Development Corporation (AGDC), owner and operator of the Alaska LNG Pipeline.[2] This special permit waives compliance from the 49 Code of Federal Regulations (CFR) 192.112(f)(1). The special permit allows use of a three-layer polyethylene (3LPE) external coating on the Alaska LNG Pipeline with the implementation of the special permit conditions, when using alternative maximum allowable operating pressure (alternative MAOP) methodology as allowed in 49 CFR 192.112,

[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] As used in these draft conditions, the term Alaska LNG Pipeline refers to the approximately 807 miles of 42-inch natural gas transmission pipeline and not to any potential owners, operators, or entities associated with the Alaska LNG Pipeline. The special permit owner, operator, and applicant/permittee name is Alaska Gasline Development Corporation. Please note that this pipeline does not transport liquefied natural gas (LNG). It will supply natural gas to a LNG facility for further transportation as LNG.

192.328, and 192.620. Section 192.112(f) requires external pipe coating to be "non-shielding" to cathodic protection (CP).

I. Purpose and Need:

The Alaska LNG Pipeline will be approximately 807 miles of 42-inch-diameter steel pipe for transporting natural gas from AGDC's gas treatment plant (GTP) on Alaska's North Slope to the liquefaction facility on the eastern shore of the Cook Inlet near Nikiski, Alaska. The pipeline will be mostly onshore, with a segment of offshore pipeline crossing the Cook Inlet. The onshore portion of the pipeline will be a buried pipeline except for short, above-ground special design segments, such as aerial water crossings and aboveground fault crossings. The Alaska LNG Pipeline's design has a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig).

AGDC is requesting a waiver of compliance with 49 CFR 192.112(f)(1) for external pipe coatings being "non-shielding" to CP. AGDC plans to use a 3LPE external coating on the ***special permit segment*** that may shield CP current from reaching the exterior of the pipe wall surface.

Federal pipeline safety regulations require that natural gas transmission pipeline operators using alternative MAOP, as allowed in 49 CFR 192.112, 192.328, and 192.620, must provide pipe coatings that are "non-shielding" to CP. Since the 3LPE external pipe coating has attributes that can lead to shielding the pipe from CP, PHMSA has included certain conditions that AGDC must meet to minimize and mitigate the threat of shielding the pipe from CP current.

II. Special Permit Segment:

The Alaska LNG Pipeline ***special permit segment*** is defined as: 807 miles of 42-inch diameter steel pipeline originating in the North Slope Borough, traversing the Yukon-Koyukuk Census Area, the Fairbanks North Star Borough, the Denali Borough, the Matanuska-Susitna Borough, and the Kenai Peninsula Borough, and terminating at the liquefaction facility on the eastern shore of Cook Inlet near Nikiski, Alaska.

PHMSA hereby grants this special permit for the ***special permit segment*** based on the findings set forth in the "*Final Environmental Assessment and Findings of No Significant Impact*" and the

"*Special Permit Analysis and Findings*" documents. The AGDC special permit application and these supporting documents can be found in their entirety in Docket No. PHMSA-2017-0046 in the Federal Docket Management System (FDMS) at www.regulations.gov.

III. Conditions:

PHMSA grants this special permit to AGDC for the use of 3LPE external coating on the ***special permit segment*** subject to the following conditions as detailed below:

1) **Applicable Regulations:** The ***special permit segment*** must be designed, constructed, operated, and maintained in accordance with 49 CFR Part 192, including but not limited to those requirements pertaining to alternative MAOP (49 CFR 192.112, 192.328, and 192.620), but with exception of the non-shielding external coating requirement in 49 CFR 192.112(f)(1). In addition to 49 CFR Part 192 conformance, the ***special permit segment*** must also be designed, constructed, operated, and maintained in accordance with the special permit conditions.

   AGDC may propose changes to the timing for any reviews for the special permit conditions to PHMSA for review and approval. Any proposed changes to the special permit conditions by AGDC must maintain equivalent levels of safety. PHMSA will determine whether substantive changes to the conditions require a modification or public notice of this special permit. PHMSA will provide AGDC with notice of its decision and an opportunity to respond to proposed changes in accordance with 49 CFR 190.341 and the Limitations section of this special permit. Any submittal timing, review timing, or completion timing in these conditions can be modified by PHMSA upon request by AGDC.[3]

2) **Maximum Allowable Operating Pressure (MAOP):** AGDC must operate the ***special permit segment*** at or below a MAOP of 2,075 pounds per square inch gauge (psig). The ***special permit segment*** may be designed for operation up to 80 percent (%) of specified minimum yield strength (SMYS), allowing for pressure build-up and overpressure protection in accordance with 49 CFR 192.620(e).

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[3] AGDC must submit any proposed changes to the conditions to the PHMSA Western Region Director or PHMSA Project Designee for review and a "no objection" letter must be received prior to usage by AGDC.

Three-Layer Polyethylene Coating:

3) **Plant-Applied 3LPE Coating Procedures and Qualification**

   a) AGDC must develop and qualify through testing a 3LPE coating procedure prior to the start of coating production. The 3LPE coating procedure must be qualified by AGDC in the factory that will make the production order of the actual pipe used for the ***special permit segment***. The procedure, at a minimum, must address the requirements of Section 9 from International Standards Organization (ISO) 21809-1.[4]

   b) The coating procedure must include required qualification tests and acceptance criteria must be in accordance with ISO 21809-1.[5]

4) **Factory-Applied Coating Specification Requirements**

   a) AGDC must perform inspections to ensure 3LPE coating applications are in accordance with the 3LPE coating procedure. At a minimum, inspections will be in accordance with ISO 21809-1, Tables 8 and 9.[6]

   b) Salt contamination on the pipe surface before coating application shall not exceed 20 mg/m^2 as measured per ISO 8502-6.[7]

   c) The dry film thickness of the fusion bonded epoxy layer shall be a minimum of 10 mils for 3LPE coating systems utilizing an extruded polyethylene outer layer and a minimum of eight (8) mils for 3LPE systems utilizing a spray applied polyethylene outer layer.

   d) The dry film thickness of the copolymer adhesive layer must be a minimum of six (6) mils.

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[4] ISO 21809-1, Second Edition, 2018-10, Petroleum and natural gas industries - External coatings for buried or submerged pipelines used in pipeline transportation systems - Part 1: Polyolefin coatings (3-layer PE and 3-layer PP), 2018, Section 9, Coating Material Qualification.

[5] ISO 21809-1, Second Edition, 2018-10, Petroleum and natural gas industries - External coatings for buried or submerged pipelines used in pipeline transportation systems - Part 1: Polyolefin coatings (3-layer PE and 3-layer PP), 2018, Section 9, Coating Material Qualification.

[6] ISO 21809-1, Second Edition, 2018-10, Petroleum and natural gas industries - External coatings for buried or submerged pipelines used in pipeline transportation systems - Part 1: Polyolefin coatings (3-layer PE and 3-layer PP), 2018, Section 12, Inspection and Testing, Tables 8 and 9.

[7] ISO 8502-6, Second Edition, 2006-07-01, Preparation of steel substrates before application of paints and related products—Tests for the assessment of surface cleanliness—Part 6: Extraction of soluble containments for analysis—The Bresle method.

e) The polyethylene outer layer must have an average dry film thickness of at least 118 mils for extruded polyethylene and an average dry film thickness of at least 47 mils for spray applied polyethylene.

f) After application and drying of the coating, holiday detection must be performed using a high voltage holiday detector at 25 kilo-volts (25,000 volts).

5) **Coating Application Quality Control Testing**

a) Inspection and testing per Section 12 of ISO 21809-1 must be performed by AGDC for quality control during 3LPE coating application.[8] Specific inspection and testing requirements are detailed in Table 8 – Requirements for inspection of surface preparation and coating application, and Table 9 – Minimum frequency and requirements for inspection and testing of applied coating of the referenced standard.

6) **Field Joint Coatings**

a) The field joint coating must consist of liquid applied epoxy, liquid applied urethane or fusion bonded epoxy. Heat shrink sleeves or tape wrap coatings are not permitted for field joints.

b) Before construction starts, the field joint and repair coating application procedures must be prepared and qualified to meet 49 CFR 192.328(a) – Quality assurance. At a minimum, the coating application procedures must specify the following:

i. Method for surface preparation, cleaning, level, if any, of allowable contaminants, and required surface profile;
ii. Method for heating the pipe and monitoring temperature;
iii. Nominal steel temperature for application of field joint coating and permitted range;
iv. Manufacturer and brand name of product;
v. Method and equipment for application of coating;
vi. Minimum dry film thickness;
vii. Method for holiday detection and repair; and
viii. Minimum qualifications for field coating installation personnel.

[8] ISO 21809-1, Second Edition, 2018-10, Petroleum and natural gas industries—External coatings for buried or submerged pipelines used in pipeline transportation systems—Part 1: Polyolefin coatings (3-layer PE and 3-layer PP), 2018, Section 12, Inspection and Testing.

c) The required qualification tests must include:

   i. Impact resistance testing,

   ii. Hot-water soak/adhesion testing,

   iii. Penetration resistance testing, and

   iv. Cathodic disbondment testing.

d) Prior to coating, the pipe surface must be prepared by abrasive blasting and visually inspected. Surface imperfections (e.g., slivers, scabs, etc.) must be removed by grinding.

e) Dry film thickness measurements must be carried out on each field joint. The minimum dry film thickness must be at least 20 mils (0.020-inch).

f) After application of the field joint coating, holiday detection must be performed in accordance with NACE SP0188.[9]

7) **Integrity Management for Cracking – Pipe Body, Seam and Girth Weld**

a) An electromagnetic acoustic transducer (EMAT) in-line inspection (ILI) tool must be run not later than fourteen (14) calendar years, not to exceed 171 months, after pipeline start-up[10] and once every seven (7) years thereafter in the ***special permit segment***. AGDC may propose an alternative ILI crack detection tool or schedule to the PHMSA Western Region Director or Project Designee, but must receive a "no objection" letter from PHMSA prior to implementation.

b) Magnetic particle inspection (MPI), phase array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), or other non-destructive examination (NDE) methods must be performed to assess the pipeline for cracking and other linear indications in areas of disbonded coating found at all direct assessment/examination excavation sites, ILI tool verification excavation sites, and any other excavations performed due to the presence of corrosion or other reported damage. Pipe body, seam or girth weld seam cracking depths must be measured with PAUT, ultrasonic shear wave, IWEX, grinding, or equivalent technologies.

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9 NACE SP0188-2006-SG (formerly RP0188) Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates, 2006.

10 Pipeline start-up is defined as an interval during which the pipeline system begins operations, and throughput (product flow through the pipeline) is ramped to its commercial capacity.

c) Fracture mechanics analysis must be performed to evaluate cracking indications reported by ILI or direct examinations. All cracking exceeding 40 percent of the pipe wall thickness or with a failure pressure ratio (FPR) below the criteria in 49 CFR 192.620(d)(11) must be remediated as follows:

  i. Should any cracking anomalies above 30 percent of the pipe wall thickness be found in the ***special permit segment***, AGDC must immediately remediate the cracks. AGDC may submit a crack anomaly evaluation procedure to the PHMSA OPS Western Region Director for review instead of performing a remediation. If AGDC does not receive a "no objection" letter or request for additional review time from PHMSA within 90 days of the notification, AGDC may proceed.

  ii. A fracture mechanics evaluation is required where an un-remediated crack of 30 percent or more (of wall thickness) is detected by ILI or direct examination 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. When analyzing cracks and crack-like defects under this condition, AGDC must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include: for the brittle failure mode, the Newman-Raju Model and PipeAssess PI™ software; and for the ductile failure mode, Modified Log-Secant Model, API RP 579-1 – Level II or Level III, CorLas™ software, PAFFC Model, and PipeAssess PI™ software.

  iii. If the ***special permit segment*** is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. Methodologies used by AGDC must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the MAOP.

8) **Interference Currents Control:** Induced alternating current (AC) from parallel electric transmission lines, foreign or nearby pipelines, telluric currents, and other interference issues, such as direct current (DC) in the segments where 3LPE coating is installed that may affect the ***special permit segment***, must be addressed. An induced AC or DC monitoring program and remediation plan to protect the ***special permit segment*** from corrosion caused by stray or interference currents must be in place within one (1) year of the pipe in the segment being installed in the ditch (including backfill).

   a) Readings must be taken at each AC mitigation test coupon location once every calendar year throughout the life of the pipeline. Additionally, there must be 24-hour recordings of AC interference voltages at 20 percent of the AC interference coupon test stations each calendar year. If there are any significant changes in the amount of electrical current flowing in the co-located high voltage AC power lines, such as from additional generation, a voltage up rating, additional lines, or new or enlarged substations, an AC interference survey along the entire co-located pipeline right-of-way must be performed within twelve (12) months of such change. To determine if remediation measures are warranted, interference areas where AC current discharge is greater than 20 amperes per meter squared must be evaluated with the most recent metal loss ILI tool results. Any interference causing AC current discharge greater than 50 amperes per meter squared of pipe surface must be remediated within twelve (12) months of the AC interference survey. At all locations where an excavation takes place in an area of suspected AC interference, a new AC mitigation test coupon must be installed and be included in the routine testing and monitoring procedure.

   b) At least once every seven (7) calendar years not exceeding 84 months, an engineering analysis on the effectiveness of AC, DC, telluric current, and other electrical interference mitigation measures must be performed. Any AC interference causing AC current discharge greater than 20 amperes per meter squared of surface area must also be performed. In evaluating such interference, the AGDC must integrate AC and other electrical interference data with the most recent metal loss ILI tool results to determine remediation measures.

c) Within twelve (12) months of the results of the interference engineering analysis, the AC interference causing AC current discharge greater than 50 amperes per meter squared of surface area must be remediated. 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 twelve (12) months of this evaluation.

Reporting and Certification:

9) **Annual Reports:** Within twelve (12) months following pipeline start-up[11] and annually[12] thereafter, the following must be reported to the PHMSA Western Region Director or Project Designee with copies to the PHMSA Engineering and Research Division Director, and PHMSA Standards and Rulemaking Division Director.[13, 14]

a) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within the potential impact radius (PIR) of the ***special permit segment***, as defined in 49 CFR 192.903, built during the previous year;

b) Any integrity threats identified during the previous year and the results of any ILI or direct assessments performed during the previous year;

c) Any reportable incident or leaks associated with the ***special permit segment*** that occurred during the previous year;

d) All repairs that occurred during the previous year;

e) Any on-going damage prevention, corrosion, and corrosion preventative initiatives and a discussion of the success of the initiatives; and

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[11] Pipeline start-up is defined as an interval during which the pipeline system begins operations, and throughput (product flow through the pipeline) is ramped to its commercial capacity.

[12] Annual reports must be received by PHMSA by the last day of the month of Pipeline Start-Up. For example, the annual report for pipeline start-up beginning March 7, 2021, must be received by PHMSA no later than March 31st each year beginning in 2022.

[13] Upon notice to the AGDC, PHMSA may update reporting contacts for **Condition 9**.

[14] Annual reports submitted to PHMSA must be posted by AGDC to Docket No. PHMSA-2017-0046 at www.regulations.gov for public review.

f) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies.

10) **Certification:**

a) A senior executive officer, vice president or higher, of AGDC must certify in writing that:
   i. The ***special permit segment*** meets the conditions described in this special permit (including applicable sections 49 CFR 192.112, 192.328, and 192.620 for alternative MAOP) and other applicable sections of 49 CFR Part 192;
   ii. The written manual of O&M procedures required by 49 CFR 192.605 for Alaska LNG Pipeline includes all additional operating and maintenance requirements of this special permit and 49 CFR Part 192.

b) The certification must be sent to PHMSA within three (3) months of placing the Alaska LNG Pipeline into natural gas service.

c) AGDC must send a copy of the certifications required in this condition, with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA Associate Administrator for Pipeline Safety with copies to the Deputy Associate Administrator for Pipeline Safety, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; PHMSA Western Region Director; PHMSA Standards and Rulemaking Division Director; PHMSA Engineering and Research Division Director; and to the Federal Register Docket (PHMSA-2017-0046) at www.regulatons.gov.[15]

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 AGDC has complied with the specified conditions of this special permit for the ***special permit segment***. Failure to comply with any condition of this special permit may result in revocation of the permit.

[15] Upon notice to the AGDC, PHMSA may update reporting contacts for **Condition 10**.

2) Any work plans and associated schedules for the Alaska LNG Pipeline are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by AGDC to submit the certifications required by **Condition 10 (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 for the Alaska LNG Pipeline. 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 AGDC sells, merges, transfers, or otherwise disposes of all or part of the assets known as the Alaska LNG Pipeline, AGDC 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. Any notifications for this limitation must be sent to the PHMSA Associate Administrator for Pipeline Safety with copies to the Deputy Associate Administrator, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; PHMSA Western Region Director; PHMSA Standards and Rulemaking Division Director; and PHMSA Engineering and Research Division Director.

AUTHORITY: 49 U.S.C. 60118 and 49 CFR 1.97.

Issued in Washington, DC on SEP 9 2019.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety