U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT – Crack Arrestor Spacing

SEP 9 2019

Special Permit Information:

Docket Number:	PHMSA-2017-0047
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(b)

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(b) for crack arrestor spacing in Class 1 locations, when using the alternative maximum allowable operating pressure (alternative MAOP) as allowed in 49 CFR 192.112, 192.328, and 192.620. Section 192.112(b) requires crack arrest based upon pipe toughness properties or the spacing of the crack arrestor to achieve 99 percent (%) probability of fracture arrest within eight (8) pipe joints.

[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] The term Alaska LNG Pipeline refers to the approximately 807 miles of 42-inch pipeline and not to any potential owners, operators, or entities associated with the Alaska LNG Pipeline. The Special Permit owner, operator, and applicant/permittee is AGDC.

I. Purpose and Need:

The Alaska LNG Pipeline is a proposed 42-inch-diameter natural gas pipeline, approximately 807 miles in length, extending from the AGDC's Gas Treatment Plant (GTP) on the North Slope to the Liquefaction Facility on the shore of the Cook Inlet near Nikiski, Alaska, including an offshore pipeline section crossing Cook Inlet. The onshore 42-inch pipeline will be a buried pipeline with the exception of short, above-ground special design segments, such as aerial water crossings and aboveground fault crossings. The Alaska LNG Pipeline design has a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig).

AGDC was granted a waiver of compliance with 49 CFR 192.112(b) for remote, sparsely populated segments in Class 1 locations designed to the alternative MAOP provisions to allow increased crack arrestor spacing from eight (8) pipe joints (320 feet) to approximately 40 pipe joints (1,600 feet). Class 1 locations are shown in Table 1: Class locations for the 42-inch Mainline.[3]

TABLE 1: Class Locations for the 42-inch Mainline		
Milepost (MP)		
Start (MP)	End (MP)	Class Location
0.00	535.99	1
535.99	536.49	3
536.49	798.65	1
798.65	801.27	2
801.27	803.78	1
803.78	806.25	2
806.25	806.57	1

Federal pipeline safety regulations require natural gas transmission pipeline operators using the alternative MAOP, as allowed in 49 CFR 192.112, 192.328, and 192.620, to use pipe materials with properties that ensure resistance to fracture initiation. The operator must address the full range of operating temperatures, pressures, gas compositions, pipe grade, and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions that the pipeline is expected to experience. Section 192.112(b) requires pipeline segments to have crack

[3] 49 CFR 192.5 defines Class location units and Class 1, 2, 3, and 4 locations.

arrest based upon pipe toughness properties or the spacing of crack arrestors to achieve 99% probability of fracture arrest within eight (8) pipe joints.

The level of pipe toughness (Charpy V-notch Impact Value) needed to arrest the fracture initiation and propagation of a rupture is determined by the pipeline's operating temperature, operating pressures, gas compositions, pipe grade, and operating stress levels. The Alaska LNG Pipeline pipe in Class 1 locations and designed using the alternative MAOP provisions, will not have the material properties to arrest a rupture fracture without crack arrestors. Therefore, crack arrestors are being installed in Class 1 locations.

II. Special Permit Segment:

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

The special permit allows alternative crack arrestor spacing in Class 1 locations on the 42-inch Alaska LNG Pipeline with the implementation of the special permit conditions.

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 "*Special Permit Analysis and Findings*" documents, which both can be read in their entirety in Docket No. PHMSA-2017-0047 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

III. Conditions:

PHMSA grants this special permit to AGDC for alternative crack arrestor spacing subject to AGDC implementing the following conditions on the Alaska LNG Pipeline 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 that are stated as pertaining to alternative MAOP (49 CFR 192.112, 192.328, and 192.620), but with exception of the crack arrestor spacing requirement in 49

CFR 192.112. In addition to 49 CFR Part 192 conformance, the Alaska LNG Pipeline ***special permit segment*** must also be designed, constructed, operated and maintained in accordance with the special permit conditions.

2. **Maximum Allowable Operating Pressure:** AGDC must operate the ***special permit segment*** at or below a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The ***special permit segment*** may be designed for operation up to 80% of specified minimum yield strength (SMYS), allowing for pressure build-up and overpressure protection in accordance with 49 CFR 192.620(e). AGDC must maintain compressor station discharge temperature and pressure records to confirm compliance with the compressor station discharge temperature limits presented in Table 2: Operational Constraints.

Table 2: Operational Constraints

Description	Pressure	Station Discharge Temperature[1,2]
Gas Treatment Plant Outlet	2025 psig	30 degrees Fahrenheit (°F) maximum
Compressor Station Discharge		
Continuous Permafrost	2050 psig	30°F maximums
Discontinuous Permafrost	2050 psig	45°F maximums
Non-Permafrost	2050 psig	80°F maximums

[1] Station discharge temperature requirements represent temperatures at the point where the mainline enters the ground. Unplanned excursions, due to cooling equipment malfunctions, of up to 10°F above the maximums are permissible for up to 24-hours in a 72-hour interval.
[2] AGDC may propose an alternative temperature excursion limits operational procedure that is supported by project-specific data, operational analysis and environmental impact analysis to PHMSA. This procedure must receive a response of "no objection" from PHMSA's Western Region Director or Project Designee prior to implementation.

3. AGDC may propose changes or timing for any reviews for the special permit conditions to PHMSA for review and approval. Any proposed changes to the conditions by AGDC must maintain equivalent/acceptable 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 any 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 the AGDC.[4]

Crack Arrestor Spacing:

4. **Fracture Control Plan:** Alaska LNG Pipeline ***special permit segments*** must develop and implement a Fracture Control Plan (FCP) and procedures that detail the pipeline's compliance with 49 CFR 192.112(b), with the exception of the crack arrestor spacing requirements in 49 CFR 192.112(b)(3) for Class 1 locations. As part of the FCP, to ensure a robust design and reduce the probability of fracture initiation, material requirements for pipe body and seam welds must be specified to achieve a large through-wall critical flaw length. This critical length must be selected as a high proportion (80-90%) of its maximum achievable threshold with a minimum requirement of four (4) inches.

5. **Intrinsic Arrest:** Certain designated sections of the pipeline ***special permit segment*** must be designed to comply with the Fracture Control Requirements in 49 CFR 192.112 without the use of external crack arrestors. These include:
   a) Strain Based Design (SBD) sections, as defined in Table 3 - Alaska LNG Pipeline - Mainline SBD Sections;

TABLE 3: Alaska LNG Pipeline - Mainline SBD Segments			
Type	**Mile Post - From**	**Mile Post - To**	**Miles**
Conventional Design	0.0	194.0	194.0
Strain Based Design	194.0	196.0	2.0
Conventional Design	196.0	227.0	31.0
Strain Based Design	227.0	230.0	3.0
Conventional Design	230.0	257.0	27.0
Strain Based Design	257.0	262.0	5.0
Conventional Design	262.0	270.0	8.0
Strain Based Design	270.0	276.0	6.0
Conventional Design	276.0	429.0	153.0
Strain Based Design	429.0	440.0	11.0
Conventional Design	440.0	541.0	101.0
Strain Based Design	541.0	544.0	3.0

[4] AGDC must submit any proposed changes to the conditions to PHMSA Director, Western Region or PHMSA project designee for review and receive a "no objection" letter prior to usage by AGDC.

TABLE 3: Alaska LNG Pipeline - Mainline SBD Segments			
Type	**Mile Post - From**	**Mile Post - To**	**Miles**
Conventional Design	544.0	559.0	15.0
Strain Based Design	559.0	563.0	4.0
Conventional Design	563.0	766.0	203.0
Offshore Conventional Design	766.0	793.3	27.3
Conventional Design	793.3	806.6	13.3

b) Sections of the ***special permit*** adjacent to the bridges and railroad crossings listed below will have an appropriate thermal exclusion zone. This thermal exclusion zone will be calculated in a similar fashion to the potential impact radius (PIR) for a gas transmission pipeline as defined in 49 CFR 192.903, taking into account a heat threshold suitable for uninhabited steel structures of 10,000 BTU/hr/ft.^{2} For a 42-inch diameter, 2075 psig MAOP pipeline the thermal exclusion zone using this methodology is 1,040 feet.[5] The pipe thickness calculated using a design factor of 0.6 for Grade X80M (wall thickness of 0.9 inches) pipe will intrinsically arrest, therefore this minimum pipe thickness must be used within 1,040 feet of the following bridge or bridge abutments or railroad crossing locations:

i. Dietrich River (1337),[6]
ii. Nenana River at Moody (1143),
iii. Nenana River at Windy (1243),
iv. Iceworm Gulch (1146),

[5] The thermal exclusion zone on either side of a bridge or railroad crossing is calculated using a derivation of the potential impact radius (PIR) in 49 CFR 192.903, which uses a thermal heat flux of 5,000 British Thermal Units/hour-feet^2 (BTU/hr.-ft^2). The PIR in 49 CFR 192.903 was derived using a thermal heat flux of 5,000 BTU/hr-ft2, while the thermal exclusion zone defined in Condition 5(b) above is based on a thermal heat flux of 10,000 BTU/hr- ft^2. In the PIR formula derivation the thermal heat flux (I) is in the denominator within the radical (i.e. square root of 1/I), thus the thermal exclusion zone distance is the square root of 5,000/10,000 times the PIR. For the Alaska LNG Pipeline, the PIR is calculated as 1,465.5 feet (includes the effects of the gas composition per ASME B31.8S as required by 49 CFR 192.903) and multiplying by the square root of 5,000/10,000 yields 1,036.2 feet. The thermal exclusion zone in Condition 5(b) is to give added protection from an incident to transportation infrastructure. Condition 5(b) uses 1,040 feet as a thermal exclusion zone for the identified bridge, or bridge abutments, or railroad crossing locations.

[6] Bridge numbers are from "Alaska 2013 Bridge Inventory Report": http://www.dot.alaska.gov/stwddes/desbridge/assets/pdf/2013bridgeinventory.pdf.

v. Antler Creek (1141),

vi. Alaska Railroad Crossing MP 532.07,[7]

vii. Alaska Railroad Crossing MP 572.79,

viii. Alaska Railroad Crossing MP 588.07, and

ix. Alaska Railroad Crossing MP 609.02.

6. **<u>Crack Arrestor Design and Materials Testing</u>:** The materials testing and crack arrestor design and testing must meet the following requirements:
   a) Material destructive testing must be carried out to demonstrate compliance with the Fracture Control requirements in 49 CFR 192.112(b)(2)(iv).
   b) Either composite or steel crack arrestors or heavy walled pipe (integral arrestor) must be used to ensure at least 99% probability of fracture arrest in one arrestor when the requirements of 49 CFR 192.112(b)(1) and (2) cannot be met. Full scale crack arrestor testing must be performed to verify the design/material of the arrestor. AGDC must perform proof testing using the combination of MAOP, gas composition, design factor, and pipe grade that has the highest driving force for fracture propagation.

7. **<u>Crack Arrestor Spacing</u>:** Crack arrestor spacing is subject to the following requirements and limitations.
   a) In Class 1 locations, the spacing of crack arrestors or pipe that otherwise meets the requirements of 49 CFR 192.112(b)(1) and (2) may extend up to 1,600 feet.
   b) Where the ***special permit segment*** crosses the Trans-Alaska Pipeline System (TAPS), AGDC must comply with 49 CFR Part 192.112(b) when within 300 feet of crossings of TAPS or TAPS Fuel Gas Line.
   c) For ***special permit segment*** located in Class 2, 3, or 4 locations and High Consequence Areas (HCAs), AGDC must comply with 49 CFR 192.112(b) fracture control requirements.

8. **<u>Coating Disbondment, Cathodic Protection Current, and Anomaly Remediation</u>:** Any section of the ***special permit segment*** with Class 1 pipe that does not meet 49 CFR

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[7] Alaska LNG Pipeline route revision C2 mileposts.

192.112(b) crack arrestor spacing requirements and is located within the thermal exclusion zone (1,040 feet) of a bridge or railroad listed in Condition 5(b) or a crossing of TAPS as described in Condition 7(b) must have the following remediation within one (1) year of the ILI tool run, excavation findings and subsequent data analysis identifying pipe anomalies greater than 40% wall loss:

a) Remediate pipe anomalies greater than 40%[8] wall loss and in accordance with 49 CFR 192.620(d)(11);
b) Take remedial action to address the condition of the coating system, the level of cathodic protection (CP), and to mitigate the corrosion that has occurred; and
c) Use technologies to demonstrate that adequate levels of CP are being afforded to the pipeline, and that coating degradation or disbondment is limited to the area in question.

Reporting, Data and Certification:

9. **Annual Reports:** Within twelve (12) months following Pipeline Start-Up[9] and annually[10] thereafter, AGDC must report the following to the PHMSA Western Region Director or Project Designee with copies to the Director, PHMSA Engineering and Research Division, and Director, PHMSA Standards and Rulemaking Division:[11, 12]
    a) The number of new residences, identified sites, or other structures intended for human occupancy and public gathering areas built within a potential impact radius (PIR) as defined in 49 CFR 192.903 built during the previous year;

[8] Anomalies greater than 20% wall loss and up to 40% wall loss may be allowed in sections of the ***special permit segment***, but must be evaluated with O&M procedures that are based upon a destructive test program and finite element evaluation that validates the procedure.

[9] 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.

[10] 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.

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

[12] AGDC must place a copy of each Alaska LNG Pipeline annual report on the PHMSA docket, PHMSA-2017-0047, at www.regulations.gov.

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 segments*** 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

f) Submit for each compressor station the discharge temperatures during the past year showing how they are in accordance with Table 2: Operational Constraints for continuous permafrost, discontinuous permafrost, and non-permafrost areas.

g) 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 of AGDC, vice president or higher, must certify in writing that:

   i. The ***special permit segments*** meet 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 10, 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-2017-0047) at www.regulations.gov.[13]

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 segments***. 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 segments*** 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 (Certifications) 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 ***special permit segments***, 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.

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

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