U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Final Environmental Assessment
and
Finding of No Significant Impact

Crack Arrestor Spacing Special Permit

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
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Code Sections:	49 CFR 192.112(b)

Crack Arrestor Spacing

Final Environmental Assessment

This Final Environmental Assessment (FEA) analyzes the Alaska LNG Pipeline for a special permit request from the Alaska Gasline Development Corporation (AGDC or Applicant) to waive the requirements of Title 49 of the Code of Federal Regulations (CFR) 192.112(b). The special permit request described herein is related to, but distinct from the Federal Energy Regulatory Commission (FERC) decision making process for siting and permitting Alaska LNG Pipeline's 42-inch Mainline Pipeline to transport natural gas from a facility on Alaska's North Slope. The United States (U.S.) Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA) does not have pipeline siting or construction approval authority, but PHMSA's Pipeline Safety Regulations impose certain safety requirements that will apply to the Alaska LNG Pipeline. The requirements for special permit applications to PHMSA to request waiver from one or more safety regulations are described at 49 CFR 190.341. This FEA references AGDC's (Applicant) FERC Resource Reports to avoid duplication. This FEA accompanies AGDC's special permit request on crack arrestor spacing. This information can also be found in Appendix C, *Environmental Information for Mainline Block Valve and Crack Arrestor Spacing Special Permit* of the Alaska LNG FERC Resource Report No. 11, *Reliability and Safety* found on the FERC docket CP17-178, Accession Number 20170417-5342 which can be accessed through https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=14562356.

I. Purpose and Need

AGDC is proposing to construct a 42-inch pipeline as part of an integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for liquefying supplies of natural gas from Alaska, from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas. FERC is the lead federal agency. Pursuant to 49 U.S.C. 60101, *et seq*, and 49 CFR Part 192, PHMSA has authority over natural gas pipeline design, construction, operation, and maintenance of natural gas pipelines to maintain safety. As noted above, PHMSA does not have pipeline siting authority or construction approval authority. Special permits can be granted under 49 CFR 190.341 for deviations from the regulatory requirements. PHMSA imposes conditions on the grant of special permits to assure safety and environmental protection in accordance with 49 CFR 190.341. PHMSA complies with the National Environmental Policy Act (NEPA) in deciding whether to issue the special permit.

> The AGDC is requesting a special permit for exemption from the requirements for crack arrestor (CA) spacing of every eight (8) pipe joints (~320 feet) for those pipeline segments subject to 49 CFR 192.112(b) where intrinsic arrest cannot be achieved. The AGDC is

proposing CA spacing of 1,600 feet. The purpose of a crack arrestor is to stop the propagation of large cracks that may occur immediately following a pipeline failure (rupture). 49 CFR 192.112(b)(2) determines the spacing of CAs:

(2) Fracture control must:

(i) Ensure resistance to fracture initiation while addressing 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. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline;

(ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;

(iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths;

II. Background and Site Description

The Alaska LNG Pipeline route from the proposed gas treatment plant (GTP) located at Prudhoe Bay to the proposed LNG Plant site located on the Kenai Peninsula is shown in Figure 1. The Alaska LNG Pipeline (Alaska LNG Pipeline or Mainline) will be a 42-inch-diameter natural gas pipeline, approximately 807 miles in length, extending from the GTP on the North Slope to the Liquefaction Facility on the shore of Cook Inlet near Nikiski, including an offshore pipeline section crossing Cook Inlet. The onshore pipeline will be a buried pipeline except for short aboveground special design segments, such as aerial water crossings and fault crossings.

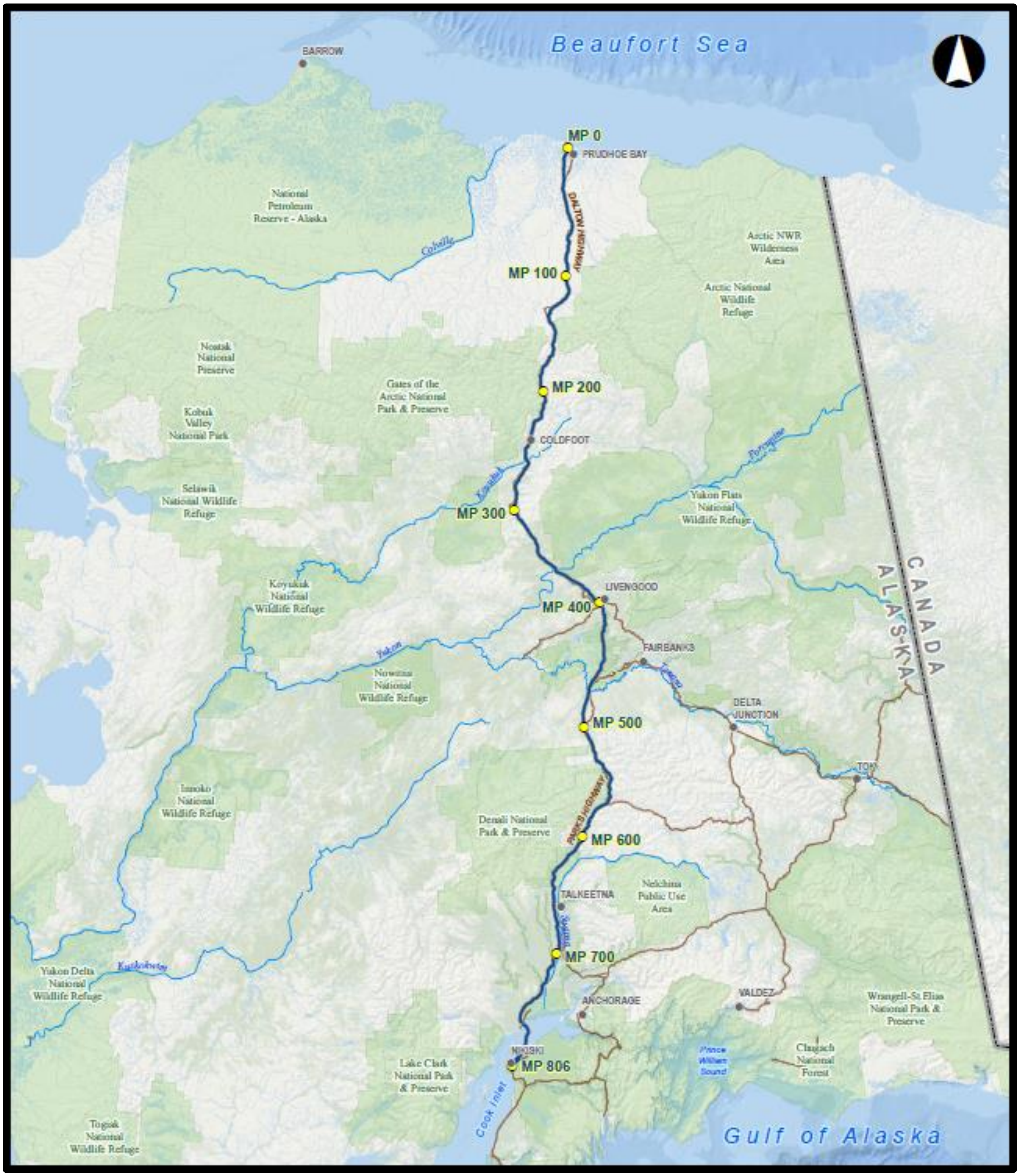


Figure 1: Mainline Route Map

As presented in Table 1.3.2-1 of FERC Resource Report No. 1, *General Project Description*, (inserted below), the Alaska LNG Pipeline will originate in the North Slope

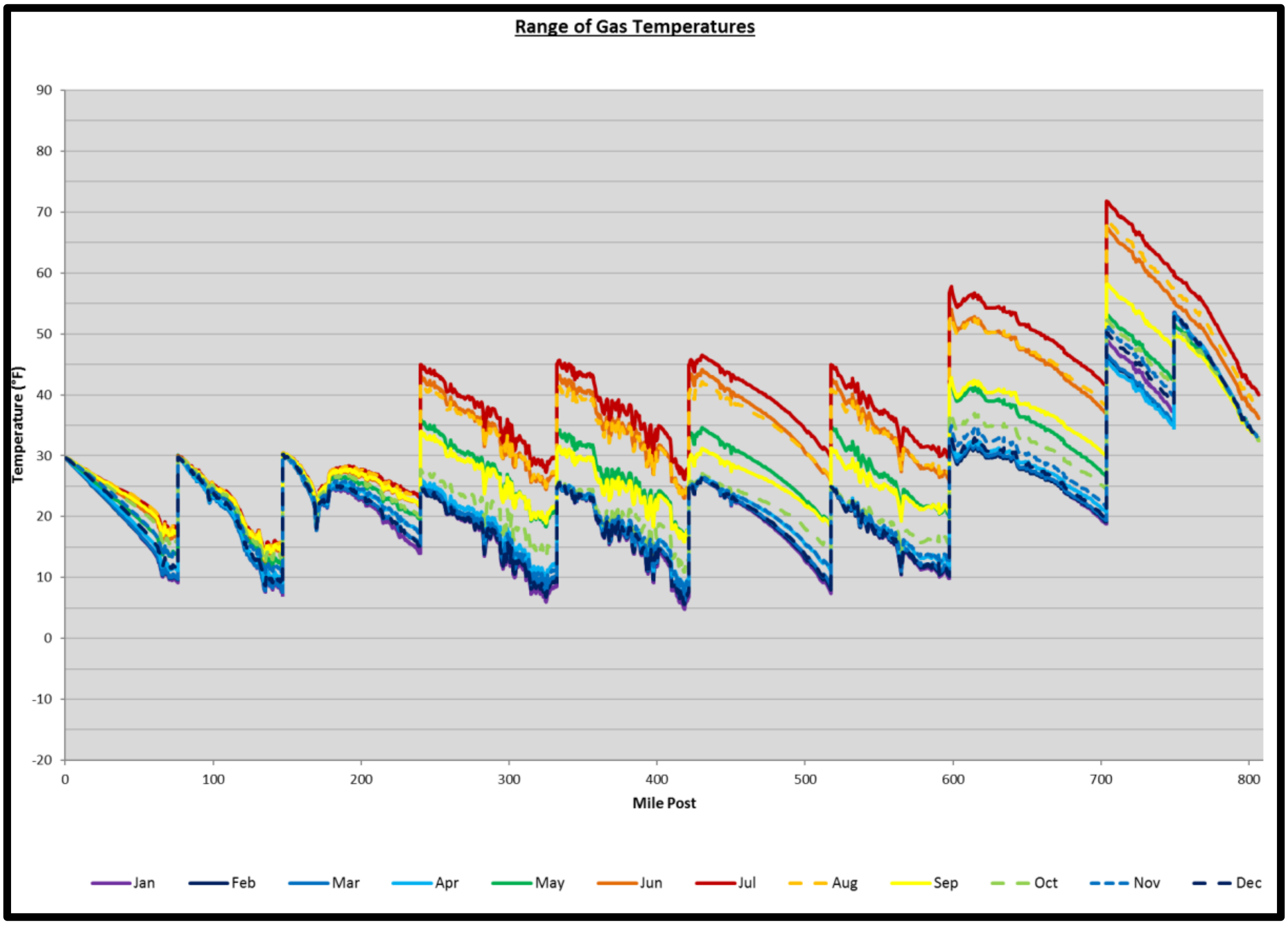
Borough, traverse the Yukon-Koyukuk Census Area, the Fairbanks North Star Borough, the Denali Borough, the Matanuska-Susitna Borough, and the Kenai Peninsula Borough, and terminate at the Liquefaction Facility. The Alaska LNG Pipeline has a maximum allowable operating pressure (MAOP) of 2,075 pounds per square inch gauge (psig). The range of gas temperatures during operations is shown in FERC Resource Report 1, General *Project Description*, Figure 1.3.2-2, repeated below.

TABLE 1.3.2-1 (From FERC Resource Report No. 1)

Mainline Route Summary for a 42-inch Pipeline

Segment or Facility Name	Boroughs or Census Areas	Approximate Length (miles)
Mainline	North Slope Borough	184.4
	Yukon-Koyukuk Census Areas	303.8
	Fairbanks North Star Borough	2.4
	Denali Borough	86.8
	Matanuska-Susitna Borough	179.9
	Kenai Peninsula Borough	51.3
Total		**806.6**

Figure 1.3.2-2 (from FERC Resource Report No. 1)



The Alaska LNG Pipeline will include several types of aboveground pipeline facilities. The design includes eight (8) compressor stations, four (4) meter stations, multiple pig launching/receiving stations, multiple mainline block valves (MLBV), and five (5) potential gas interconnection points. A list of compressor stations, heater station, and meter stations is provided in Table 1.3.2-6 of FERC Resource Report No. 1 (inserted below).

TABLE 1.3.2-6 (From FERC Resource Report No. 1)
Preliminary Locations of Pipeline Aboveground Facility Stations

Station	Type	Location (Pipeline Mile Post (MP))
GTP/Mainline Meter Station	Meter Station	0.0
Sagwon Compressor Station	Compressor Station with Cooling	76.0
Galbraith Lake Compressor Station	Compressor Station with Cooling	148.5
Coldfoot Compressor Station	Compressor Station with Cooling	240.1
Ray River Compressor Station	Compressor Station with Cooling	332.6
Minto Compressor Station	Compressor Station with Cooling	421.6
Healy Compressor Station	Compressor Station with Cooling	517.6
Honolulu Creek Compressor Station	Compressor Station without Cooling	597.4
Rabideux Creek Compressor Station	Compressor Station with Heating and without Cooling	675.2
Theodore River Heater Station	Heater Station	749.1
Nikiski Meter Station	Meter Station	806.6

Approximately 36 percent of the Alaska LNG Pipeline route is collocated within 500 feet of an existing right-of-way (ROW) to include the Trans Alaska Pipeline System (TAPS) and other pipelines, highways or major roads, utilities and railroads. Table 1.3.2-2 of FERC Resource Report No. 1 (inserted below) summarizes collocation of the Alaska LNG Pipeline route that are within 500 feet of highways, major roads, TAPS, other pipeline ROWs, utilities, and railroads. The Alaska LNG Pipeline crosses TAPS and its associated Fuel Gas Line 12 and 5 times, respectively, along with four (4) railroad crossings. Design of the road and railroad crossings will determine the minimum wall thickness requirements for service loads in accordance with American Petroleum Institute (API) Recommended Practice (RP) 1102, and complying with the requirements of 49 CFR 192.111. The minimum depth of cover will be four (4) feet for road crossings as specified by the Alaska Administrative Code 17.AAC 15.211 “Underground Facilities” and ten (10) feet for railroad crossings, as specified in Alaska Railroad Corporation (ARRC) standards. These values exceed the 49 CFR 192.327 requirement of a minimum of three (3) feet at drainage ditches of public roads and railroads. Site-specific designs for major highway and railroad crossings are provided in Appendix H of FERC Resource Report No. 1, *General Project Description*. Additional details on roads, railroads, pipelines, utilities, and power lines crossings can be found in FERC Resource Report No. 8, *Land Use, Recreation, and Aesthetics*.

TABLE 1.3.2-2 (From FERC Resource Report No. 1)
Collocated ROWs with the Mainline (within 500 feet)

Borough/Census Area Category	Length (Miles)	Length (Feet)
North Slope Borough		
Trans-Alaska Pipeline System (TAPS)	24.39	128,768
Other Pipelines[a]	34.83	183,904
Highways or Major Roads[b]	59.97	316,630
Utilities	108.65	573,692
Railroads	–	–
Yukon-Koyukuk Census Area		
TAPS	64.14	338,653
Other Pipelines[a]	–	–
Highways or Major Roads[b]	94.13	496.985
Utilities	106.42	561.898
Railroads	0.83	4,405
Denali Borough		
TAPS	–	–
Other Pipelines[a]	0.09	453
Highways or Major Roads[b]	13.25	69,984
Utilities	46.21	243,983
Railroads	1.00	5,283
Matanuska-Susitna Borough		
TAPS	–	–
Other Pipelines[a]	2.31	12,206
Highways or Major Roads[b]	26.76	141,289
Utilities	29.76	157,157
Railroads	2.30	12,123
Kenai Peninsula Borough[c]		
TAPS	–	–
Other Pipelines[a]	3.37	17,810
Highways or Major Roads[b]	1.58	8,342
Utilities	0.02	130
Railroads	–	–
Total Collocation Opportunities	**289.58**	**1,528,971**

a Other Pipelines – any pipeline other than the Trans-Alaska Pipeline System
b Highways or Major Roads – includes public roads only
c Kenai Peninsula Borough – includes offshore portions of the Mainline

Aerial crossings on pipeline specific bridges (i.e. bridges that carry only a pipeline) are located at Nenana River at Moody and Lynx Creek. The design factor for the pipeline at aerial crossings will comply with 49 CFR 192.111 (i.e., the design factor in Class 1 locations will be 0.60).

Pipeline design standards in 49 CFR 192.5(a)(1) are based on "class location units," which classify locations based on population density near an existing or proposed pipeline system. The lower the class location (1-4), the higher the design factor used to find the minimum required wall thickness for pressure containment (i.e. the required minimum thickness of the pipe increases as the Class location increases). Ninety-nine percent of the Alaska LNG Pipeline route is in Class 1, which is defined as having 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of pipeline. On the Kenai Peninsula, near Nikiski, there is a Class 2 location that is about 2.6 miles long. Also on the Kenai Peninsula there is another potential Class 2 location as the Mainline nears the LNG Plant. In the Nenana Canyon region of Denali National Park (~milepost [MP] 536) there is approximately 0.5-mile of Class 3 location. Additional details on class locations for the Alaska LNG Pipeline can be found in FERC Resource Report No. 11, *Reliability and Safety*, Section 11.7. Resource Report No. 11, Table 11.7.2-1 that outlines Class Locations for Route Revision C2 is reproduced below.

TABLE 11.7.2-1 (From FERC Resource Report No. 11)
Class Locations for the Alaska LNG Pipeline

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

There are 10 potential high consequence areas (HCA) along the Mainline as defined under 49 CFR 192.903. Details of HCA locations can be found in FERC Resource Report No. 11, Section 11.7, Table 11.7.4-1 (shown below).

TABLE 11.7.4-1 (From FERC Resource Report No. 11)
Potential HCA Takeoff Mainline Route Revision C2

From MP	To MP	Length (mi.)	Description
236.08	237.33	1.25	Marion Creek Campground
352.21	353.35	1.14	Hotspot Cafe
529.21	530.44	1.23	RV Park and Motel
535.54	537.74	2.20	Denali Riverside RV Park, McKinley Chalet Resort, Denali Rainbow Village and RV, Denali Princess Wilderness Lodge, Denali Crow's Nest Cabins, Grand Denali Lodge, Denali Bluffs Hotel
551.34	552.27	0.93	Denali Perch Resort
565.77	567.23	1.46	DOT/PF Cantwell Station
629.75	631.35	1.60	Byers Lake Campground (73 units)
633.75	634.50	0.75	Trappers Creek Pizza Pub
797.71	799.28	1.57	Nikiski Middle/High School, Kenai Heliport, Commercial Buildings, Industrial Sites
803.39	806.05	2.66	Conoco Phillips Property and Tesoro Kenai Refinery
Total		14.79	

In addition, the pipeline route segments addressed in the special permit for Strain Based Design, (SBD segments), will be incorporated into the integrity management program (IMP), and treated as covered segments in HCA, in accordance with 49 CFR Part 192, Subpart O, and the associated special permit conditions.

The construction ROW width will vary depending on the type of terrain, the season of construction, and the ease of access from nearby roads. The permanent ROW width will be 50 feet plus the diameter of the pipeline (i.e. 53.5 feet). Greater details on construction ROW can be found in FERC Resource Report No. 1, *General Project Description*. The Mainline will be sited on land composed of more than 85 percent federal, State of Alaska, and borough land of various holdings, with the remainder on privately owned land (see Resource Report No. 8, *Land Use, Recreation and Aesthetics*).

The pipeline corridor spans nine (9) ecoregions including the Beaufort Coastal Plain, Brooks Foothills, Brooks Range, Kobuk Ridges and Valleys, Ray Mountains, Yukon-Tanana Uplands, Tanana-Kuskokwim Lowlands, Alaska Range, and Cook Inlet Basin. These regions host a variety of ecosystems including muskeg bogs, spruce upland forest, alpine and Arctic tundra, high brush, and bottomland spruce and poplar forests. The associated ecosystems support a variety of species which include grizzly and black bears, arctic foxes, seals, caribou, moose, small terrestrial mammals, birds, and anadromous fish. A variety of marine mammals inhabit the coastal waters in the Project area, including the bowhead whale, polar bear, beluga whale, ringed seal, bearded seal, Stellar sea lion, harbor seal, ribbon seal and spotted seal. Some of these species are critical subsistence resources for Alaska Native peoples. For additional information see FERC Resource Report No.3, *Fish, Wildlife and Vegetation Resources*.

A detailed description of the Mainline ROW is included in Section 1.3.2.1 of FERC Resource Report No. 1, *General Project Description*. Supporting facilities are described in Section 1.3.2.1.3 and temporary construction infrastructure is described in Section 1.3.2.4 of FERC Resource Report No. 1, *General Project Description*. Baseline environmental conditions and the analysis of environmental effects resulting from construction and operation of the Mainline are addressed in the individual FERC Resource Reports which can be accessed by entering the FERC Docket Number "CP17-178" and then opening the Accession Number of the FERC filing for that Resource Report. Direct links to the Accession File for each Resource Report are given below:

a) Resource Report No. 1 (General Project Description) 20170417-5337.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561634

b) Resource Report No. 2 (Water Use and Quality) 20170417-5341.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561641

c) Resource Report No. 3 (Fish, Wildlife and Vegetation) 20170417-5351.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561657

d) Resource Report No. 4 (Cultural Resources) 20170417-5336.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561631

e) Resource Report No. 5 (Socioeconomics) 20170417-5338.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635

f) Resource Report No. 6 (Geological Resources) 201704167-5338.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561635

g) Resource Report No. 7 (Soils) 20170417-5345.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645

h) Resource Report No. 8 (Land Use, Recreation and Aesthetics) 20170417-5345.
https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645

i) Resource Report No. 9 (Air and Noise Quality) 20170417-5345. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561645

j) Resource Report No. 10 (Alternatives) 20170417-5340 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561638

k) Resource Report No. 11, (Reliability and Safety) 20170417-5342. https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14561642

Description of the Special Permit Request

As stated above, the AGDC is seeking exemption from the requirements for crack arrestor (CA) spacing of every eight pipe joints (~320 feet) for those Alaska LNG Pipeline special permit segments subject to 49 CFR 192.112(b) where intrinsic arrest cannot be achieved to stop propagation of a crack along the 42-inch diameter pipeline. The AGDC is proposing CA spacing of 1,600 feet and will typically be specified in all areas where API 5L X80 pipe with wall thicknesses corresponding to design factors of 0.8 (Alternative MAOP) and 0.72 will be installed. This includes the majority of Class 1 Locations along the alignment. Additional details on Class locations for the Alaska LNG Pipeline can be found in FERC Resource Report No. 11, *Reliability and Safety*, Section 11.7.

The pipeline will traverse areas commonly used for outdoor recreation, sporting, and subsistence activities. It is possible individuals could be near the pipeline even if there are 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of pipeline.

III. Alternatives

An applicant requesting a special permit from PHMSA has the option of building a pipeline which will not require PHMSA to issue a special permit. This will require the design, construction, and operation of a pipeline in-compliance with 49 CFR 192 and will install CA at a maximum spacing of eight pipe joints within Mainline segments subject to 49 CFR 192.112(b) where intrinsic arrest cannot be achieved. Therefore, PHMSA's NEPA assessment is slightly different from other agencies in that the No Action alternative is not a "no build" alternative. Rather, the No Action alternative reflects a pipeline design that will not require issuance of a special permit. The Proposed Action alternative reflects the Applicant's increase of CA spacing for which a Special Permit with conditions will be issued. The two alternatives are described below.

a. **No Action Alternative** – Design, construct, operate and maintain the pipeline in compliance with 49 CFR 192. This will require crack arrestors to be placed at 320-foot intervals for those segments subject to 49 CFR 192.112(b) or pipe capable of intrinsic arrest specified through pipe toughness properties or thicker wall thickness pipe.

b. **Proposed Action Alternative** – Design, construct, operate, and maintain the pipeline in compliance with the CA spacing special permit conditions.

i. *Explain what the special permit application asks for.*

Increase in CA Spacing up to 1,600 feet from the requirement in 49 CFR 192.112(b), which is spacing every 320 feet.

Note, as per Special Permit Condition 5(b), pipe compliant with 49 CFR 192.112(b)(1) and (2) and capable of intrinsic arrest will be installed whenever the Alaska LNG Pipeline is within a distance defined by a maximum thermal flux of 10,000 British Thermal Units/hour/feet^2 (BTU/hr/ft^2) (approximately1,040 feet) when crossing key highway bridges or railroads. The applicable bridges and railroad crossing locations are designated in the special permit condition7(b) (i through viii). Crack arrestor spacing, or intrinsic arrest, will comply with 49 CFR 192.112(b) when within 300 feet of crossings of TAPS or TAPS Fuel Gas Line per special permit Condition 7(b).

ii. *Cite regulation(s) for which special permit is sought in accordance with 49 CFR 190.341:*

49 CFR 192.112(b).

iii. *Explain/summarize how the design/operation/maintenance of the pipeline operating under the special permit would differ from the pipeline in the no action alternative.*

The requirements of 49 CFR 192.112 apply to pipe designed using the Alternative MAOP rules of 49 CFR 192.620. When the pipe cannot achieve intrinsic arrest (i.e. arrest based on material toughness properties of the pipe) within eight pipe joints, a mechanical crack arrestor such as a joint of thicker-walled pipe or a specialty mechanical arrest mechanism, is inserted every eight joints. The proposed alternative uses the same procedure, described below, as the no-action alternative to designate which types of pipe (grade & wall thickness combination) cannot intrinsically arrest a fracture.

To address the requirements of 49 CFR 192.112, a preliminary fracture control plan has been developed for the Alaska LNG Pipeline. The objectives of the fracture control plan are to: 1) determine the required material toughness to prevent fracture initiation; 2) determine requirements to prevent brittle fracture propagation; and 3) establish measures to control ductile fracture propagation.

The minimum toughness requirements for the AGDC's fracture control plan are based on a method developed by Battelle in the late 1960s and early 1970s[1,2], which remains an industry standard and has been supplemented by additional research through application of factors to account for high toughness steels and backfill properties. This method was originally validated against 92 burst tests on pipe vessels containing axial, through-wall flaws, which showed the analytical predictions to be extremely accurate[3]. This method can be used to calculate the toughness required to prevent an unstable fracture as a function of the length of a through-wall flaw and is used by the pipeline industry to specify toughness requirements for pipelines.

Fracture Initiation

Fracture initiation will not occur unless a through-wall flaw develops, and a rupture will not occur unless the length of the through-wall flaw exceeds a critical length (typically denoted L_{crit}). The critical flaw length generally depends on pipe geometry, material flow stress (a function of yield strength and tensile strength) and toughness. The Battelle method is used to determine the critical flaw length and the required Charpy V-notch (CVN) energies as a function of flaw length. The critical lengths calculated are presented in FERC Resource Report 11, Table 11.7.2-12 (duplicated below). It is standard industry practice to specify minimum CVN energies corresponding to 80 to 90 percent of the critical flaw length for the pipe body. This practice has proved to provide for acceptable critical flaw sizes without requiring impractical CVN energy values. For the Alaska LNG Pipeline 90 percent is used for Class 1 and 2 locations, while 80 percent is used for Class 3 and 4 locations. Due to the rigorous pipe mill non-destructive examination and the fact the pipe is subjected to pressure testing, the values required for the seam weld and heat affected zone (HAZ) are significantly lower. Thus, a critical through-wall length of four (4) inches is considered completely adequate for establishing required CVN energies. The calculated required CVN energies,

[1] J. Kiefner, "Fracture Initiation," American Gas Association, New York, USA, 1969.

[2] J. Kiefner, W. Maxey, R. Eiber and A. Duffy, "Failure Stress Levels of Flaws in Pressurized Cylinders," ASTM STP 536, Philadelphia, PA, USA, 1973.

[3] A. Rothwell and D. Horsley, "Evolution and Current Status of Fracture control Design for Gas Pipelines," Canberra, Australia, 2007.

along with the preliminary project minimum values are presented in Table 11.7.2-13 of FERC Resource Report No. 11, replicated below. Test temperature for CVN testing will be the minimum design temperature, set conservatively at 5°F.

TABLE 11.7.2-13 (from FERC Resource Report No. 11)
Fracture Control: Fracture Initiation

Section	Grade	Class Location	Design Factor	Wall thickness (in)	L_{crit} (in)**	
					Pipe Body	Seam Weld/HAZ
Strain-Based (Type 2)	X70M	1	0.72	0.86	8.7	7.5
		2	0.6	1.03	11.4	9.0
		3	0.5	1.24	15.4	11.8
Conventional (Type 1)	X80M	1*	0.8	0.68	5.9	5.1
		1	0.72	0.75	7.5	6.5
		2	0.6	0.90	10.6	9.7
		3	0.5	1.08	13.4	10.2

Notes: * - utilizing Alternative MAOP
**L_{crit} is the critical length of a through-wall flaw for occurrence of fracture initiation

Table 1 – Fracture Initiation CVN Requirements[4]

Section	Grade	Class Location	Design Factor	Wall thickness (in)	Calculated Required CVN (foot-pounds) (ft-lb)		Specified CVN (ft-lb)	Specified > Required?	Specified CVN (ft-lb)		Specified > Required?
					90%	80%	Pipe Body		4-inch	Seam Weld/HAZ	
Strain-Based (Type 2)	X70M	1	0.72	0.86	49	NA	118	YES	YES	44	YES
		2	0.6	1.03	66	NA	74	YES	YES	30	YES
		3	0.5	1.24	NA	53	74	YES	YES	30	YES
Conventional (Type 1)	X80M	1*	0.8	0.68	46	NA	103	YES	YES	44	YES
		1	0.72	0.75	55	NA	103	YES	YES	44	YES
		2	0.6	0.90	74	NA	103	YES	YES	44	YES
		3	0.5	1.08	NA	60	74	YES	YES	30	YES

Notes: * - utilizing Alternative MAOP
To convert ft-lb to J multiply by 1.356, e.g. 103 ft-lb times 1.356 equals 140 J.
There are no Strain-Based Design segments in Class 2 or 3 locations

A review of the results in Table 1, above, shows in all cases the specified CVN energies are higher than the calculated required values. This means fracture

[4] AGDC Work Product

initiation should not occur. Therefore, consideration of mitigating requirements for fracture initiation for both the proposed and no-action alternative is not required for this evaluation, since the intrinsic material property requirements are equally capable of resisting initiation.

Fracture Propagation

Brittle Fracture Propagation

Brittle fracture is unacceptable because the associated fracture speeds are higher than the acoustic velocity in the gas. As a result, there is no reduction in pressure at the propagating crack tip. Brittle fractures also tend to have a small crack tip opening angle, which limits the effectiveness of external crack arrestors that depend on a large crack tip opening angle to transfer load from the pipe to the crack arrestor. Therefore, brittle fractures can travel very long distances before arrest compared to ductile fractures.

Preventing brittle fracture is achieved by having the material operating above its brittle-to-ductile Fracture Propagation Transition Temperature (FPTT). The Drop Weight Tear Test (DWTT) is an effective way to determine the full-scale fracture behavior of pipe. Particularly, a shear area over 85 percent in the DWTT at the minimum design temperature ensures a ductile fracture in the pipeline.[5].

All observations and testing carried out to date support the finding that specification of 85 percent shear area in the DWTT eliminates the possibility of brittle fracture propagation. For pipe utilizing Alternative MAOP, 49 CFR 192.112 requires a minimum DWTT shear area of 80 percent average, with a minimum single specimen result of 60 percent.

For the Alaska LNG Pipeline, the minimum required shear area for any test (set of two specimens) will be greater than or equal to 85 percent, with no individual test specimen exhibiting less than 75 percent shear area. Test temperature for DWTT will be the minimum design temperature, set conservatively at 5°F.

Ductile Fracture Propagation

In the unlikely event of a running longitudinal rupture, it is necessary to arrest a ductile fracture within a limited distance. In principle, and in accordance with the applicable regulations and standards, this can be achieved either through

[5] R. Eiber, T. Bubenik and W. Maxey, "Fracture Control Technology for Gas Pipelines," Pipeline Research Council International, 1993.

specifying material toughness high enough for intrinsic arrest or by using crack arrestors.

The industry-standard Battelle Two-curve Method[6] [7] with an appropriate Correction Factor (CF) required for high strength materials and rich gases was used to determine the CVN energy for fracture arrest.

The Leis correction factor[8] was adopted for X65 and X70 steel grades, while the Eiber modification[9] of the Leis correction was found to be more accurate for X80 steel and was, therefore, adopted in the fracture propagation analysis.

Calculations used the nominal gas composition and the conventional backfill coefficient for unfrozen soil[10], which provides conservative results for frozen soil. An additional level of conservatism is introduced by the fact the cover depth for Alaska LNG Pipeline is 36 inches in order to meet the requirements in 49 CFR 192.328, while the backfill coefficient was initially developed for a standard cover depth of 30 inches.

Fracture propagation analysis assumed the most demanding combination of operating pressure and temperature within the system operating envelope, namely the maximum operating pressure of 2,075 psig and a temperature of 5°F. This temperature was found to provide the maximum driving force for fracture, and hence the maximum arrest toughness requirement. The calculated required CVN energies, along with the preliminary project minimum values, are presented in Table 2, below.

Table 2 – Fracture Propagation CVN Requirements[11]

Section	Grade	Class Location	Design Factor	Wall Thickness (in)	Required CVN (ft-lb)	Correction Factor	Required CVN w/ Correction Factor (ft-lb)	Specified CVN (ft-lb)	Specified CVN > Required CVN?

[6] Ibid

[7] W. Maxey, "Fracture Initiation, Propagation and Arrest," Pipeline Research Council International, Falls Church, VA, USA, 1974.

[8] X. Zhu and B. Leis, "CVN and DWTT Energy Methods for Determining Fracture Arrest Toughness of High Strength Pipeline Steels," Proceedings of the 2012 9th International Pipeline Conference, no. IPC2012-90624, 2012.

[9] B. Eiber, "Fracture Propagation – 1: Fracture-Arrest Prediction Requires Correction Factors," Oil and Gas Journal, vol. 106, no. 39, 2008.

[10] R. Eiber, T. Bubenik and W. Maxey, "Fracture Control Technology for Gas Pipelines," Pipeline Research Council International, 1993.

[11] AGDC Work Product.

Strain-Based (Type 2)	X70M	1	0.72	0.86	111	1.23	137	155	YES
		2	0.6	1.03	76	1.04	79	103	YES
		3	0.5	1.24	55	1.00	55	103	YES
Conventional (Type 1)	X80M	1*	0.8	0.68	199	1.93	384	133	NO
		1	0.72	0.75	142	1.61	229	133	NO
		2	0.6	0.90	95	1.31	124	133	YES
		3	0.5	1.08	68	1.00	68	103	YES

Notes: * - utilizing Alternative MAOP
To convert ft-lb to J multiply by 1.356, e.g. 103 ft-lb times 1.356 equals 140 J.
There are no Strain-Based Design segments in Class 2 or 3 locations

A review of the results in the Table 2, above, shows in all cases except for conventional (Type 1) in Class 1 locations regardless of the use of Alternative MAOP provisions, the specified CVN energies are higher than the calculated required values. This means a fracture propagating in the longitudinal direction of the pipe will self-arrest, also known as intrinsic arrest, and meets the requirements of 49 CFR 192.112(b)(2)(iii). In the two cases where intrinsic arrest is not considered achievable, mechanical crack arrestors will be used. For those sections of X80M pipe in Class 1 locations, crack arrestors at 1,600-foot spacing will be installed in lieu of 320-foot spacing, except for certain situations detailed in the conditions. This construction will not affect maintenance and operations, except as further specified in the conditions.

The fracture control plan will also require the pipeline designed using the Alternative MAOP provisions to be able to stop a propagating fracture within eight (8) pipe lengths (320 feet) through either crack arrestors, or intrinsic arrest, per the requirements of 49 CFR 192.112(b)(3), when in proximity to key infrastructure (e.g. key bridges and TAPS). A table of proximate infrastructure in Class 1 Locations is presented in Table 6 at the end of this attachment.

Additional detail on the requirements for design, construction, and operation is provided in Section VIII of this document and the special permit conditions.

iv. ***Applicant*** *should include the pipeline stationing and mile posts (MP) for the location or locations of the applicable* ***special permit segment(s)***

The CA special permit segments are not continuous but are wholly within Class 1 locations to the onshore mainline Alternative MAOP segments. The CA special permit segments presented below in Table 3 are the same as those identified in the special permit application for use of the three-layer polyethylene (3LPE) coating.

Table 3 – Segments for 1,600 feet CA spacing[12]

Milepost (MP)	
Start (MP)	**End (MP)**
0.00	535.99
536.49	766.00
793.00	798.65
801.27	803.78
806.25	806.57

v. *Mitigation Measures*

A number of mitigation measures are planned for the Project:

- Material requirements for the pipe body and seam welds will be specified to reduce the probability of fracture initiation. This will be achieved by ensuring the critical through-wall flaw length (80 to 90 percent of the maximum achievable threshold) is at least four (4) inches. The pipe specifications will have a defined minimum toughness requirement given as Charpy-V-notch impact energy. The minimum toughness requirement for Class 1 pipe will be 103 ft-lbs. at five (5) degrees F in the pipe body for onshore pipe.

- Pipe with toughness properties that will achieve intrinsic arrest will be required and installed when within the distance defined by a maximum thermal radiation flux of 10,000 BTU/hr/ft^2 of railroad crossings and certain key bridges as defined in the Special Permit Condition 5(b) (i through viii).

- Crack arrestor spacing, or intrinsic arrest must comply with 49 CFR 192.112(b) within 300 feet of crossings of TAPS or TAPS Fuel Line and in Class 2, 3, or 4 locations, or HCAs per Special Permit Condition 7.

- Crack arrestor design will be tested to ensure at least 99 percent probability of fracture arrest in one arrestor.

Additional information on mitigation measures is presented in Section VIII of this document and the Special Permit Conditions.

IV. Environmental Impacts of Proposed Action and Alternatives

[12] AGDC Work Product.

a. *Describe how a small and large leak/rupture to the pipeline could impact safety and the environment/human health.*

i. In support of the AGDC's request, an engineering analysis was performed in accordance with ASME B31.8 § 846.1, Required Spacing for Valves. This study evaluated the thermal radiation effects of increasing CA spacing from the eight-pipe length (~320 feet) requirement in 49 CFR 192.112(b)(2)(iii), to 40 pipe lengths (~1,600 feet). A summary of those results is presented in Attachment D – Crack Arrestor Spacing, Technical Support Document[13], Section 2.3.1 to the Special Permit application. The study concluded increasing CA spacing up to 1,600 feet had no impact on the thermal dosage (i.e., cumulative heat exposure) of a person near the pipeline.

ii. If a fracture develops following a rupture and then runs along the pipe before arrest, the initial impact circle (with a radius of the potential impact radius (PIR)) will start to elongate along the centerline, but the circular ends will have the same radius as the initial circle. If the rupture were to extend far enough along the pipe centerline, the elongated circle will split into two (2) individual circles, and in fact will have smaller radii since each is only being fed from one side, not both as with the initial circle. See Figure 3.7 a, b, and c in Section 2.1.3 of Attachment D – Crack Arrestor Spacing, Technical Support Document.

iii. Any discussion of the consequence of a leak or rupture must be put into the context of its probability. It is highly unlikely a leak or rupture occurring in the Alaska LNG Pipeline Class 1 locations will impact the environment or human health for the following reasons:

a) Remoteness of the pipeline route: more than 99 percent of the Alaska LNG Pipeline route is in Class 1 location (800.98 miles of 806.57 miles).

b) Resistance to mechanical damage: A puncture analysis was completed in accordance with the Australian Pipeline Code AS 2885-1 (*Pipelines – Gas and Liquid Petroleum Part 1: Design and Construction*). Results of these calculations confirmed no combination of excavator and tooth type will result in a puncture and are presented in Table 4. Additional information is presented in the attached Technical Support document, Section 3. Further, fracture mechanics calculations based on the mechanical properties of the pipe material and operating conditions of the pipe have shown the pipe is very

[13] Attachment D – Crack Arrestor Spacing – Technical Support Document for the Alaska LNG Pipeline was prepared by AGDC and can be found at Docket No. PHMSA-2017-0047 on www.regulations.gov.

resistant to fracture, capable of withstanding a through wall thickness puncture of greater than 4 inches in length without rupturing. Additional information is presented in the Technical Support document, Section 4.

Table 4 – Excavator Tooth and Penetration[14]

Excavator Weight (tonne)	Max Tooth Length i.e., Max Hole Length (mm)	General Purpose Tooth			Single Point Penetration				
							Hole Diameter (mm)		
		R_p	Fb × B	Hole Dia (mm)	R_p	Fb × B	Pen Tooth	Single Point of Tooth	Tiger Tooth
5	70	512.4	47.3	0	217.4	47.3	0	0	0
10	70	798.0	91.7	0	261.5	91.7	0	0	0
15	85	857.2	133.1	0	308.6	133.1	0	0	0
20	95	987.6	171.6	0	335.7	171.6	0	0	0
25	100	1182.0	207.2	0	351.3	207.2	0	0	0
30	110	1348.6	239.9	0	370.5	239.9	0	0	0
35	125	1572.3	269.6	0	396.9	269.6	0	0	0
40	135	1646.3	296.4	0	425.1	296.4	0	0	0
55	145	1865.8	359.3	0	436.2	359.3	0	0	0

c) Very low probability of corrosion damage: The Mainline will be transporting a dry, LNG specification gas, which contains no significant quantities of the impurities required to cause corrosion: water (<0.1 lbs./MMSCF), CO_2 (<50 ppmv) and H_2S (≤4 ppmv). With these low impurity contents, a corrosive liquid water phase will not form inside the pipeline. Therefore, the probability of internal corrosion is minimal. To confirm the integrity of the pipeline, the in-line inspection program will comply with the robust requirements of 49 CFR 192.620. External corrosion will be mitigated by using a high integrity coating and a cathodic protection system.

iii. Compliance with Alternative MAOP requirements: the entire 42-inch pipeline will be operated and maintained per 49 CFR 192.620, which establishes robust operational requirements. Additionally, more than 750 miles of the total Mainline length, to include Alternative MAOP and SBD segments, will also comply with 49 CFR 192.112, as modified by this special permit, and 49 CFR 192.328, which, respectively, establish robust design and construction requirements.

[14] AGDC Work Product.

iv. A small leak from a buried pipeline would result in a much slower release of gas, when compared with a full-bore rupture, with the total amount of gas being released dependent on the time it takes for the leak to be detected and fixed. Small leaks would be identified through a variety of techniques, such as routine surveillance, pipeline inspection programs, and mass balance systems incorporated in gas pipeline control. These techniques are not impacted by CA spacing. Gas from a small leak would permeate through the backfill material (soil) before dissipating into the air. Small gas pipeline leaks may result in some impacts to, or loss of, surrounding vegetation. This localized browning of vegetation can facilitate identification of small underground leaks during right of way inspection, which will be performed at intervals not exceeding 45 days, but a least 12 times each calendar year (per 49 CFR 192.620(d)(4)). Other visual techniques are available including inspection of snow pack (seasonal). The rate at which gas is lost, and total volume of gas lost from a small leak is independent of CA spacing, and is more contingent on identification timelines; therefore, the environmental impacts from a small leak are the same in both the proposed action and non-action case.

v. A rupture would result in the rapid release of a large volume of natural gas resulting in significant damage to the pipeline and would create a trench or crater in the immediate vicinity of the rupture. If an ignition source is present, an intense fire or explosion would result. For a fire resulting from a rupture; the damage due to the fire would depend on the extent of the combustible materials in the vicinity (infrastructure, vegetation), and local environmental conditions (e.g., rain, snow cover, etc.). The probability for human injury or fatality and property damage is relatively small for this largely remote pipeline, and decreases as distance from the rupture increases. Large ruptures would be easily detectable through monitoring of pressure and flow conditions at pipeline facilities and the mainline block valves.

b. *Submit an explanation of* ***delta/difference*** *in safety and possible effects to the environment between the 49 CFR Part 192 baseline (Code baseline) and usage of the special permit, including the special permit conditions for CA spacing mitigation measures.*

1. Human Health and Safety

For personnel, there is no difference in consequence between 320 and 1,600-foot CA spacing.[15] In the unlikely event of a rupture, a person in the near vicinity of a fracture resulting from a rupture without the benefit of nearby CA will have increased likelihood, depending on that person's distance from the pipeline, of

[15] Section 2.3.1 of Attachment D.

death or injury as a result of the rupture. However, the Class 1 location pipe that is not in close vicinity to TAPS, certain bridges, and railroads, for which PHMSA authorizes a 1,600-foot CA spacing, is extremely remote, with human use consisting primarily and occasionally of subsistence and recreational hunting and related activities.

2. Air Quality

There will be no significant difference during construction in emissions between the No Action and Proposed Action alternatives. The majority of heavy equipment required for construction in either alternative will be the same, including equipment such as brushers and bulldozers for the clearing and leveling of the ROW, trucks for transporting pipe, and side booms and welding trucks for pipe placement and welding. During the construction process, fewer installations of CAs could result in fewer emissions, but will not significantly affect overall emissions.

Operations and Maintenance activities to maintain the pipeline for the No Action and Proposed Action alternatives will require similar equipment and personnel. This comparison will apply equally to pollutant and greenhouse emissions.

In the unlikely event of a pipeline rupture or leak large enough to depressurize the pipeline and trigger valve closure, there will be no incremental increase of greenhouse gas emissions for the Proposed Action alternative, relative to the No Action alternative. (valve spacing remains unchanged for these alternatives).

Detailed description of air emissions, including greenhouse gas emissions, from pipeline construction and operations are contained in FERC Resource Report No. 9, *Air and Noise Quality*.

3. Aesthetics

There will be no difference in visual effects between the No Action and Proposed Action alternatives as a result of the CA spacing. Both alternatives will be below ground, and follow the same route.

4. Biological Resources (including vegetation, wetlands, and wildlife)

There will be no difference in impacts to vegetation, wetlands and wildlife between the between the No Action and Proposed Action alternatives. Both alternatives will be below ground, and follow the same route.

FERC Resource Report No. 3, *Fish, Wildlife and Vegetation*, contains descriptions of vegetation and wildlife resources, and potential impacts associated with the Mainline route. FERC Resource Report No. 2 contains a detailed analysis of wetlands affected by the Mainline route, and mitigation of impacts.

5. Resilience and Adaptation

The potential effects of a changing climate on Mainline design and operation are not expected to differ between the No Action and Proposed Action alternatives. Project design criteria incorporated consideration of a range of variable site conditions that could occur based upon historic information and future conditions. Mitigations are integrated into the design where appropriate or required for facility integrity and safe operations. Opportunities for resilience and adaptation to potential weather effects have been considered in the design of the Mainline. For example, geothermal modeling will be used to assess potential changes in ground temperatures that could be caused by longer-term geothermal impacts of pipeline construction, operations and changes in climate. Other resilience and adaptation design considerations for the Mainline are addressed in FERC Resource Report No. 1, *General Project Description*.

FERC Resource Report No. 9 (*Air and Noise Quality*) discusses greenhouse gas emissions from the Project.

6. Cultural Resources

There will be no difference in the effect on Cultural Resources between the No Action and Proposed Action Alternatives. Construction activities have the potential to affect cultural resources. Ground-clearing activities under both cases will be similar. The FERC is conducting the Section 106 consultation process with stakeholders; that process will lead to the development of an agreement that will address identification and management of known cultural resources and any discovered during project implementation. The cultural resources requirements will apply to both the No Action and Proposed Action alternatives to mitigate effects on these resources. FERC Resource Report No. 6, *Cultural Resources*, addresses cultural resources affected by the Project, and associated mitigations.

7. Environmental Justice

Since both pipeline designs will be sited in the same footprint, there will be no difference in effects on environmental justice resulting from construction or operation of the pipeline between the No Action and Proposed Action alternatives.

8. Geology, Soils and Mineral Resources

There will be no difference in the effect on Geology, Soils and Mineral Resources between the No Action and Proposed Action Alternatives. Construction activities have the potential to affect soils in a localized manner with minimal effect on regional geology or mineral resources. Construction activities that could contribute to erosion include clearing and grading, excavation trenching, stockpile management, backfilling, and the development of gravel pads. Most erosion effects are effectively managed through the use of erosion and sediment control measures, including, as appropriate and practicable:

a) The use of winter construction in areas of inundated and frozen ground conditions;

b) Use of settlement basins, silt fences, and other Best Management Practices (BMP) for storm water control;

c) Use of engineered flow diversions and slope breakers to control water flow on slopes and around water courses; and

d) Installation of trench breakers to address storm and groundwater flow through the trench backfill or during construction.

Operations and Maintenance activities along the pipeline right-of-way performed to meet 49 CFR Part 192 will be similar for the No Action and Proposed Action alternatives. Operations and Maintenance excavations will be conducted as authorized under the applicable ROW authorization. As the land management agencies responsible for lands along the pipeline route, ROWs will be issued by one, or both, of the Bureau of Land Management and Alaska Department of Natural Resources. Excavations and other applicable activities will be permitted through the appropriate Federal and State agencies for both alternatives. Both alternatives will have similar impacts on soil resources.

FERC Resource Report No. 7, *Soils*, contains a more detailed discussion of impacts to soils and erosion resulting from the pipeline construction and the potential mitigation measures to address those impacts.

9. Indian Trust Assets

No Indian Trust Assets or Native allotments are located within the pipeline route.

10. Land Use, Subsistence, and Recreation

There will be no difference in the effect on Land Use, Subsistence, and Recreation between the No Action and Proposed Action Alternatives. During construction, land use in the form of subsistence activities and recreation for both alternatives could be altered in the immediate vicinity of activities. The pipeline's remote location combined with the relatively small width of the ROW will generally limit the extent of displacement by users to the active construction zones.

After construction, the ROW will be graded and revegetated to a stable condition in accordance with the FERC approved Alaska LNG Upland Erosion Control, Revegetation and Maintenance Plan; Alaska LNG Wetland & Waterbody Construction & Mitigation Procedures; and the associated Alaska LNG Project Restoration Plan. No long term linear access along the pipeline alignment is proposed. However, under either alternative, PHMSA regulations will require that the pipeline ROW is brushed to prevent the growth of large vegetation over and around the pipeline to maintain a clearly defined ROW.

FERC Resource Report No. 8, *Land Use*, *Recreation and Aesthetics*, considers potential effects to land use and recreation activities. FERC Resource Report No. 5, *Socioeconomics*, considers potential impacts to subsistence.

11. Noise

During normal operations, there will be no difference in Noise Impacts between the No Action and the Proposed Action Alternatives.

12. Water Resources

There will be no difference in impacts to water resources between the No Action and the Proposed Action Alternatives. For both alternatives, stabilization techniques, including gravel blankets, riprap, gabions, or geosynthetics, will be used to stabilize the channel bed and stream banks at stream crossings. The majority of rivers and streams along the pipeline route will be crossed by an open-cut method during winter months; during these months, the flows of rivers and streams are lowest, and disturbance of the channel and stream bank can be minimized. Burial depths for crossings have been based on site specific calculations to avoid the potential for scour. Watercourse crossing methods for each watercourse crossing are the same for both alternatives.

FERC Resource Report No. 2, *Water Use and Quality*, contains a detailed discussion regarding the management of water during construction and operation of the pipeline, as well as impacts to ground, surface water flow and quality resulting from the construction and operation of the pipeline.

c. *Describe safety protections provided by the special permit conditions.*

As specified in the special permit conditions, AGDC will be required to provide intrinsic crack arrest through material toughness within the potential impact radius of bridges and railroads. These areas must also 1) undergo remediation for anomalies greater than 40% within one year of the ILI tool run; 2) be remediated for coating holidays, CP levels, and external corrosion and 3) comply with 49 CFR Part 192.112(b) when within 300 feet of crossings of TAPS and the TAPS Fuel Gas Line per special permit Condition 7b, or Class 2, 3, or 4 locations and HCAs.

The Applicant conducted an analysis to determine whether increasing the CA spacing will impact pipeline safety. The analysis compared the hazards in terms of the volume of natural gas released over time, the potential for damage to surrounding structures, and the life safety risk to personnel and the public. This same study also evaluated the thermal radiation effects of increasing CA spacing from 320 feet, to 3,200 feet (See Section 2.3.1 of Attachment D – Technical Support Document). The 320-foot spacing corresponds to 8 pipe lengths that are each 40 feet in length. It was found that there was no effect on the areas located perpendicularly from the pipeline center line that are exposed to key thermal radiation dosages for people for CA spacings up to 1,600 feet. The conclusions from the report were reached by comparing the total threshold thermal dosage (the total accumulated amount of damaging heat) that various receptors (humans, trees/wooden structures) will be subjected to during a pipeline rupture and ignition event[16]. (Damage thresholds are summarized in the Table 2.1 below[17] and explained further in the basis document for the Potential Impact Radius (PIR) formulation of 49 CFR 192.903(4) (c) [18]).

[16] The concepts of threshold dosage can be observed at any camp fire. Logs must be placed within a certain proximity (thermal radiation intensity) of the fire for them to begin burning (ignition). Logs that are too far away from the fire to ignite may absorb a large amount of thermal radiation over time, but they will never burn.

[17] GRI-00/0189, "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines," C-FER Report 99068 prepared for Gas Research Institute, October 2000. https://pstrust.org/docs/C-FerCircle.pdf

[18] Ibid.

Radiation Intensity or Heat Flux (Btu/hr ft^2)	Radiation Intensity or Heat Flux (kW/m^2)	Time to Burn Threshold (Eisenberg et al. 1975) $t*I^{1.15}$ = 195	Time to Blister Threshold - lower[1] (Hymes 1983)[2] $t*I^{1.33}$ = 210	Time to Blister Threshold - upper[1] (Hymes 1983)[2] $t*I^{1.33}$ = 700	Time to 1% Mortality (Hymes 1983)[2] $t*I^{1.33}$ = 1060	Time to 50% Mortality (Hymes 1983)[2] $t*I^{1.33}$ = 2300	Time to 100% Mortality[3] (Bilo & Kinsman 1997) $t*I^{1.33}$ = 3500
1600	5.05	30.3	24.4	81.3	123.1	267.1	406.4
2000	6.31	23.5	18.1	60.4	91.5	198.5	302.1
3000	9.46	14.7	10.6	35.2	53.4	115.8	176.2
4000	12.62	10.6	7.2	24.0	36.4	79.0	120.2
5000	15.77	8.2	5.4	17.9	27.0	58.7	89.3
8000	25.24	4.8	2.9	9.6	14.5	31.4	47.8
10000	31.55	3.7	2.1	7.1	10.8	23.3	35.5
12000	37.85	3.0	1.7	5.6	8.4	18.3	27.9

Note:
1) Hymes gives a thermal load range (210 to 700) rather than a single value for blister formation
2) the thermal load values given by Hymes are based on a revised interpretation of the results obtained by Eisenberg et al.
3) Bilo and Kinsman assume that 100% mortality corresponds to a lower bound estimate of the thermal load associated with the spontaneous ignition of clothing

Table 2.1 Effects of thermal radiation on people.

The report outlines that for both people and resources, the total thermal dosage is largely identical, differing only in cases where CA spacing exceeds 1,600 feet. In the event that a pipeline fracture occurred or a longer fracture occurred following a failure due to greater CA spacing, more acreage will be subject to thermal radiation, but the highest thermal intensity will occur at the ruptured ends. Duration of the high intensity heat will be unchanged by fracture length. Distance from the centerline will not increase because the largest radius around the rupture is exposed to the largest amount of thermal radiation during the period when gas flows. Both the thermal intensity and impacted area drop sharply in the minutes following the initial event. As a result, the zone of thermal intensity required to cause fatality, injury, or resource damage shrinks over time to well within the area initially impacted by significant thermal dosage. This means the total damaging heat (thermal dosage) is similar in effect.

Third, the Special Permit Conditions, which are summarized in Section VIII below, ensure additional focus on fracture control using intrinsic arrest or CA, especially in proximity to key infrastructure (key bridges identified by Alaska Department of Transportation and Public Facilities (ADOT&PF), Alaska Railroad crossings, and crossings of the TAPS pipeline).

d. *Explain the basis for the particular set of alternative mitigation measures used in the special permit conditions. Explain whether the measures will ensure that a level of safety and environmental protection equivalent to compliance with existing regulations is maintained.*

The basis for the mitigation measures is the engineering analysis, combined with consultation with PHMSA and ADOT&PF. These measures help ensure that no significant environmental or human safety impact will result from increasing the CA spacing.

e. *Discuss how the special permit would affect the risk or consequences of a pipeline leak, rupture or failure (positive, negative, or none). This would include how the special permits preventative and mitigation measures (conditions) would affect the consequences and socioeconomic impacts of a pipeline leak, rupture or failure.*

Previous studies have examined the results of NTSB and PHMSA incident databases and concluded the risk to the public is independent of valve spacing.[19,20] This is attributed to the fact that "the injuries and fatalities on gas transmission pipelines generally occur during the first 30 seconds after gas has been released from a pipeline." This statement is consistent with the findings of the Project's engineering analysis and applies to increased CA spacing.

Ruptures may result in longer pipeline fracture lengths in Class 1 Alternative MAOP pipeline segments with the Proposed Alternative. However, a through wall penetration of at least four (4) inches in length will be required to initiate a propagating rupture. Due to the remoteness of the Alaska LNG Pipeline Class 1 locations, there is a greatly reduced risk of mechanical damage, so development of a 42-inch pipeline penetration of this size is highly unlikely.

f. *Discuss any effects on pipeline longevity and reliability such as life-cycle and periodic maintenance including integrity management. Discuss any technical innovations as well.*

There will be no impact on pipeline longevity and reliability with the Special Permit.

g. *Discuss how the special permit would impact human safety.*

Ruptures may result in longer pipeline fracture lengths in Class 1 Alternative MAOP pipeline segments with the Proposed Alternative. However, the risk to human safety is low because even in the unlikely event of a failure, the portions of the pipeline with increased CA spacing will be in largely uninhabited areas.

h. *Discuss whether the special permit would affect land use planning.*

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[19] Eiber, R., McGehee, W., Hopkins, P., Smith, T., Diggory, I., Goodfellow, G., Baldwin, T. R. and McHugh, D. 2000. Valve Spacing Basis for Gas Transmission Pipelines. Pipeline Research Council International, PRCI Report PR 249 9728. January.

[20] Eiber, R., and Kiefner, J. 2010. Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing. ASME Standards Technology, LLC. Columbus. July.

Special permit status will not change land use planning processes, given the Proposed Action and No Action alternatives will both be premised a below ground basis. The ROW authorization requirements, and other land use planning notification processes will be the same with or without a special permit.

i. *Discuss any pipeline facility, public infrastructure, safety impacts and/or environmental impacts associated with implementing the special permit. In particular, discuss how any environmentally sensitive areas could be impacted.*

Ruptures may result in longer pipeline fracture lengths in Class 1 Alternative MAOP pipeline segments with the Proposed Alternative. However, in the unlikely event of a pipeline failure, a length of area exposed to intense heat following a failure will be increased by a maximum of 1,280 feet. There is no significant impact to environmentally sensitive areas.

V. Consultation and Coordination

a. *Please list the name, title and company of any person involved in the preparation of this document.*

PHMSA –Amelia Samaras (Senior Attorney), Joshua Johnson (Engineer); Steve Nanney (Engineer).
Alaska Gasline Development Corporation – Frank Richards (Senior Vice President).
Alaska LNG LLC – Rick Noecker (PHMSA Filing Coordinator), Mario Macia (Pipeline Technology Lead), Norm Scott (ERL Advisor)
Michael Baker International – Keith Meyer (Senior Pipeline Advisor), Paul Carson (Corporate Pipeline Engineer).

b. *Please provide names and contact information for any person or entity you know will be impacted by the special permit. PHMSA may perform appropriate public scoping. The applicant's assistance in identifying these parties will speed the process considerably.*

Adjacent landowners/land managers potentially impacted:

Cook Inlet Region, Inc.
Ben Mohr
Sr. Director, Land and Resources
PO Box 93330
Anchorage, AK 99509
(907) 263-5140

Bureau of Land Management
Earle Williams
Chief, Branch of realty and Conveyance Services
BLM Alaska State Office222 W. 7th Avenue #13
Anchorage, AK 99513-7504
(907) 271-5762

Alaska Department of Natural Resources
Thomas Stokes
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3651 Penland Parkway
Anchorage, AK 99508
(907) 269-6419

Alaska Dept. of Transportation & Public Facilities
Joseph Kemp
Gasline Liaison
2301 Peger Road
Fairbanks, AK 99709
(907) 451-2959

Brooke Merrell
Chief of Planning and Compliance
United States National Park Service, Alaska Regional Office
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Anchorage, AK 99501
(907) 644-3397

Don Striker
Superintendent
Denali National Park and Preserve
PO Box 9
Denali Park, AK 99755-0009
(907) 683-9532

c. *If you have engaged in any stakeholder or public communication regarding this request, please include information regarding this contact.*

AGDC has been active in stakeholder engagement throughout Alaska. As well, Federal, State and Local agency engagement is ongoing. In 2015 and 2016, Alaska LNG Pipeline held one on one as well as multiagency engagement meetings to cover pipeline design construction and routing. Additionally, there have been over 20 engagement meetings between Alaska LNG Pipeline and PHMSA. The MLBV and

CA spacing Special Permit were a topic of discussion at multiple meetings. Additionally, an overview of this Special Permit was provided at a joint meeting with PHMSA and FERC on April 16, 2016.

PHMSA has participated in scoping and public outreach lead by FERC related to the Alaska LNG Pipeline FERC Resource Reports. Details of the public outreach, which included both members of tribal entities and the general public, are provided in Sections 1.9 and Appendix D of the FERC Resource Report No. 1.

VI. Response to Public Comments Placed on Docket PHMSA-2017-0047

PHMSA published a Notice of Availability in the Federal Register on May 28, 2019 for four (4) special permit requests for the line pipe of the Alaska LNG Pipeline. (84 FR 24594, Docket Nos.: PHMSA-2017-0044, Usage of Strain Based Design; PHMSA-2017-0045, Alternative Mainline Block Valve Spacing; PHMSA-2017-0046, Usage of 3LPE Coating; and PHMSA-2017-0047, Usage of Crack Arrestor Spacing at Regulations.gov). PHMSA requested comment on the special permit applications, the draft permit conditions, and the draft environmental analyses. The public notice comment period ended on July 29, 2019, with all comments received through July 29, 2019, being reviewed and considered. PHMSA received a public comment concerning usage of fossil fuels, the building of the Alaska LNG Pipeline, and the building of a liquified natural gas (LNG) facility. PHMSA does not have siting authority over pipeline facilities. The public comment received did not submit concerns directed towards the special permit, the environmental assessment, or the special permit conditions, which were the issues within PHMSA's decision making authority and the intent of the public notice.

VII. Finding of No Significant Impact

Although technically distinct, PHMSA considered the combined impacts and safety risks associated with the issuance and implementation of the special permits, including the special permit conditions, for usage of 3LPE coating, usage of strain based design, alternative spacing of mainline block valves, and alternative spacing of crack arrestors. PHMSA finds that special permits and associated special permit conditions will not impose a significant impact on the human environment. The special permit conditions are designed to be consistent with pipeline safety and to ensure the same or a greater level of safety as will be achieved if the pipeline were designed, constructed, operated, and maintained in full compliance with 49 CFR Part 192.

VIII. Bibliography

Applicant to document information submitted, if they consulted a book, website, or other document to answer the question, please provide a citation.

Please see footnotes within this document.

IX. Conditions: Example of what special permit (SP) conditions address

a) Produce a fracture control plan and ensure the critical length of a through wall thickness penetration that will result in a rupture is greater than or equal to four (4) inches.

b) Pipe will comply with the Fracture Control Requirements in 49 CFR 192.112 without the use of crack arrestors in Strain Based Design segments (Table 5 below) and within a distance defined by a maximum thermal radiation flux of 10,000 BTU/hr/ft^2. for key bridges and railroad crossings, as defined by ADOT&PF and PHMSA (Special Permit Condition 5(b)).

Table 5: Summary of SBD Segments

SBD Segment	Start Milepost	End Milepost	Strain Demand Mitigation
1	194	196	Frost Heave
2	227	230	Frost Heave
3	257	262	Potential Frost Heave
4	270	276	Potential Frost Heave
5	429	440	Potential Thaw Settlement
6	541	544	Frost Heave
7	559	563	Frost Heave

c) In High Consequence Areas (49 CFR 192.905) in Class 1 and 2 locations, pipe capable of intrinsic arrest, or crack arrestors spaced every eight pipe lengths must be installed from the start to end Mile Posts of the HCA (Special Permit Condition 7).

d) CA destructive testing to demonstrate compliance with the Fracture Control requirements.

Table 6 – Infrastructure Proximate to the 42-inch Pipeline in Class 1 Locations

Mileposts		Feature	Compliance
63.25	63.30	Dalton Highway/TAPS FGL BG Crossing	49 CFR Part 192 -Intrinsic Arrest
68.05	68.11	Dalton Highway/TAPS FGL BG Crossing	49 CFR Part 192 -Intrinsic Arrest
115.26	115.34	TAPS AG Crossing	49 CFR Part 192
122.87	122.91	Dalton Highway/TAPS FGL BG Crossing	49 CFR Part 192 -Intrinsic Arrest
136.30	136.38	TAPS AG Crossing	49 CFR Part 192
136.48	136.52	Dalton Highway/TAPS FGL BG Crossing	49 CFR Part 192 -Intrinsic Arrest
141.23	141.24	Galbraith Airport Road Crossing	49 CFR Part 192 -Intrinsic Arrest
143.82	143.87	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
145.45	145.53	TAPS AG Crossing/FGL BG Crossing	49 CFR Part 192
148.20	148.27	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
149.31	149.36	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
168.64	168.68	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
168.99	169.03	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
169.12	169.14	TAPS BG Crossing	49 CFR Part 192
169.78	169.89	Dalton Highway Parallel Encroachment	49 CFR Part 192 -Intrinsic Arrest
170.13	170.27	Dalton Highway Parallel Encroachment	49 CFR Part 192 -Intrinsic Arrest
171.78	171.82	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
171.90	171.96	Dalton Highway Parallel Encroachment	49 CFR Part 192 -Intrinsic Arrest
178.85	179.00	Dalton Highway Parallel Encroachment	49 CFR Part 192 -Intrinsic Arrest
179.07	179.11	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
181.90	181.98	TAPS AG Crossing	49 CFR Part 192
182.01	182.05	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
193.30	193.34	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
196.50	196.54	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
206.53	206.57	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
208.60	208.90	Dietrich River Bridge -Proximity	49 CFR Part 192 -Intrinsic Arrest
210.19	210.23	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
228.10	228.14	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
230.98	231.03	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
252.16	252.24	TAPS AG Crossing	49 CFR Part 192
252.25	252.29	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
257.74	257.82	TAPS AG Crossing	49 CFR Part 192
259.79	259.85	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
310.65	310.70	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
310.73	310.81	TAPS AG Crossing	49 CFR Part 192
341.61	341.66	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
342.62	342.70	TAPS AG Crossing	49 CFR Part 192
347.77	347.81	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
351.82	351.90	TAPS AG Crossing	49 CFR Part 192
357.90	357.98	TAPS AG Crossing	49 CFR Part 192
370.18	370.22	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
370.50	370.58	TAPS AG Crossing	49 CFR Part 192
384.73	384.81	TAPS AG Crossing	49 CFR Part 192
388.82	388.90	TAPS AG Crossing	49 CFR Part 192
398.17	398.21	Dalton Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
400.71	400.72	Elliott Highway Crossing	49 CFR Part 192 -Intrinsic Arrest

Mileposts		Feature	Compliance
470.72	470.76	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
472.28	472.30	FAA Hill Road Crossing	49 CFR Part 192 -Intrinsic Arrest
472.64	472.75	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
498.69	498.73	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
513.00	513.01	Rock Creek Road Crossing	49 CFR Part 192 -Intrinsic Arrest
514.68	514.69	Ferry Road Crossing	49 CFR Part 192 -Intrinsic Arrest
521.73	521.77	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
523.16	523.17	Stampede Road Crossing	49 CFR Part 192 -Intrinsic Arrest
530.28	530.49	Antler Creek Bridge - Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
531.92	532.28	Alaska Railroad Crossing and Nenana River Bridge at Moody - - Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
532.35	534.65	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
534.85	535.99	Parks Highway Crossing/Iceworm Gulch Bridge - - Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
535.99	536.49	Class 3 Location	NA - Intrinsic Arrest
566.42	566.46	Denali Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
566.74	566.77	Old Anchorage-Fairbanks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
572.60	572.64	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
572.77	572.81	Alaska Railroad Crossing - Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
588.05	588.09	Alaska Railroad Crossing- Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
588.20	588.24	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
608.99	609.05	Alaska Railroad Crossing- Required intrinsic arrest set at 930 feet proximity as per Special Permit Conditions.	49 CFR Part 192 -Intrinsic Arrest
612.55	612.60	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
625.05	625.10	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
630.16	630.21	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
631.60	631.65	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
640.43	640.48	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
648.47	648.51	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
657.56	657.60	Parks Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
664.69	664.70	Petersville Road Crossing	49 CFR Part 192 -Intrinsic Arrest
765.00	765.04	Beluga Highway Crossing	49 CFR Part 192 -Intrinsic Arrest
765.87	765.88	Grant Street Crossing	49 CFR Part 192 -Intrinsic Arrest
796.99	797.01	Kaskakoff Avenue Crossing	49 CFR Part 192 -Intrinsic Arrest
797.30	797.31	Sylvian Way Crossing	49 CFR Part 192 -Intrinsic Arrest
798.56	798.57	Nikishka Beach Road Crossing	49 CFR Part 192 -Intrinsic Arrest
798.65	801.27	Class 2 Location	NA - Intrinsic Arrest
803.78	806.25	Class 2 Location	NA - Intrinsic Arrest
806.50	806.51	Miller Loop Road Crossing	49 CFR Part 192 -Intrinsic Arrest

Completed by PHMSA in Washington, DC on: September 9, 2019