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

Special Permit Information:

Docket Number:	PHMSA-2017-0045
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 192.179(a)(4)

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 49 Code of Federal Regulations (CFR) 192.179(a)(4) for sectionalizing mainline valve spacing in Class 1 locations. This special permit requires the use of remote controlled valves (RCV) or automatic shut-off valves (ASV) for the Alaska LNG Pipeline and mandates specific design, construction, operations, and maintenance procedures in accordance with the special permit conditions.

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

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

I. Purpose and Need:

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

AGDC is requesting a waiver of compliance with 49 CFR 192.179(a)(4) for remote, sparsely populated segments along the 42-inch pipeline route. AGDC's special permit request is specifically for the Class 1 location segments.[3]

Federal pipeline safety regulations require natural gas transmission pipeline operators to have sectionalizing block valves within 10 miles of each point on the pipeline (or no more than 20 miles between sectionalizing mainline valves) in a Class 1 location. AGDC's request allows for a valve spacing greater than 20 miles in Class 1 locations but requires all of the mainline valves to be either RCVs or ASVs.

II. Special Permit Segment:

<u>State of Alaska</u>

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

The special permit allows alternative mainline valve placement in Class 1 locations on the 42-inch ***special permit segment*** with the implementation of the special permit conditions.

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

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*" documents, which both can be read in their entirety in Docket No. PHMSA-2017-0045 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 mainline valve spacing subject to AGDC implementing the following conditions on the ***special permit segment*** 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 mainline valve spacing requirement 49 CFR 192.179(a)(4). In addition to 49 CFR Part 192 conformance, the ***special permit segment*** must also be designed, constructed, operated and maintained in accordance with the special permit conditions.

2. **Maximum Allowable Operating Pressure (MAOP):** 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, allowing for pressure build-up and overpressure protection in accordance with 49 CFR 192.620(e).

Mainline Valve Spacing, Control, Closure, Operations & Maintenance:

3. **Transmission Line Valves:** Sectionalizing block valves along the ***special permit segment*** must be spaced as shown in Table 1[4] and as follows for class location segments:[5]
   a) Class 1 locations north of Fairbanks from Mile Post 0.00 to Mile Post 422 must have a 50-mile maximum sectionalizing block valve spacing between block valves (each point on the pipeline must be within 25 miles of a sectionalizing block valve).

[4] If AGDC determines that the sectionalizing block valve spacing or operational controls (RCV or ASV), as shown in Table 1 need to be modified, AGDC must submit proposed changes to the conditions and Table 1 to PHMSA's Western Region Director or PHMSA Project Designee for review and a "no objection" letter must be received prior to the change by AGDC.

[5] Transmission line class locations are defined in 49 CFR 192.5.

b) Class 1 locations south of Fairbanks from Mile Post 422 to Mile Post 807 must have a 30-mile maximum sectionalizing block valve spacing between block valves (each point on the pipeline must be within 15 miles of a sectionalizing block valve).

c) Class 2, 3, and 4 locations between Mile Post 0.00 to Mile Post 807 must comply with the requirements of 49 CFR 192.179.[6]

d) High consequence areas (as defined in 49 CFR 192.903 and 192.905) located in Class 1 and 2 locations, must comply with the requirements of 49 CFR 192.179.

4. **Valve Monitoring, Control and Closure:** All mainline valves[7] within the ***special permit segment*** must be controlled by a supervisory control and data acquisition (SCADA) system and must be equipped for remote monitoring and control, or remote monitoring and automatic control, in accordance 49 CFR 192.620(d)(3)(iii), and the below requirements:

    a. If any crossover or lateral pipe for gas receipts or deliveries connects to the isolated segment between the upstream and downstream mainline valves, the nearest valve on the crossover connection(s) or lateral(s) must be isolated, such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment);

    b. All interconnect and/or meter and regulator stations must be monitored and capable of remote operation for isolating from the pipeline such that, when all valves are closed, there is no flow path for gas to flow to the leak or rupture site (except for residual gas already in the shut-off segment);

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

    d. Closure of the appropriate valves following a pipeline leak or rupture meeting the criteria of **Condition 4** must occur as soon as practicable from the time the

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[6] Mile Post 0.00 to Mile Post 807 is the starting and ending mile posts of the ***special permit segment***. If the length of the pipeline length should change due to routing or survey changes, these mile posts must be adjusted based upon these changes.

[7] Both RCV and ASV are permissible at sectionalizing mainline valves locations. RCV's must be installed at all powered and telecommunications-equipped locations, that are: compressor, heater and metering locations.

pipeline leak or rupture location is confirmed, not to exceed 30 minutes from such confirmation;[8]

i. "Rupture" means a significant breach of a pipeline that results in a large-volume, uncontrolled release of gas, over a short period of time as defined below. For purposes of this special permit, AGDC must treat all the following as ruptures:

1. ***Special permit segment*** pressure drops to 75% of the operating pressure at the sectionalizing mainline valve based upon maximum flow model gradients for the upstream compressor station discharge at MOP (2050 psig). In addition, ASV set-points must not be less than that required to actuate the valve before a downstream RCV actuates;[9]
2. A release of gas observed or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (3) or (4) of this definition;
3. An unanticipated or unplanned pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less; or
4. An unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event defined in paragraph (2) of this definition.

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

[9] AGDC must notify the PHMSA Western Region Director in writing of the reasons the pressure drop cannot be met and obtain a letter of "no objection" from PHMSA prior to implementing any pressure drop below 75% of maximum operating pressure based upon pressure loss through flow gradient.

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

ii. Within five (5) minutes of the initial notification to AGDC, AGDC must evaluate and identify a rupture, as defined above, as being either an actual leak event, rupture event or non-rupture event in accordance with operating procedures and 49 CFR 192.615. Once a rupture is verified, closure of the appropriate valves must comply with the timing requirements of **Condition 4(d).**

e. The Alaska LNG Pipeline_Gas Control Center must monitor the pipeline 24 hours a day, 7 days a week, and must confirm the existence of a leak or rupture as soon as practicable in accordance with **Condition 4(d)**;

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

g. AGDC must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with 49 CFR 192.631(c) and (e);

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

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

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

   ii. Designate an alternative valve within seven (7) calendar days of the finding while repairs are being made; and

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

5. **Mainline Valve Locations**: Mainline valves will be sited per Table 1:

Table 1: Mainline Valve Locations for Alaska LNG Pipeline[10]

MLBV #	MP	Δ MP	Location Description	Valve Type	Class Location(s)	HCA Yes/No
1	0.00		GTP Meter Station	RCV	1	No
2	36.74	36.74	Stand-alone MLBV - Potential Station	ASV	1	No
3	75.97	39.23	Compressor Station - Sagwon	RCV	1	No
4	112.04	36.07	Stand-alone MLBV - Potential Station	ASV	1	No
5	148.51	36.47	Compressor Station - Galbriath Lake	RCV	1	No
6	194.09	45.58	Stand-alone MLBV - Potential Station	ASV	1	No
6	194.09	45.58	Stand-alone MLBV - Potential Station	ASV	1	No
7	240.10	46.01	Compressor Station - Coldfoot	RCV	1	No
8	286.05	45.95	Stand-alone MLBV - Potential Station	ASV	1	No
9	332.64	46.59	Compressor Station - Ray River	RCV	1	No
9A	356.22	23.58	Added for potential "Hotspot Café" HCA	ASV	1	No
10	377.95	21.78	Stand-alone MLBV - Potential Station	ASV	1	No
11	421.56	43.61	Compressor Station - Minto	RCV	1	No
12	444.90	23.34	Stand-alone MLBV	ASV	1	No
13	467.10	22.20	Stand-alone MLBV - Potential Station	ASV	1	No
14	492.96	25.86	Stand-alone MLBV	ASV	1	No
15	517.62	24.66	Compressor Station - Healy	RCV	1	No
16	534.79	17.17	Upstream of Class 3 Location - Nenana Canyon	ASV	1	No
17	538.79	4.00	Downstream of Class 3 Location - Nenana Canyon	ASV	1	No
18	546.50	7.71	Stand-alone MLBV - Potential Station	ASV	1	No
19	572.23	25.73	Stand-alone MLBV	ASV	1	No
20	597.35	25.12	Compressor Station - Honolulu Creek	RCV	1	No
21	625.83	28.48	Stand-alone MLBV	ASV	1	No
22	648.16	22.33	Stand-alone MLBV - Potential Station	ASV	1	No
23	675.24	27.08	Compressor Station - Rabideux Creek	RCV	1	No
24	703.67	28.43	Stand-alone MLBV - Potential Station	ASV	1	No
25	725.93	22.26	Stand-alone MLBV - Potential Station	ASV	1	No
26	749.11	23.18	Heater Station - Theodore River	RCV	1	No

[10] Sectionalizing mainline valve siting is based upon the latest route revision C2 and may be subject to change with future route alternatives. The final siting will follow the requirements and limitations of the special permit conditions.

Table 1: Mainline Valve Locations for Alaska LNG Pipeline[10]						
MLBV #	**MP**	**Δ MP**	**Location Description**	**Valve Type**	**Class Location(s)**	**HCA Yes/No**
27	766.01	16.90	Upstream of Cook Inlet crossing	ASV	1	No
28	793.34	27.33	Downstream of Cook Inlet crossing	RCV	1	No
29	799.85	6.51	Stand-alone MLBV - Potential Class 2 Location	RCV	2	No
30	806.57	6.72	LNG Meter Station	RCV	1	No

6. **Emergency Operations**:
   a) Alaska LNG Pipeline control center operators must continually monitor position and operational status of all RCVs affected by a leak/rupture event until positive isolation of the effected segment is confirmed.
   b) AGDC must immediately and directly notify the appropriate public safety access point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located when a release is indicated. [11]
   c) AGDC must establish actions required to be taken by a pipeline controller, or the appropriate emergency response coordinator, during an emergency in accordance with these special permit conditions and as required in 49 CFR 192.615 and 192.631.
   d) Emergency closure drills simulating shutting down a randomly selected section of transmission line must be performed at least once in a calendar year, but within an interval not to exceed 15 months. AGDC may conduct a table-top emergency closure drill to meet this requirement for no more than two out of each three calendar years. The operator will conduct a site-specific emergency closure drill at a field site at least once every three calendar years.

7. **Emergency Training and Planning:** AGDC must develop and implement emergency response plans and procedures for the ***special permit segment*** in accordance with 49 CFR 192.615 and the following requirements:
   a. Identify the appropriate public safety access point (911 emergency call center), fire, police, and other public officials to be notified;

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

b. Identify responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency; and

c. Inform emergency officials (911 emergency call centers, fire, police, and other public officials) about the operator's ability to respond to the pipeline emergency and means of communication.

d. Emergency response plans must be reviewed, updated and communicated, as required in this **Condition 7** and 49 CFR 192.615(b) and (c), on a calendar year basis, not to exceed 15 months.

Reporting and Certification:

8. **Annual Reports:** Within twelve (12) months following pipeline start-up[12] and annually[13] 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:[14, 15]

   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) of the ***special permit segment***, as defined in 49 CFR 192.903;

   b) Any reportable incidents associated with the ***special permit segment*** that occurred during the previous year;

   c) Any emergency events that cause closure of mainline valves as described in **Condition 4**, including the location (mile post) of valves and closure times;

   d) Any emergency drills performed in accordance with **Condition 6(d).** Submit a brief description of the emergency drill and date of the drill; and

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[12] 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 commercial capacity.

[13] 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.

[14] Upon notice to the AGDC, PHMSA may update reporting contacts for **Condition 7**.

[15] AGDC must place a copy of each Alaska LNG Pipeline annual report on the PHMSA docket, PHMSA-2017-0045, at www.regulations.gov.

e) 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.

9. **Notifications**: AGDC must notify the PHMSA OPS Western Region Director or Project Designee, at least 14 days prior to conducting field activities associated with the ***special permit segment*** to meet **Conditions 6(d).**

10. **Certification:**
    a) A senior executive officer of AGDC, vice president or higher, must certify in writing that:
        i. The ***special permit segment*** meets the conditions described in this special permit (including applicable sections 49 CFR 192.112, 192.328, and 192.620 for alternative MAOP) and other applicable sections of 49 CFR Part 192; and
        ii. The written manual of O&M procedures required by 49 CFR 192.605 for the Alaska LNG Pipeline includes all additional operating and maintenance requirements of this special permit and 49 CFR Part 192;
    b) The certification must be sent to PHMSA within three (3) months of placing the Alaska LNG Pipeline into natural gas service.
    c) AGDC must send a copy of the certifications required in this condition, with completion dates, 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; Director, PHMSA Standards and Rulemaking Division; Director, PHMSA Engineering and Research Division; and to the Federal Register Docket (PHMSA-2017-0045) at www.regulations.gov.

11. AGDC may propose changes to these special permit conditions by making a request to PHMSA in writing. Any proposed changes to the conditions by AGDC must maintain equivalent levels of safety, as determined by PHMSA. 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 PHMSA-proposed changes to AGDC's request in accordance with 49 CFR 190.341. Any submittal timing, review timing, or completion timing in these conditions can be modified by PHMSA upon request by AGDC and with a "no objection" letter from PHMSA[16] to AGDC.

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 Alaska LNG Pipeline. 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 Alaska LNG Pipeline supporting this special permit are automatically incorporated into this special permit and are enforceable in the same manner.

3) Failure by AGDC to submit the certifications required by **Condition 10 (Certification)** within the time frames specified may result in revocation of this special permit.

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

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

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

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

Figure 1: Alaska LNG Pipeline Route


Beaufort Sea
BARROW
MP 0
PRUDHOE BAY
DALTON HIGHWAY
MP 100
MP 200
COLDFOOT
MP 300
LIVENGOOD
MP 400
FAIRBANKS
DELTA JUNCTION
MP 500
TOK
MP 600
TALKEETNA
MP 700
ANCHORAGE
VALDEZ
NIKISKI
MP 806
Cook Inlet
Gulf of Alaska
CANADA
ALASKA

Table 2: Mainline Valve Locations for Alaska LNG Pipeline with High Consequence Areas, Bridges, and Railroad Locations						
MLBV #	**MP**	**Δ MP, miles**	**Location Description**	**Valve Type**	**Class Location(s)**	**HCA Yes/No**
1	0.00		GTP Meter Station	RCV	1	No
2	36.74	36.74	Stand-alone MLBV - Potential Station	ASV	1	No
3	75.97	39.23	Compressor Station - Sagwon	RCV	1	No
4	112.04	36.07	Stand-alone MLBV - Potential Station	ASV	1	No
5	148.51	36.47	Compressor Station - Galbriath Lake	RCV	1	No
6	194.09	45.58	Stand-alone MLBV - Potential Station	ASV	1	No
6	194.09	45.58	Stand-alone MLBV - Potential Station	ASV	1	No
	236.08 to 237.33	1.25	HCA – Marion Campground – 1.25 miles		1	Yes
7	240.10	46.01	Compressor Station - Coldfoot	RCV	1	No
8	286.05	45.95	Stand-alone MLBV - Potential Station	ASV	1	No
9	332.64	46.59	Compressor Station - Ray River	RCV	1	No
	352.21 to 353.35	1.14	HCA - Hotspot Café		1	Yes
9a	356.22	23.58	Added for potential "Hotspot Café" HCA	ASV	1	No
10	377.95	21.73	Stand-alone MLBV - Potential Station	ASV	1	No
11	421.56	43.61	Compressor Station - Minto	RCV	1	No
12	444.90	23.34	Stand-alone MLBV	ASV	1	No
13	467.10	22.20	Stand-alone MLBV - Potential Station	ASV	1	No
14	492.96	25.86	Stand-alone MLBV	ASV	1	No
15	517.62	24.66	Compressor Station - Healy	RCV	1	No
	529.21 to 530.44	1.23	HCA – RV Park and Hotel – 1.23 miles		1	Yes
	532.07		Alaska Railroad Crossing		1	No
	532.13		Nenana River Bridge Crossing		1	No
16	534.79	17.17	Upstream of Class 3 Location - Nenana Canyon	ASV	1	No
	535.54 to 535.99	0.45	HCA - Denali Riverside RV Park, McKinley Chalet Resort, Denali Rainbow Village and RV, Denali Princess Wilderness Lodge, Denali Crows Nest Cabins, Grand Denali Lodge, and Denali Bluffs Hotel – 2.20 miles		1	Yes
	535.99 to 536.49	0.50	HCA - Denali Riverside RV Park, McKinley Chalet Resort, Denali Rainbow Village and RV, Denali Princess Wilderness Lodge, Denali Crows Nest Cabins, Grand Denali Lodge, and Denali Bluffs Hotel – 2.20 miles		3	Yes
	536.49 to 537.74	1.25	HCA - Denali Riverside RV Park, McKinley Chalet Resort, Denali Rainbow Village and RV, Denali Princess Wilderness Lodge, Denali Crows Nest Cabins, Grand Denali Lodge, and Denali Bluffs Hotel – 2.20 miles		1	Yes

Table 2: Mainline Valve Locations for Alaska LNG Pipeline with High Consequence Areas, Bridges, and Railroad Locations						
MLBV #	MP	Δ MP, miles	Location Description	Valve Type	Class Location(s)	HCA Yes/No
	537.79		Lynx Creek Bridge Crossing		1	Yes
17	538.79	4.00	Downstream of Class 3 Location - Nenana Canyon	ASV	1	No
18	546.50	7.71	Stand-alone MLBV - Potential Station	ASV	1	No
	551.34 to 552.27	0.93	HCA – Denali Perch Resort – 0.93 miles		1	Yes
	565.77 to 567.23	1.46	HCA – DOT/PF Cantwell Station – 1.46 miles		1	Yes
19	572.23	25.73	Stand-alone MLBV	ASV	1	No
	572.79		Alaska Railroad Crossing		1	No
	588.07		Alaska Railroad Crossing		1	No
20	597.35	25.12	Compressor Station - Honolulu Creek	RCV	1	No
	609.02		Alaska Railroad Crossing		1	No
21	625.83	28.48	Stand-alone MLBV	ASV	1	No
	629.75 to 631.35	1.60	HCA – Byers Lake Campground (73 units) – 1.60 miles		1	Yes
	633.75 to 634.50	0.75	HCA – Trappers Creek Pizza Club – 0.75 miles		1	Yes
22	648.16	22.33	Stand-alone MLBV - Potential Station	ASV	1	No
23	675.24	27.08	Compressor Station - Rabideux Creek	RCV	1	No
24	703.67	28.43	Stand-alone MLBV - Potential Station	ASV	1	No
25	725.93	22.26	Stand-alone MLBV - Potential Station	ASV	1	No
26	749.11	23.18	Heater Station - Theodore River	RCV	1	No
27	766.01	16.90	Upstream of Cook Inlet crossing	ASV	1	No
28	793.34	27.33	Downstream of Cook Inlet crossing	RCV	1	No
	797.71 to 798.65	0.94	HCA – Nikiski Middle/High School, Kenai Heliport, Commercial Buildings, and Industrial Sites – 1.57 miles		1	Yes
	798.65 to 799.28	0.63	HCA – Nikiski Middle/High School, Kenai Heliport, Commercial Buildings, and Industrial Sites – 1.57 miles		2	Yes
	799.28 to 801.27	1.99			2	No
29	799.85	6.51	Stand-alone MLBV - Potential Class 2 Location	RCV	2	No
	803.39 to 803.78	0.39	HCA – Conoco Phillips Property and Tesoro Kenai Refinery – 2.66 miles		1	Yes
	803.78 to 806.05	2.27	HCA – Conoco Phillips Property and Tesoro Kenai Refinery – 2.66 miles		2	Yes
	806.05 to 806.25	0.20			2	No

Table 2: Mainline Valve Locations for Alaska LNG Pipeline with High Consequence Areas, Bridges, and Railroad Locations						
MLBV #	**MP**	**Δ MP, miles**	**Location Description**	**Valve Type**	**Class Location(s)**	**HCA Yes/No**
30	806.57	6.72	LNG Meter Station	RCV	1	No