4.0 ENVIRONMENTAL ANALYSIS

4.13 CULTURAL RESOURCES

Section 106 of the NHPA, as amended, requires FERC to take into account the effects of its undertakings on properties listed on or eligible for listing on the NRHP and afford the ACHP an opportunity to comment. AGDC, as a non-federal party, is assisting us in meeting our obligations under Section 106 of the NHPA and the implementing regulations at 36 CFR 800 by providing information, analyses, and recommendations as authorized by 36 CFR 800 2(a)(3).

Project construction and operation could potentially affect historic properties (i.e., cultural resources either listed or eligible for listing in the NRHP). These historic properties could include prehistoric or historic archaeological sites, districts, buildings, structures, or objects, as well as locations with traditional value to federally recognized tribes, ANCSA village and regional corporations, or other groups. Historic properties must generally possess integrity of location, design, setting, materials, workmanship, feeling, and association, and must meet one or more of the criteria specified in 36 CFR 60.4.

4.13.1 Cultural Resources Surveys

Previous archaeological surveys that overlap the direct area of potential effects (APE) for the Project were documented through archival research and used to inform the survey methodology for the Project. A sensitivity model was developed for the Project for identifying areas with a high potential for containing cultural resources. The main data categories that formed the basis of the sensitivity model included known site locations, land cover, slope, surface geology, soils, distance to water, distance to trails, and wildlife distributions. Pre-survey helicopter overflights were also undertaken to verify the mapped sensitivity and identify locations that warranted visual inspection, shovel testing, or methods to sample deeply buried cultural deposits (greater than 3 feet).

AGDC identified the archaeological APE for direct Project effects as the rights-of-way for construction of the PTTL, PBTL, and Mainline Pipeline; and the footprint of off-corridor facilities, ATWS, permanent and temporary access roads, and the GTP and Liquefaction Facilities, including submerged lands in the Beaufort Sea and Cook Inlet. AGDC identified an indirect APE of a 1-mile buffer around all Project components. To ensure full coverage of the terrestrial direct APE, AGDC generally surveyed a 300-foot-wide corridor for the Mainline Pipeline, PTTL, and PBTL; a 150-foot-wide corridor centered on access roads; and the entire footprint of compressor stations and ancillary facilities. To date, AGDC has surveyed about 25,050 acres (87 percent) of the terrestrial direct APE.

Archaeological resources surveys for the Project have not been completed. About 13 percent of the onshore portion of the Project remains to be surveyed for archaeological resources. AGDC has not yet initiated the aboveground resources surveys or surveys within the indirect APE. A database inventory of shipwrecks and remote-sensing data was examined to assess the potential for submerged resources along the offshore Mainline Pipeline route, Marine Terminal and approach channel, and two offshore dredged material placement areas in Cook Inlet. Offshore marine surveys were also conducted.

AGDC submitted 22 reports to FERC, the Alaska SHPO, the BLM, and/or the NPS that provided the results of the archaeological studies conducted between 2013 and 2019, including site evaluations on BLM lands, an assessment of submerged resources in Cook Inlet, and a survey of NPS lands. AGDC would survey the remaining Mainline Pipeline route, including the portion of the route on NPS lands, and ancillary facilities for archaeological and aboveground historic architectural resources, and submit the results of these surveys to the appropriate agencies in future survey reports.

4.13.1.1 Gas Treatment Facilities

No archaeological sites were identified within the GTP or along the PBTL. One previously recorded archaeological site consisting of historic cache pits and surface artifacts associated with a winter house (XBP-00020) was identified along the PTTL. AGDC recommends the site is NRHP-eligible. Information is pending regarding any Project effects on this site. In a letter dated October 4, 2019, the Alaska SHPO requested additional documentation of the site. No aboveground resources were identified within the direct APE for the GTP or along the PTTL or PBTL.

4.13.1.2 Mainline Facilities

Archaeological Sites

Archaeological surveys to date have resulted in the identification of 122 archaeological resources and other sites—including segments of 14 historic highways and trails—in the survey corridor for the Mainline Pipeline and access roads and within the footprint of material sites, camps, and a helipad. Information on these resources—including site number, description, NRHP eligibility, and status of Alaska SHPO comments—is provided in table 4.13.1-1.[116] We concur with the findings of the Alaska SHPO as summarized in this table.

As indicated in the table, two prehistoric sites require additional documentation or clarification from AGDC. Two segments of the Parks Highway are listed on the Alaska Route List for the Interstate Highway System Section 106 Exemptions (Federal Register, March 10, 2005). The Alaska SHPO commented that Section 106 consideration of the two segments of the Parks Highway is not warranted if the segments are within the interstate right-of-way. Avoidance of a historic burial is recommended. Information is pending regarding Project effects on the Gallagher Flint Station National Historic Landmark, an NRHP-listed resource, and the Rosebud Archaeological District, which is eligible for the NRHP.

The Gallagher Flint Station site is near the upper Sagavanirktok River and has been radiocarbon-dated at 10,540 ± 150 years before present. The site is situated on a large ice-contact kame formed during the Antler Valley stage of the Itkillik glaciation. Discovered in 1970 during environmental surveys for construction of the TAPS, it is the earliest dated archeological site in northern Alaska. The material remains recovered from the site demonstrate associations between the indigenous peoples of Alaska and Siberia. The Gallagher Flint Station site became a national historic landmark in 1978. If the Project would have an adverse effect on this site, the Commission would give special consideration to protecting the national historic landmark and initiate the process set forth at 36 CFR 800.6, Resolution of Adverse Effects.

AGDC has not yet identified how NRHP-eligible sites would be avoided or mitigated or how the historic burial would be avoided.

Aboveground Resources

No aboveground resources were identified in the direct APE of the Mainline Facilities.

[116] Highways, roads, and trails are considered single sites even where more than one site number has been issued for these resources. Additionally, highway, road, and trail segments may have different NRHP-eligibility statuses associated with different site numbers as reported here. Therefore, the total site count will be less than the total count of eligibility status.

TABLE 4.13.1-1

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
Mainline Facilities			
Mainline Pipeline			
XBP-00128	Historic, modern un-named dirt road	Not eligible	Concurred not eligible, 2/11/2016
XBP-00114 [b]	Historic Dalton Highway	Treat as eligible	Treat as eligible, Spring 2015
SAG-00098	Historic Hickel Highway	Treat as eligible	Treat as eligible, 11/7/2018
BET-00201 [c]	Historic Hickel Highway	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 9/30/2016
BET-00253	Prehistoric artifacts	2016 Phase II evaluation completed, data insufficient	Unevaluated, 5/16/2019
FAI-02439	Parks Highway – Bypass Segment #3	Exempt from Section 106 consideration	Agree if Segment #3 remains within Interstate right-of-way, 5/16/19
FAI-02441	Parks Highway – Bypass Segment #3	Exempt from Section 106 consideration	Agree if Segment #3 remains within Interstate right-of-way, 5/16/19
PSM-00059	Prehistoric artifacts	Not eligible	Additional documentation requested, 10/4/2019
PSM-00075	Prehistoric artifacts	Eligible	Concurred eligible, 2/11/2016
PSM-00172	Prehistoric artifacts	Not eligible	Additional field documentation and determination of eligibility recommended, 10/4/2019
PSM-00573	Prehistoric artifacts	Eligible	Eligible, 5/9/2016
PSM-00574	Prehistoric isolated find	Not eligible	Concurred not eligible, 3/21/2016
PSM-00576	Prehistoric artifacts	Not eligible	Concurred not eligible, 3/21/2016
PSM-00577	Prehistoric artifacts	Not eligible	Concurred not eligible, 2/11/2016
PSM-00578 [d]	Prehistoric artifacts	Eligible	Concurred eligible, 2/11/2016
PSM-00579	Prehistoric artifacts	Not eligible	Concurred not eligible, 3/21/2016
PSM-00580	Prehistoric isolated find	Not eligible	Concurred not eligible, 9/15/2016
PSM-00584	Prehistoric artifact	2016 Desktop review: not eligible	Concurred not eligible, 11/23/2016
PSM-00600	Prehistoric artifacts	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 9/30/2016
PSM-00601	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Concurred eligible, 11/23/2016
PSM-00603	Prehistoric artifacts	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 11/23/2016
PSM-00606 [e]	Prehistoric isolated find	2016 Phase II evaluation completed, data insufficient	Unevaluated, 5/16/19
PSM-00607	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Concurred eligible, 11/23/2016
PSM-00616 [e]	Prehistoric artifacts	Data insufficient	Unevaluated, 5/16/19
PSM-00050	Gallagher Flint Station National Historic Landmark	Listed in the NRHP	Eligible (Landmark status 6/2/1978)
CHN-00025	Historic artifacts	Eligible	Concurred eligible, 2/11/2016
CHN-00077	Prehistoric artifacts	Eligible	Concurred eligible, 2/11/2016

TABLE 4.13.1-1 (cont'd)

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
CHN-00080	Historic artifacts and surface feature	Not eligible	Concurred not eligible, 2/11/2016
CHN-00124	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Concurred eligible, 9/30/2016
WIS-00287	Historic surface feature	Not eligible	Concurred not eligible, 2/11/2016
WIS-00436	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Concurred eligible, 9/30/2016
BET-00074	Prehistoric artifacts	Eligible	Concurred eligible, 2/11/2016
BET-00081	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Concurred eligible, 9/30/2016
BET-00139	Prehistoric artifacts	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 9/30/2016
BET-00250	Prehistoric artifacts	2016 Phase II evaluation completed, eligible	Eligible, 1/4/2017
BET-00255 [f]	Prehistoric artifacts	Eligible	Concurred eligible, 10/4/2019
LIV-00284 [g]	Rosebud Knob Archaeological District	Eligible	Concurred eligible, Spring 2015. SHPO noted on 2/11/2016 that one site within the APE may contribute to the overall eligibility of the district.
LIV-00392	Historic Livengood Tram Road	Not eligible	Identification efforts recommended, 10/4/2019
LIV-00394	Prehistoric isolated find	Not eligible	Concurred not eligible, 2/11/2016
LIV-00403	Historic surface feature	Not eligible	Not eligible, 1/12/2017
LIV-00553	Prehistoric artifacts	Eligible	Concurred eligible, 2/11/2016
LIV-00556 [h]	Historic Dunbar-Brooks Terminal Trail	Eligible	Concurred eligible, 2/11/2016
LIV-00748	Prehistoric artifacts	Eligible	Concurred eligible, 3/21/2016
LIV-00749	Prehistoric artifacts	Eligible	Concurred eligible, 3/21/2016
LIV-00751 [i]	Historic Elliot Highway	Not eligible	Concurred not eligible, February 2015
LIV-00752 [j]	Historic Elliot Highway	Not Eligible	Not eligible, 4/24/2015
LIV-00764	Historic Elliot Highway	Eligible	Concurred eligible, 2/19/2016
LIV-00780	Prehistoric isolated find	Data insufficient	Unevaluated, 5/16/19
LIV-00783	Prehistoric artifacts	Data insufficient	Unevaluated, 5/16/19
FAI-02177 [k]	Historic Dunbar-Minto-Tolovana Trail	Eligible	Concurred eligible, 2/11/2016
FAI-02288	Undetermined surface features	Not eligible	Concurred not eligible, 3/21/2016
FAI-02299	Modern artifacts	Not eligible	Concurred not eligible, 2/11/2016
FAI-02366	Historic Nenana-Knights Roadhouse Trail	Eligible	Concurred eligible, 2/11/2016
FAI-02386	Historic artifacts and surface features	2016 Phase II evaluation completed, eligible	Concurred eligible, 11/23/2016
FAI-02389	Historic artifacts and surface features	2016 Desktop review, not eligible	Concurred not eligible, 11/23/2016
FAI-02390	Historic artifacts and surface features	2016 Desktop review, eligible	Concurred eligible, 9/30/2016

TABLE 4.13.1-1 (cont'd)

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
HEA-00015	Prehistoric artifacts	2016 Desktop review, not eligible	Concurred not eligible, 11/23/2016
HEA-00062	Prehistoric and historic artifacts	2016 Phase II evaluation completed, eligible	Eligible, 2/3/2006
HEA-00091	Historic Stampede Trail	Not eligible	Concurred not eligible, 2/11/2016
HEA-00450 [l]	Historic Denali Highway	Treat as eligible	Treat as eligible
HEA-00595	Prehistoric artifacts	Eligible	Concurred eligible, 3/21/2016
HEA-00596	Prehistoric artifacts	Not eligible	Concurred not eligible, 3/21/2016
HEA-00600	Prehistoric isolated find	Phase II evaluation recommended	Treat as eligible, 11/7/2018
HEA-00601	Prehistoric artifacts	Phase II evaluation recommended	Treat as eligible, 11/7/2018
HEA-00603	Historic artifacts and surface features	Not eligible	Concurred not eligible, 2/11/2016
HEA-00604	Prehistoric isolated find	Data insufficient	Unevaluated, 5/16/19
HEA-00605	Historic artifacts	Not eligible	Concurred not eligible, 2/11/2016
TLM-00327	Prehistoric artifacts	Eligible	Concurred eligible, 3/21/2016
TAL-00117 [m]	Historic Petersville Road	Not eligible	Concurred not eligible, 2/11/2016
TAL-00181 [n]	Historic artifacts and surface features	Eligible	Concurred eligible, 3/21/2016
TAL-00186	Undetermined surface features	Not eligible	Concurred not eligible, 2/11/2016
TAL-00194	Historic, modern surface feature	Not eligible	Concurred not eligible, 2/11/2016
TAL-00195	Modern artifact	Not eligible	Concurred not eligible, 2/11/2016
TAL-00208	Prehistoric artifacts	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 9/30/2016
TAL-00209	Undetermined surface features	Phase II evaluation recommended	Treat as eligible, 11/7/2018
TYO-00084 [o]	INHT System	Eligible	Concurred eligible, 2/11/2016
TYO-00228	USGS Base Winter Trail 1	Eligible	Concurred eligible, 2/11/2016
TYO-00318 [p]	Undetermined surface feature	Not eligible	Concurred not eligible, 3/21/2016
TYO-00326 [q]	Prehistoric surface features	2016 Desktop review, eligible	Concurred eligible, 11/23/2016
TYO-00338	Prehistoric surface features	2016 Desktop review, recommended eligible	Concurred eligible, 11/23/2016
TYO-00340	Prehistoric surface feature	2016 Desktop review, recommended eligible	Concurred eligible, 11/23/2016
TYO-00352	Prehistoric isolated find	2016 Desktop review, recommended eligible	Concurred eligible, 11/23/2016
TYO-00357	Prehistoric artifacts	Data insufficient	Unevaluated, 5/16/19
TYO-00359	Prehistoric artifacts	Data insufficient	Unevaluated, 5/16/19
KEN-00703	Undetermined surface feature	Data insufficient	Unevaluated, 5/16/19
KEN-00705	Prehistoric surface features	Eligible	Concurred eligible, 10/4/2019

TABLE 4.13.1-1 (cont'd)

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
KEN-00706	Prehistoric surface features	Data insufficient	Unevaluated, 5/16/19
KEN-00707	Undetermined surface features	Data insufficient	Unevaluated, 5/16/19
KEN-00708	Prehistoric surface features	Eligible	Concurred eligible, 10/4/2019
Camps			
CHN-00122	Historic surface features	Not eligible	Concurred not eligible [no date provided]
FAI-02387	Prehistoric artifacts	Data insufficient	Unevaluated, 5/16/19
HEA-00292	Historic burial	Avoid	Concurred not eligible, 10/4/2019 (Alaska statutes include protection of graves)
Access Roads			
PSM-00197	Prehistoric artifacts and surface feature	2016 Phase II evaluation completed, eligible	Concurred eligible, 11/23/2016
CHN-00125	Historic artifacts	Eligible	Concurred eligible, 9/30/2016
LIV-00778	Prehistoric artifacts	Eligible	Concurred eligible, 9/15/2016
HEA-00066	Historic, modern artifacts	Considered eligible	Eligible, 10/10/2007
TYO-00350	Prehistoric surface features	Eligible	Concurred eligible, 11/23/2018
TYO-00358	Prehistoric surface features	Data insufficient	Unevaluated, 5/16/19
TYO-00360	Prehistoric surface features	Eligible	Concurred eligible, 10/4/2019
Material Sites			
PSM-00011	Prehistoric artifacts	Not eligible	Determined not eligible, 11/4/2015
PSM-00056	Prehistoric artifacts and surface features	Data insufficient	Unevaluated, 5/16/19
PSM-00080	Prehistoric artifacts and surface features	Not eligible	Concurred not eligible, 2/11/2016
PSM-00456	Prehistoric isolated find	Not eligible	Concurred not eligible, 2/11/2016
PSM-00617 [e]	Undetermined surface features	Data insufficient	Unevaluated, 5/16/19
CHN-00040	Historic surface features	2016 Phase II evaluation completed, not eligible	Concurred not eligible, 11/23/2016
WIS-00441	Prehistoric artifacts	Phase II evaluation recommended	Concurred not eligible, 6/28/2017
WIS-00442 [e]	Historic Coldfoot-Wiseman Sled Road	Data insufficient	Unevaluated, 5/16/19
WIS-00443 [f]	Prehistoric artifacts	Eligible	Concurred eligible, 10/4/2019
LIV-00031	Prehistoric artifacts	Not eligible	No eligibility determination required, 5/16/19
LIV-00784	Prehistoric artifacts	Eligible	Concurred eligible, 10/4/2019
FAI-02289	Historic surface features and artifacts	Not eligible	Concurred not eligible, 10/4/2019

TABLE 4.13.1-1 (cont'd)

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
HEA-00012	Prehistoric artifacts	Not eligible	Concurred not eligible, 2/11/2016
HEA-00032	Prehistoric isolated find	Not eligible	No eligibility determination required, 5/16/19
HEA-00680	Prehistoric artifacts	Phase II evaluation recommended	Treat as eligible, 11/7/2018
TAL-00210	Undetermined surface feature	Data insufficient	Unevaluated, 5/16/19
Liquefaction Facilities			
KEN-00642	Historic surface features	Not eligible	Concurred not eligible, 2/12/2015
KEN-00643	Prehistoric surface features	Not eligible	Concurred not eligible, 2/12/2015
KEN-00644	Historic isolated find	Not eligible	Concurred not eligible, 2/12/2015
KEN-00645	Historic artifacts and surface feature	Not eligible	Concurred not eligible, 2/12/2015
KEN-00646	Historic, recent surface feature	Not eligible	Concurred not eligible, 2/12/2015
KEN-00647	Historic surface feature	Not eligible	Concurred not eligible, 2/12/2015
KEN-00648	Historic artifacts	Not eligible	Concurred not eligible, 2/12/2015
KEN-00649	Historic artifacts	Not eligible	Concurred not eligible, 2/12/2015
KEN-00650	Historic isolated find	Not eligible	Concurred not eligible, 2/12/2015
KEN-00651	Historic, modern artifacts	Not eligible	Concurred not eligible, 2/12/2015
KEN-00652	Historic isolated find	Not eligible	Concurred not eligible, 2/12/2015
KEN-00656	Prehistoric, historic surface features	Eligible	Concurred eligible, 9/15/2016

AHRS = Alaska Heritage Resources Survey

[a] The SHPO commented on AGDC's reports in letters dated February 11, March 21, September 15 and 30, and November 23, 2016; June 28, 2017; and May 16 and October 4, 2019.

[b] Portions of the Historic Dalton Highway have been identified within the direct APE of the Mainline Pipeline and eight access roads. The Dalton Highway is represented by eight AHRS numbers, XBP-00114, SAG-00097, PSM-00570, CHN-00070, WIS-00408, BET-00200, TAN-00118, and LIV-00501.

[c] Portions of the Historic Hickel Highway have been identified within the direct APE of the Mainline Pipeline and one access road. The Hickel Highway is represented by two AHRS numbers, SAG-00098 and BET-00201.

[d] PSM-00578 has been identified within the direct APE of the Mainline Pipeline and an access road.

[e] The BLM agrees that data is insufficient to make the NRHP eligibility determination.

[f] The BLM requires a report indicating whether the site maintains integrity and a statement of eligibility.

[g] Portions of LIV-00284 (Rosebud Knob Archaeological District) are within the Mainline Pipeline and a camp. The district consists of 17 sites (LIV-00030, 00040-00048, 00050, 00103-00108). One of the sites within the district, LIV-00047, is within the direct APE of the Mainline Facilities.

[h] Portions of the Historic Dunbar-Brooks Terminal Trail have been identified within the Mainline Pipeline and two material sites. The Dunbar-Terminal Trail is represented by two AHRS numbers, LIV-00556 and FAI-02102.

[i] Portions of the Historic Elliot Highway have been identified within the direct APE of the Mainline Pipeline and two access roads. The Elliot Highway is represented by three AHRS numbers, LIV-00751, LIV-00752, and LIV-00764.

[j] Information provided by AGDC is contradictory. LIV-00752 within the Mainline Pipeline lists a recommendation of "not eligible" and SHPO concurrence of not eligible February 2015; LIV-00752 within access road AR-E-401.2 lists a recommendation of "eligible" and SHPO preliminary comment of "assume eligible" Spring 2015.

[k] Portions of the Historic Dunbar-Minto-Tolovana Trail have been identified within the direct APE of the Mainline Pipeline and one access road. The Dunbar-Minto-Tolovana Trail is represented by one AHRS number, FAI-02177.

[l] Portions of the Historic Denali Highway have been identified within the direct APE of the Mainline Pipeline and one access road. The Denali Highway is represented by one AHRS number, HEA-00450.

TABLE 4.13.1-1 (cont'd)

Archaeological Sites Within the Mainline and Liquefaction Facilities Survey Area

Site Number	Description	NRHP Status/Eligibility Recommendation	SHPO Comment [a]
[m]	Portions of the Historic Petersville Road have been identified within the direct APE of the Mainline Pipeline and one access road. The Petersville Road is represented by one AHRS number, TAL-00117.		
[n]	TAL-00181 has been identified within the direct APE of the Mainline Pipeline and one access road.		
[o]	Portions of the INHT System have been identified within the direct APE of the Mainline Pipeline and one access road. The INHT System is represented by two AHRS numbers, TYO-00084 and TYO-00086. One unrecorded connecting trail segment would be crossed by the Project. Any mitigation measures would be included in a treatment plan and referenced in a site-specific crossing plan for the INHT (see section 4.9).		
[p]	TYO-00318 has been identified within the direct APE of the Mainline Pipeline and a helipad.		
[q]	TYO-00326 has been identified within the direct APE of the Mainline Pipeline and one access road.		

Offshore Resources

The potential for shipwrecks along the Mainline Pipeline route in Cook Inlet warranted a review of remote sensing data and geophysical samples that were collected to identify and characterize seafloor features and hydrographic conditions. Data from single- and multi-beam bathymetry, side-scan sonar imagery, magnetometry, and sub-bottom profiles were examined. These methods examined data for two proposed dredged material disposal areas (DP1 and DP2), each measuring 5,000 by 2,000 feet, and the proposed offshore Mainline Pipeline route across Cook Inlet that encompassed an area measuring 2,066 feet by 27 miles. In a letter dated May 16, 2019, the Alaska SHPO concurred that avoidance of submerged resources is appropriate. If avoidance is not possible, the SHPO recommended additional investigation.

Twenty-nine sonar targets were identified during the side scan sonar survey of DP1. None of the sonar targets were coincident with magnetic anomalies and, after review, were determined to be geological in nature. Fifteen magnetic anomalies were identified during the survey of DP1. None of these anomalies had high signal strength, and they likely represent small pieces of manmade debris.

Fifteen sonar targets were identified during the side scan sonar survey of DP2. None of the sonar targets were coincident with magnetic anomalies and, after review, were determined to be geological in nature. Thirteen magnetic anomalies were identified during the survey of DP2. None of these anomalies had high signal strength, and they likely represent small pieces of manmade debris.

Along the Mainline Pipeline route, two of fourteen sonar targets are potential cultural resources. Sonar Target 2 is a rectangular object measuring about 8.5 by 12.1 feet that occurs about 6.5 feet above the sea floor. Sonar Target 7 is a wedge-shaped symmetrical object measuring 17.7 by 29.0 feet with no relief above the seafloor. Only 2 of the 10 magnetic anomalies identified had high signal strength, including anomalies 3 and 7. None of the magnetic anomalies were coincident with sonar targets.

The remote sensing data results are insufficient to determine whether the sonar targets and magnetic anomalies along the proposed offshore Mainline Pipeline route represent historic properties. Further investigation of these anomalies would be undertaken by AGDC if disturbance of the seafloor should be planned in the target locations. Remote sensing data was not collected for portions of the temporary construction right-of-way. Remote sensing surveys would be completed where anchoring of the pipe laydown barge is planned.

4.13.1.3 Liquefaction Facilities

Archaeological Sites

Twelve sites were identified within the LNG Plant footprint as shown in table 4.13.1-1. Two sites have a prehistoric affiliation, eight sites have historic temporal affiliations, and two sites are modern.

Eleven of the archaeological sites were recommended not eligible for the NRHP. The Alaska SHPO concurred with these recommendations in a letter dated February 12, 2016. One prehistoric site was recommended eligible and SHPO concurred with this recommendation in a letter dated September 15, 2016. We also concur.

Aboveground Resources

No aboveground resources were identified in the footprint of the Liquefaction Facilities.

Marine Terminal

A review of remote sensing data associated with the geotechnical investigation of the Marine Terminal and approach channel identified 12 sonar targets and 77 magnetic anomalies. Three of the twelve sonar targets (Sonar Targets 1, 2, 3) were coincident with weak magnetic anomalies, and three larger sonar targets (Sonar Targets 5, 7, 8) likely represent objects lost or dropped from the existing dock structure and are modern in origin. Target number 5 is a rectangular object measuring about 6.5 by 23 feet. Target number 7 is a rectangular object measuring about 9 by 31 feet with a ladder-like form. Target number 8 is a linear object measuring about 3.5 by 38 feet and may represent a section of pipe or cable. The remaining targets were considered geologic features such as boulders or outcrops.

The magnetic anomalies may be associated with fishing practices on the coast where seaward gillnet ends are often secured to the seabed with steel anchors or are associated with existing piers and berthing facilities. Most of the magnetic anomalies are outside the Marine Terminal footprint, but 2 of the 77 magnetic anomalies could be affected during construction of the Marine Terminal. AGDC has not indicated whether these would be avoided.

4.13.2 Alaska Native Tribal Consultations

On March 4, 2015, we sent our NOI to the 38 federally recognized tribes identified in table 4.13.2-1. We received comments from the Chickaloon Native Village, the Knik Tribe, and the Native Village of Tyonek. In a letter dated November 25, 2015, the Chickaloon Village Traditional Council stated their interest in participating in the Section 106 process. The Chickaloon Village Traditional Council additionally requested that all available data from ASAP be reviewed to assess potential Project impacts on cultural resources. We have reviewed the cultural resources data collected for ASAP to inform this analysis.

Nine tribes requested meetings with FERC staff, including the Chickaloon Native Village, Kenaitze Indian Tribe, Native Village of Nuiqsut, Native Village of Tyonek, Nenana Native Association, Knik Tribe, Allakaket Village, Alatna Village, and Village of Anaktuvuk Pass. During government-to-government meetings, each tribe provided comments about the Project.

On October 13, 2015, during a meeting with the Chickaloon Native Village, the village commented that the Project crosses the western limits of the tribe's traditional use area, and requested a detailed Project schedule, construction measures that would minimize environmental impacts, a review of field survey results for the ASAP Project, and alignment sheets. Additionally, the tribe was interested in future meetings with AGDC and FERC staff.

TABLE 4.13.2-1

Consultation with Federally Recognized Tribes for the Project

Tribe Name	Date of Communication	Comment
Alatna Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	August 23, 2016	Alatna Village requested a face-to-face consultation meeting with FERC.
Allakaket Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	February 5, 2016	Comments provided to FERC that AGDC has not scheduled meetings with Allakaket Village.
	August 23, 2016	Allakaket Village and FERC participated in a face-to-face tribal consultation meeting.
Arctic Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Beaver Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Birch Creek Tribe	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Cheesh-Na Tribe	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Chickaloon Native Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 13, 2015	Chickaloon Native Village and FERC participated in a face-to-face tribal consultation meeting.
	November 25, 2015	Chickaloon Village Traditional Council sent a letter to FERC requesting participation in the Section 106 process.
Circle Native Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Eklutna Native Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Evansville Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Gulkana Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Inupiat Community of the Arctic Slope		
	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Kaktovik Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Kenaitze Indian Tribe	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 15, 2015	Kenaitze Indian Tribe and FERC participated in a face-to-face tribal consultation meeting.

TABLE 4.13.2-1 (cont'd)

Consultation with Federally Recognized Tribes for the Project

Tribe Name	Date of Communication	Comment
Knik Tribe	March 4, 2015	FERC issued NOI. No response received.
	February 20, 2015	The Knik Tribe requested that FERC initiate consultation under Section 106 of the NHPA.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 16, 2015	Knik Tribe and FERC participated in a face-to-face tribal consultation meeting.
	October 16, 2015	Knik Tribe provided comments to FERC regarding Project impacts on cultural resources of concern to the Tribe.
	July 25, 2016	Knik Tribe provided comments on Resource Report 2.
Manley Hot Springs Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Barrow	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Cantwell	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Chenega	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Eyak	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Fort Yukon	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Gakona	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Kluti-Kaah	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Minto	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Nanwalek	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Nuiqsut	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 15, 2015	Native Village of Nuiqsut and FERC participated in a face-to-face tribal consultation meeting.
Native Village of Port Graham	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Stevens	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Tanana	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Tatitlek	March 4, 2015	FERC issued NOI. No response received.

TABLE 4.13.2-1 (cont'd)

Consultation with Federally Recognized Tribes for the Project

Tribe Name	Date of Communication	Comment
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Native Village of Tyonek	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 16, 2015	Native Village of Tyonek and FERC participated in a face-to-face tribal consultation meeting.
	October 21, 2019	Native Village of Tyonek and FERC participated in an in-person meeting.
Nenana Native Association	March 4, 2015	FERC issued NOI. No response received.
	September 10, 2015	Nenana Native Association requested an in-person meeting with FERC.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	October 16, 2015	Nenana Native Association and FERC participated in a face-to-face tribal consultation meeting.
Ninilchik Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Rampart Village	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Seldovia Village Tribe	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Village of Anaktuvuk Pass	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
	April 13, 2016	FERC participated in Tribal Council's meeting (telecom) and the tribe requested a face-to-face meeting.
Village of Salamatof	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.
Village of Venetie	March 4, 2015	FERC issued NOI. No response received.
	September 15, 2015	FERC invited tribe to participate in an in-person meeting.

On October 15, 2015, during a meeting with the Kenaitze Tribe, the tribe stated an interest in opportunities for economic development, and stated concerns about the Project's environmental and economic impacts on water resources, subsistence use areas, job training opportunities and local hiring, housing constraints due to an influx of workers, and increased traffic. Mitigation measures for water resources are discussed in section 4.3. Impacts on subsistence, jobs and housing, and traffic are discussed in sections 4.14, 4.11, and 4.12, respectively.

On October 15, 2015, during a meeting with the Native Village of Nuiqsut, the village asked to be involved in AGDC's Project planning process and that the Arctic Slope Regional Corporation be involved in the NEPA process. The tribe recommended the construction of a lateral pipeline to Anaktuvuk Pass due to their proximity to the proposed Mainline Pipeline route, that all aboveground pipeline portions be camouflaged to avoid affecting the caribou migration due to the reflection from galvanized steel, and mitigation measures for all environmental, economic, and cultural impacts. Mitigation measures for environmental, cultural, and economic impacts are discussed throughout this EIS.

On October 16, 2015, during a meeting with the Native Village of Tyonek, the village stated concerns about Project impacts on moose populations, marine mammals (particularly the Cook Inlet beluga

whale population), threatened and endangered species, and cultural resources within the tribe's cultural landscape. The village recommended a review of alternative routes near Cook Inlet. On October 21, 2019, during a second meeting with the Native Village of Tyonek, the village expressed these same concerns and raised additional concerns about construction methods, timing, and number of vessels in Cook Inlet; impacts on subsistence resources including moose, salmon, and marine resources; the effects of climate change on subsistence resources; safety; and employment opportunities. Alternative routes are discussed in section 3.0. Construction methods are discussed in section 2.2. Vessel traffic is discussed in section 2.2, 2.5, and 4.12.2.3. Impacts on subsistence uses are discussed in section 4.14. Impacts on wildlife, marine mammals, fisheries, and threatened and endangered species are discussed in sections 4.6, 4.6.3, 4.7.1, and 4.8, respectively. Reliability and safety are discussed in section 4.18. Socioeconomics is discussed in section 4.11.

On October 16, 2015, during a meeting with the Nenana Native Association, the association stated concerns about Project impacts on wetlands near Minto Flats and Nenana, and requested a Project plan for road maintenance, Project coordination with the association for timber clearing on tribal lands, and a detailed Project map.

In letters dated February 20 and October 16, 2015, the Knik Tribe stated their interest in participating in the Section 106 process and identified particular areas of concern. On July 25, 2016, the Knik Tribe provided comments on Resource Report 2.

On October 16, 2015, during a meeting with the Knik Tribe, the tribe provided several comments regarding cultural and natural resources. The tribe requested the development of a Section 106 PA and participation in the archaeological survey. The tribe also commented that pipeline construction and operation have the potential to affect surface water, ground water, and air quality. Impacts and mitigation measures for water resources are discussed in section 4.3. Impacts and mitigation measures for air quality are discussed in section 4.15.

On May 17, 2018, AGDC met with representatives from the Knik Tribal Council to discuss the Mainline Pipeline between MPs 674.0 and 730.0 and to address the Tribal Council's concerns about Project impacts on their traditional lands, cultural heritage, and water resources. AGDC modified the route to avoid areas of concern to the tribe and invited tribal members to participate in the cultural resources survey within the tribe's traditional lands. At the meeting, the Tribal Council indicated that AGDC's route modifications adequately addressed their concerns. Because the Tribal Council's concerns were addressed, we did not conduct further evaluation of route alternatives in this area.

AGDC provided a copy of its Environmental Report (including the Project mapping and cultural resources survey reports) to the Chickaloon Native Village, Kenaitze Indian Tribe, Native Village of Nuiqsut, Native Village of Tyonek, Nenana Native Association, and Knik Tribe.

FERC staff participated in meetings with Allakaket Village on February 5 and August 23, 2016, to provide a Project update. Members of Alatna Village were invited to attend the August 26 meeting, and at the community meeting, the tribe requested a separate meeting in their village. We continue to coordinate with Alatna Village.

On April 13, 2016, FERC staff participated in a conference call with the Village of Anaktuvuk Pass Tribal Council to provide a Project overview. The Tribal Council requested that FERC share with AGDC the village's interest in receiving natural gas. FERC staff spoke to AGDC in May 2016 to convey the village's request. AGDC provided a point of contact to the tribe to facilitate communication regarding the tribe's concerns. The Tribal Council requested a meeting with FERC and we continue to coordinate with the tribe.

In addition to our contacts with the tribes, AGDC sent Project introduction letters to 19 of the tribes to provide them an opportunity to identify any concerns related to properties of traditional religious or cultural significance that could be affected by the Project. Of the 19 tribes, the Ninilchik Traditional Council and the Village of Salamatof did not request further consultation.

On April 26, 2018, AGDC met with the Native Village of Minto to discuss any known burial or other tribal sites that the Project would affect. The tribal representatives stated that the Project would not affect any known burial or other tribal sites.

4.13.3 Other Interested Parties

During the scoping period, we received comments from the Tanana Chiefs Conference in a letter dated December 4, 2015, stating that the cultural resources review should include extensive outreach regarding traditional and customary use areas as well as historic ethno-geographical research to understand the affected human environment. Additionally, the letter said the Project crosses the traditional lands of the villages of Allakaket, Alatna, Evansville, Stevens Village, Rampart, Minto, Nenana, and possibly other federally recognized tribes. The Tanana Chiefs Conference also stated that federally recognized tribes residing near the Project should be afforded the opportunity to participate in government-to-government consultation. As noted above, FERC has initiated, and continues, outreach with tribes that expressed an interest.

Cook Inlet Region, Inc. (CIRI) requested a face-to-face meeting with FERC. On August 26, 2017, FERC participated in CIRI's quarterly meeting and provided an overview of the Project's status.

In a letter dated October 18, 2018, Ahtna, Inc. requested consultation with FERC and commented that about 40 miles of the Mainline Pipeline would cross corporation lands that were conveyed or selected under ANCSA and hold cultural significance to the shareholders. In a letter dated October 3, 2019, Ahtna, Inc. commented on safety; socioeconomic impacts; customary and traditional subsistence use impacts, particularly for the Native Village of Cantwell; and consultation. Reliability and safety are discussed in section 4.18. Socioeconomics is discussed in section 4.11. Impacts on subsistence uses are discussed in section 4.14. FERC staff provided the same information to Alaska Native corporations and Alaska Native villages (including Ahtna, Inc.) to initiate consultation for NEPA and Section 106 (see sections 1.3.2 and 1.3.3).

AGDC sought input from several Certified Local Governments, including the Fairbanks North Star Borough, City of Fairbanks, City of Kenai, Kenai Peninsula Borough, City of Seward, MSB, Municipality of Anchorage, and North Slope Borough. The MSB Cultural Resources Division requested to be kept apprised of cultural resources investigations for the Project.

4.13.4 Plan for Unanticipated Discovery of Cultural Resources and Human Remains

AGDC has prepared procedures to be used in the event that any unanticipated historic properties or human remains are encountered during construction and provided the Project Plan for Unanticipated Discovery of Cultural Resources and Human Remains to FERC, the Alaska SHPO, and the BLM. The plan includes procedures for notifying consulting and interested parties, including Alaska Native tribes, in the event of any discovery. To date, AGDC has not filed any SHPO or BLM comments on the plan.

4.13.5 Impacts and Mitigation

Project construction and operation could potentially affect historic properties (i.e., cultural resources listed on, or eligible for, the NRHP). Effects could include destruction or damage to all, or a

portion, of a historic property; alteration of a property including restoration, rehabilitation, repair, maintenance, or stabilization inconsistent with federal standards; removal of the property from its historic location; change of the character of the property's use or of physical features within the property's setting that contribute to its historic significance; and introduction of visual, atmospheric, or audible elements that diminish the integrity of the property's significant historic features. If NRHP-eligible resources are identified that cannot be avoided, AGDC would prepare treatment plans. Treatment plan implementation would only occur after Project authorization and after FERC provides written notification to proceed.

AGDC has not completed cultural resources surveys and/or NRHP evaluations. To ensure that FERC's responsibilities under the NHPA and its implementing regulations are met, the Commission is consulting with the ACHP, Alaska SHPO, BLM, NPS, and concurring parties to prepare a PA that will outline the process for identifying historic properties and measures that would be taken to resolve adverse effects on historic properties that cannot be avoided. Therefore, **we recommend that**:

- **AGDC should <u>not begin</u> implementation of any treatment program/measures (including archaeological data recovery); facility construction; or use of staging, storage, or temporary work areas, ancillary facilities, and new or to-be-improved access roads <u>until</u>:**

  a. AGDC completes outstanding archaeological and architectural surveys and any special studies, and files with the Secretary all remaining cultural resources survey, evaluation, and special studies reports, and the Alaska SHPO comments, the applicable land management agency comments, and consulting party comments on the reports;

  b. AGDC files any necessary avoidance or treatment plans that outline measures to avoid, reduce, and/or mitigate effects on historic properties, and the Alaska SHPO comments, the applicable land management agency comments, and consulting party comments on the plans;

  c. the ACHP is provided an opportunity to comment on the undertaking if historic properties would be adversely affected; and

  d. FERC staff reviews, and the Director of the OEP approves in writing, all cultural resources survey reports and plans; and FERC staff notifies AGDC in writing that treatment plans/mitigation measures may be implemented or that construction may proceed.

  All material filed with the Commission containing <u>location, character, and ownership information</u> about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "<u>CUI/PRIV – DO NOT RELEASE</u>."[117]

4.14 SUBSISTENCE

The customary and traditional use of wildlife resources has been important to Alaska Native communities for millennia. Alaska Natives have a long relationship and connection to the land and water resources within their traditional territories. The land and all it provides are considered essential to Alaska Native economic and cultural identity and continuity. The traditional use of land and the resources it provides in support of life is commonly referred to as subsistence. Alaska Natives view subsistence

[117] CUI/PRIV = Controlled Unclassified Information/Privileged

holistically as a way of being or a way of life and a significant element of their cultural identity and relationship with the land and resources of Alaska.

More recently, subsistence use has also become an important way of life for many non-Natives, especially for rural Alaska residents. Therefore, our analysis of impacts on subsistence includes Alaska Native and non-native communities whose subsistence economies could be affected by the Project. As used in this EIS, the term "subsistence" means the customary and traditional uses by rural Alaska residents of wild, renewable resources for direct personal or family consumption as food, shelter, fuel, clothing, tools, or transportation; for the making and selling of handicraft articles out of nonedible byproducts of fish and wildlife resources taken for personal or family consumption; for barter; or for sharing for personal or family consumption (see section 1.6 for federal and state regulations). Furthermore, the holistic nature of subsistence encompasses traditional activities that include transmission of knowledge between generations, connection of people to their land and environment, maintenance of a healthy diet and nutrition, and support of social and spiritual aspects of life (Case and Voluck, 2012). The knowledge and skills needed to subsist involve an understanding of relationships between people, animals, and the natural environment that is the basis for the Alaska Native system of stewardship.

With Alaska statehood in 1958, the state was allowed the selection of 104 million acres from the public domain. When the state began selecting lands traditionally used by Alaska Natives, tension developed. Alaska Native villages mobilized to halt the transfer of land to the state. However, the state's land selection continued until the Interior Secretary froze the conveyance of state-selected lands in 1966. Alaska Native leaders formed the Alaska Federation of Natives (AFN) in the same year and supported a fair land settlement. In 1967, state leaders, the AFN, and the Department of the Interior agreed to work together to settle the aboriginal land claims and formed the Alaska Native Claims Task Force. This task force recommended a settlement of land, money, and continued use of traditional lands for Alaska Native hunting, fishing, and gathering (Anderson, 2007). Through the AFN's advocacy, legislation was passed that protects a traditional subsistence lifestyle. The AFN continues to advocate for Alaska Native governments regarding federal, state, and local laws. The federal government continues to play a role in protecting subsistence rights in Alaska. A detailed discussion of the regulatory context for the protection of subsistence resources and practices is provided in section 1.6.

In December 1980, Congress passed ANILCA, designating more than 100 million acres of federal land in Alaska as new or expanded conservation system units. These conservation units include national parks and preserves, national wildlife refuges, designated wilderness areas, Wild and Scenic Rivers, and the INHT. Among other things, ANILCA is designed to provide the opportunity for rural residents engaged in a subsistence way of life to continue to do so. The BLM is required to prepare an analysis under Section 810 of ANILCA because a portion of the Project construction and operation would occur on BLM lands. The analysis of potential impacts on subsistence under the Section 810 guidelines was prepared by the BLM and is included in appendix U.

Subsistence in Alaska is characterized by a high level of consumption of wild foods (game, fish, and vegetation), hunting and gathering activities organized by kinship groups, and the pursuit of these activities within traditional territories (Wolfe, 1998; Fall, 2016). Subsistence activities are generally carried out using small-scale tools and machines to harvest and process natural resources. The technologies used are typically a mix of traditional equipment—fish nets and drying racks, knives and axes, and game traps—and modern equipment—firearms, snowmachines, land based vehicles, and motor boats (Wolfe, 1998). Subsistence harvest levels vary widely among individuals in a community, from one community to the next, and from year to year. Sharing of subsistence resources is common in rural Alaska; often, the proportion of households giving or receiving resources exceeds 80 percent (Martin, 2015).

Historically, Alaska Native communities relied on fishing and hunting within specific territories as part of a traditional economic system of wild food production and distribution. After the mid-19th century, businesses and governmental interests expanded to Alaska. Commercial industries such as fishing, mining, oil extraction, tourism, and defense began to emerge as major sectors of Alaska's economy (Wolfe, 2004). Urban growth in Alaska occurred as people from the contiguous United States and Alaska's rural areas found employment opportunities in these industries. By the 20th century, the majority of Alaska's population resided in urban areas. The concentration of people in urban areas accelerated industrial growth and the replacement of traditional subsistence economic systems.

In Alaska's rural areas, traditional economies began to change as a cash economy was incorporated, but a strong reliance on wild foods continued, providing a reliable economic base for individuals and communities as well as food security. The participation in both the traditional subsistence and a cash economy is often referred to as a "mixed subsistence-market economy," wherein individuals and families or households rely on and trade wild foods and goods to supplement their diet and income (Wolfe and Walker, 1987). Families and households move between traditional subsistence and market activities, depending on opportunities and preferences.

The following section summarizes the methodology we used to analyze potential impacts on subsistence communities resulting from construction and operation of the Project. To understand current subsistence use patterns in the Project area, the section also provides community summaries, including the seasonal round of subsistence resource gathering, the subsistence use areas, and an assessment of impacts on subsistence for each community.

4.14.1 Methods to Assess Subsistence Impacts

The Project's potential to affect subsistence resources and users has been a concern explicitly expressed by Alaska Natives, federal and state resource agencies, and many others in scoping meetings, government-to-government meetings, and letters to the Commission. Effects on subsistence resources and associated habitat often result in effects on subsistence users and their harvest success.

In order to assess the Project's potential impacts on subsistence, we identified subsistence communities near the Project (see below). The subsistence behaviors of community members were characterized based on household surveys, interviews, and traditional knowledge workshops. Additionally, we reviewed the vegetation; wildlife; aquatic; and threatened, endangered, and other special status species analyses in this EIS to consider Project effects on vegetation, wildlife, and fish populations and their habitats (see sections 4.5 through 4.8).

To better understand the subsistence activities of these communities, ADF&G household surveys, subsistence mapping interviews, and traditional knowledge workshops were conducted (see section 1.4 for a summary of traditional knowledge workshops). In cases where a community chose not to participate in subsistence surveys or mapping interviews, the most current available data is used in the analysis. About half of the household survey data is from the last 5 years. Virtually all of it is from the last 10 years. Recognizing the potential imposition on the communities of conducting these surveys on such a frequent basis, and that for many of the communities we did not identify recent changes that would significantly modify subsistence activities, we determined that the most current data available allows us to draw conclusions regarding impacts on subsistence.

4.14.1.1 Subsistence Communities

The description of subsistence harvest patterns focuses on community profiles from five regions (see table 4.14.1-1). Within each region, subsistence users generally share a common language and some

common harvest patterns. The decision to examine subsistence at the community level and provide a regional summary is to offer a landscape level perspective for communities that often have overlapping subsistence harvest areas. The parameters used to identify the subsistence communities analyzed is described below.

Any community within 30 miles of the Project—and any community more than 30 miles from the Project area[118] but with a subsistence use area within 30 miles of the Project area—was identified as a subsistence community for this analysis. The geographic ranges of subsistence use areas and wildlife migration patterns change over time; therefore, 30 miles was selected to account for this variability and broadly encompass all communities that could be affected by the Project.[119] Thirty-three communities are within 30 miles or have subsistence use areas within 30 miles of the Project (see table 4.14.1-1).

TABLE 4.14.1-1

Subsistence Regions and Study Communities

Region	Community
North Slope	Utqiagvik (Barrow), Nuiqsut, Kaktovik, Anaktuvuk Pass
Yukon River	Evansville, Alatna, Allakaket, Stevens Village, Rampart, Wiseman, Coldfoot, Bettles
Tanana River	Tanana, Manley Hot Springs, Minto, Nenana, Four Mile Road CDP, Anderson, Ferry, Healy, Denali Park CDP
South-Central	Cantwell, Chase, Talkeetna, Trapper Creek, Skwentna, Alexander Creek/Susitna, Beluga, Tyonek
Kenai Peninsula	Nikiski, Seldovia, Port Graham, Nanwalek

"Subsistence use area" is the geographic range of residents' use of the environment to harvest subsistence resources. This range includes geographic features associated with subsistence search and harvest areas, camp and cabin locations, and subsistence travel routes to show the geographic extent of each community's use area. In general, each community's subsistence use area can be characterized by hunting, trapping, fishing, and gathering locations and activities.

4.14.1.2 Household Surveys

Project-specific household surveys and subsistence mapping were completed by the ADF&G Division of Subsistence for 17 subsistence communities (see table 4.14.1-2). Household surveys were completed for other projects in 15 additional communities but are relevant to this analysis. One community, Kaktovik, declined to participate in ADF&G household surveys because they had conducted their own survey in 2012 (Harcharek et al., 2018). The subsistence data collected for 31 of the 33 communities are less than 10 years old. Of these, 16 surveys are 5 years old or less. Only one survey is older than 10 years. The ADF&G surveys are quantitative in nature and involve documenting the amount of wildlife, fish, and plant resources harvested by a community with the household as the primary focus of analysis. Using a standardized methodology and statistical analysis, ADF&G household surveys collect baseline information about contemporary harvests and uses of wildlife, fish, and plant resources, as well as local observations about wild resource populations and trends. The surveys document subsistence use areas for a 1-year period. Information collected during the surveys included subsistence use area; harvest timing, amount, and diversity; and temporal trends to assess changes over time. These surveys also collected data on food security defined as "access by all people at all times [to provide] enough food for an active healthy life" (Jones and Kostick, 2016). The questionnaire used to solicit information was modified for local conditions aimed at identifying whether food insecurities, if any, are related to wild harvests or store-bought foods.

[118] "Project area" refers to the pipeline centerlines and the centers of major aboveground facilities such as compressor stations, work camps, borrow areas, pipe storage yards, access roads, etc., when such are distant from the centerline.

[119] FERC's subsistence criteria were established for the Alaska Pipeline Project. The 30-mile buffer was developed in coordination with federal cooperating agencies and tribes in an attempt to adequately assess potential environmental impacts on subsistence resources and users.

Each community's food security status was compared to conditions at the national and statewide levels. In most instances, the communities were comparable to the national and statewide conditions. In response to these surveys, Alaska Natives stressed that subsistence harvests are essential to social connections, cultural continuity and heritage, and spiritual life. However, wild resources are also important for nutrition and represent good sources of protein, oils, minerals, and micronutrients. A more detailed discussion of food security is provided in section 4.17.

4.14.1.3 Subsistence Mapping Interviews

AGDC completed subsistence mapping interviews in 24 communities, of which 10 are Alaska Native communities, to establish a baseline map of subsistence use areas for those communities (see table 4.14.1-2). The interviews addressed subsistence activities, subsistence during both the last 12 months and the past 10 years, overall satisfaction with the resource harvests, and other general observations about subsistence with active harvesters. The interviews were typically conducted with one individual but occasionally included two or three respondents. When more than one respondent participated, they were often hunting partners, family members, or spouses who traveled to many of the same areas for subsistence purposes. Elders or others in the community who were not active harvesters, but knowledgeable about subsistence harvests, were asked to provide comments about resource status and changes as well as comments about the Project. If respondents reported that they led charters or acted as a hunting or fishing guide for cash, these areas were not mapped as part of the subsistence use area.

Mapping for 10-year subsistence harvests identified use areas for each of 18 resource categories.[120] The use areas were recorded on an acetate sheet overlain on a topographic base map (1:250,000 scale) that was later digitized on the same topographic map. For each subsistence use area, the interviewer recorded the species harvested, month(s) of use, access or travel method used from the community to the use area, and travel method used within the use area. Access and search method choices included boat, snowmachine, off-road recreational vehicle, truck/car, plane, foot, or other travel methods (e.g., horses, bicycle, tractor, dog team). The resultant mapping includes community harvest polygons for all resource categories that differentiate between areas where a small number of use areas were reported and where higher numbers of use areas were reported, regional mapping of use areas accessed by each search method reported, and regional subsistence use areas by month. For communities where subsistence uses were mapped by month or season, a 12-month or seasonal calendar of resources harvested is provided as a table in the community summaries. A harvest calendar table is not provided where subsistence harvest data is limited.

[120] Information on 18 subsistence categories was collected. These categories are caribou, moose, bear, Dall sheep, deer, other large land mammals; small land mammals; marine mammals; migratory birds, upland birds; eggs; salmon, non-salmon fish; marine invertebrates; berries, plants, wood; and other.

TABLE 4.14.1-2

Subsistence Study Communities Associated with the Project

Region and Community	Subsistence Mapping Completed [a]	Traditional Knowledge Workshop (project, year) [b]	ADF&G Household Survey Data Collection Year [c]
North Slope Region			
Utqiagvik (Barrow)	No	Alaska Pipeline Project, 2012	2014
Nuiqsut	No	Alaska Pipeline Project, 2012	2014
Kaktovik [d]	Declined	Alaska Pipeline Project, 2012	N/A [c]
Anaktuvuk Pass	No	Alaska Pipeline Project, 2012	2014
Yukon River Region			
Wiseman	Yes	N/A	2011
Coldfoot	Yes	N/A	2011
Evansville	Yes	Alaska Pipeline Project, 2012	2011
Bettles	Yes	N/A	2011
Alatna	Yes	Alaska Pipeline Project, 2012	2011
Allakaket	Yes	Alaska Pipeline Project, 2012	2011
Stevens Village	Yes	Alaska Pipeline Project, 2012	2014
Rampart	Declined	Alaska Pipeline Project, 2012	2014
Tanana River Region			
Tanana	No	Did not meet AGDC criteria for a traditional knowledge workshop	2014
Manley Hot Springs	No	2014 and 2015	2012
Minto	Yes	2015	2012
Nenana	Yes	2014	2015
Four Mile Road CDP	Yes	N/A	2015
Anderson	Yes	N/A	2015
Ferry	Yes	N/A	2015
Healy	Yes	N/A	2014
Denali Park CDP	Yes	N/A	2015
South-Central Region			
Cantwell	Yes	Susitna-Watana Hydroelectric Project, 2013	2012
Chase	Yes	N/A	2012
Talkeetna	Yes	N/A	2012
Trapper Creek	Yes	N/A	2012
Skwentna	Yes	N/A	2012
Alexander Creek/Susitna	Yes	N/A	2012
Beluga	Declined	N/A	2006 [e]
Tyonek	No	Susitna-Watana Hydroelectric Project, 2013	2013
Kenai Peninsula Region			
Nikiski	Yes	N/A	2014

TABLE 4.14.1-2 (cont'd)

Subsistence Study Communities Associated with the Project

Region and Community	Subsistence Mapping Completed [a]	Traditional Knowledge Workshop (project, year) [b]	ADF&G Household Survey Data Collection Year [c]
Seldovia	Yes	Alaska LNG Project, 2014	2014
Port Graham	Yes	Alaska LNG Project, 2015	2014
Nanwalek	Yes	Alaska LNG Project, 2015	2014

N/A = Not applicable

[a] The most current available community subsistence mapping is depicted in this EIS. Note that the map scale varies depending on the source of the mapping.

[b] Traditional knowledge workshops were held in communities that are Alaska Native villages or in communities with more than 50-percent Alaska Native residents.

[c] ADF&G completed subsistence studies in 17 communities for the Project: Utqiagvik, Nuiqsut, Anaktuvuk Pass, Stevens Village, Rampart, Tanana, Nenana, Four Mile Road CDP, Anderson, Ferry, Healy, Denali Park CDP, Tyonek, Nikiski, Seldovia, Port Graham, and Nanwalek.

[d] Kaktovik completed a subsistence study in 2012 (Harcharek et al., 2018).

[e] ADF&G completed subsistence household surveys for the Chuitna Coal Mine.

Mapping for 12-month subsistence activities recorded the number of trips taken for each harvested resource, the success of the trips, and the month(s) during which each trip occurred. For each activity identified, the study team recorded the following information: month, targeted and non-targeted resources categories/species, number of trips by month, number of overnight (i.e., one or more nights) trips, and number of successful trips (for targeted resources only). Targeted resources are those resources that the respondent identified as being the primary purpose of the subsistence activity. Non-targeted resources are those resources that the respondent identified as being secondary resources that the respondent harvested opportunistically, but that were not the main purpose or target of the trip. The resultant mapping includes use areas by month and an overview map depicting the extent of all resource use areas.

General observations were provided to open-ended interview questions. Respondents were asked to describe the importance of subsistence and provide the three most important subsistence resources, a description of the area important to community subsistence, and suggestions for the Project. These data, where available, are integrated into the community summaries in section 4.14.3.

4.14.1.4 Traditional Knowledge Workshops

Traditional knowledge workshops were held to request input about the participant's personal experience with the environment and its connection to their subsistence traditions. Individuals and communities use traditional knowledge to inform subsistence in a number of ways. Subsistence users rely on the collective history of tested observations about the connections between plants, fish, wildlife, water, and weather to know when migratory fish or wildlife will arrive and generally where to harvest them. Therefore, participant's observations about the connections between plants, wildlife, fish, water, and weather were documented at these workshops (see section 1.4 for a discussion of traditional knowledge and table 4.14.1-2 for a list of communities that participated in traditional knowledge workshops).

4.14.1.5 Subsistence Characteristics

Subsistence mapping by ADF&G and AGDC along with the traditional knowledge study provide current baseline data relevant to measuring changes in subsistence use areas, resources, harvest success, frequency of trips, transportation methods, timing of harvest activity, and harvest effort. Subsistence household harvest surveys such as those conducted by the ADF&G provide data to measure changes related to harvest amounts, harvest participation, harvest diversity, and harvest sharing.

Based on the information provided by the surveys, interviews, and workshops, 12 general subsistence characteristics were identified. The choice of subsistence characteristic is informed by the ways in which subsistence uses may change over time. The subsistence characteristics identified for the Project are listed in table 4.14.1-3 and described below (Braund, 2010). These characteristics describe subsistence strategies of subsistence users. In this context, a strategy is a set of behavioral choices, selected from a limited set, that are intended to produce a desired outcome.

For each subsistence characteristic, change indicators were defined. These indicators allow for a comparison to identify changes in subsistence resources and users. The abundance and quality of subsistence resources; physical and regulatory restrictions affecting access; visual, noise, and other human activity disturbances; and the time and funds available to the harvester are all factors that could affect the subsistence use area and availability of, or access to, an individual resource. A decrease in subsistence use in one area may result in an increased use of another area.

The distribution, migration, and the seasonal and long-term variation of animal populations make determining when and where to harvest a subsistence resource a complex activity. Areas that are used infrequently can be important harvest areas when they are used. Species use and harvest success can vary greatly over short periods of time, and analyzing only short-term harvest data can result in an inaccurate characterization of a community's baseline subsistence activities. For example, if a North Slope community did not harvest any bowhead whales in a particular year, the use of caribou and other species would increase in that year to compensate for the loss of whale harvest. If caribou are not available in a particular winter, other marine and terrestrial species would be hunted with greater intensity during that time. Additionally, the cultural value of sharing and reciprocity ensures that other communities will contribute subsistence foods to the communities that have had limited or failed harvests.

Subsistence use area refers to the locations in which subsistence users search for and harvest subsistence resources. The use of an area is dependent upon a harvester's ability to access the area and on the availability of the subsistence resources within the area. Abundance, distribution, migration, quality of subsistence resources, physical restrictions to access, visual and social disturbances, and the time and funds available to the harvester are all factors that could affect the subsistence use area for an individual resource. Subsistence use areas can range in size, depending on the targeted resource, from a small berry patch to an expansive overland caribou hunting area. Changes in subsistence use areas are a leading indicator of change in subsistence because harvesters are likely to compensate for impacts in one geographic area by increased use of other areas (Braund, 2014; Fall et al., 2001; Baltensperger and Joly, 2019; Van Lanen, et al., 2012).

In addition to the mapped data associated with subsistence use areas, subsistence baseline indicators that are useful in characterizing a subsistence use area, such as harvest effort (e.g., frequency and duration of trips), have also been analyzed and are summarized in table 4.14.1-3. Within a subsistence use area, harvest activities follow a seasonal cycle. The harvest activities are characterized by highs and lows for different resources throughout the year. The timing of these activities are influenced by a number of factors, including wildlife and vegetation availability, climate and weather conditions, harvest regulation, and personal reasons (e.g., work commitments and family needs). Individual resources are not typically pursued continuously throughout the year.

If a portion of a community's subsistence use area is within the Project footprint, a direct impact on subsistence use would occur. In general, with the exception of downstream effects (e.g., movements of migratory terrestrial species), the farther a community's subsistence use area is from the Project area, the less the potential exists for a direct impact on residents' subsistence uses.

TABLE 4.14.1-3

Baseline Subsistence Characteristics

Subsistence Characteristic	Description of Subsistence Characteristic	Change Indicator	Data Source
Subsistence use area	Geographic extent of harvest pursuits	Change in use area may reflect quality and abundance of resources, physical or regulatory restrictions to access, time, and funds available to harvester	ADF&G 1-year mapping and subsistence mapping for 10 years of subsistence
Harvest amount	Harvest by species are represented as pounds of edible resources	Change (decrease) in harvest amount has implications for household nutrition, quality of life, and cultural continuity	ADF&G household surveys for harvested pounds and per capita
Harvest effort	Time and money spent on harvest activities as measured on a resource-specific basis	Change in the percentage of households attempting to harvest a specific resource as a result of changes in the number of harvesters, geographic distribution of resources, frequency of harvest trips, or months of use	ADF&G survey of percent of households trying to harvest and from subsistence mapping interviews percent of active harvesters trying to harvest by resource category for last 10 years and last 12 months
Harvest timing	Season of use	Changes in annual cycle as a result of changes in seasonal abundance, physical and regulatory restrictions	Subsistence mapping interviews for last 10-year use area/harvesters by month and last 12-month trips by month
Harvest participation	Harvest participation measured as the percentage of households attempting to harvest, harvesting, using, giving, and receiving specific subsistence resources	Changes in resource abundance and quality, season and bag-limits; changes in physical access, time, and funds available for harvest	ADF&G household harvest surveys as reflected in the percent of households using subsistence resources
Harvest success	Harvest success as represented by comparing the percentage of households attempting to harvest a resource and those reporting successful harvests	Change in abundance and availability of subsistence resources	ADF&G household harvest surveys as reflected in the percent of households successful and mapping interviews for successful number of trips by resource category for last 12 months
Harvest sharing	Percentage of households that give and receive subsistence resources	Change in social bonds in a community	ADF&G household harvest surveys as reflected in percent of households giving and receiving
Harvest diversity	Number of different resources harvested	Change in diet and potential change in nutrition	ADF&G household harvest surveys as reflected in list of species/resource categories harvested and subsistence mapping of resource categories targeted for the last 10-year use area and last 12 months
Transportation methods	Method of transportation during subsistence pursuit (foot, snowmachine, truck, plane, boat, etc.)	Change in access to harvest area or weather variability	Subsistence mapping interviews as reflected in access and search methods for the last 10-year use area
Duration of harvest trips	Length of harvest trips	Change in resource distribution, abundance or access, harvester's available time, methods of transportation, or distance of travel	Subsistence mapping interviews as reflected in the number of overnight trips by resource category during the last 12 months

TABLE 4.14.1-3 (cont'd)

Baseline Subsistence Characteristics

Subsistence Characteristic	Description of Subsistence Characteristic	Change Indicator	Data Source
Frequency of harvest trips	Number of times harvest trips occur	Change in harvest success, cultural value of an area, distance of resource, harvester's available time, funds to support trips and access to subsistence areas	Subsistence mapping interviews as reflected by the number of trips during the last 12 months by resource category
Resource change and status	Local observations or traditional knowledge of resource use, abundance, quality, and distribution/migration; counts of observations constitute baseline indicators of status whereas the observations represent traditional knowledge	Changes in residents' satisfaction with their use of a resource (effort and harvest amount), resource availability (abundance, distribution/migration), and health (quality)	Subsistence mapping interviews reflected in the availability, harvest quantity, health/quality, time and effort

Harvest amount is a measurement by species in pounds per edible resource. Changes in harvest amounts constitute one of the primary indicators of changes in subsistence. A decrease in the harvest of major species or in overall harvest amounts could reduce household nutrition, quality of life, and cultural continuity. Changes in overall harvests for a community may be influenced by changes in population. Other baseline indicators (e.g., subsistence use areas, harvest success, harvest participation) are important to understanding changes in harvest amounts.

Harvest effort is a product of the time and money spent on harvest-related activities. Changes in the number of harvesters, the geographic distribution of subsistence use areas, the frequency of trips to subsistence use areas, and the harvest months reflect the harvest effort. Harvest effort is expressed as the percentage of households attempting to harvest specific resources as well as traditional knowledge observations about changes in resource use.

Changes in the seasonal abundance of resources, physical and regulatory restrictions, and visual and human disturbances may affect the use of subsistence areas during an annual harvest cycle. Impacts on the timing of harvest activities are more likely to occur if there is an overlap in the time of use and the disturbance (e.g., road traffic during hunting).

Harvest success in specific subsistence use areas is affected by the abundance and availability of subsistence resources. Harvest success is measured through a comparison of the percentage of households attempting to harvest a resource and households reporting successful harvests.

The participation in harvest activities may be affected by changes in resource abundance and quality, hunting restrictions by season and bag-limits, changes in physical access to a resource, visual and other human disturbances, as well as the time and funds available for hunting. Harvest participation is measured as the percentage of households attempting to harvest, harvesting, using, giving, and receiving specific subsistence resources. Continued participation in subsistence harvests is important to facilitating the transfer of knowledge and skills, maintaining social relationships, and maintaining cultural identity.

The number of different resources harvested by a household often bolsters resource abundance. A diverse harvest is associated with a more varied diet, benefiting both nutrition and taste preferences.

The method of transportation to harvest specific resources affects the cost and the time required for subsistence activities. Changes in transportation methods can be an indicator of changes in access to use areas, changes in the cost of fuel, changes in migratory patterns, or weather variability.

Subsistence trip length affects harvesting costs and may be an indicator of changes in resource availability. Multi-day trips can also provide significant opportunities for transfer of traditional and local knowledge. Changes in resource distribution and abundance as well as changes in access and available time can affect the distance that harvesters travel. In addition, changes in methods of transportation can affect trip duration.

The frequency of harvest trips to an area may be affected harvest success, cultural values that tie a subsistence user to a specific harvest area, distance from the community, the time available to harvesters, the funds available to support harvest trips, ease of access, and the attractiveness of the area for harvesting activity. Important to the analysis of changes in subsistence use over time is the concurrence of a decreased number of trips to some subsistence use areas and a compensatory increased number of trips to other subsistence use areas. A decreased number of trips to a hunting area (without a corresponding increase in trips elsewhere) may also indicate increased success due to harvests requiring less overall effort.

Harvester satisfaction with the use of a resource (effort and harvest amount) and a resource's availability (abundance, distribution/migration) and health (quality) are indicators of the status of a resource. Changes in the condition and/or availability of a resource may raise concerns about the overall health of the animal, which may reduce its status to the subsistence user.

4.14.2 General Impacts and Mitigation

Attendees at scoping meetings in Kaktovik, Nuiqsut, Coldfoot, and Tyonek; Alaska Natives who participated in the traditional knowledge workshops; letters to the Commission from Ahtna Incorporated, Chickaloon Native Village, and the Knik Tribe; and participants in government-to-government meetings with the Kenaitze Tribe, Nenana Native Village, and Native Village of Tyonek expressed concern that the Project would adversely affect subsistence. Section 4-4 of EO 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, calls for consideration of populations that rely on subsistence consumption of fish and wildlife for a principal portion of their diet. Comments offered by subsistence harvesters in the scoping meetings, letters, and the traditional knowledge study provide the data on subsistence patterns needed to conduct the impact assessment for the environmental justice communities, described in more detail in section 4.11.8.

General concerns about Project effects included a decrease in the availability of subsistence resources (wildlife, fish, and vegetation); increased costs and greater travel to harvest resources; a reduction in physical access to resources; increased competition for resources; and contamination (e.g., noxious weeds, invasive species, and dust) of vegetation and wildlife habitat. Subsistence resources and activities would be adversely affected to varying degrees. Our review in this section is focused on the following impacts, which are common issues in the subsistence communities included in our analysis:

- a reduction in the availability of wildlife, fish, and vegetation resources;
- increases to the cost and effort required to harvest resources;
- diminished or enhanced physical access to subsistence resources; and
- increased competition for resources.

4.14.2.1 Resource Availability

Subsistence users harvest a variety of terrestrial, avian, marine, and freshwater game resources as well as other non-game resources (e.g., plants, berries, and wood) in and near the Project. The Project crosses several ADF&G GMUs and subunits (see section 4.6.1). GMUs each have a specific set of regulations governing the harvest limit and timing of hunts for the wildlife species in that unit. The subunits may have additional regulations. Alaska does not regulate the harvest of nongame resources.

Successful subsistence harvests depend on continued availability of healthy populations of wild resources (wildlife, fish, and vegetation) in traditional use areas. Resource availability and condition are affected by weather, wildlife population trends, natural variation, human disturbance, changes to habitat, contamination (e.g., invasive species, dust, and parasites), and federal, state, and tribal management practices. Impacts on resource availability considers the impacts on vegetation and wildlife identified in sections 4.5 and 4.6 for the Project.

4.14.2.2 Cost and Effort of Harvest

Numerous factors affect the costs incurred by individuals making use of subsistence resources. Costs may be measured in a variety of terms, including dollars, time, personal satisfaction, physical risk, and social standing. For example, increased difficulties in accessing resources may require subsistence users to travel further, increase trip duration or make use of more expensive means of transportation. These responses on the part of subsistence users may increase fuel costs, require investment in new equipment, increase time requirements, or expose users to increased hazards such as longer exposures to cold weather.

Most rural residents rely on motorized vehicles (e.g., boats, off-road recreational vehicles [OHVs], trucks, and snowmachines) to hunt, fish, and gather subsistence resources. These modes of transportation have extended the range of users and made subsistence harvests more efficient, but their use has also resulted in making cultural and nutritional preferences for wild foods dependent on wage employment and fuel. Communities that are not near roads tend to pay higher prices than the statewide average for fuel due to transportation costs to deliver fuel and then store it in these communities. For example, Nenana residents paid $3.35 per gallon of gas whereas Anaktuvuk Pass residents paid $7.20 per gallon of gas in July 2017 (ADCCED, 2017b). In addition to incurring high fuel costs, these rural communities tend to have lower per capita income than urban communities (Brinkman et al., 2014).

High gasoline prices have a significant effect on subsistence harvests, such as requiring subsistence users to reduce the number, duration, or distance of trips due to high costs or limited supply; combine hunting, fishing, or gathering trips with other activities and limit the amount of time spent on subsistence activities; and share fuel costs with other subsistence users. Residents competing for stored fuel may result in an overall reduction, duration, or distance traveled during harvests. During traditional knowledge workshops in the Yukon River Region, a number of participants commented on changes in the caribou migration routes and herd numbers due to the construction of TAPS that were still evident in 2012. Harvesters were traveling 110 miles and noted, "that's a lot of gas." Another participant commented that moose and king (Chinook) salmon populations are dropping and (the cost of) gas is the only thing increasing.

The Project could reduce resource availability or restrict access to resources, resulting in reduced personal satisfaction and social standing if, for example, subsistence users are unable to obtain highly valued resources for their dependents or have to rely more heavily on the generosity of others. It is also possible that Project impacts could reduce costs. For instance, the dispersal of subsistence resources in response to construction activities may move resources closer to some communities.

4.14.2.3 Access to Subsistence Resources

The successful harvest of subsistence resources depends in large part upon resource population size and seasonal distribution, but more critical to a subsistence user's ability to harvest resources is access to land. A body of spatial and seasonal data collected on hunter-wildlife interactions has shown how hunters use the landscape. In general, these data have shown that hunters predominantly use easily accessible areas (Johnson et al., 2016). A change in access can increase or decrease hunting pressure in a region. Subsistence users travel along land, waterway, and air routes to reach harvest areas that would be in and

near the Project. Annual variation in travel routes is common, but harvesters often follow similar routes to specific harvesting locations that have proven to be efficient (e.g., based on terrain or a road system). Depending on the resource and proximity to the harvester community, the primary modes of access include foot, dog sled, highway vehicle, off-road recreational vehicle, snowmachine, boat/airboat, and airplane. Successful subsistence harvests also depend on access to subsistence resources and use areas. Access is affected by weather, fuel prices, equipment costs, personal time demands, travel distances, road conditions, competition, management practices, and physical barriers such as infrastructure and utility work.

During subsistence mapping interviews in the Tanana River Region, participants commented on restricted access to moose as a result of hunting regulations, particularly in areas that would be crossed by the Project. Regulations dictate areas that allow motorized hunting, hunting of moose without antlers, hunting bull moose of a certain size, and areas where no moose hunting is allowed. Overall, these regulations have resulted in harvesting fewer bull moose.

More commonly, participants in traditional knowledge workshops commented on impacts associated with increased access to areas that were previously difficult to reach. On the Kenai Peninsula, highways, logging roads, and seismic trails have created easy access to traditional moose hunting areas. Participants noted increased competition and vehicle–moose collisions as detrimental to the moose population.

4.14.2.4 Resource Competition

Resource competition is defined as individuals or communities (e.g., other subsistence users, non-rural residents, and non-residents) vying for the same subsistence resource(s) in the same geographic area. Competition often contributes to decreases in resource populations as a result of overharvest. Increased competition may be driven by a variety of factors. Development of the Mainline Pipeline corridor, the establishment of work camps, or pipeline operation may facilitate travel into a community's subsistence use area by subsistence users from other communities or urban areas, resulting in increased competition for local resources. Participants in the Yukon River Region traditional knowledge workshops commented that the Dalton Highway and TAPS allowed for easier access to traditional harvest areas by nonlocals, including pipeline employees. One result they noted is that fewer caribou are available. Avoidance of the Project area by wildlife, the perception by subsistence users that resources have been contaminated, and changes in access to subsistence areas could also result in competition among subsistence users from the same community. These impacts could also increase competition for the resources necessary to support subsistence. Increases in trip frequency, length, and duration due to the factors described above could deplete a community's reserves of fuel and increase competition for supplies that are necessary for subsistence activities.

4.14.2.5 Harvest Rates

Harvest rate refers to the ratio between the costs incurred during subsistence behaviors and the benefits that those behaviors produce. Subsistence costs are often calculated in terms of time or money, while benefits are typically measured in terms such as calories or pounds of edible resources. However, other currencies are possible, including risk, prestige, or personal satisfaction.

The four general Project effects discussed above—changes in resource availability, cost and effort, physical access, and resource competition—would all be expected to affect harvest rates by changing the ratio between cost and benefit.

4.14.2.6 General Impact Assessment

In this section, we assess impacts on subsistence users and use areas affected by the Project. We considered existing subsistence uses and behaviors as characterized above and used the baseline indicators to inform our review. As discussed below and in the community-specific discussions (see section 4.14.3), the geographic extent of impacts on subsistence would vary. Communities that are within 30 miles of the Project area or whose subsistence use area would be bisected by the Project (e.g., intersected in or near the middle of the use area) would likely experience a greater impact than those communities that are farther away or only have a small portion of their use areas affected by the Project.

The Project crosses traditional use areas of Alaska Native communities included in this analysis. These communities have long histories of collective resource use based on traditional knowledge about the relationship of individuals to one another and the environment that have developed over generations. Subsistence land use patterns are localized, tied to specific wildlife and plant populations and local customs and traditions. Adaptive practices have evolved through systematic observation and interpretation of changes in natural resource systems that are shared with one another. For instance, subsistence resources for one community may be sought in the same places over time. However, when resources become less abundant, the harvest areas may change. As information is shared about changing resource availability, communities and/or individual harvesters adapt. These adaptations are based on concern for meeting basic nutritional needs as well as concern for resource viability and future availability. These adaptive changes are rooted in social norms and informal rules of stewardship. Such traditional management practices may make use of landscape diversity by rotational use of harvest areas for specific resources or target other sources of traditional food to offset decreased availability of another resource to lessen the potential for individuals, families, or communities to experience shortages. These adaptive strategies, based on social systems of sharing knowledge and subsistence resources, foster sustainability of these traditional resources.

While it is common to consider the available information about physiology, biological needs, and life stage to assess the likely behavioral responses of wildlife to Project impacts (e.g., the behavioral response of a sea otter to noise is based on the noise level and distance of the animal to the noise source), individual and community adaptations and responses to ecological variability that may result from Project construction and operation would be community-specific and localized to its subsistence use areas. Achieving a desired outcome for resource sustainability in the face of change lies in a community's resilience or capacity to draw on their social, economic, and cultural systems to drive change (Brown et al., 2015). Change occurs over different temporal scales and different rates (i.e., cyclical changes in wildlife populations, extreme weather events, and post-fire forage growth) and influences choices available to communities (e.g., harvest resources farther from their community during short-term cyclical changes in species availability or seek food substitution such as a less-preferred wild resource or purchase store-bought foods). Responses to change in ecosystems are mediated by many social, cultural, and economic factors. This assessment addresses three periods for pipeline activities to examine potential impacts of Project construction and operation.

The duration of impacts on subsistence would be temporary, long term, and permanent. Temporary impacts would result from Project activities that cause limited or temporary displacement or disruption of resources or harvester access to a use area during construction (generally about 6 years for the pipeline and about 8 years for the overall Project), with the resource returning to pre-construction condition soon after restoration or within a few months to a year following the installation of permanent erosion control measures. Long-term impacts would result from Project activities that would cause loss of access to a subsistence use area, or impacts on resource movement or habitat for the life of the Project (e.g., during construction and continuing into operation), estimated between 5 and 30 years. Permanent impacts would result from Project activities that cause permanent loss of a resource's habitat, a resource's access to habitat,

loss of subsistence user access to all or part of a subsistence use area (e.g., from the construction and operation of aboveground facilities), or loss of availability of a resource (e.g., wildlife population decline).

We assessed the significance of impacts based on both the magnitude and duration of the effects. Specifically, if the Project would result in a substantial reduction in the opportunity to continue use of subsistence resources, the effect would be considered significant. If the Project would result in a long-term to permanent impact, the effect could also be significant. However, a minor reduction in the opportunity for subsistence uses would not be significant even if it is long term. Substantial reductions in the opportunity to continue subsistence uses generally are caused by large reductions in resource abundance (e.g., a decline in population size); a major redistribution of resources (e.g., the permanent alteration of migration routes); extensive interference with access (e.g., infrastructure blocking or limiting access); or major increases in the resource use by non-subsistence users (e.g., increased competition by recreational hunters using new Project roads).

It is possible for some or all of these types of impacts to occur at some locations for the duration of construction activities and continue throughout operation and maintenance. Construction activities would occur over a 90-month (7-year and 6-month) period for the Gas Treatment Facilities, a 57-month (4-year and 9-month) period for the Mainline Facilities, and an 81-month (6-year and 9-month) period for the Liquefaction Facilities. Because construction would occur during both summer and winter, construction would affect subsistence activities.

Construction activities for the Mainline Pipeline would not be continuous but rather seasonal, primarily occurring during summer and winter seasons depending on location (see section 2.0). Active construction at any single point along the Mainline Pipeline would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors such as the use of specialized construction methods. Construction activities at the Gas Treatment Facilities, Mainline aboveground facilities such as compressor stations and the heater station, and Liquefaction Facilities would occur year-round.

Overall, the types of impacts on subsistence resources described above would mostly be limited to the duration of construction activities in a given area. Although it is difficult to quantify each of these impacts on individual harvesters and communities due to different biological, environmental, and socioeconomic constraints across the Project area, we conclude that subsistence would be affected. The effects could include a decline in participation, use, and harvest amounts or an increase in cost and effort to harvest.

As described in sections 4.5 through 4.8, Project effects on vegetation, wildlife, and fisheries, would range from temporary to permanent. Vegetation would be cleared (and maintained) for construction and operation of Project facilities and, in many areas, would be affected for decades. When compared to the amount of vegetation present in Alaska and the general Project area, the loss of vegetation over the relatively small temporary and permanent Mainline Pipeline right-of-way and aboveground facility sites would not significantly affect subsistence vegetation (e.g., berries). The increased potential for the introduction and spread of invasive plant species (e.g., noxious weeds) or invasive pests (e.g., bark beetles), however, could affect the quality of adjacent vegetation and use by wildlife.

Wildlife would avoid and be displaced by construction, operation, and maintenance activities. Vehicles, aircraft, and vessels used to move equipment, personnel, and materials would likely startle wildlife, resulting in further avoidance and displacement, or could result in mortality of individual animals due to vehicle collisions. Wildlife avoidance and displacement would affect subsistence resource availability, access, and effort required for harvest. Individual wildlife vehicle collisions would not be expected to result in population level effects; therefore, changes in harvest rates would not be expected

from collisions. Intermittent events such as aircraft takeoff, landing, and overflight and blasting could create elevated noise levels that are audible to avian species, marine mammals, and terrestrial mammals on a short-term basis, but would be unlikely to result in significantly reduced abundance or availability of subsistence resources that could avoid the area of aircraft takeoff and landing, and blasting activity.

Noise generated by aircraft could result in brief behavioral responses by marine mammals, such as sudden diving or turning away from the sound source, and by terrestrial mammals, such as moving away from the source of the noise or altering migration patterns. AGDC would use PSOs to monitor construction activities and minimize exposures of marine mammals to sound levels in excess of NMFS injury thresholds. During operation, AGDC would use helicopter or fixed wing flights to complete pipeline surveillance overflights at a minimum flight altitude of 1,500 feet over Cook Inlet, the GTP, PTTL, and PBTL. At that altitude, received sound levels at the water surface would remain below the NMFS threshold for continuous sound sources resulting in a minor disturbance to marine mammals. During construction and operation of the Project, potential impacts on terrestrial wildlife from aircraft would include infrequent noise disturbance due to aircraft takeoff, landing, and general overflight patterns. While the impact would be greater in more remote areas with little human activity, the overall wildlife avoidance or displacement would be unlikely to result in significant impacts on terrestrial subsistence resources.

The timing of in-stream blasting would be scheduled when fish and embryos are not present, if possible, or would implement measures in the Blasting Standard in consultation with the ADF&G to minimize impacts on fish (see section 4.7). Due to the ephemeral nature of vessels in transit, vessel noise impacts would be expected to be minor from vessels transiting to and from and docking at Project facilities in Cook Inlet and Prudhoe Bay during construction and operation (see section 4.6.3). Fisheries would be temporarily affected at waterbody crossings along the Mainline Pipeline from displacement, removal of wetland and riparian buffers, and changes in streamflow and stream turbidity and sedimentation, but fisheries should not experience long-term impacts. In the community-specific discussions below, we attempt to describe impacts in more detail; however, the extent of avoidance and displacement impacts would depend upon construction timing and species presence and migration.

In addition to wildlife avoidance and displacement, socioeconomic changes within a community could affect the cost and effort expended to harvest subsistence resources. The time, distance, and use of equipment and other resources involved with harvesting wildlife could increase because of impacts on wildlife. Indirect effects of greater travel distances or more time required to locate and harvest displaced subsistence resources would also include increased safety risks. For community members who choose to work on some part of the Project or an associated activity, continued participation in subsistence activities and associated traditional cultural events/festivals would not be affected assuming that harvest schedules are accommodated. Income from employment on the Project or an associated activity could offset the loss of wild foods during construction by allowing the purchase of store-bought foods.

Time available for subsistence activities may be negatively affected by employment. Harvesters would have less time to participate in subsistence activities. Conversely, employment opportunities may result in increased income to support subsistence activities. Other socioeconomic impacts (described in section 4.11), including increased costs of fuel, equipment, and other goods and services, would likely increase the cost of harvests. Cleared rights-of-way, construction equipment, access roads, air strips, granular fill pads, vehicle and marine vessel traffic, construction crews, and Project construction (including lighting and noise) could serve as physical barriers and reduction/loss of physical access to wildlife movement and subsistence harvesters. Connectivity and the ability to move across and between habitats, foraging land, and breeding grounds both on land and in water is important to maintain viable and healthy wildlife populations, which in turn is an essential component of sustainable subsistence.

The magnitude of an impact due to a physical barrier and reduction or loss of access would be dependent on the time of year and wildlife needs and behaviors (e.g., the tendency of a species such as caribou, spectacled eider, and king eider to return to or remain in the same location at certain times of the year). Several important subsistence species are highly mobile, and migration is part of their life history. For example, individual caribou may travel 3,100 miles during one season, and broad whitefish may travel 60 miles between seasonal habitats. Historic studies have noted that if caribou have a perpendicular approach to linear infrastructure, they may follow the feature until they reach its end, which may alter their migration route. Unlike TAPS, however, nearly all of the Mainline Pipeline would be buried and the likely potential "infrastructure barrier" would consist of a change in vegetation and substrate.

Decreased access could reduce competition in the potentially affected area because harvesters could no longer access previously used hunting or fishing areas or, alternatively, introduce additional competition in new areas. Furthermore, a decrease in resource availability due to a reduction in or loss of access may result in increased competition among harvesters as they try to meet their harvest needs from depleted or displaced resource stocks. Physical barriers and changes to access could affect subsistence species, the cost and effort expended to participate in subsistence activities, and overall harvest rates.

Traditional knowledge workshop participants stated that the Mainline Pipeline right-of-way and associated access roads would create transportation corridors that would allow greater access to largely undeveloped areas that contain subsistence resources. While this would likely be beneficial for harvesters that already use these areas, an influx of non-local hunters, including Project employees, along these new corridors would increase competition as subsistence and recreational users compete for the same resources. Increased competition could result in a subsequent decrease in wildlife populations. To address this concern, as described further below, AGDC would implement an employee hunting prohibition at construction camps. However, the workforce would likely participate in recreational hunting and fishing outside of work. Project roads and the cleared Mainline Pipeline right-of-way also would increase access by predator species such as wolves into caribou or moose ranges. In turn, increased predation rates on moose and caribou may limit subsistence harvest rates, particularly where game density is low. Both increased human and non-human competition would adversely affect subsistence harvesters and resources, leading to reduced hunter success; a decrease in available resources; and a need to hunt, fish, or gather in more distant locations.

We determine that the Project would result in dust contamination of wetland water quality and wetland and terrestrial plant resources as well as increasing thermokarst from construction of the Mainline Pipeline right-of-way, airstrips, and access roads, particularly where the surface is unpaved. Alteration in water quality, wetland and terrestrial plants, and increased thermokarst could reduce the diversity of plant species or cause a change in species composition. Some wildlife could benefit from these changes while others would not. For example, increased thermokarst may result in a decline of lichens, which are critical for caribou, but an increase in graminoids, which are used by geese. In turn, changes in forage location would result in different harvest rates for a particular wildlife species. Dust deposition would be expected to decrease rapidly from the source of the dust. These effects would also diminish with effective dust control measures as described in the Project Fugitive Dust Control Plan (see section 4.15).

In summary, Project construction and operation have the potential for both adverse and beneficial effects on subsistence resources and users. Potential beneficial effects would include improved or new access routes to traditional harvest areas by subsistence harvesters. In some locations, vegetation conversion would create new forage for moose. Potential adverse effects on subsistence as described in the preceding sections include reductions in subsistence resource abundance and availability, restrictions in access to traditional use areas, and increased competition for subsistence resources from rural and non-local harvesters. The nature of potential effects would vary by community and geographic region. In general, habitat loss would occur in the Mainline Pipeline construction right-of-way (and continue into Project

operation); at permanent operational facilities; and at facilities supporting construction, including material extraction sites and temporary access roads. Construction activities would affect animal behavior by temporarily disturbing or displacing wildlife, fish, and marine life or obstructing their movement. Mainline Pipeline construction would increase external competition for subsistence resources from non-locals, including from Project employees. Access roads also would offer new access routes for animal predators, resulting in increased pressure on subsistence resources. Competition would continue during operation. Each of these general impacts could adversely affect individual or community harvest rates.

The impacts described above would be expected to cause changes in the strategies of individual subsistence users. The impacts would consist of changes in the subsistence characteristics listed in table 4.14.1-3 and would be observable as the change indicators defined for each characteristic. The strategies chosen by subsistence users reflect an attempt to balance competing needs based on traditional and contemporary knowledge in a continually changing environment to optimize harvest rates. Because subsistence users typically want to realize benefits in a variety of forms —for example, in the quantity of resources, social connections, and personal safety—subsistence strategies would optimize the greatest number of benefits.

While our analysis has concluded that Project construction and operation would result in a variety of impacts on subsistence users, the magnitude, if not the duration, of the impact is difficult to define. This is primarily due to the complexity of predicting the numerous interactions between human behavior and physical resources, both of which would be affected. However, it is clear there are a number of measures that, if adopted by the Project, would lessen its impact on subsistence users.

To reduce Project impacts on subsistence, AGDC would implement the measures described below.

- Coordinate with local communities, including tribal councils, to identify locations and times where subsistence activities occur, and modify schedules to minimize work, particularly work that could reduce resource availability or user access (e.g., blasting, trenching), to the extent practicable, in those locations and times.

- If local communities, including tribal councils, identify locations where blasting could reduce resource availability or user access, a site specific blasting plan would be developed prior to blasting activities. Mitigation measures specific for conducting blasting could include:

    - restricting blasting activities during sensitive life stages of wildlife (e.g., nesting or denning);

    - restricting blasting during subsistence hunting periods;

    - use of blasting mats or pads for containing noise;

    - identifying acceptable noise levels and guidelines for limiting shot size and frequency of blasting to control noise levels;

    - procedures for minimizing vibration; and

    - monitoring of nests/denning locations during blasting operations.

- Employ community representatives to alert the Project about planned subsistence activities or key places to avoid, inform local residents about upcoming construction activities, and pass on concerns from locals regarding subsistence impacts on appropriate Project

construction management personnel, who can then make efforts to minimize the cause of the concerns. Emphasis should be on clear communication protocols, adequate training, and hiring local and knowledgeable residents.

- Minimize access along the right-of-way into undeveloped areas (e.g., Minto Flats and west of the Susitna River) by installing fencing, berms, and/or signs at access points to prevent or deter use of the right-of-way. Coordinate with local communities to ensure that measures taken to deter outside access do not obstruct access for local users. Allow for the crossing of the right-of-way or access roads by local subsistence harvesters where right-of-way or access roads would block or impede access to key subsistence use areas.

- Reduce the potential for increased competition related to temporary outside workers, station all Project employees at construction camps, and prohibit hunting, fishing, and gathering activities by workers while stationed at camps.

- Avoid and minimize impacts on subsistence whaling and marine mammal hunting by coordinating with individual whaling associations. Reduce or temporarily halt barging activities during peak whale hunting times. Require vessels operators to enter into Conflict Avoidance Agreement negotiations with NMFS and the Alaska Eskimo Whaling Commission (AEWC) to identify measures that would minimize vessel traffic overlapping with the bowhead whale subsistence hunt. Components of the Conflict Avoidance Agreement should include the use of communication centers, marine mammal observers, and vessel transit guidelines.

- Require mandatory subsistence-related training for the Project workforce, including training in the protection of subsistence resources, lands, wildlife, and culturally valued places.

- Establish a Local Subsistence Implementation Committee consisting of Project personnel, local subsistence representatives, and appropriate agency personnel. The committee(s) could be established on a regional basis (e.g., sections of the pipeline corridor with socioeconomic and/or subsistence continuity). The committees(s) would meet on a regular basis (e.g., monthly or quarterly) and serve as a vehicle to:

    - provide Project information to communities;

    - identify community issues, including where the Project and subsistence uses could conflict;

    - review data and identify options for resolving these issues;

    - establish a Local Subsistence Implementation Plan to resolve issues; and

    - work to resolve the issues in a mutually satisfactory manner for all parties (e.g., communities, developer, and governmental entities, as appropriate).

Additionally, prior to construction, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, the Project Local Subsistence Implementation Plan and a signed Conflict Avoidance Agreement prepared in coordination with NMFS and the AEWC.

4.14.3 Community-Specific Impacts

Traditional and contemporary subsistence uses and resources are discussed for communities in five geographic regions, including the North Slope, Yukon River, Tanana River, South-Central, and Kenai Peninsula (see table 4.14.1-1). Additionally, a summary of subsistence is provided for each region to illustrate temporal trends in subsistence pursuits within traditional subsistence use areas.

4.14.3.1 North Slope Region

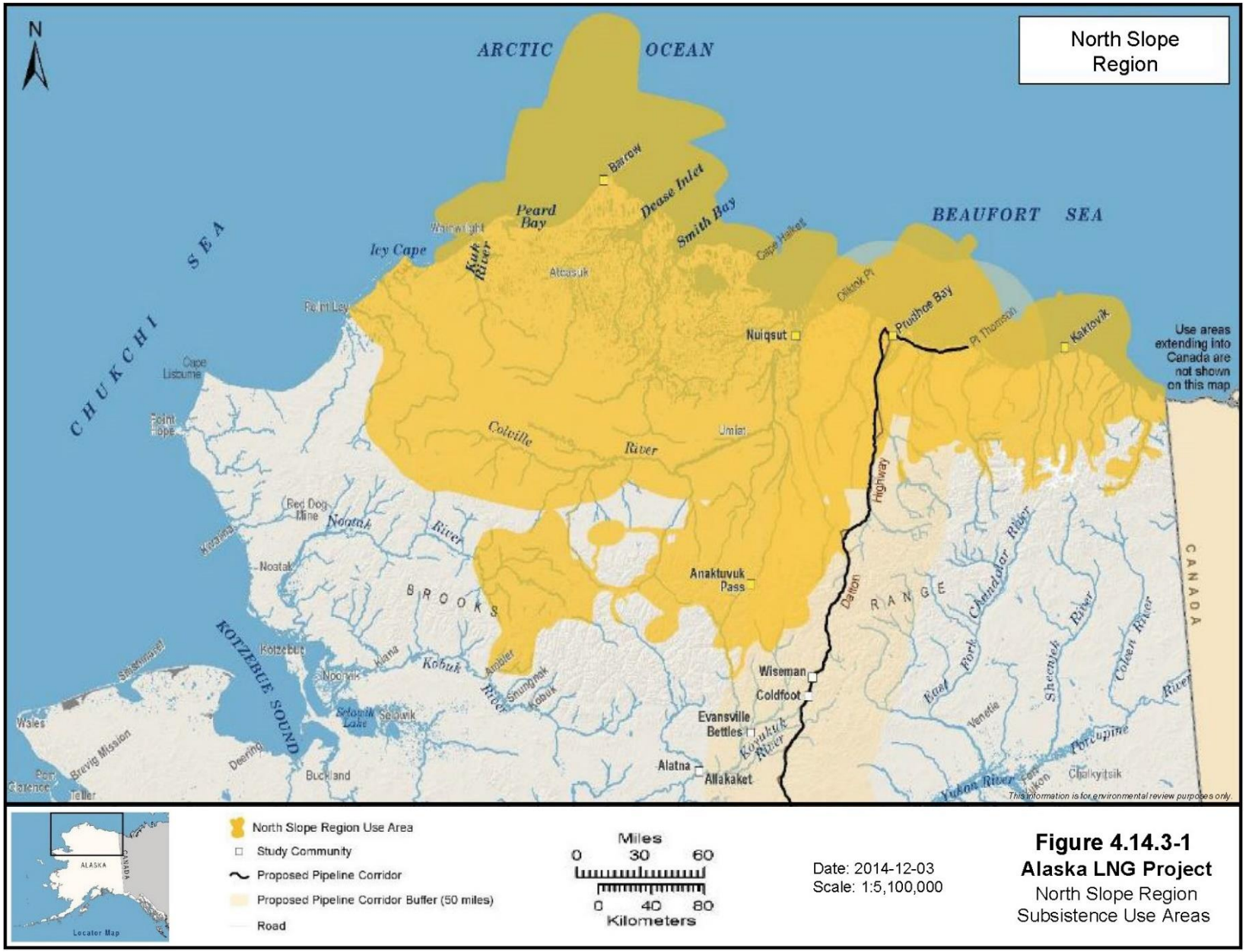
The North Slope Region encompasses the communities of Utqiagvik (Barrow), Nuiqsut, Kaktovik, and Anaktuvuk Pass (see figure 4.14.3-1). The region is home to predominantly Iñupiaq inhabitants. Utqiagvik, Nuiqsut, and Kaktovik are coastal communities. Anaktuvuk Pass is an inland community about 160 miles from the Beaufort seacoast.

Each of the study communities in the North Slope Region have archaeological evidence of the Iñupiaq inhabitants who occupied the area prior to contact with Europeans in the 1800s. Although occupation of this region and other parts of Alaska likely occurred prior to the submersion of Beringia about 10,000 years ago, humans are known to have occupied the Utqiagvik area for at least 5,000 years, and continuous occupation of the area began about 1,300 years ago. The Nuiqsut and Kaktovik areas were known as places where Iñupiaq and Athabascan people gathered to trade and fish, maintaining connections between the inland areas and the coast for millennia (Arctic Slope Community Foundation, 2018; Brown, 1979; Impact Assessment Inc., 1990b). Before European contact, the Prudhoe Bay area was used by Iñupiaq for hunting, fishing, and whaling, and several families now residing in other communities had cabins and camps there (Impact Assessment, Inc., 1990a, 1990b). The Anaktuvuk Pass and greater Brooks Range area has been used by the Nunamiut, meaning "people of the land," for at least 500 years, and by Iñupiaq predecessor groups for at least 4,000 years (Rausch, 1951; Hall et al., 1985).

Today, the majority (greater than 50 percent) of residents in these communities are members of federally recognized tribes. These tribes have traditional and current resource uses, including customary and traditional uses, in or near the Project (see figure 4.14.3-1). A description of the four communities and their subsistence use areas, harvest patterns, and seasonal round is provided in the following sections.

The timing of subsistence activities by resource for the North Slope Region is depicted in table 4.14.3-1. A month is shaded if two or more communities in the region reported subsistence activity for a particular resource during that month.

Waterfowl and bowhead whales migrate through the area during spring. The spring bowhead whale hunt occurs in Utqiagvik. North Slope residents participate in harvests of bowhead whales during fall and/or spring seasons. Spring marks the end of furbearer hunting and trapping and the beginning of intensified harvests of freshwater fish. Seal harvests are a focus of the coastal communities starting in the spring, while large land mammal harvests, including caribou and moose, occur for all communities during this time. Upland bird and small land mammal harvests also occur during the spring.



Date: 2014-12-03
Scale: 1:5,100,000

Figure 4.14.3-1
Alaska LNG Project
North Slope Region
Subsistence Use Areas

TABLE 4.14.3-1

North Slope Region Subsistence Harvest

Resources	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon	■	■	■	■	■	■	■	■	■	■	■	■
Marine non-salmon							■	■	■	■		
Pacific salmon								■	■	■		
Caribou	■	■	■	■	■	■	■	■	■	■	■	■
Moose		■	■	■			■	■	■	■		
Bear	■	■	■	■	■	■	■	■	■	■	■	■
Muskoxen								■	■	■		
Dall sheep			■	■							■	■
Furbearers	■	■	■	■	■			■	■	■	■	■
Small land mammals		■	■	■	■	■		■	■			
Marine mammals			■	■	■	■	■	■	■	■	■	
Upland birds			■	■	■	■				■	■	■
Waterfowl				■	■	■	■	■	■	■		
Plants and berries						■	■	■	■			

Source: Braund, 2015

Fish harvests continue and intensify over the summer (June through August) with the addition of salmon and marine non-salmon fish harvests. Caribou harvest occurs throughout the year but is particularly common during the summer months as the caribou seek relief from insects in coastal areas. Residents of the North Slope Region diversify large land mammal subsistence activities during the summer with harvests of moose, bear, and muskoxen. Coastal communities also focus on marine mammal resources, such as bearded seals. Hunting furbearers begins again in late summer, and waterfowl harvests continue through the summer through the fall migration. The period for plant and berry harvests is limited due to a brief growing period and occurs over the summer months and into early fall.

Fall (September through October) is a particularly important time for residents of Kaktovik and Nuiqsut to harvest bowhead whales, as the whales are migrating in September and October. Subsistence activity for moose, muskoxen, and freshwater fish, particularly arctic cisco, broad whitefish, and burbot, amplifies during the fall months. Caribou remain a targeted resource over the fall months as subsistence activity for marine mammals decreases.

Winter (November through March/April) harvests include furbearing animals and upland birds. Kaktovik and Anaktuvuk Pass residents pursue Dall sheep in the early winter (November and December) and again in late winter through early spring. Freshwater fishing generally declines in the winter with the exception of burbot fishing in Nuiqsut. Caribou harvests remain a focus over the winter, particularly in Anaktuvuk Pass. Marine mammals, specifically ringed seals, continue to be harvested through the winter in the coastal communities, but to a lesser extent than during the rest of the year.

In the North Slope, traditional knowledge and new subsistence mapping studies were not completed for the Project. However, data collected in 2012 identified resources important to the North Slope communities, including bowhead whale, seal, a variety of fish, and caribou. The communities in the North Slope region stressed the importance of caribou as a subsistence resource. Residents rely on the predictable annual migration of caribou through traditional hunting areas; however, observed changes include herds

using different migratory routes and caribou splitting up into smaller groups rather than traveling in large herds, which reduces chances for successful harvests. Residents noted that disturbances such as the physical presence of pipelines impede passage and/or change migration routes and contribute to shrinking caribou foraging area. Regulations regarding the use of access roads associated with new development impedes hunter access to caribou (Braund, 2017). Where road access was not restricted, residents noted benefits of using the Spur Road for caribou hunting. Additionally, anthropogenic noise during subsistence harvest was noted as undesirable because some terrestrial, avian, and marine resources are sensitive to noise from aircraft and machinery.

North Slope Temporal Trends

Temporal trends in per capita harvest data for the North Slope Region are based on a limited number of studies collected at various and often different times for each community. Anaktuvuk Pass subsistence harvests are predominantly of large land mammals (between 77 and 96 percent of total harvest), followed by non-salmon fish (between 3 and 21 percent), and with additional contributions from migratory birds and vegetation (between 1 and 4 percent). Utqiagvik, Kaktovik, and Nuiqsut harvests are more evenly distributed between marine mammals, large land mammals, and non-salmon fish that together represent about 90 percent of the annual harvest. Of these three study communities, Utqiagvik consistently harvests marine mammals annually. There were a number of study years when no bowhead whales were harvested in Nuiqsut and Kaktovik. During these study years, Nuiqsut (1985 and 1994 to 1995) and Kaktovik (1985) increased their harvest of other resources including non-salmon fish and large land mammals, respectively.

For the North Slope Region, marine mammal and large land mammal harvests comprise the majority of the total subsistence catch (about 40 percent each), with the remaining harvest coming from non-salmon fish (15 percent), migratory birds (2 percent), and upland game birds and vegetation (about 1 percent each). Furbearers are also caught for subsistence purposes but their meat is rarely consumed and thus, the contribution of furbearers is typically not included in the total harvest of edible resources.

North Slope Region Summary

Project construction activities, including construction of the Gas Treatment and Mainline Facilities, and increased vessel traffic in the Beaufort Sea, could have negative impacts on resource availability. The likelihood of resource availability impacts on caribou during construction would be greater for Nuiqsut, Anaktuvuk Pass, and Kaktovik because of their closer proximity to the Project. Of all study communities, Anaktuvuk Pass has the greatest reliance on caribou (about 94 percent of the total harvest in 2014) to meet their subsistence needs. In addition, residents hunt caribou at high levels during both the summer and winter months when construction of the Mainline Pipeline through the foothills into the Brooks Range would occur. In contrast, there would be less likelihood of impacts on Nuiqsut and Kaktovik caribou harvesters because the PTTL and Mainline Pipeline construction on the North Slope would occur primarily in winter when caribou hunters are less active. Construction impacts on marine mammal resource availability would affect harvesters in Nuiqsut and Utqiagvik, whose marine mammal use areas, including bowhead whale hunting areas, are crossed by the vessel transit routes to the West Dock Causeway. The West Dock Causeway is occasionally accessed by whaling crews for gathering supplies needed for whale harvests. Construction-related activities (modifications to the West Dock Causeway and sealift deliveries) may limit or prohibit the occasional use of this area during the fall whaling season for up to 7 years.

Utqiagvik (Barrow)

Barrow is a coastal community bordered on the west by the Chukchi Sea and on the east by the Beaufort Sea. Barrow is the northernmost community in the United States, the largest community on the North Slope, and is home to Iñupiat people who called the community "Utqiagvik," which translates to either the "place where snowy owls are hunted" or "place of gathering wild roots" (Brown et al., 2016).

European contact with the Iñupiat began in the mid-19th century when the whaling industry arrived in the Arctic Ocean. Explorer Thomas Roy discovered a large population of bowhead whales, and subsequently commercial ships sailed to the Bering Sea to hunt whales for their oil, a source of fuel. In the 1870s, as the use of whale oil for fuel decreased, whale baleen became the focus of commercial whaling for its use in the clothing industry. Commercial whalers established a whaling station in 1886 in what became Utqiagvik. During the height of commercial whaling between 1848 and 1914, about 2,700 whaling ships are estimated to have passed through the region (Brown et al., 2016). As a result of commercial harvesting, the bowhead whale population declined dramatically. The Iñupiat and their ancestors had hunted bowhead whale for about 2,500 years, and this decline due to commercial whaling posed a threat to their cultural, social, and economic systems.

Various whaling nations recognized the continued availability of whales was important for economic gain (Gupta, 1999; Case and Voluck, 2012). An international convention for monitoring whales was established in 1946 and created the International Whaling Commission to monitor whaling as discussed above.

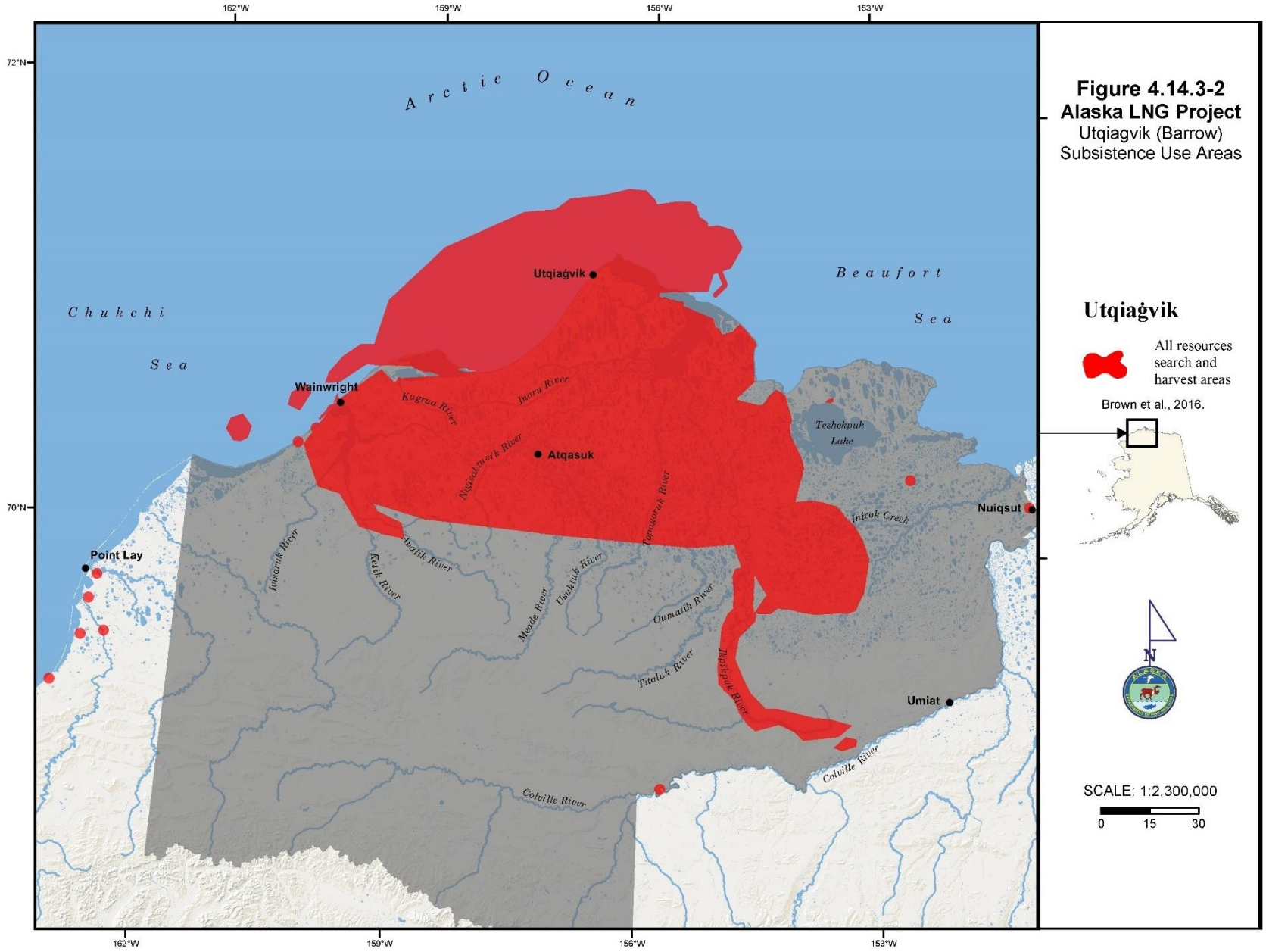
In 1923, the U.S. Navy (Navy) established the Petroleum Reserve Number 4, with Utqiagvik at its northern tip. The Navy intended to use the reserve as a source of fuel in the event of a wartime emergency. Development of the reserve did not begin until 1944 when a construction battalion, known as "Seabees," established a camp, built an airstrip in Utqiagvik, and began exploratory drilling (COE, 1988). In 1946, the operation was transitioned from a naval to commercial operation, and a civilian contractor continued exploratory work until 1953 when the Navy decided to recess the project (Reed, 1958). When the project ended, 36 test wells and 44 core tests were drilled. Oil, gas, or both were discovered in many geologic structural features across the North Slope. In 1946, the Navy also established the Arctic Research Laboratory in Utqiagvik to conduct research on the arctic environment (Reed, 1958).

Subsistence Use Areas

Figure 4.14.3-2 depicts the extent of the known Utqiagvik subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2015 and has been documented from Point Lay continuously overland to the Kuparuk River area. Isolated use areas occur near Prudhoe Bay and Point Thomson. The subsistence use area also encompasses the foothills of the Brooks Range along the Colville River and its various tributaries and, less frequently, near Anaktuvuk Pass (Braund and ISER, 1993). Offshore subsistence use occurs in the Chukchi and Beaufort Seas from Prudhoe Bay west to Icy Cape, and extends more than 60 miles north of Utqiagvik.

Seasonal Round

The residents of Utqiagvik use a large number of both terrestrial and aquatic subsistence resources (see table 4.14.3-2). The largest number of resources are harvested from late spring to early fall with peaks in June through September. Subsistence activities decline in the winter with the fewest resources harvested in January. Hunters target bowhead whale, ringed and bearded seals, and Pacific walrus as they migrate north in the Chukchi Sea, and also hunt bowhead whale on their southward migration in the fall. Caribou move throughout the tundra throughout the year, but are most readily available when they head to coastal areas to escape insects and heat during the summer and fall.


162°W
159°W
156°W
153°W
72°N
70°N
Arctic Ocean
Chukchi Sea
Beaufort Sea
Utqiaġvik
Wainwright
Atqasuk
Point Lay
Nuiqsut
Umiat
Kugrua River
Ipnaru River
Nigisektuvik River
Teshekpuk Lake
Inicok Creek
Topagoruk River
Ivisaruk River
Kealok River
Avalik River
Meade River
Usuktuk River
Oumalik River
Titaluk River
Itkillik River
Colville River
Figure 4.14.3-2
Alaska LNG Project
Utqiagvik (Barrow)
Subsistence Use Areas
Utqiaġvik
All resources search and harvest areas
Brown et al., 2016.
N
SCALE: 1:2,300,000
0
15
30

Preparation for a spring bowhead whale hunt begins in late winter with the preparation of whaling gear and equipment, particularly the skin whaling boats, as well as breaking a trail across the ocean ice. Whaling camps are established on the edge of the ice in mid- to late-April. The characteristics of the ice determine how long the camp is occupied and the size of the whales being hunted. Camps can be occupied from 2 to 6 weeks. After a whale is harvested, the crew butchers it on the ice. Often the successful whaling crews will stay in camp to help other crews land and butcher whales. The meat is shared with the community in mid-June at the Nalukataq Festival. Bear and moose are also hunted in the spring.

Following whaling, migratory waterfowl are hunted in late spring and early summer. King eiders migrate through first and are hunted from the ice. Later, common eiders are harvested. Hunters move inland in late May and early June to hunt greater white-fronted geese and, to a lesser extent, Canada and snow geese. In late June, gull, goose, duck, and swan eggs are harvested.

Subsistence pursuits in the summer months of July and August include setting nets on the coast and rivers to harvest chum and pink salmon and, to a lesser extent, Chinook salmon. Also during the summer, bearded and ringed seals and Pacific walrus are hunted. The skins of these marine mammals are used to make the traditional umiaq whaling boats. Caribou are hunted year-round, but August is the peak of caribou hunting. Berries and plants are also gathered in the summer months. Fish are caught in rivers and lagoons during summer months.

Whaling during the fall migration in September and October take crews away from their community on day trips. Caribou are hunted in the fall as well as fish and birds. When the rivers freeze, under ice nets are set to catch whitefishes, arctic grayling, and burbot. Eiders are the focus of bird hunting in the fall. Nine years of available data on polar bear harvest suggest that they are commonly harvested in November; however, polar bears have been taken in May and October.

Subsistence pursuits decline in the winter and include caribou hunting, seal harvest on the edge of the ice, and trapping of furbearing animals (fox, gray wolf, and wolverine). Trapping begins in December and ends in early spring.

TABLE 4.14.3-2

Utqiagvik (Barrow) Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Marine non-salmon fish		■	■		■	■	■	■	■	■	■	■
Freshwater fish	■	■	■	■	■	■	■	■	■	■	■	■
Pacific salmon						■	■	■	■	■		
Bird/eggs				■	■	■	■	■	■	■		
Berries and plants					■	■	■	■	■			
Moose							■	■	■			
Caribou	■	■	■	■	■	■	■	■	■	■	■	■
Furbearers	■	■	■	■						■	■	■
Bear	■	■	■	■	■	■	■	■	■	■	■	■
Polar bear					■					■	■	
Seals and walrus			■	■	■	■	■	■	■	■	■	■
Bowhead whale				■	■				■	■		

Source: Braund, 2015

Harvest Data

In 2014, ADF&G reported about 1.9 million pounds of wild food was harvested by residents in Utqiagvik, representing 361.9 pounds per capita.[121] By weight, marine mammals accounted for the largest harvest, followed by caribou and fish. The residents reported smaller harvests of birds, eggs, and marine invertebrates (see table 4.14.3-3). Bowhead whales were the greatest contributor to the marine mammal harvest and represent the second most used resource by household during 2014. Of the large land mammals, caribou was the most widely harvested resource and the most commonly used resource by household during 2014. Respondents commented on the importance of broad whitefish in the diet: it represented the majority of the non-salmon fish harvested for the study year. Chum salmon represented the most harvested salmon. The most common avian resource was the greater white-fronted goose. Mussels were the predominant marine invertebrate harvested by the residents. Cloudberries (*Rubus chamaemorus*) and blueberries were the most common berries gathered.

TABLE 4.14.3-3

Estimated Subsistence Harvest for Utqiagvik

Resource	Per Capita (pounds)	Total (pounds)
Caribou	110.6	587,897.1
Moose	1.2	6,580.6
Bear	0.1	526.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	192.1	1,020,942.6
Marine invertebrates	0.2	1,096.3
Migratory birds	9.1	48,270.6
Upland birds	0.1	637.9
Eggs	0.2	1,113.0
Pacific salmon	10.8	57,262.3
Non-salmon fish	36.9	196,049.4
Berries	0.5	2,281.7
Plants	<0.1	153.6
Wood	–	–
Other	–	–

Source: Brown, et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Utqiagvik is about 200 miles west of the Project; however, the vessel route that passes from the Chukchi Sea into the Beaufort Sea overlaps with Barrow subsistence uses for marine mammals, including bowhead whale, ringed and bearded seals, Pacific walrus, and waterfowl. Additionally, caribou, upland birds, and non-salmon fish use areas are also crossed by the Project. Project construction activities, including construction of Mainline Pipeline, and increased barging in the Beaufort Sea, would affect

[121] For all communities, the recorded harvest amounts in pounds per capita are estimated quantities based on conversion factors and do not reflect actual weights of each resource harvested.

resource availability through temporary displacement of resources and habitat loss. Increased cost and effort to harvest these resources would be anticipated to occur during Project construction for all resources and continue into Project operation for caribou.

The increased vessel traffic (maximum increase of 80 percent during the height of construction, as noted in section 4.12) and associated underwater noise could cause a change in the migratory behavior of the marine mammals, displacing them from Utqiagvik's traditional use areas. Additionally, the underwater noise could displace seal and Pacific walrus that could occur in vessel transit routes during the summer months; however, this impact would be minor due to the ephemeral nature of the vessels in transit. Construction-related activities (modifications to the West Dock Causeway and sealift deliveries) would be completed outside of bowhead whale migration; therefore, no impact on bowhead whale harvest would be anticipated as a result of modifications to the West Dock Causeway. Additionally, West Dock Causeway piles and sheet piles would be installed between June and August, outside the federally listed bowhead whale sensitive period. Non-salmon fish would be temporarily affected by the modifications at the West Dock Causeway, including changes to a fish passage area.

Winter construction of the GTP and PTTL would affect upland migratory bird harvest and would result in permanent habitat displacement for these avian resources. Construction impacts associated with the PTTL would occur in winter when fewer caribou are harvested. For the GTP and the elevated PTTL, disturbances to caribou habitat during Project operation would be long term. Mainline Facilities would be constructed within this summer and winter ranges. Since Project facilities would be within the caribou range, the Project could serve as a barrier to migration between habitat areas or movement to specialized habitats, such as access to calving range, during construction. Any disruption to migration could continue into Project operation due to the presence of the maintained right-of-way.

Nuiqsut

Nuiqsut is about 20 miles inland on the lower Colville River within the Coastal Plain. It is on the west bank of the Nigliq Channel, the westernmost of three main channels of the Colville River that flows into Harrison Bay in the Beaufort Sea. The landscape consists of slow-growing vegetation, including sedges, tussocks, grasses, and mosses, as well as dwarf shrubbery such as birch, alder, and willow. Polygonal soil patterns and low-lying bluffs are common. Permafrost in and surrounding Nuiqsut is estimated to be several hundred feet thick (Brown et al., 2016). As a result, surface water does not penetrate the permafrost, but instead creates an extensive network of wetlands. The landscape changes about 100 miles to the south of Nuiqsut near the foothills of the Brooks Range.

Historically, seasonal movement in the Colville River area was dictated by subsistence availability. Families moved between seasonal camps to harvest and trade resources. The area hosted annual trade opportunities between the coastal and inland Inupiat communities. The Colville River area was centrally located on an extensive trade network. Coastal Inupiat families traveled inland bringing marine resources to trade and inland Inupiat families traveled north in the spring bringing furs, caribou skins, and other implements to trade in mid-summer.

By the 1950s, one family lived in the Colville River area. After the passage of ANCSA, 27 families returned to the Colville River area and established Nuiqsut on lands selected under ANCSA. In 1974, the Arctic Slope Regional Corporation funded construction of the community. This represented a return to ancestral lands for many of the families that moved to Nuiqsut.

Since its establishment, Nuiqsut has grown. The community has a school (pre-kindergarten through 12), an airport, community center, wastewater treatment center, power plant, post office, hotel, and grocery store. Natural gas, made available by nearby oil and gas development, heats many of the homes. The governance of the community is provided by the City of Nuiqsut, the Native Village of Nuiqsut, and the North Slope Borough. The local Native Corporation of Kuukpik owns land in and around Nuiqsut, including some land within the National Petroleum Reserve boundaries.

Nuiqsut is surrounded by numerous oil company facilities and industrial developments. Oil was discovered about 8 miles north of Nuiqsut in 1994. In 1998, the BLM prepared an Integrated Activity Plan / Environmental Impact Statement for a portion of the National Petroleum Reserve. The Record of Decision opened about 87 percent of the area to oil and gas leasing. Nuiqsut is situated within its boundaries. By 2010, about 140 wells were in the Alpine oil field to the north. Due to the proximity of this industrial development, previous subsistence harvest areas have been reduced to the area east of the community (Braund, 2017). The stated loss of subsistence harvest is attributed to several factors, including restriction by oil companies or government, difficulty in accessing former harvest areas, and a perception that the resources are not edible due to contamination. Nevertheless, subsistence continues to be a focus of life in Nuiqsut where a mixed subsistence and cash economy is maintained. Sharing, bartering, and trade of wild food, furs, and skins occurs within and between communities. Earned income is through local government, Kuukpik Corporation, and the oil and gas industry. In 2014, about 66 percent of Nuiqsut's adults were employed for 28 weeks (Brown et al., 2016).

Subsistence Use Areas

Figure 4.14.3-3 depicts the extent of Nuiqsut subsistence use areas for several periods ranging between 1995 and 2006. The North Slope Borough reports the subsistence use area for Nuiqsut covers an area of 34,500 square miles (North Slope Borough, 2016b). Between 1995 and 2006, the subsistence use area extended from Utqiagvik in the west and Kaktovik in the east, and as far south as Anaktuvuk Pass.

The majority of Nuiqsut use areas are concentrated around the Colville River, overland areas to the south and southwest of the community, offshore areas north of the Colville River delta, and northeast of Cross Island. Household surveys were completed for the Project in 2014, and the subsistence use area for that year was documented within a 16,322-square-mile range that is encompassed within the larger subsistence use area (Brown et al., 2016).

Areas consistently used by Nuiqsut residents to harvest caribou extend from the Beaufort Sea coast south to the foothills of the Brooks Range, and from the Sagavanirktok River and Prudhoe Bay in the east to Utqiagvik and Atqasuk to the west. Areas with a high number of overlapping use areas occur primarily along the Colville, Itkillik, Chandler, Anaktuvuk, and Kikiakrorak Rivers; along the coast between Atigaru and Oliktok Points; and in an overland area surrounding Fish Creek, Judy Creek, and Colville River to the west, and the Colville and Itkillik Rivers to the east. The maximum extent of the use area is mapped from Atqasuk to Point Thomson and south along the Colville and Anaktuvuk Rivers to Anaktuvuk Pass.

Nuiqsut residents hunt caribou often by boat during the summer and fall and by snow machine during the winter and spring. The majority of winter hunting occurs west of the community toward Fish Creek and south toward the foothills of the Brooks Range. During the summer and fall harvest, hunters travel by boat both along the coast and inland along various rivers. A few residents also reported hunting substantial distances east and west of the community, although several people commented that hunting has declined east of the community due to activities associated with oil and gas development.

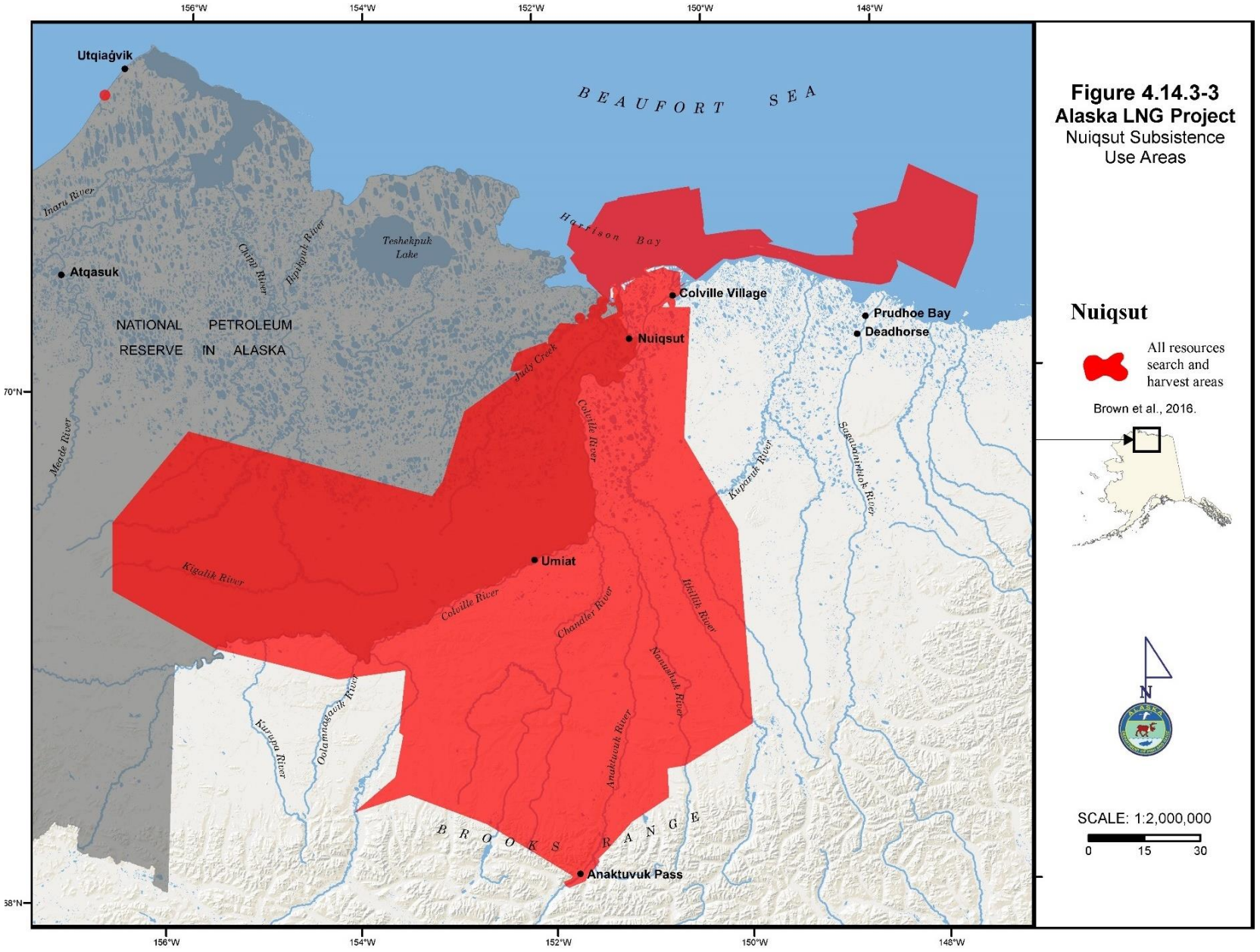


Figure 4.14.3-3
Alaska LNG Project
Nuiqsut Subsistence Use Areas

Nuiqsut's location on the Colville River and proximity to the Beaufort Sea offers harvesting opportunities for many species, including migratory species. Several species of whitefish live in the Colville River for portions of their life cycle. Of particular importance is arctic cisco, which migrates from the Mackenzie River Delta in Canada to the drainages of the North Slope. Whaling is based from Cross Island about 12 miles northeast of Prudhoe Bay. Caribou migrate through the area and migratory waterfowl nest in nearby tundra. Lands and waters traditionally and currently used for subsistence harvests by the residents of Nuiqsut overlap geographically with the Project's construction and operational footprint.

Seasonal Round

Migratory waterfowl are harvested in Nuiqsut's subsistence use area in spring, the most productive time (see table 4.14.3-4); however, geese and ducks are available from spring through fall. Burbot fishing typically begins in March and lasts until the ice breakup. As the river clears of ice, Nuiqsut's subsistence users begin setting nets for returning broad whitefish. Nets are typically left in the Colville River throughout the summer and into early winter. Salmon are harvested in the summer, but in lesser amounts than other fish. Lake trout, northern pike, and humpback whitefish are also harvested in July. After the ice breaks, ringed and bearded seal harvests continue throughout the summer with a peak in July. Berries are seasonally harvested between June and August.

The fall/winter under-ice fishing begins after freeze up and continues for about 1 month until the ice is too thick to set nets through holes in the ice. The primary species harvested during fall/winter are arctic and least cisco.

Caribou (of the Western Arctic Herd) return in June. Nuiqsut hunters travel by boat to the Colville River delta to locations that caribou frequent. Hunting begins to decrease in mid- to late September during the caribou rut. Caribou harvests continue throughout the winter, but the harvest range increases as the caribou migration continues southward.

Whaling begins in late August and continues through mid- to late September, but occasional bowhead whale harvests have occurred in mid-October. Harvests of whitefishes and other types of non-salmon occur during the fall, and set nets are used in open water before freezing. Moose hunting also occurs during the fall. Wolves and wolverines are harvested in the winter.

TABLE 4.14.3-4

Nuiqsut Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Fish	■	■	■	■	■	■	■	■	■	■	■	
Bird/eggs	■	■	■	■	■	■	■	■	■	■	■	■
Berries						■	■	■				
Moose							■	■	■			
Caribou	■	■	■	■	■	■	■	■	■	■	■	■
Furbearers	■	■	■	■	■					■	■	■
Polar Bear	■	■	■	■	■				■	■	■	■
Seals			■	■	■	■	■	■	■	■	■	■
Bowhead whale								■	■			

Source: Braund, 2015

Harvest Data

ADF&G completed subsistence household surveys in 2014 (Brown et al., 2016); however, historic and contemporary harvest data is also available for various years between 1985 and 2011 (Braund, 2016). In 2014, about 95 percent of the sampled households attempted to harvest wild foods, and more than half of Nuiqsut households attempted to harvest several subsistence species, including land mammals, marine mammals, non-salmon fish, birds, eggs, and plants. More than 90 percent of the households shared resources with others in the community and with members of other communities.

In 2014, marine mammals accounted for about half of the total harvest due to the successful harvest of bowhead whales. Large land mammals and non-salmon fish made up the majority of the remaining harvest with caribou and whitefishes representing the largest categories harvested. Birds, eggs, plants, and salmon represented less than 3 percent of the harvest.

Bowhead whale, caribou, and whitefishes provided the most edible weight for Nuiqsut households in 2014 (see table 4.14.3-5). Combined, these resources represent 89 percent of the per capita pounds harvested and provided about 800 pounds per capita. Bowhead whales and bearded and ringed seals provided about 400 pounds per capita, representing 45 percent of the total harvest weight. Caribou and moose harvests accounted for 29 percent and arctic cisco and broad whitefish provided 88 pounds and 78 pounds respectively of edible fish for each Nuiqsut resident during the study year.

TABLE 4.14.3-5

Estimated Subsistence Harvest for Nuiqsut

Resource	Per Capita (pounds)	Total (pounds)
Caribou	253.3	105,193.2
Moose	7.2	3,005.4
Bear	0.4	160.1
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	407.9	169,366.5
Marine invertebrates	–	–
Migratory birds	11.4	4,742.1
Upland birds	0.2	78.2
Eggs	0.1	36.8
Pacific salmon	9.4	3,888.7
Non-salmon fish	205.0	85,106.3
Berries	1.0	407.8
Plants	<0.1	6.6
Wood	–	–
Other	–	–

Source: Brown et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Nuiqsut is about 57 miles west of the Project. The eastern extent of Nuiqsut's non-marine subsistence use area overlaps with the Project area for the three resources of high importance in terms of edible weight, including caribou, upland birds, and non-salmon fish. The community's marine use area for bowhead whale, bearded and ringed seal, and marine migratory birds overlaps with the vessel transit route in areas of moderate to high use by the community for marine mammal species. Project construction activities, including construction of the GTP, PTTL, and Mainline Pipeline, and increased barging in the Beaufort Sea, would affect resource availability through displacement of resources. Increased cost and effort to harvest marine mammals is anticipated during construction.

The increased vessel traffic and associated noise could cause a change in the migratory behavior of bowhead whales, displacing them from Nuiqsut's traditional use area. Vessel traffic could displace waterfowl present in the vessel routes. Noise could affect the whale and seal populations that occur in vessel transit routes during the summer months. Construction-related activities (modifications to the West Dock Causeway and sealift deliveries) could limit or prohibit use of this area during the fall whaling season for up to 7 years.

Winter construction of the GTP and PTTL would affect upland migratory bird harvest and would result in permanent habitat displacement for these avian resources.

Construction of the Mainline Pipeline, PTTL, and GTP would occur over winter seasons and would therefore have limited impacts on resource availability for Nuiqsut harvesters. Furbearer harvest is the primary winter activity as well as harvests of non-salmon fish and caribou.

Although caribou hunting occurs nearly year-round, the summer and fall months are a time of cooperative group hunting and extended camping trips. Winter caribou harvest generally occurs when meat supplies are low. For the GTP and the elevated PTTL, disturbances to caribou habitat during operation would be long term. Mainline Facilities would be constructed within caribou summer and winter ranges. Since Project facilities would be within the caribou range, the Project could serve as a barrier to migration between habitat areas or movement to specialized habitats, such as access to calving range. The disruption to migration could continue into Project operation due to the presence of the maintained right-of-way. Nuiqsut subsistence users could experience impacts on caribou hunting west of the Project during operation; caribou harvests to the east previously declined because of existing oil and gas development.

Kaktovik

Kaktovik is on Barter Island at the northern boundary of the ANWR. Barter Island, characterized as a tundra plateau, is separated from the mainland in summer by the Kaktovik Lagoon Channel and is connected in winter by frozen sea ice. The island, an area of about 6 square miles, is flat with its highest point 55 feet above sea level. The village site is at 20 feet above sea level. Permafrost extends hundreds of feet below the surface of the island. The active permafrost layer melts in the summer. Barter Island receives little precipitation and, therefore, qualifies as a polar desert. The Beaufort Sea modifies the climate such that the winter is warmer and the summer is cooler than expected for this latitude. July and August are typically the only months when the minimum average temperatures are above freezing. Arctic currents of the eastern Beaufort Sea result in shore-fast ice for more than 9 months a year.

Kaktovik village is situated on the northeastern shore of Kaktovik Lagoon between the Okpilak and Jago Rivers. Kaktovik is the easternmost village in the North Slope Borough about 70 miles west of the Canadian border (Kaktovik, 2015). Barter Island was a seasonal home to the ancestors of present-day Kaktovik. During the 1920s and 1930s, most residents were semi-nomadic and lived along the coast, but gathered at the trading post for specific occasions. Kaktovik became a permanent settlement in 1923. At that time, a fur trading post was established.

The village was moved three times by the U.S. Air Force for military operations. The Barter Island Long Range Radar Station, a Distant Early Warning Line network station, was established in 1947. In this year, the village site relocated to the west, and the former site was used as an airstrip. In 1953, changes in the Distant Early Warning Line layout caused the village to move. A third move occurred in 1964, when the U.S. Air Force expanded its facilities. The third move represents Kaktovik's current location.

Subsistence continues to be a focus of life in Kaktovik where a mixed subsistence and cash economy is maintained. The harvest of local foods, barter for foods and services, subsistence sharing with those who cannot participate in harvest activities, wage labor, and dividends characterize the economy. The primary sources of wage labor include employment with regional and local government, public education, and the village corporation, Kaktovik Iñupiat Corporation.

Subsistence Use Areas

Figure 4.14.3-4 depicts the extent of Kaktovik subsistence use areas for several periods ranging between 1996 and 2006. The majority of Kaktovik's use area is concentrated along the Hulahula, Opilak, and Jago Rivers, an area extending about 20 miles offshore from the community, and various coastal locations between Prudhoe Bay and Canada. The most recent household survey in Kaktovik was in 2012.

Kaktovik's location on the Beaufort Sea offers harvesting opportunities for marine mammals (whale, seal, and polar bear), land mammals, and fish. Of particular importance as subsistence resources are caribou and bowhead whale. Two caribou herds are hunted within Kaktovik's subsistence use area, including the Central Arctic Herd and the Porcupine Caribou Herd. Muskox, brown bear, and Dall sheep also are important terrestrial resources. Bearded, ringed, and spotted seals are supplemental resources as well as ducks, geese, and several species of fish, including Dolly Varden (also referred to as Dolly Varden char), arctic cisco, arctic grayling, broad whitefish, and Pacific salmon. The Shaviovik, Kavik, Hulahula, Canning, Sadlerochit, Okpilak, and Kiongakut Rivers are considered subsistence rivers. Kaktovik is also an Alaska Eskimo whaling community. Bowhead whales are harvested in the fall when the whales migrate closer to shore than the spring migration. Lands and waters traditionally and currently used for subsistence harvests by the residents of Kaktovik overlap geographically with the Project's construction and operational footprint from Point Thomson to Prudhoe Bay and along the Dalton Highway south.

Seasonal Round

Kaktovik residents capitalize on a large number of both terrestrial and aquatic subsistence resources (see table 4.14.3-6). Subsistence activity is highest in the spring and late summer and declines mid-winter, with the fewest resources targeted in January and February. The spring season in Kaktovik is focused around the spring migration and harvest of migratory birds, although other subsistence activities occur during this time, including the harvest of marine mammals, caribou, moose, Dall sheep, small land mammals, and freshwater fish. Dall sheep, brown bear, gray wolf, and wolverine become less desirable after mid-May. In late May and early June, migratory waterfowl hunting begins with a focus on geese and eider. Waterfowl hunting continues through the summer and early fall months. Subsistence activities in June are limited due to a lack of snow for snow machine transportation and ice conditions that make boat travel difficult.

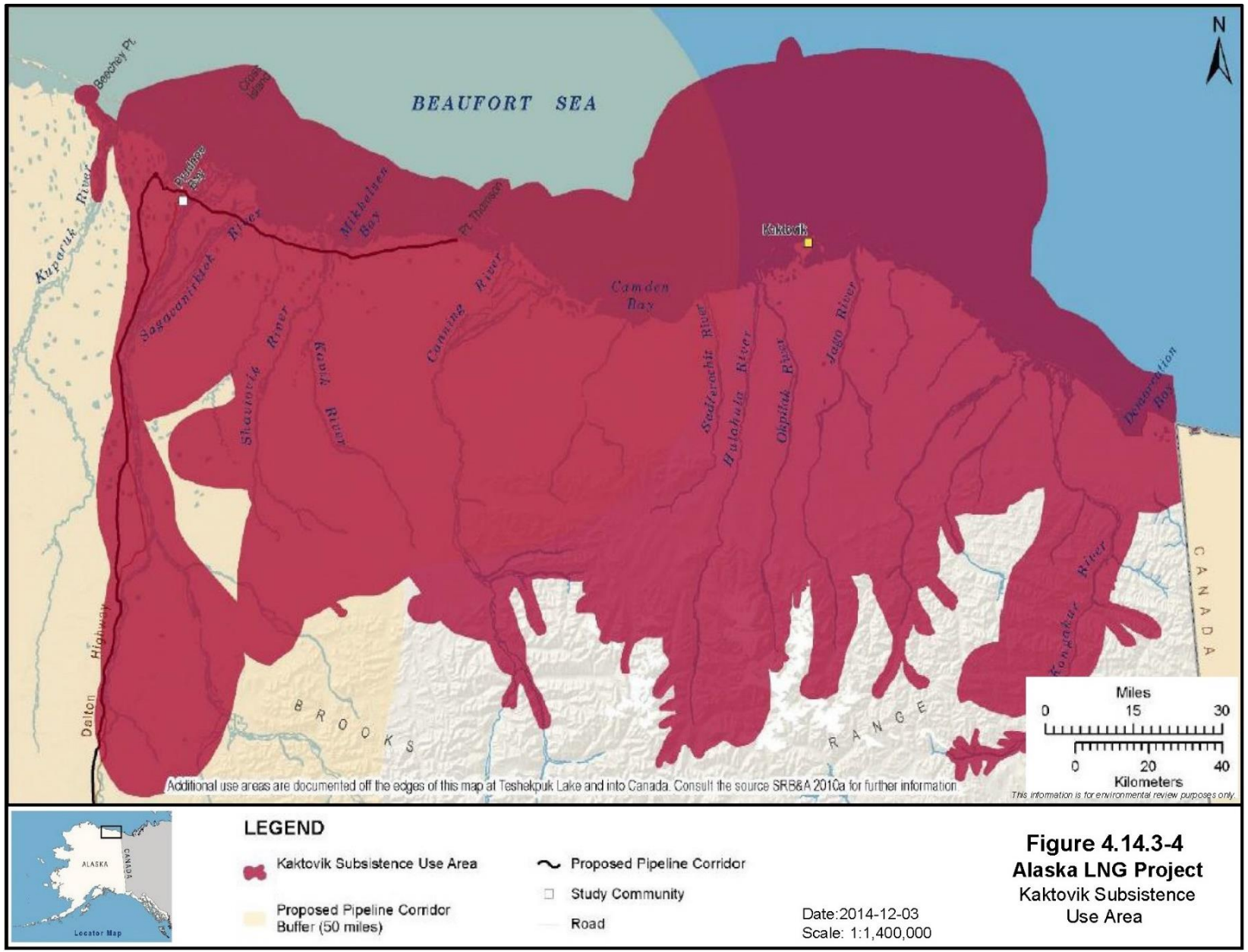

BEAUFORT SEA
Beechey Pt.
Prudhoe Bay
Kuparuk River
Sagavanirktok River
Mikkelsen Bay
Pt. Thomson
Kaktovik
Camden Bay
Canning River
Shaviovik River
Kavik River
Sadlerochit River
Hulahula River
Okpilak River
Jago River
Demarcation Bay
CANADA
Dalton Highway
BROOKS RANGE
Kongakut River
N
Miles
0 15 30
0 20 40
Kilometers
This information is for environmental review purposes only
Additional use areas are documented off the edges of this map at Teshekpuk Lake and into Canada. Consult the source SRB&A 2010a for further information
ALASKA
CANADA
Locator Map
LEGEND
Kaktovik Subsistence Use Area
Proposed Pipeline Corridor Buffer (50 miles)
Proposed Pipeline Corridor
Study Community
Road
Date:2014-12-03
Scale: 1:1,400,000
Figure 4.14.3-4
Alaska LNG Project
Kaktovik Subsistence Use Area

TABLE 4.14.3-6

Kaktovik Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Fish	■	■	■	■	■		■	■	■	■	■	■
Upland bird/eggs				■	■	■					■	
Waterfowl				■	■	■	■	■	■	■		
Plants and berries							■	■	■			
Moose	■	■	■	■			■	■	■	■	■	■
Caribou	■	■	■	■	■	■	■	■	■	■	■	■
Bear									■	■	■	
Muskoxen								■		■		
Dall sheep			■	■						■	■	■
Furbearers	■	■	■	■	■			■		■	■	■
Seals							■	■	■			
Bowhead whale								■	■	■		

Source: Braund, 2015

During the summer season (June through August), Kaktovik residents target the greatest number of resources in August. Summer caribou hunting peaks in July when animals seek relief from insects at the coast, and the harvest continues into the fall months. The majority of the fish are harvested in the summer months. Dolly Varden, arctic cisco, and broad whitefish are primarily harvested in July and August; however, fall fishing extends into September. Recent studies show Kaktovik hunters harvest bearded, ringed, and spotted seals by boat throughout the summer and fall months (July through September). Plants and berries are harvested during summer, as well as marine invertebrates and muskox, with a resumption of small land mammal harvests in August.

The fall season (September and October) is focused primarily on harvests of bowhead whale, although caribou and fish are also important resources during this time. The majority of bowhead whale harvests occur during the month of September when the whales migrate closest to shore. Several sources report the harvesting of bowhead whales starting in August and continuing with increasing intensity into fall. At the end of the whaling season, hunters once again focus on caribou, supplementing these resources with fish, plants, and berries, and the occasional muskox, bear, or moose.

Kaktovik residents pursue few resources during the winter as the length of daylight diminishes (November through April). The primary winter subsistence resources are furbearers, Dall sheep, caribou, gray wolf, wolverine, an occasional moose, and fish. Winter fishing is primarily for Dolly Varden. Freshwater and marine non-salmon fish, small land mammals, marine mammals, and upland birds are also taken during the winter months.

Harvest Data

While the village of Kaktovik declined to participate in household surveys by ADF&G and mapping for the Project, the North Slope Borough (Harcharek, 2018) documented annual harvests of animal and plant species that the village gathered over 6 years between 2007 and 2012. The subsistence study documented the species and number of individual animals harvested, harvest method, and location of harvest among other variables (Harcharek, et al., 2018). The number of animals harvested was converted to edible pounds, except berries that were converted to edible volume; per capita weight was not calculated.

Of 80 households surveyed in 2012, 64 participated during the first 6-month survey and 57 participated during the second 6-month survey. The combined data from these surveys are presented in table 4.14.3-7. Bowhead whale harvest numbers were not estimated and reported by Kaktovik. In 2012, Kaktovik's residents relied heavily on marine mammals, large land mammals, specifically caribou, and non-salmon fish (see table 4.14.3-7).

Impacts on Subsistence

Kaktovik is on Barter Island in the Beaufort Sea more than 100 miles east of the GTP and the Mainline Pipeline. The PTU is about 60 miles west of the community. The community's terrestrial subsistence use areas overlap with the Gas Treatment Facilities (including the PTTL) and Mainline Pipeline. The marine vessel transit route overlaps only the western limits of Kaktovik's marine mammal use area. Construction is anticipated to have a limited effect on resource availability as a result of displacement of resources and habitat loss. Increased cost and effort to harvest these resources is not anticipated during construction or operation because the Project is on the periphery of the subsistence use area with limited use by harvesters.

TABLE 4.14.3-7

Estimated Subsistence Harvest for Kaktovik

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	2217.0
Moose	–	376.0
Polar bear [a]	–	373.0
Brown bear	–	75.0
Dall sheep	–	272.0
Deer	–	–
Other large land mammals	–	131.0
Small land mammals	–	1.0
Marine mammals (excluding whale)	–	608.0
Marine invertebrates	–	–
Birds [b]	–	246.0
Eggs	–	–
Pacific salmon	–	14.0
Non-salmon fish	–	1654.0
Berries	–	29.0
Plants	–	3.0
Wood	–	–
Other	–	–

Source: Harcharek et al., 2018

"–" = No harvest for this resource was reported.

[a] Added polar bear as a category.

[b] Distinction not made between upland and migratory birds in this study.

A high number of overlapping bowhead whale use areas occur up to 25 miles from shore between Arey Island and Griffin Point. Arey Island is about 50 miles east of the PTTL. Whale hunting activities occur primarily during the month of September using motorized boats. Impacts on bowhead whale harvest

would be in an area of low user overlap at the limits of Katovik's use area. Therefore, the displacement of whales would not be in an area heavily used by subsistence harvesters, and a decrease in resource availability is not anticipated.

Caribou is one of the most important and intensively hunted resources by the residents of Kaktovik. The winter construction of the PTTL could temporarily disrupt winter subsistence harvests of caribou between October of Year 3 and December of Year 4 resulting in a temporary impact. However, primary use of this area occurs during the summer months; winter use of the area is limited. Therefore, a significant reduction in the availability of caribou during construction is not anticipated.

During Project operation, impacts on Kaktovik's caribou subsistence use area would occur in a previously developed area with an existing aboveground pipeline and in an area of limited harvest activity. While impacts could include disruptions to migrating caribou, a significant reduction in the availability of caribou during operation is not anticipated.

Anaktuvuk Pass

Anaktuvuk Pass is in a wide valley of the Brooks Mountain Range about 60 miles west of the Dalton Highway. The pass divides the Brooks Mountain Range from north to south and generally marks the transition from arctic to subarctic climate zones where temperatures can range from -50°F in the winter to 90°F in the summer. Anaktuvuk Pass is 2,200 feet above sea level and the surrounding terrain reaches 7,000 feet above sea level. The vegetation at lower elevations is white spruce and paper birch forests. Above 3,000 feet, the tundra mat consists of lichens, grasses, and shrubs.

Anaktuvuk Pass is the last remaining settlement of the Nunamiut people. Historically, this inland Iñupiaq group was organized into small groups of nuclear families that moved seasonally throughout the region. The caribou migration in the spring and fall determined the groups' seasonal movements. By the early 1900s, a few hundred Nunamiut occupied the interior arctic Alaska. People had moved north in search of reliable sources of wild food in response to a decline in the Western Arctic Herd of caribou and jobs. It was not until 1948, when the caribou herd rebounded, that Anaktuvuk Pass was established. Mail service arrived in 1951 and a school was established in the 1960s. Today, the city also has an airport for passenger and freight services (the city is not on the road system), a health clinic, small hotel, grocery store, museum, library, and community hall (Brown et al., 2016).

Most of the employed residents work for local and tribal governments; however, other employment sectors include transportation and utilities. About 55 percent of the adults were employed throughout the year (Brown et al., 2016).

Subsistence Use Areas

Anaktuvuk Pass subsistence users harvest to the west beyond the Noatak River to Ambler and near the Dalton Highway, east of Galbraith Lake. A large area surrounding the Killik, Chandler, Anaktuvuk, and John River Drainages is also part of the subsistence use area. Subsistence use areas have also been recorded near Umiat along the Colville River and a broad area in the foothills of the Brooks Range north of Anaktuvuk Pass. The greatest concentration of Anaktuvuk Pass subsistence use areas occurs in a network of mountain passes and valleys about 30 miles from the community. This network of use areas, which was recorded in 2001, has remained consistent based on the current data documented by Brown et al. (2016).

Anaktuvuk Pass relies heavily on terrestrial mammals and fish for subsistence. Caribou is the main terrestrial mammal resource, with moose and Dall sheep also important resources. Fish from area lakes and streams are an important supplement to terrestrial mammals. Terrestrial resources are often bartered for marine resources from other communities, particularly Nuiqsut and Utqiagvik (Bacon et al., 2009; Brower and Opie, 1996; Fuller and George, 1999). New household surveys were completed for Anaktuvuk Pass, and the most current information was collected in 2014 (Brown et al., 2016). Lands and waters traditionally and currently used for subsistence harvests by the residents of Anaktuvuk Pass overlap geographically with the Project's construction and operational footprints (see figure 4.14.3-5).

Seasonal Round

The residents of Anaktuvuk Pass are highly mobile and travel throughout the Brooks Range to hunt, fish, and gather. Subsistence activities are highest in late summer and early fall, and decrease during the winter with the least resources harvested in November (see table 4.14.3-8). The spring season (April and May) is the peak waterfowl and freshwater fish harvests. The spring fish harvest includes lake trout, arctic char, and arctic grayling. The fish harvest continues and intensifies during the summer months (June through August), which are a high point of activity for many subsistence pursuits.

Caribou are predominantly hunted in the fall (September and October) when they migrate through the area; however, caribou hunting occurs all year. A high number of caribou harvests have been reported during certain years in the late winter and early spring months (February through May) (Bacon et al., 2009; Brower and Opie, 1996).

Moose and Dall sheep subsistence harvests begin in the summer. Berries and roots are an important resource and are also gathered in the summer. Furbearer and small land mammal harvests are more common in the winter but may occur during the summer, as may the occasional brown bear harvest.

During the winter months, ptarmigan and furbearers are actively pursued, particularly during the late winter months of February and March.

Freshwater non-salmon fish and Dall sheep are harvested throughout the year.

Harvest Data

The most current data, collected in 2014 by ADF&G, indicates that about 90.6 percent of the sampled households (53 of 99 households) attempted to harvest wild foods. More than half of these households attempted to harvest several subsistence species, including caribou, Dall sheep, moose, brown bear, broad whitefish, arctic grayling, lake trout, blueberry, and cloudberry (see table 4.14.3-9). About 76 percent of the households shared wild resources. Caribou and non-salmon fish were the most commonly shared resources with others in the community (Brown et al., 2016).

In 2014, large land mammals made up the largest category of the subsistence harvest, totaling 111,302.1 pounds (350.5 pounds per capita). Caribou was the most harvested resource weighing in at about 104,663.5 pounds total. Dall sheep was the second most harvested resource consisting of 3,302.5 pounds total. Non-salmon fish were 8 percent of the total harvest. Wild plants made up 1 percent of the harvest with blueberries the most harvested berry. Birds and eggs made up 1 percent of the annual harvest.

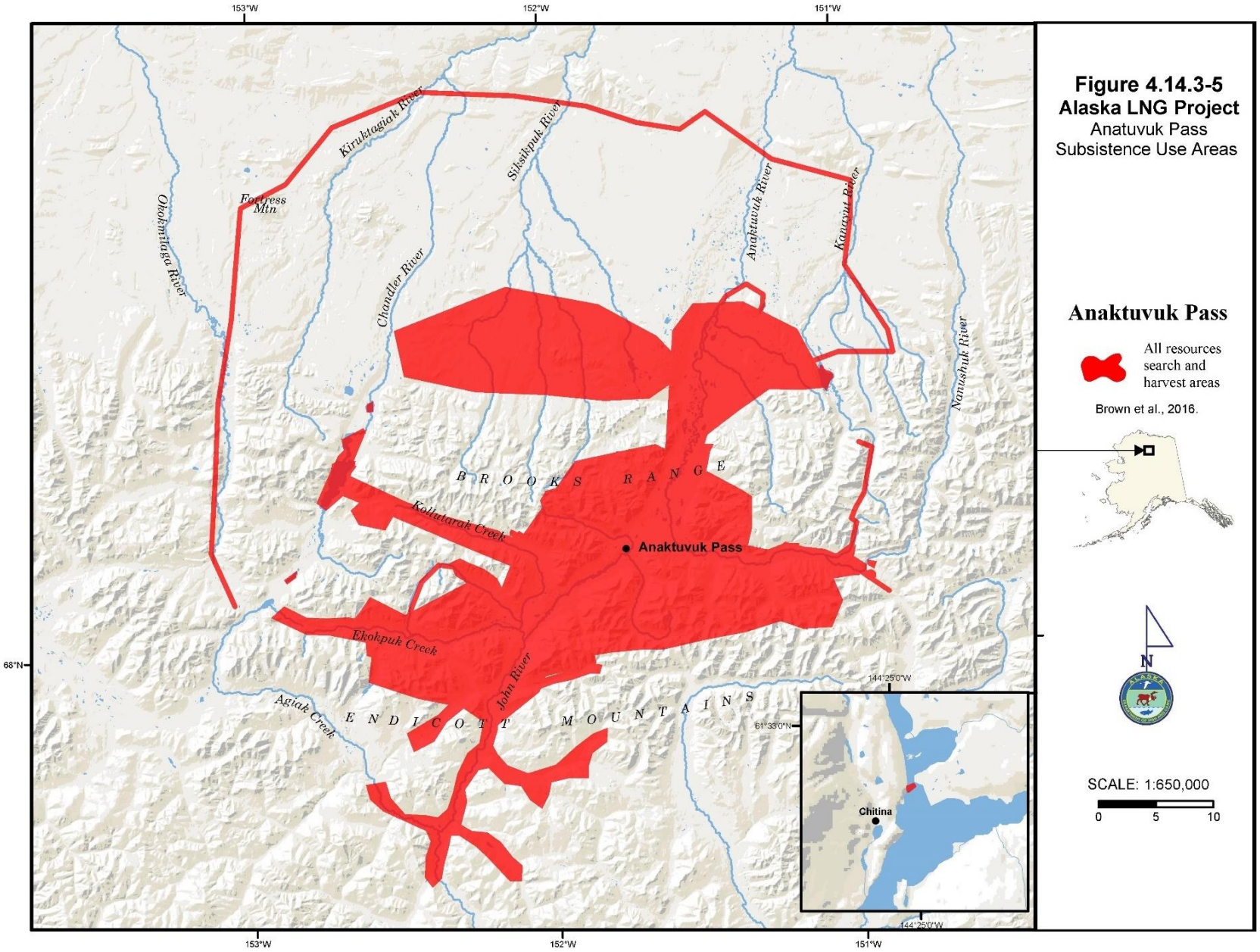

153°W
152°W
151°W
68°N
Kiruktagiak River
Siksikpuk River
Anaktuvuk River
Kanayut River
Okokmitaga River
Fortress Mtn
Chandler River
Nanushuk River
B R O O K S R A N G E
Killutarak Creek
Anaktuvuk Pass
Ekokpuk Creek
John River
Agiak Creek
E N D I C O T T M O U N T A I N S
144°25'0"W
61°33'0"N
Chitina
Figure 4.14.3-5
Alaska LNG Project
Anatuvuk Pass
Subsistence Use Areas
Anaktuvuk Pass
All resources search and harvest areas
Brown et al., 2016.
N
SCALE: 1:650,000
0
5
10

TABLE 4.14.3-8

Anaktuvuk Pass Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Caribou												
Moose												
Bear												
Dall sheep												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Plants and berries												

Source: Braund, 2015

TABLE 4.14.3-9

Estimated Subsistence Harvest for Anaktuvuk Pass

Resource	Per Capita (pounds)	Total (pounds)
Caribou	329.6	104,663.5
Moose	9.5	3,014.8
Bear	1.0	321.3
Dall sheep	10.4	3,302.5
Deer	–	–
Other large land mammals	–	–
Small land mammals	0.1	35.2
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	1.7	549.4
Upland birds	0.8	257.6
Eggs	–	–
Pacific salmon	0.7	225.9
Non-salmon fish	32.2	10,222.3
Berries	3.9	1,249.4
Plants	1.3	427.1
Wood	–	–
Other	–	–

Source: Brown et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

The community of Anaktuvuk Pass is in the Brooks Range about 50 miles west of the Project. The Project overlaps a small portion of the eastern periphery of the community's subsistence use area in the foothills of the Brooks Range. Project construction activities, including construction of the GTP, PTTL, and Mainline Pipeline would affect resource availability through displacement of resources and habitat loss. Increased cost and effort to harvest caribou and increased competition is anticipated during construction and operation.

Caribou is the most important and intensively hunted resource by the residents of Anaktuvuk Pass. Construction of the Mainline Pipeline could disrupt caribou movement through the foothills of the Brooks Range during construction. Anaktuvuk Pass residents hunt caribou year-round with peak harvests in late summer, early fall, and mid-winter. During traditional knowledge workshops, residents expressed concern about the impacts of associated traffic along the Dalton Highway on caribou harvesting success, stating that noise and human presence associated with the Mainline Pipeline construction would compound these effects.

Construction and operation of the GTP, PTTL, and Mainline Pipeline would result in long-term disturbance of caribou habitat. The Project could serve as a barrier to migration between habitat areas or movement to specialized habitats, such as access to calving range. The disruption to migration would continue into Project operation due to the presence of the maintained right-of-way. Additionally, new access roads would be constructed and maintained in support of pipeline operation. Unauthorized use of these roads by non-local hunters would increase competition for caribou, thereby reducing its abundance and availability.

4.14.3.2 Yukon River Region

The Yukon River Region subsistence analysis includes eight communities along the Yukon River and its tributaries. These communities are Wiseman, Coldfoot, Evansville, Bettles, Alatna, Allakaket, Stevens Village, and Rampart. The region generally encompasses the area north of Fairbanks and south of the Brooks Range. Located on the banks of the Koyukuk River near the confluence of the Alatna River, Alatna and Allakaket are the western-most communities. Bettles and Evansville are to the north of Alatna and Allakaket near the confluence of the Middle Fork Koyukuk and the John River. Wiseman and Coldfoot are the northernmost communities in the region. Stevens Village and Rampart are on the banks of the Yukon River. Located in the Yukon Flats, Stevens Village is the easternmost community, and Rampart is the southernmost community in the Yukon River Region.

The Yukon River Region communities have varied histories, with some that extend into prehistory and others that were established as mining camps and trading posts at the turn of the 20th century. The area at the confluence of the Alatna and Koyukuk Rivers was settled by Kobuk Iñupiaq and later used as a trading post between the Iñupiaq and Athabascan peoples for products from the coast and furs of the interior regions. Rampart and Stevens Village areas were used prehistorically by Athabascan people. Evansville and neighboring Bettles were used historically by Athabascan and Iñupiat groups. The discovery of gold deposits in the Yukon River Region and the subsequent gold rush led to the establishment of trading posts and mining camps at Stevens Village, Rampart, Wiseman, and Coldfoot. Stevens Village and Rampart had

been previously occupied as ancestral village sites, but Wiseman and Coldfoot were founded during the gold rush.

With the exception of Wiseman, Coldfoot, and Bettles, the majority (greater than 50 percent) of residents in these communities are federally recognized tribes (U.S. Census Bureau, 2016). These tribes have traditional and current resource uses, including customary and traditional uses, in or near the Project area (see figure 4.14.3-6). Wiseman, Coldfoot, and Bettles have current subsistence resource use areas in or near the Project area. A description of the eight communities and their subsistence use areas, harvest patterns, and seasonal round is provided in the following sections.

Spring (April through May) in the Yukon River Region is characterized by warming temperatures and lengthening days (see table 4.14.3-10). Spring marks a decrease in seasonal harvests of furbearers and upland birds; however, it also marks the beginning of the waterfowl hunting season as ducks and geese arrive in the area. Yukon River Region residents occasionally harvest small land mammals, including American marten, hare, and American beaver. Fishing for non-salmon fish occurs in the region most of the year. Harvests of caribou and bear may also occur in the springtime in a number of communities.

During summer (June through August), residents of the Yukon River Region focus on fishing and collecting plants and berries. Pacific salmon abundance varies throughout the region. Harvesting salmon is a strong focus of some communities, including Allakaket, Alatna, Rampart, and Stevens Village. Communities farther from major salmon rivers (Coldfoot, Wiseman, Bettles, and Evansville) harvest non-salmon fish. Berries are a particularly important resource in the region; they are among the highest-used resources (in terms of the percentage of households using) in many of the communities (Holen et al., 2012).

Many subsistence activities such as fishing, waterfowl hunting, and large land mammal hunting, continue or increase during the fall (September through October). Caribou and moose are particularly important resources for the northern communities in the Yukon River Region (Wiseman, Coldfoot, Evansville, and Bettles), and by weight make up the majority of the annual subsistence harvest in these communities. Moose harvests most commonly occur in September, and residents harvest caribou during the fall and into the winter months. Dall sheep and bear harvests occur in early fall, and berry picking may also continue from the summer into the early fall. Fall in the Yukon River Region marks the end of waterfowl subsistence activity and the beginning of harvests of upland birds such as grouse and ptarmigan. Wood is collected year-round for heating fuel.

During the winter season (November through March), harvests of small land mammals and furbearers occurs. Large land mammals, including caribou, moose, and bears, are harvested in the winter months although moose and bear harvests occur with more frequency during other seasons. Ice fishing for non-salmon fish occurs over winter months. In Bettles and Evansville, changing ice conditions have decreased winter non-salmon fishing subsistence activities in recent years (Holen et al., 2012). Residents of the Yukon River Region harvest upland birds throughout the winter and into the spring as the annual cycle of subsistence activities begins again.

As part of the subsistence mapping and traditional knowledge study for the Project, each community in the Yukon River Region was asked to identify the three most important subsistence resources. At a regional level, moose was identified as the most important resource, fish was second, and berries and caribou were third. Migratory birds, bear, and wood were mentioned in more than 5 percent of the responses while salmon, ducks, and American beaver were mentioned in fewer than 5 percent of the responses.

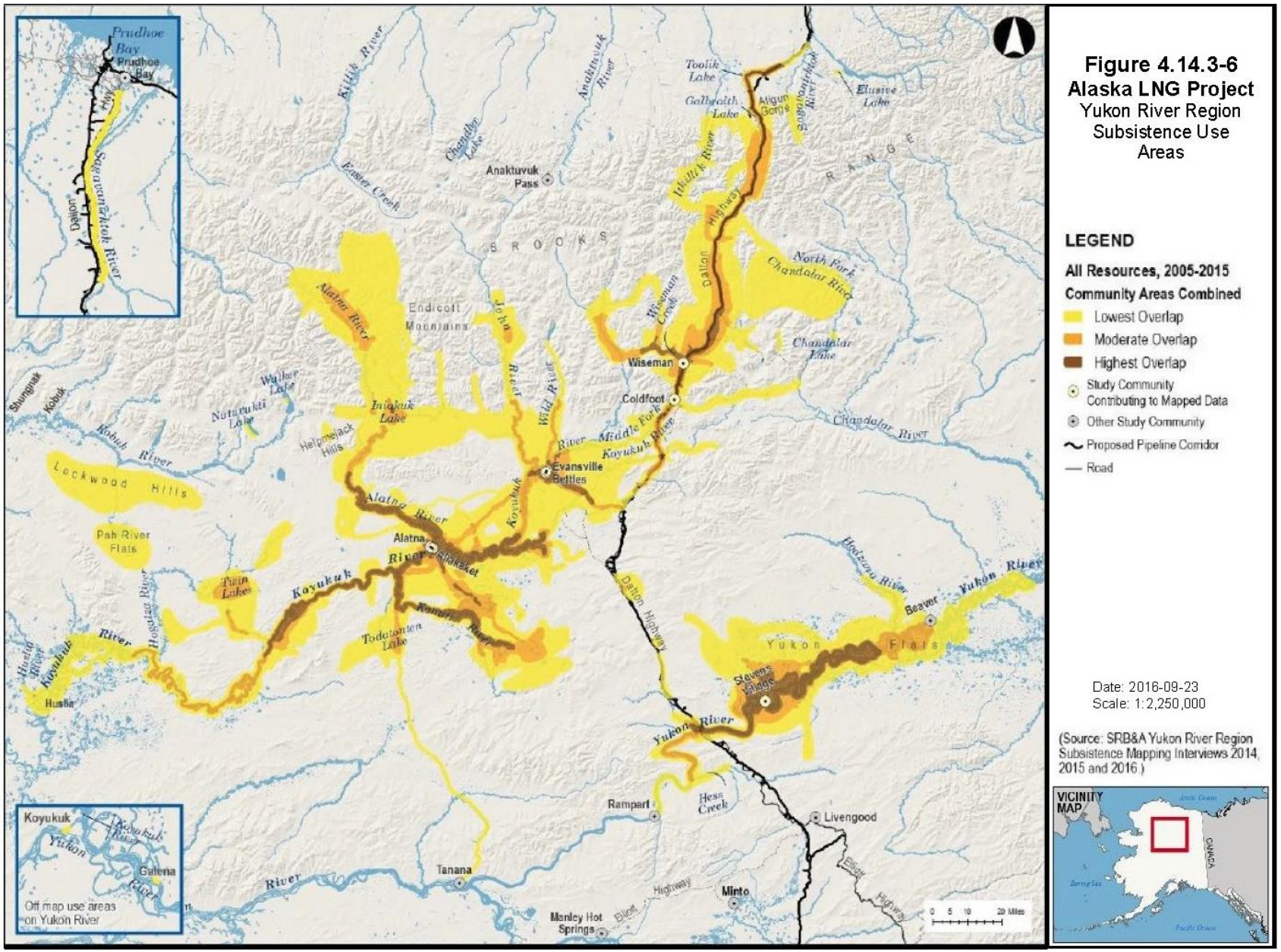


Figure 4.14.3-6
Alaska LNG Project
Yukon River Region
Subsistence Use
Areas

LEGEND

All Resources, 2005-2015
Community Areas Combined

- Lowest Overlap
- Moderate Overlap
- Highest Overlap
- Study Community Contributing to Mapped Data
- Other Study Community
- Proposed Pipeline Corridor
- Road

Date: 2016-09-23
Scale: 1:2,250,000

(Source: SRB&A Yukon River Region Subsistence Mapping Interviews 2014, 2015 and 2016.)

TABLE 4.14.3-10

Yukon River Region Subsistence Harvest

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Caribou												
Moose												
Bear												
Dall sheep												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Plants and berries												
Wood												

Source: Braund, 2015

During subsistence mapping interviews in Yukon River Region communities between 2014 and 2016, respondents were asked to comment on concerns about subsistence resources and their subsistence lifestyle. The concerns ranged from direct impacts on subsistence resources to future development activities.

Major concerns noted by subsistence users in the Yukon River Region included impacts outside hunters have on subsistence resources in the region. Non-local sport hunters that do not understand traditional harvest practices have the potential to impact animal populations and their migration. For example, a caribou herd follows a lead bull; if the lead bull is harvested, the migration pattern of the herd may change.

The proposed Ambler Road was identified as an issue of concern by almost all respondents in Alatna, Allakaket, Bettles, and Evansville. The road would provide access to non-resident hunters, placing unwanted strain on subsistence resources and increased competition for those resources.

Comments specifically related to impacts resulting from Project construction include:

- altering the caribou migration;
- spills contaminating watersheds that fish and terrestrial mammals inhabit or use; and
- disturbance to fish camps adjacent to the Yukon River bridge.

Yukon River Region Temporal Trends

Temporal trends in harvest data for the Yukon River Region suggest that the number of months for harvesting non-salmon fish, large and small land mammals, and waterfowl has decreased. The most recent data for Bettles and Evansville indicate residents presently fish for non-salmon fish during the summer months only, in contrast to a longer season in the past that began in late spring and continued through early winter. The most recent data from Holen et al. (2012) indicates that a change in ice conditions constrains Evansville residents to summer fishing only; neighboring Bettles is likely subject to the same conditions (Holen et al., 2012). A change in the timing of non-salmon fish harvesting is also apparent in Alatna and

Allakaket. From the 1960s to the 1980s, the timing of subsistence activity for non-salmon fish shifted from all non-summer months to subsistence activity beginning in the spring and continuing into early winter.

In many of the region's communities, a decline is also apparent in the number of months used per year for harvesting large land mammals such as caribou, moose, bear, and Dall sheep. Although fewer months of the year are used for large land mammal subsistence activities, the overall seasons for these activities have not shifted substantially over time.

Limited comparative data are available to address changes over time in small land mammal subsistence harvests in the Yukon River Region; however, an increase in the number of months used for small land mammal subsistence harvests is evident in Alatna and Allakaket. The most recent data for these communities show that small land mammal harvests occur year-round, in contrast to the fall through spring months reported in previous studies.

Changes in waterfowl harvest varies throughout the Yukon River Region. A decrease in the number of months used to target waterfowl is apparent in Stevens Village and Rampart. The most recent data available for these communities show harvests of waterfowl only occur during the spring, in contrast to older data indicating that this subsistence activity occurred during both spring and fall.

Yukon River Region Summary

Project construction activity and operation of the Mainline Pipeline in the Yukon River Region would affect subsistence by reducing resource availability and access while increasing harvest cost and effort and potential resource competition. Subsistence use areas in the region tend to be focused along the Yukon and Koyukuk Rivers and their major tributaries and roads and trails, including the Dalton Highway.

Wiseman

The community of Wiseman is on the southern slope of the Brooks Range on the west side of the Middle Fork Koyukuk River at the confluence of the Koyukuk and Wiseman Creek and about 1 mile west of the Dalton Highway. The Koyukuk River valley in the vicinity of Wiseman is marshy and characterized by numerous meander scars. Mountains of the southern Brooks Range rise on either side of the valley to more than 1,000 feet. Wiseman does not have a predominantly Alaska Native population and, therefore, did not participate in traditional knowledge workshops.

Wiseman is about 19 miles upstream and to the northeast of the point at which the Dalton Highway reaches the Koyukuk River, and about 8 miles upstream and to the north of the community of Coldfoot, also along the Koyukuk River.

Settlement at what is today the community of Wiseman began after gold was discovered along Nolan Creek, which flows into Wiseman Creek a short distance northwest of the community. Wiseman grew quickly when most of the government and commercial services, which had been established earlier at Coldfoot, were relocated to Wiseman (Holen et al., 2012).

Unlike the community of Coldfoot to the south, development continued at Wiseman even after mining production in the area declined and many residents left. During the 1920s, the Army Signal Corps established a wireless station at Wiseman, and a school and airstrip were built at the community. Despite these developments, the community's population continued to decrease although, unlike Coldfoot, the town was never completely abandoned. During this time, Wiseman residents increasingly relied on subsistence resources (Holen et al., 2012).

The population of Wiseman increased after the Dalton Highway was built on the far side of the Koyukuk River in the 1970s. After reaching a population of 33 in 1990, the number of residents declined to 14 living in five households in 2010. In 2011, the ADF&G recorded five households and a population of 13 individuals, none of whom were Alaska Natives (Holen et al., 2012).

In 2011, the ADF&G conducted a study of the harvest and use of subsistence resources in Wiseman (Holen et al., 2012). Investigators from the ADF&G interviewed all five households in the community.

All of the households surveyed by the ADF&G in 2011 reported harvesting subsistence resources. The ADF&G reported that three of the five households in the community received cash income through employment. Community members were employed by the federal and state government; in the agriculture, forestry, and fishing industries; in the mining industry; in the retail trade; and by local service providers.

Subsistence Use Areas

Figure 4.14.3-7 depicts the extent of the Wiseman subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011. The community's subsistence use area is concentrated along the Dalton Highway, but extends north of the Yukon River Region along the Dalton Highway past Toolik Lake. From the Dalton Highway corridor, use areas branch off along river corridors and mountain valleys. A continuous area of high use extends west along Wiseman Creek to the Glacier River. Valleys where Wiseman harvesters target resources include Atigun Gorge and the Oolah Valley. Additionally, subsistence resources are harvested along the North Fork Chandalar River, the South Fork Koyukuk River, and the Jim River. Lands used for subsistence harvests by the residents of Wiseman overlap geographically with the Project's construction and operational footprint (see figure 4.14.3-7).

Seasonal Round

The residents of Wiseman harvest a variety of species throughout the year and target species following a seasonal cycle (see table 4.14.3-11). The number of resource categories hunted or harvested is highest in September and is maintained at a relatively low level for the remainder of the year, with the least resources targeted in June and October. During the springtime (April/May), Wiseman residents harvest migratory waterfowl and, depending on breakup, non-salmon fish species in late May (Holen et al., 2012).

The summer months (June through August) are a period of reduced subsistence activity. During the summer, harvests of non-salmon fish continue to occur and residents take advantage of the growing season with harvests of plants, including wood and berries.

The fall (September through October) is characterized by large land mammal harvests. Moose provide the most meat per capita in Wiseman and are most commonly taken in September along with Dall sheep and caribou. Harvests of plants and berries continue into the early fall, and bear subsistence activity occurs before the bears begin hibernation. Wood collection for use in the upcoming winter months also occurs during this time.

From November until March, residents of Wiseman focus their subsistence activities on harvesting furbearers and firewood. Furbearers are harvested in the winter for personal use and income. The most sought after species include gray wolf, wolverine, and Canadian lynx, but American marten, arctic fox, and snowshoe hare are also harvested. Ice fishing for trout in nearby lakes occurs in the winter months. Occasionally, caribou and moose supplement the winter subsistence diet. Upland bird harvests, including grouse and ptarmigan, occur year-round.

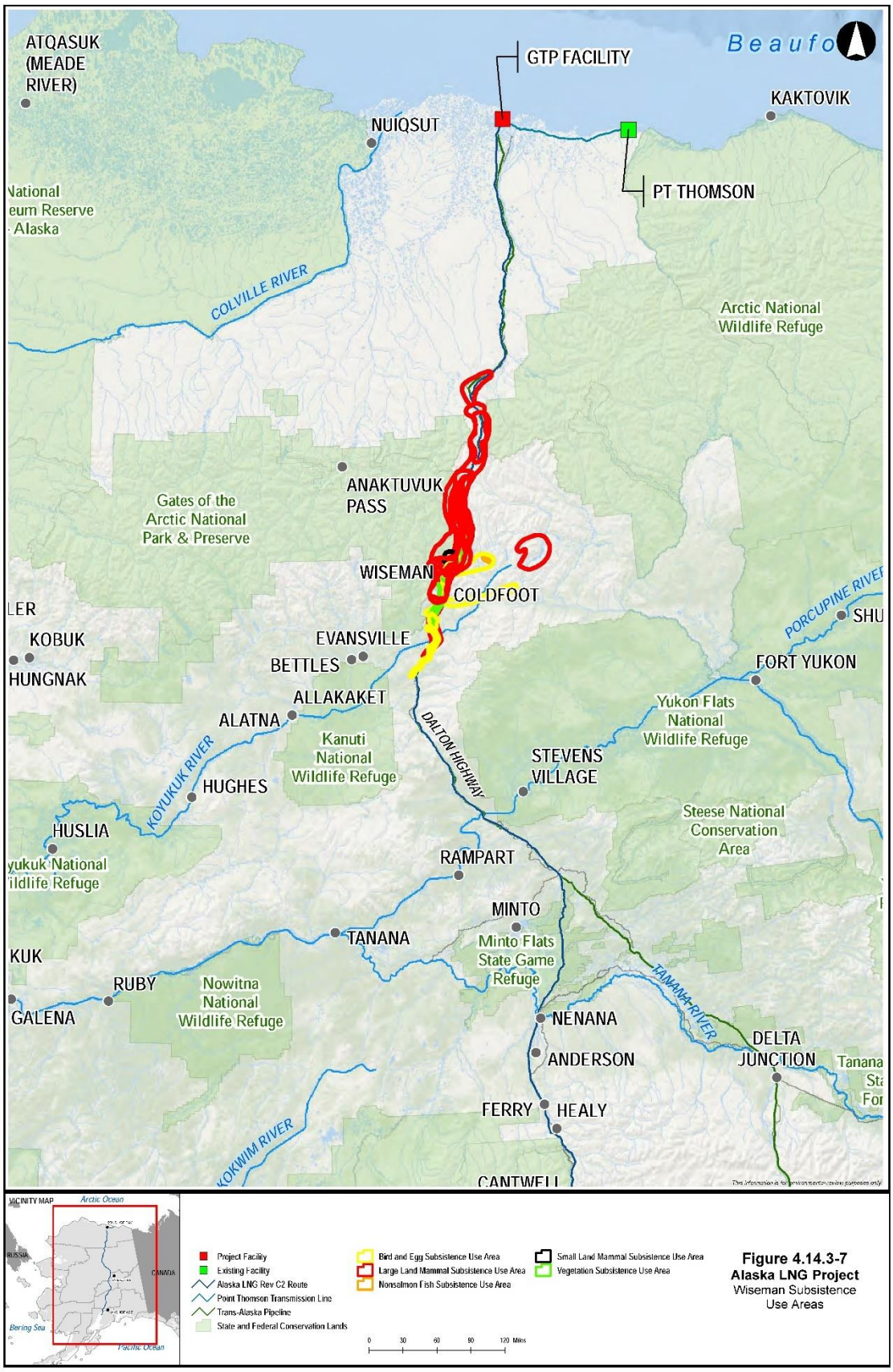


Figure 4.14.3-7
Alaska LNG Project
Wiseman Subsistence Use Areas

TABLE 4.14.3-11

Wiseman Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caribou				■	■						■	
Moose									■			
Bear				■	■				■	■		
Dall sheep												
Furbearers	■	■	■	■							■	■
Plants and berries							■	■	■			
Wood	■	■	■			■	■	■	■		■	■

Source: Braund, 2015

Harvest Data

The five households contacted by the ADF&G in 2011 reported harvesting and using subsistence resources. All households reported using salmon and non-salmon fish, large land mammals, upland game birds, berries, and wood. Sixty percent of households reported the use of small land mammals, migratory birds, and plant resources other than berries and wood.

In 2011, total harvest weight of subsistence resources harvested by the community totaled about 3,818.5 pounds, or 293.7 pounds per capita (Holen et al., 2012). The pounds per capita of general subsistence resource categories are shown below (see table 4.14.3-12). The three most important land mammals include moose, caribou, and Dall sheep. Ptarmigan and spruce grouse were the most important upland game birds. Sockeye salmon and arctic grayling were the most important fish. Lowbush cranberry (*Vaccinium vitis-idaea*, also known as mountain cranberry), blueberry, and raspberry were the most important plant resources (Holen et al., 2012).

Impacts on Subsistence

Wiseman subsistence harvesting activities generally occur along the Dalton Highway and are year-round, with a peak in the number of resources sought during September and October. Construction of the Mainline Pipeline and Aboveground Facilities would occur over 75 months, including six winters and seven summers. In addition, several access roads would be constructed and used within Wiseman's subsistence use area. Blasting would occur within 0.5 mile of Wiseman's subsistence use areas. Construction activities along the Mainline Pipeline would overlap with several resources, including moose, caribou, Dall sheep, upland game birds, non-salmon fish at stream crossings, berries, wood, small land mammals, migratory birds, and plants. Construction would temporarily affect access to resources and availability of these resources as a result of habitat loss, increased traffic, increased competition along the easily accessible Dalton Highway, and additional cost and effort to harvest resources. Impacts would not likely continue into Project operation in this already developed area along the Dalton Highway and TAPS.

TABLE 4.14.3-12

Estimated Subsistence Harvest for Wiseman

Resource	Per Capita (pounds)	Total (pounds)
Caribou	40.0	520.0
Moose	166.2	2,160.0
Bear	–	–
Dall sheep	16.0	208.0
Deer	–	–
Other large land mammals	–	–
Small land mammals	1.3	17.5
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	3.9	50.6
Upland birds	20.1	261.2
Eggs	–	–
Pacific salmon	11.6	151.2
Non-salmon fish	13.2	172.2
Berries	20.4	264.8
Plants	1.0	13.0
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

Coldfoot

The community of Coldfoot is on the southern slope of the Brooks Range on the east side of the Middle Fork Koyukuk River and immediately south of the confluence of the Koyukuk and Slate Creeks. The Koyukuk River valley in the vicinity of Coldfoot is marshy and characterized by numerous meander scars. Mountains of the southern Brooks Range rise on either side of the valley to more than 1,000 feet.

Coldfoot is about 8 miles upstream and to the northeast of the point at which the Dalton Highway reaches the Koyukuk River, and about 11 miles downstream and to the south of the community of Wiseman, also along the Koyukuk River.

The community of Coldfoot was settled after a placer gold deposit was found in 1898 at the confluence of Slate and Myrtle Creeks, about 5 miles to the southeast of Coldfoot. The community was originally known as Slate Creek, but was renamed Coldfoot in 1900. Coldfoot became the center of local mining activities until a gold discovery on Nolan Creek, near the community of Wiseman, drew most of the population away. A small population continued to live in Coldfoot until 1930, when the community was abandoned.

The Coldfoot town site was sporadically occupied until the 1970s when a construction camp for TAPS and a Department of Transportation facility were built nearby. The contemporary community of Coldfoot was established when a truck stop was opened at the same location in 1981 to serve truck traffic on the Dalton Highway (Holen et al., 2012).

In 2011, the ADF&G conducted a study of the harvest and use of subsistence resources in Coldfoot (Holen et al., 2012). Investigators from the ADF&G interviewed four of the five households in the community. The findings cited below are based on this sample.

All Coldfoot households in 2011 harvested subsistence resources and all households exchanged resources with other households in the community, i.e., either giving or receiving resources (Holen et al., 2012).

The ADF&G reported that all households in the community received cash income through employment with the state and federal government or local service providers. The community of Coldfoot is strongly connected to the cash economy. Employers in the community include the federal government, state government, mining, transportation, communications and utilities, and local service providers (Holen et al., 2012).

Subsistence Use Areas

Figure 4.14.3-8 depicts the extent of the Coldfoot subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011. The community's subsistence use area is primarily in the Yukon River Region, but it extends along the Dalton Highway north past Toolik Lake. Overall, the subsistence use area follows the Dalton Highway and branches off along river corridors and mountain valleys. A continuous area of high use extends west along Wiseman Creek to the Glacier River. Coldfoot harvesters target resources in Atigun Gorge and Oolah Valleys. Additionally, subsistence resources are harvested along the North Fork Chandalar, South Fork Koyukuk, and Jim Rivers. Lands used for subsistence harvests by the residents of Coldfoot overlap geographically with the Project's construction and operational footprint (see figure 4.14.3-8).

Seasonal Round

Timing of subsistence activity data for the community of Coldfoot are limited, consisting of a single study by the ADF&G (Holen et al., 2012); therefore, a subsistence harvest calendar is not provided. Compared with other subsistence communities, the population of Coldfoot is small and the residents report working year-round, full-time jobs, which limit the timing and duration of subsistence endeavors. Therefore, Holen et al. (2012) noted that the use of subsistence resources by its residents is relatively modest.

Harvest Data

The five households contacted by the ADF&G in 2011 reported harvesting and using subsistence resources. Residents of Coldfoot reported using a relatively narrow range of resources in 2011 compared to other communities in the study. All households reported using large land mammals and berries. Twenty-five percent of Coldfoot households reported using salmon, upland game birds, and plant resources other than wood or berries (Holen et al., 2012).

Based on 2011 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community totaled 707.6 pounds, or 70.8 pounds per capita (Holen et al., 2012). The pounds per capita of general subsistence resource categories are shown below (see table 4.14.3-13). Caribou represented the most important resource. The remaining three resources were plant products, blueberries, lowbush cranberries, and Labrador tea (*Ledum* spp.) (Holen et al., 2012).

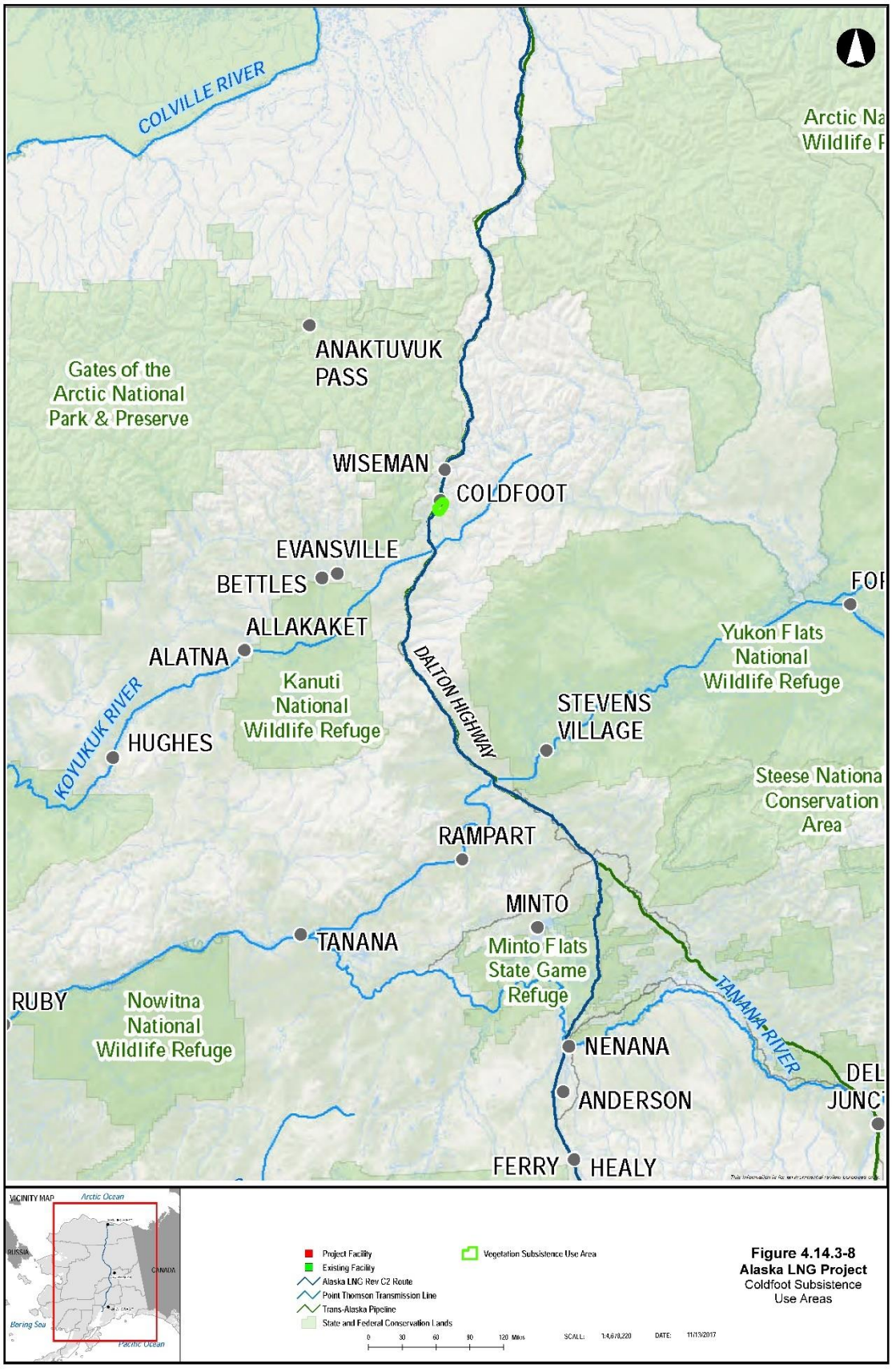


Figure 4.14.3-8
Alaska LNG Project
Coldfoot Subsistence
Use Areas

TABLE 4.14.3-13

Estimated Subsistence Harvest for Coldfoot

Resource	Per Capita (pounds)	Total (pounds)
Caribou	32.5	325.0
Moose	–	–
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	–	–
Upland birds	–	–
Eggs	–	–
Pacific salmon	–	–
Non-salmon fish	–	–
Berries	38.1	381.3
Plants	0.1	1.3
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Construction of the Mainline Pipeline where it extends through Coldfoot's subsistence use areas (including areas for Coldfoot and Wiseman combined) would occur between April of Year 1 and December of Year 5. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. The Project would overlap Coldfoot's subsistence use areas for six subsistence resources, including moose, caribou, small land mammals, berries, wood, and upland game birds. Mainline Pipeline construction could potentially disrupt subsistence resources, such as moose, caribou, and small land mammals along the Project corridor; temporarily reduce the availability of fish in streams and rivers crossed by the Project; temporarily block harvester access to hunting and harvesting areas; and remove previously used vegetation and wood harvesting areas. Impacts would not likely continue into Project operation in this already developed area along the Dalton Highway and TAPS.

Evansville

The community of Evansville is on the south bank of the Koyukuk River between the confluences of the John and Wild Rivers and immediately to the east of the community of Bettles. Evansville is about 40 air miles to the northeast of Alatna and Allakaket, 180 miles northwest of Fairbanks, and 224 air miles to the northeast of the confluence of the Koyukuk and Yukon Rivers.

The village of Evansville and Bettles are on the northern edge of the Kanuti Flats, a region of relatively low relief that encompasses the Koyukon River valley between Alatna and Bettles. The area is

characterized by numerous small lakes and meander scars of the Koyukon and Kanuti Rivers (Wahrhaftig, 1965).

When the Russians reached the upper Koyukuk River in the 19th century, the Alaska Native residents were speakers of the Koyukon Athabascan language (Holen et al., 2012; Krauss, 2011). However, cultural exchange and trade were frequent among the Athabascan-speakers living along the Koyukuk River and Iñupiaq-speakers living in the Kobuk River Drainage to the north. Intermarriage between the two groups and bilingualism were not uncommon (Holen et al., 2012).

When a mining camp was established in 1899, about 5 miles downstream from modern-day Evansville, both Athabascan and Iñupiaq-speaking people began settling there, seeking trading opportunities and employment. Mining activity in the region largely ended by the beginning of the First World War. Athabascan and Iñupiaq residents remained in the area, harvesting wild resources and trading, although some Athabascan-speakers moved to Allakaket. Residents of contemporary Evansville have ancestral ties to both groups (Holen et al., 2012).

The community of Evansville was founded after the establishment of Bettles Field by the Navy in 1945, now the site of the community of Bettles. The development of the airstrip at Bettles Field was part of the U.S. government's exploration of petroleum resources on the North Slope. The residents of Bettles were Euro-American, while the community of Evansville immediately to the east was settled by Alaska Natives (Holen et al., 2012).

The federal census of 2010 recorded 12 households at Evansville consisting of 15 individuals, 8 of whom were Alaska Natives. In 2011, the ADF&G recorded 13 households consisting of 20 individuals, 9 of whom were Alaska Natives (Holen et al., 2012).

The communities of Evansville and Bettles share a number of services, including a post office, store, and utility company; however, the original Native–non-Native divide is still present. The population of Bettles is "entirely Euro-American," while Evansville has "a recognized Alaska Native tribal government" (Holen et al., 2012).

In 2011, the ADF&G conducted a study of the harvest and use of subsistence resources in Evansville. Investigators from the ADF&G interviewed all 13 households in the community. The ADF&G reported that nine households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local service providers (49.5 percent); local government, including tribal government (31.7 percent); and state government (10.1 percent) (Holen et al., 2012).

Ethnographic research in the 1960s (Clark and Clark, 1974) suggested that the residents of Evansville had largely abandoned the use of subsistence resources in favor of participation in the cash economy.

Subsistence Use Areas

Figure 4.14.3-9 depicts the extent of the Evansville subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011 (Holen et al., 2012). Evansville use areas are all west of the Dalton Highway, with a continuous use area extending west and south as far as Alatna and Allakaket. Discontinuous use areas are further west and north in the upper reaches of the Alatna River in the Brooks Range; other areas are on the lower reach of the Alatna River as well as in Iniakuk and Wild Lakes. The Koyukuk, John, and Wild Rivers are important use areas and facilitate travel into further inland hunting areas. Evansville subsistence use areas are adjacent to the Project near where Fish Creek meets the Dalton Highway.

Seasonal Round

The number of resources hunted or harvested is relatively stable throughout the year with the greatest number harvested in August and September (see table 4.14.3-14). Spring (April through May) subsistence activities in Evansville often begin in late May, with the migration of waterfowl and setting nets for non-salmon fish. Spring also marks the end of the seasonal harvests of furbearers and upland birds.

TABLE 4.14.3-14

Evansville Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon						■	■	■				
Pacific salmon						■	■	■	■			
Caribou	■	■	■					■				■
Moose									■			
Bear								■				
Dall sheep								■	■			
Furbearers	■	■	■	■	■						■	■
Small land mammals	■	■	■	■	■	■	■	■	■	■	■	■
Upland birds	■	■	■	■					■	■	■	■
Waterfowl				■	■	■		■	■			
Plants and berries							■	■	■			

Source: Braund, 2015

The most recent data from the 2011 study year (Holen et al., 2012) indicates fishing occurs only during the summer months (June through August) with rod and reel. Harvests of waterfowl continue in the summer. Large land mammal harvests begin in the summer and continue into early fall. Summer berry harvests are particularly important to Evansville residents; blueberries are second only to moose in terms of the most used resource (Holen et al., 2012).

Fall (September through October) subsistence activities are characterized by large land mammal harvests. Moose is the most harvested and most used resource in Evansville. Caribou, bear, and Dall sheep harvests also occur during the fall as well as continuing fishing efforts. Bird harvests target upland birds as well as the fall migration of waterfowl.

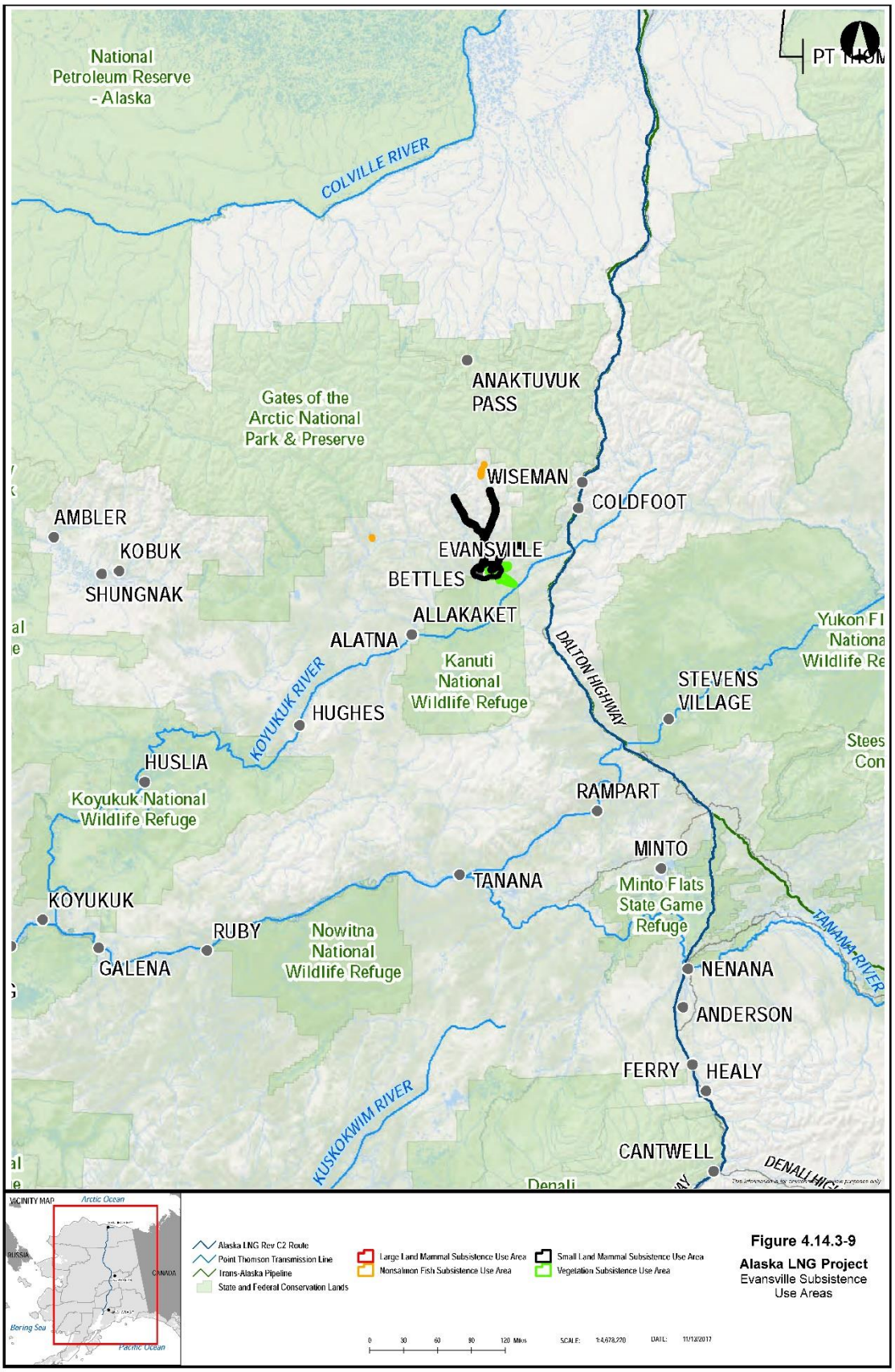


Figure 4.14.3-9
Alaska LNG Project
Evansville Subsistence Use Areas

Subsistence activities shift during the winter months (November through March) from predominantly large land mammal harvests to small game trapping and hunting. Although caribou harvests may continue through the winter months, the focus shifts to upland bird harvests that begin in the late fall and continue throughout the winter. Furbearers are most commonly taken in the wintertime when frozen waterways provide routes to trapping sites.

Harvest Data

In 2011, a wide range of subsistence resources was used by substantial percentages of Evansville residents. Ninety-two percent of the households reported using large land mammals and berries. Seventy-seven percent reported using non-salmon fish. Sixty-two percent of households reported using salmon, upland game birds, and wood. Fifteen percent reported using small land mammals and migratory birds. Eight percent reported using plant resources other than wood and berries. Marine mammals and invertebrates were used by 23 and 15 percent of households, respectively (Holen et al., 2012).

In 2011, ADF&G estimated that the total weight of subsistence resources harvested by the community totaled 1,056.4 pounds, or 52.9 pounds per capita (Holen et al., 2012). The pounds per capita of general subsistence resource categories are shown in table 4.14.3-15.

TABLE 4.14.3-15

Estimated Subsistence Harvest for Evansville

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	27.0	540.0
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	–	–
Upland birds	1.6	31.3
Eggs	–	–
Pacific salmon	7.4	147.3
Non-salmon fish	5.5	109.5
Berries	11.4	228.3
Plants	–	–
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

Moose, an important subsistence resource, represented the largest harvest of large land mammals (see table 4.14.3-15). Sockeye salmon was the most important salmon species followed by Chinook. Sheefish, followed by lake trout and rainbow trout, were the most important non-salmon fish species.

Lowbush cranberry, blueberry, and highbush cranberry (*Viburnum edule*) were the most important plant species. Spruce grouse was the most important upland game bird (Holen et al., 2012).

Impacts on Subsistence

The community of Evansville is on the Koyukuk River, downstream from the Project and west of the Mainline Pipeline. Construction of the Project along the Mainline east of Evansville use areas would occur between April of Year 1 and December of Year 5. Pipeline construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Construction could therefore cause temporary disruption of harvesting activities for caribou, moose, and small land mammals as a result of displacement. Additionally, construction activities could cause downstream effects on non-salmon fish. However, non-salmon fish use areas are distant from the Koyukuk River crossing and buried trenchless construction of the Middle Fork Koyukuk River would minimize downstream effects. Impacts during operation would be unlikely due to the distance of the community from the Project.

Bettles

The community of Bettles is on the south bank of the Koyukuk River between the confluence of the John and Wild Rivers and immediately to the west of the community of Evansville. Bettles is about 40 air miles to the northeast of Alatna and Allakaket, 180 miles northwest of Fairbanks, and 224 air miles to the northeast of the confluence of the Koyukuk and Yukon Rivers.

The villages of Evansville and Bettles are in the Kanuti Flats, a region of relatively low relief that encompasses the Koyukon River valley between Alatna and Bettles. The area is characterized by numerous small lakes and meander scars of the Koyukon and Kanuti Rivers (Wahrhaftig, 1965). Each winter, the two Alaska communities rely on an ice-road lifeline across the frozen landscape. The seasonal connection to the Dalton highway is critical to the small communities that winter in Evansville and Bettles. The ice-road is used to freight supplies and haul in an annual supply of diesel for the community from Fairbanks.

As noted above, the community of Bettles was founded by the Navy in 1945 as an airstrip named Bettles Field. The development of the airstrip was part of the U.S. government's exploration of petroleum resources on the North Slope. The communities of Bettles and Evansville share a number of services, including a post office, store, and utility company (Holen et al., 2012). Tourism is an important industry in Bettles, and the "main commercial enterprise" in the community is the Bettles Lodge.

In 2011, the ADF&G recorded eight households consisting of 12 individuals, none of whom were Alaska Natives (Holen et al., 2012). The ADF&G subsistence study collected subsistence information from the eight households in the village. The ADF&G reported that seven of the eight households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local service providers (61.6 percent), federal government (36.6 percent), and agriculture, forestry, and fishing (1.8 percent) (Holen et al., 2012).

Subsistence Use Areas

Figure 4.14.3-10 depicts the extent of the Bettles subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011 (Holen et al., 2012). Earlier studies show residents using areas near Alatna and Allakaket and along the Alatna River in the south, in mountainous areas of the Brooks Range near the John River in the north, as far east as the Dalton Highway, and along the Alatna River within the Brooks Range in the west. Use areas documented during the earlier studies overlap with those of the nearby communities of Alatna and Allakaket, and tend to correspond with major river

drainages. Use areas reported to the ADF&G encompass a much smaller area that no longer overlaps Alatna and Allakaket and includes smaller portions of the major drainages. The 2011 data also includes a new use area around Iniakuk Lake and the Iniakuk River. The Bettles subsistence use area overlaps with the Project where Fish Creek meets the Dalton Highway. The subsistence use area comes within 5 miles of the Project south of where the Koyukuk River meets the Dalton Highway.

Seasonal Round

The number of resources hunted or harvested varies little throughout the year except for peaks in the number of resources targeted in August and September (see table 4.14.3-16). Spring (April through May) marks the end of the seasonal harvests of furbearers and upland birds and turns to the spring migration of waterfowl.

TABLE 4.14.3-16

Bettles Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon						■	■	■				
Pacific salmon						■	■	■	■			
Caribou	■								■			■
Moose									■			
Bear								■	■			
Dall sheep								■	■			
Furbearers	■	■	■	■	■						■	■
Small land mammals	■	■	■	■	■	■	■	■	■	■	■	■
Upland birds	■	■	■	■					■	■	■	■
Waterfowl				■	■	■		■	■			
Plants and berries							■	■	■			

Source: Braund, 2015

During the summer (June through August), salmon and non-salmon fish harvests begin (Holen et al., 2012). Bear and Dall sheep harvests occur in late summer as well as waterfowl harvests associated with the fall migration. Harvested in late summer and early fall, berries are the most used resource in Bettles.

Fall (September through October) marks the beginning of the large land mammal harvest. Upland bird and waterfowl harvests begin again in September and berry harvests continue from summer to fall.

Subsistence activities shift during the winter months (November through March) from predominantly large land mammal harvests to small game trapping and hunting. Furbearers are most commonly taken in the wintertime when frozen waterways provide routes to trapping sites. Upland bird harvest continues throughout the winter and small land mammals are taken year-round. Occasional caribou harvests also occur during the winter season.

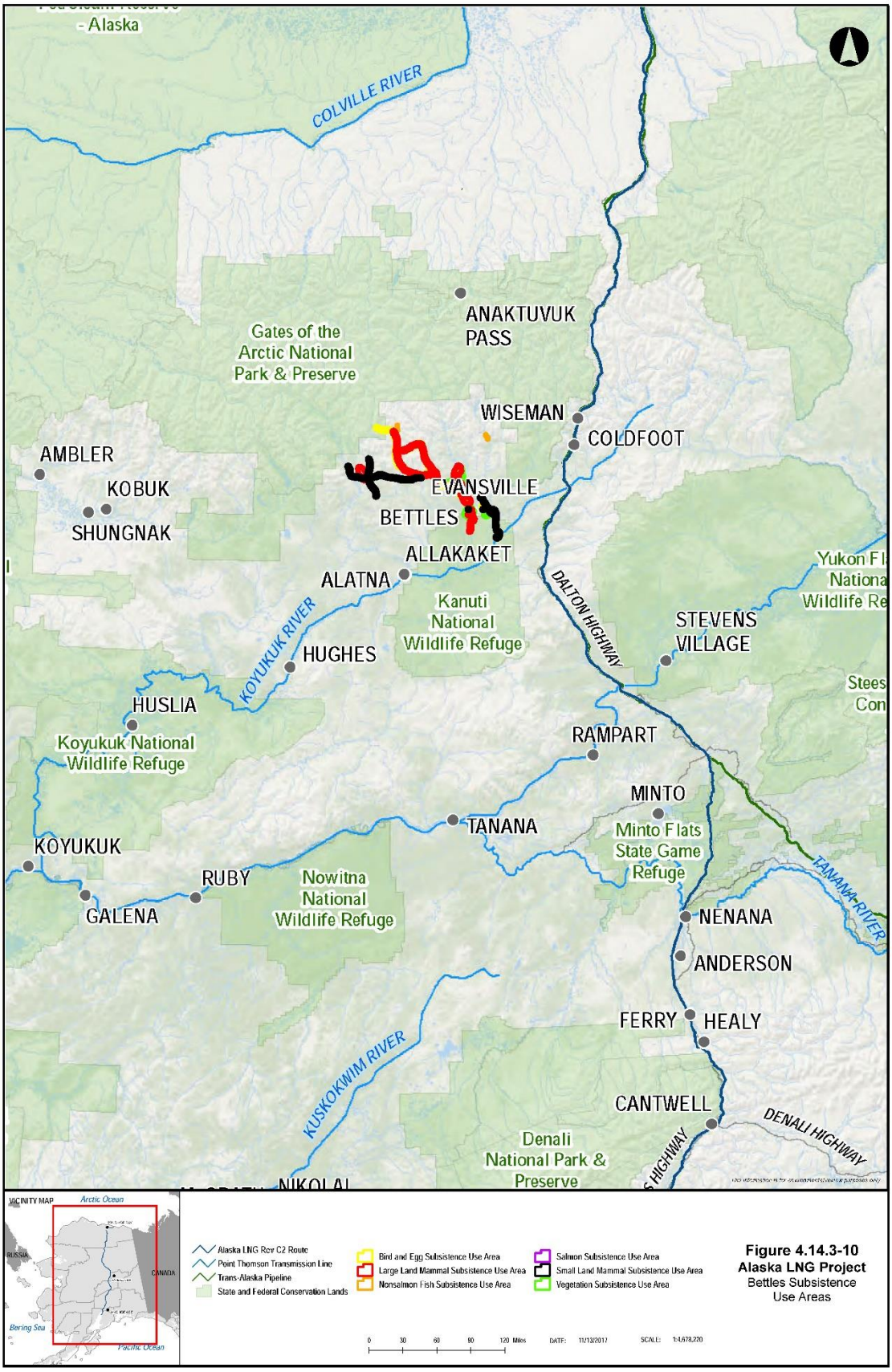


Figure 4.14.3-10
Alaska LNG Project
Bettles Subsistence Use Areas

Harvest Data

In 2011, a wide range of subsistence resources was used by Bettles residents (see table 4.14.3-17). The resource categories used by the largest percentage of households were berries (100 percent), wood (88 percent), large land mammals (88 percent), and small land mammals (63 percent). Fifty percent of households in Bettles used non-salmon fish, and 38 percent used salmon. Use of migratory birds and upland game birds were reported by 13 and 38 percent of households, respectively. Thirty-eight percent of households used plant resources other than wood and berries. None of the households in the community made use of marine mammals or marine invertebrates (Holen et al., 2012).

TABLE 4.14.3-17

Estimated Subsistence Harvest for Bettles

Resource	Per Capita (pounds)	Total (pounds)
Caribou	65.0	780.0
Moose	90.0	1080.0
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	0.3	3.6
Upland birds	2.1	25.2
Eggs	–	–
Pacific salmon	4.2	50.8
Non-salmon fish	7.8	93.4
Berries	5.1	61.1
Plants	0.8	9.5
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

Based on 2011 survey data, the total harvest weight of subsistence resources harvested by the community totaled 2,103.6 pounds, or 175.3 pounds per capita (Holen et al., 2012). Moose represented the largest harvest of large land mammals, followed by caribou. Chum salmon was the most important salmon species. Northern pike, followed by lake trout and arctic grayling, were the most important non-salmon fish species. Blueberry and lowbush cranberry were the most important plant species. Ptarmigan was the most important upland game bird, followed by spruce grouse (Holen et al., 2012).

Impacts on Subsistence

The Project would overlap Bettles subsistence use areas for berries in a limited area of community use. The use area for wood is within 2 miles of the Project. Construction of the Mainline Pipeline east of Bettles would occur between April of Year 1 and December of Year 5. Construction at any single point

would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Construction could therefore cause temporary disruption of harvesting activities for caribou, moose, and small land mammals as a result of displacement. Additionally, construction activities could cause downstream effects on non-salmon fish. However, non-salmon fish use areas are distant from the Koyukuk River crossing, and buried trenchless construction of the Middle Fork Koyukuk River would minimize downstream effects. Impacts during operation would be unlikely due to the distance of the community from the Project.

Alatna

The village of Alatna is on the north bank of the upper Koyukuk River about 2.5 air miles (3.5 river miles) below its confluence with the Alatna River. The Koyukon River extends southwestward from its headwaters in the Brooks Range to its confluence with the Yukon River about 300 miles downstream. A short distance to the east of Alatna, and on the south bank of the upper Koyukuk River, is the village of Allakaket. The two communities share an airport and school, which are in Allakaket, resulting in daily interactions between residents of the two communities. Subsistence resource use for Allakaket is summarized in the following section.

The village of Alatna is in the Kanuti Flats, a region of relatively low relief that encompasses the Koyukon River valley between Alatna and Bettles. The area is characterized by numerous small lakes and meander scars of the Koyukon and Kanuti Rivers (Wahrhaftig, 1965).

The Alaska Native residents of Alatna have cultural and ancestral ties to the Iñupiaq-speaking peoples living in the Kobuk River Drainage and Kotzebue Sound region. Across the river, the Alaska Native residents of Allakaket predominantly trace their ancestry to Athabascan-speaking peoples living along the upper Koyukon River. The villages of Alatna and Allakaket were both founded in 1906 with the establishment of an Episcopal mission at the confluence of the Alatna and upper Koyukon. However, the two villages represent a joint Iñupiaq and Athabascan occupation of the region that extends centuries and possibly millennia into the past (Holen et al., 2012).

The use of subsistence resources plays an important role in Alatna's local economy. In 2011, the ADF&G conducted a study of the harvest and use of subsistence resources in Alatna. Investigators interviewed six of the nine households in Alatna (Holen et al., 2012), all of whom reported harvesting subsistence resources. The ADF&G reported that nine households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local government, including tribal government (95.3 percent); federal government (3.9 percent); and other employers (0.8 percent) (Holen et al., 2012).

Subsistence Use Areas

Figure 4.14.3-11 depicts the extent of the Alatna subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011 (Holen et al., 2012). Earlier studies documented subsistence use areas along the Alatna River north to the Brooks Range, west as far as Norutak Lake, south along the Kanuti River, and beyond Bettles and Evansville in the east on the South Fork Koyukuk River. The 2011 study by ADF&G documented that Alatna residents' use areas were concentrated along major river systems closer to the community.

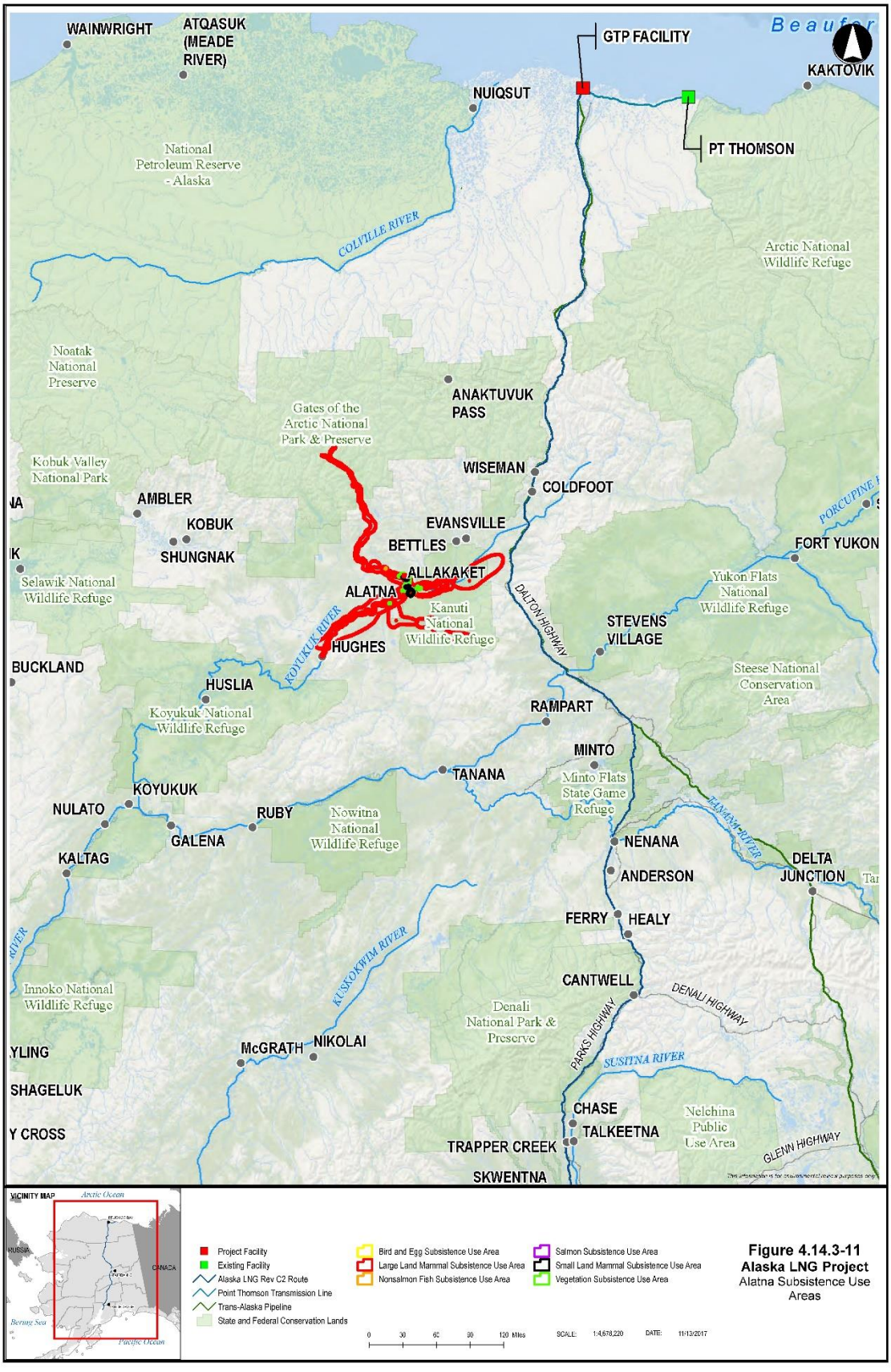


Figure 4.14.3-11
Alaska LNG Project
Alatna Subsistence Use Areas

Current subsistence use by residents of Alatna are largely focused on the lower Alatna and upper Koyukon River Drainages. Harvest areas for small land mammals, migratory birds, and berries are along the lower Alatna between Budzoc Slough and the confluence of the Alatna and Koyukon Rivers, and in the flood plain of the upper Koyukon River immediately south of Allakaket. Harvest areas for large land mammals covered a much larger area, encompassing much of the Alatna River valley, the lower Kanuti River valley, and the upper Koyukon River valley from slightly above the confluence of the South Fork of the Koyukon River and the main stem downstream to the approximate vicinity of the village of Hughes. The harvest of salmon occurred in the Koyukon River close to the village of Alatna (Holen et al., 2012). The subsistence use area does not overlap with the Project, but is within 5 miles of the Project between the South Fork Koyukuk River and the Dalton Highway.

Seasonal Round

The harvest of subsistence resources by Alatna residents follows a cyclical seasonal pattern (see table 4.14.3-18). Harvest activities during the spring include setting gillnets for a variety of species including whitefish, longnose suckers, and northern pike. These activities take place in the Koyukuk as the ice leaves the river and tributary streams. Black bears and waterfowl are also taken at this time of year.

TABLE 4.14.3-18

Alatna Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon							■	■	■	■	■	
Pacific salmon						■	■	■	■			
Caribou									■		■	■
Moose									■			
Bear					■		■					
Dall sheep								■	■			
Furbearers	■	■	■	■	■				■	■	■	■
Small land mammals	■	■	■	■	■	■	■	■	■	■	■	■
Upland birds	■	■	■	■					■	■	■	■
Waterfowl				■	■	■		■	■			
Plants and berries							■	■	■			
Wood	■	■	■						■	■	■	■

Source: Braund, 2015

During the summer, some families move to fish camps to harvest salmon. Alatna sees runs of both chum and Chinook salmon. Sockeye salmon do not run in the upper Koyukuk, although in 2011, some Alatna residents obtained Chinook by traveling to other locations. Berries are harvested during the late summer, with berry picking often occurring while people are at their fish camps. A variety of non-salmon fish is harvested during the summer as well.

With the arrival of fall, attention turns to the hunting of large mammals, including moose, caribou, and black bear. Caribou are typically harvested in August, November, and December. Moose are harvested in September, and black bear are harvested in May and August. Some berry picking extends into the fall season and often occurs during hunting activities. Whitefish continue to be netted during the fall, and arctic

grayling are taken using rod and reel or by ice fishing after rivers freeze. Sheefish are harvested by net under the ice.

Moose are typically the most important large mammal harvested by Alatna residents. Caribou, when present in the immediate vicinity of the village, may result in more caribou harvested than moose.

The hunting of large mammals continues into the winter. Most of the small mammals trapped by Alatna residents are also obtained at this time. Burbot are harvested using traps set under the ice.

Harvest Data

All six households contacted by the ADF&G in 2011 reported harvesting and using subsistence resources. In 2011, a wide range of subsistence resources was used by substantial percentages of Alatna residents (see table 4.14.3-19). All Alatna households reported using large land mammals, migratory birds, upland game birds, berries, and wood. Fifty percent or more of households reported using salmon and non-salmon fish and small land mammals. In addition, all Alatna households reported using marine mammals, all of which were received from friends and relatives in other communities.

TABLE 4.14.3-19

Estimated Subsistence Harvest for Alatna

Resource	Per Capita (pounds)	Total (pounds)
Caribou	117.6	3,705.0
Moose	51.4	1,620.0
Bear	23.8	750.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	10.1	319.5
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	16.8	538.3
Upland birds	1.0	32.4
Eggs	–	–
Pacific salmon	27.3	860.7
Non-salmon fish	21.5	675.8
Berries	3.6	115.9
Plants	<0.1	0.3
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

In 2011, the total harvest weight of subsistence resources harvested by the community totaled 8,617.9 pounds, or 273.2 pounds per capita. Caribou represented the largest harvest of large land mammals, followed by moose and black bear. Chum salmon was the most important salmon species, while humpback whitefish, followed by sheefish, were the most important non-salmon fish species. American beaver

accounted for the most pounds per capita among small land animals. Greater white-fronted goose was the most important migratory bird, while the most important plant resource was highbush cranberry.

Impacts on Subsistence

Alatna is on the Koyukuk River downriver from its union with the Alatna River, and just over 50 miles west of the Mainline Pipeline. The Project does not overlap with Alatna subsistence use areas; however, caribou harvest areas are within 2 miles of the Mainline Pipeline. Construction of the Mainline Pipeline east of Alatna's use areas would occur between April of Year 1 and December of Year 5. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Construction is anticipated to have a limited effect on resource availability as a result of displacement of resources and habitat loss. Increased cost and effort to harvest these resources is not anticipated during construction or operation because the Project is on the periphery of the subsistence use area with limited use by harvesters.

Potential impacts on Alatna subsistence uses could occur during construction by temporarily displacing migratory mammals, including moose and caribou, traveling through the Project into community use areas, or by causing downstream effects on non-salmon fish in the Koyukuk River or other streams not crossed by the Project. Downstream effects would be unlikely because of the substantial distance of community non-salmon fish use areas from the Koyukuk River crossing, and because the crossing would be constructed using the DMT method. Impacts during operation would be unlikely due to the distance of the use area from the Project.

Allakaket

The village of Allakaket is on the south bank of the upper Koyukuk River less than 1 river mile below its confluence with the Alatna River near the community of Alatna. The physiographic and cultural setting of Allakaket is discussed in the section above on Alatna.

The use of subsistence resources plays an important role in the local economy of Allakaket. In 2011, the ADF&G conducted a study of the harvest and use of subsistence resources in the community. Investigators interviewed 42 of the 57 households in Allakaket (Holen et al., 2012). Most of the households surveyed by the ADF&G (92.9 percent) reported harvesting subsistence resources. The ADF&G reported that 48 households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local government (65.1 percent), local service providers (10.5 percent), and federal government (10.1 percent) (Holen et al., 2012).

Subsistence Use Areas

Figure 4.14.3-12 depicts the extent of the Allakaket subsistence use areas. These areas encompass the subsistence use area reported by the ADF&G for 2011 (Holen et al., 2012). Earlier studies document the subsistence use area extending north along the Alatna River into the Brooks Range, west to Norutak Lake, south along the Kanuti River, and east of Bettles and Evansville on the South Fork Koyukuk River. In 2011, Allakaket residents used a similarly large use area; however, the residents used a more expansive area to the south along the Koyukuk River past its confluence with the Indian River. Allakaket residents did not use areas near Norutak Lake or near the headwaters of the Alatna River in the Brooks Range in the most recent study. Allakaket's subsistence use area does not overlap with the Project, but is within 5 miles of the Project between the South Fork Koyukuk River and the Dalton Highway.

Seasonal Round

In Allakaket, spring (April through May) marks the beginning of non-salmon fishing as residents set nets in the Koyukuk River (see table 4.14.3-20). Migratory waterfowl is another subsistence resource for residents at this time. The harvest of upland birds and furbearers ends in spring.

TABLE 4.14.3-20

Allakaket Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon					■	■	■	■	■	■	■	
Pacific salmon						■	■	■	■			
Caribou		■	■					■		■	■	■
Moose		■	■					■	■			
Bear							■	■	■	■	■	
Dall sheep							■	■				
Furbearers	■	■	■	■	■						■	■
Small land mammals	■	■	■	■	■	■	■	■	■	■	■	■
Upland birds	■	■	■	■					■	■	■	■
Waterfowl				■	■	■		■	■			
Plants and berries							■	■				
Wood	■	■	■						■	■	■	■

Source: Braund, 2015

Harvests of chum and Chinook salmon and non-salmon fish harvests occur throughout the summer (June through August) and as long as the waterways are clear of ice (Holen et al., 2012). During the summer, Allakaket residents begin to hunt bear, Dall sheep, and other large land mammals, an activity that extends into the fall. In late summer, migratory waterfowl are harvested as they move south through the area. Plants and berries are important summer resources for Allakaket residents.

Residents harvest large land mammal resources in the fall (September through October). Caribou and moose harvests provide the most meat per capita for Allakaket residents. The bulk of the moose harvests occur in September. Black bear also make up a substantial portion of the total large land mammal harvest weight, with harvests primarily occurring in September and October. Waterfowl provide an additional subsistence resource as they migrate through the area, with upland bird harvests beginning in fall.

Winter (November through March) is a particularly important time for harvesting caribou. Moose and upland bird harvests may also continue into the winter months. Hunting and trapping of furbearers occurs in winter and into spring. Small land mammal harvests occur throughout the year, but the majority of the harvest occurs in the winter. Wood collection for heating homes throughout the winter begins in the fall and continues through the winter months.

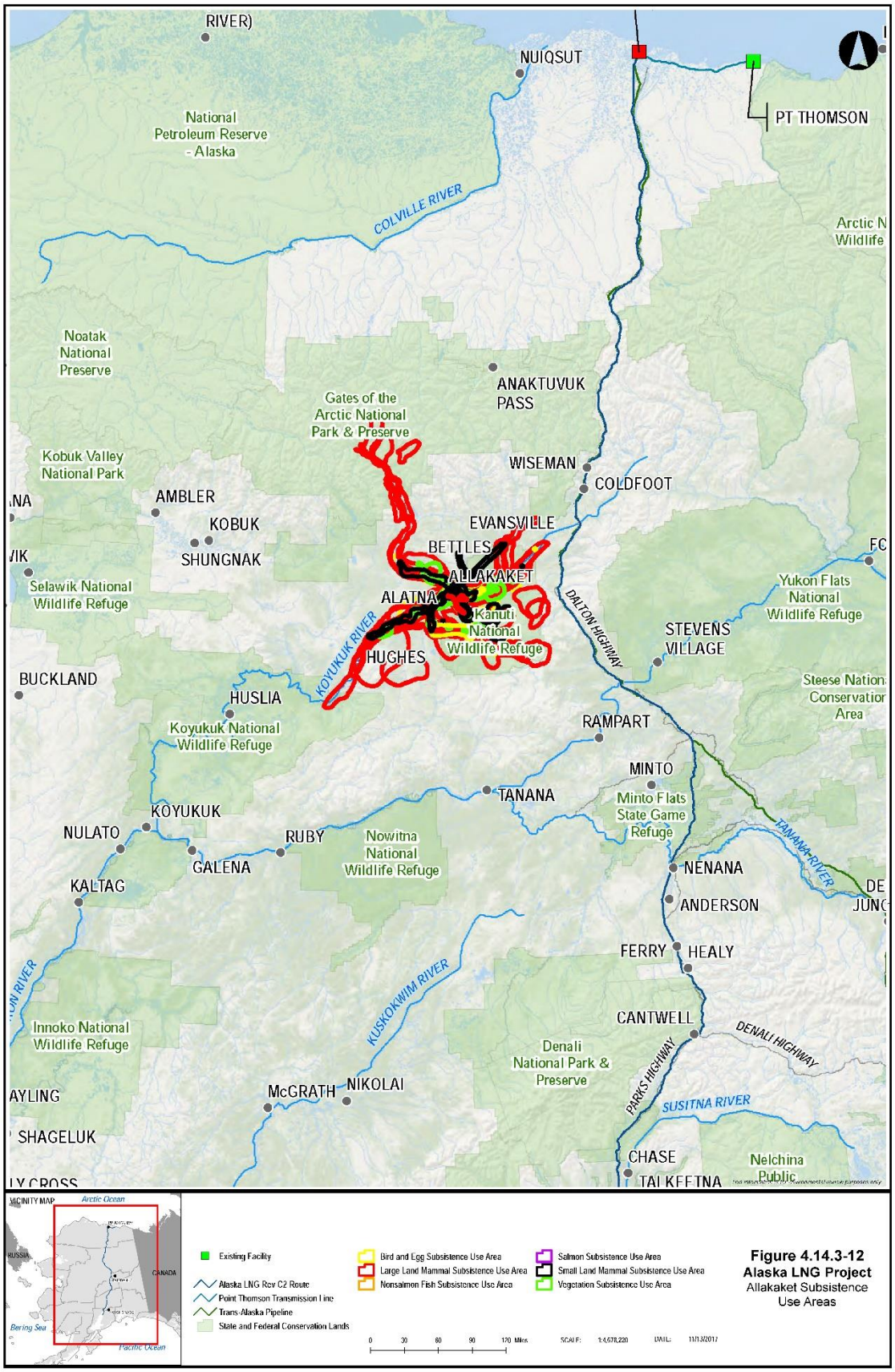


Figure 4.14.3-12
Alaska LNG Project
Allakaket Subsistence Use Areas

Harvest Data

The ADF&G estimated that most households in 2011 (92.9 percent) harvested subsistence resources, while all households reported using subsistence resources. In 2011, a wide range of subsistence resources was used by a substantial percentage of Allakaket residents. More than 75 percent of Allakaket households reported using non-salmon fish, large land mammals, berries, and wood. More than 50 percent of households reported using salmon, small land mammals, and migratory birds. Smaller percentages made use of upland game birds and plant resources other than wood and berries. In addition, 55 percent of Allakaket households reported using marine mammals, and 2 percent reported using marine invertebrates, all of which were received from friends and relatives in other communities.

The total weight of subsistence resources harvested by the community totaled 76,261.4 pounds, or 520.3 pounds per capita. Measured in pounds per capita, caribou represented the largest harvest of large land mammals, followed by moose and black bear. Chum salmon was the most important salmon species, followed by Chinook and coho salmon. Sheefish, humpback whitefish, northern pike, and broad whitefish were the most important non-salmon fish species (see table 4.14.3-21).

TABLE 4.14.3-21

Estimated Subsistence Harvest for Allakaket

Resource	Per Capita (pounds)	Total (pounds)
Caribou	84.3	12,350.0
Moose	65.0	9,527.1
Bear	13.3	1,955.7
Dall sheep	2.9	423.4
Deer	–	–
Other large land mammals	–	–
Small land mammals	9.4	1,371.4
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	11.6	1,698.1
Upland birds	1.4	205.5
Eggs	–	–
Pacific salmon	151.8	22,254.0
Non-salmon fish	174.7	25,603.8
Berries	5.9	860.1
Plants	0.1	12.3
Wood	–	–
Other	–	–

Source: Holen et al., 2012
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Allakaket is about 50 miles west of the Project. Allakaket is a federally designated rural community. The Project overlaps Allakaket subsistence use areas for Dall sheep, a resource harvested in lower quantities than other larger terrestrial mammals. Additionally, the Project would come within 2 miles

of subsistence use areas for moose and caribou, both of which are important for the amount of pounds in edible weight they provide. Construction of the Mainline Pipeline east of Allakaket's use areas would occur between April of Year 1 and December of Year 5. Construction at any single point would last about 6 to 12 weeks or longer, depending on the rate of progress, weather, terrain, and other factors. Construction is anticipated to have a limited effect on resource availability as a result of displacement of resources and habitat loss. Increased cost and effort to harvest resources is not anticipated during construction or operation because the Project is on the periphery of the subsistence use area with limited use by harvesters.

Potential impacts on Alatna subsistence uses could occur during construction by temporarily displacing migratory mammals, including moose and caribou, traveling through the Project into community use areas, or by causing downstream effects on non-salmon fish in the Koyukuk River or other streams not crossed by the Project. Downstream effects would be unlikely because of the substantial distance of community non-salmon fish use areas from the Koyukuk River crossing, and because the crossing would be constructed using the DMT method. Impacts during operation would be unlikely due to the distance of the use areas from the Project.

Stevens Village

The community of Stevens Village is on the north bank of the Yukon River, about 5 air miles to the southwest of the community of Beaver, 46 air miles to the northeast of the community of Rampart, and 20 air miles to the northeast of the Dalton Highway bridge across the Yukon River.

Stevens Village is at the western end of the Yukon Flats, near the eastern end of the Rampart Trough. The Yukon Flats designates a large region consisting of riverine sediments and outwash fans that encompasses the northernmost bend of the Yukon River. In the vicinity of Stevens Village, the Yukon River follows a braided course, and the surrounding region is dotted with small lakes and cut by meander scars (Wahrhaftig, 1965).

The community of Stevens Village was founded by Koyukon Athabascans who occupied the area prior to Euro-American settlement. In 1898, the U.S. Coast and Geodetic Survey recorded the presence of a village, designated Shamansville, near the location of the present-day community. The current name of the village dates to 1902 and recognizes a local chief; however, the community was also referred to as Shamans or Shaman Village (Brown et al., 2016).

A school was opened in the community in the early 1900s, and a post office and scheduled air service were established in the 1930s. A tribal government was formed by village residents following the Indian Reorganization of 1934. In the 1960s, the village protested and ultimately stopped the Rampart Dam Project. The project proposed the construction of a dam on the Yukon River downstream in the Rampart Canyon, creating a large impoundment that would have inundated wildlife habitat important to the village economy. At the present time, the community offers few services. There are no stores in Stevens Village and the school is currently closed (Brown et al., 2016).

In 2015, the ADF&G conducted a study of the harvest and use of subsistence resources in 2014 by Stevens Village residents (Brown et al., 2016). The ADF&G estimated that the 2014 population of Stevens Village consisted of 10 individuals, all of whom were Alaska Natives, living in four households (Brown et al., 2016). Investigators from the ADF&G interviewed all four households in the community. All of the households surveyed by the ADF&G in 2015 reported using subsistence resources, while 75 percent reported harvesting resources. Most households reported exchanging resources with other households in the community, receiving resources (100 percent), or giving resources to others (50 percent) (Brown et al., 2016).

Because the small sample size raised concerns about confidentiality, the ADF&G did not report employment statistics (Brown et al., 2016).

Subsistence Use Areas

The Stevens Village subsistence use area occurs along the Yukon River between its confluence with the Big Salt River and the community of Beaver, and extends over land generally north of the village and east of the Dalton Highway. The Stevens Village subsistence use areas overlap with the Project in two locations along the Dalton Highway west and northwest of the community (see figure 4.14.3-13).

Seasonal Round

Spring (April through May) subsistence harvests include American marten, fox, waterfowl, American beaver, muskrat (*Ondatra zibethicus*), ducks, geese, and whitefish (see table 4.14.3-22). North American porcupine and ptarmigan hunting may also occur during April and May.

TABLE 4.14.3-22

Stevens Village Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Moose												
Bear												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Plants and berries												
Wood												

Source: Braund, 2015

After the ice breaks up on the Yukon River, subsistence activities shift to the local watersheds during the summer months (June through August). Stevens Village residents participate in a salmon harvest from mid-summer to early fall, beginning with Chinook salmon in the months of June and July and ending with harvests of chum and coho salmon in September and October. Non-salmon fish (e.g., whitefish, sheefish, northern pike, and burbot) are harvested throughout the summer and into early winter (October through November). Harvest of bear and small game often occurs at fish camps. Berries are also a focus of residents' summer harvests.

During the fall (September through October) in Stevens Village, subsistence activities shift to terrestrial resources, including moose. Non-salmon fish continue to be netted in the ice-free streams. Fall harvests also include migratory waterfowl as well as upland birds.

With colder temperatures and less light during the winter season (November through March), residents engage in fewer subsistence activities than in the summer and fall months. Winter subsistence activities focus on furbearer harvests (particularly hare, Canadian lynx, and American mink) as well as some non-salmon fish in early winter. Harvesting of firewood is a regular activity year-round.

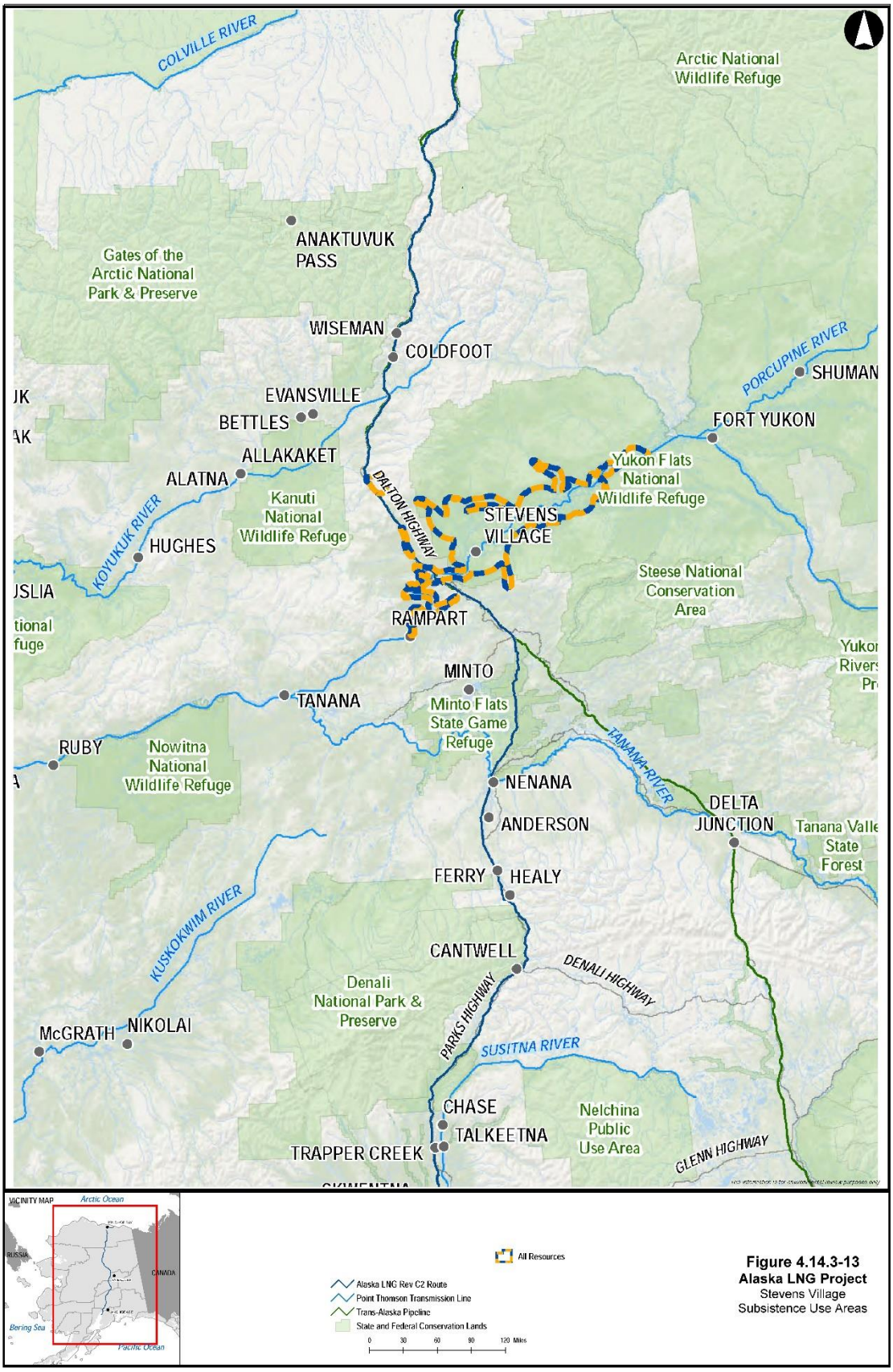


Figure 4.14.3-13
Alaska LNG Project
Stevens Village
Subsistence Use Areas

Harvest Data

Stevens Village households reported using a wide range of resources in 2014. Half of the households interviewed by the ADF&G reported the use of salmon and non-salmon fish. Three-quarters of households made use of large and small land mammals, birds and eggs, and vegetation. One quarter reported the use of marine mammals.

The ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2014 totaled 3,748.3 pounds, or 374.9 pounds per capita (Brown et al., 2016). The category of subsistence resource receiving the greatest use was salmon (307.3 pounds per capita), followed by non-salmon fish (46.0 pounds per capita). Far less use was made of small land mammals (13.3 pounds per capita), birds and eggs (4.5 pounds per capita), and vegetation (3.8 pounds per capita) (see table 4.14.3-23).

The most important subsistence resource was chum salmon, which was harvested in far greater quantities (269.9 pounds per capita) than other resources. The next most important resources were harvested in quantities ranging between slightly more than 10 pounds per capita to slightly more than 30 pounds per capita, including humpback whitefish, sheefish, and Chinook salmon. Six resources were harvested at levels below 10 pounds per capita, including American beaver, muskrat, cackling goose (*Branta* spp.), northern pike, snowshoe hare, and blueberry.

Table 4.14.3-23

Estimated Subsistence Harvest for Stevens Village

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	–	–
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	13.3	132.5
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	4.2	41.6
Upland birds	0.4	3.5
Eggs	–	–
Salmon	307.3	3,073.1
Non-salmon fish	46.0	459.6
Berries	2.0	20.0
Plants	1.8	18.0
Wood	–	–
Other	–	–

Source: Brown et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Stevens Village is on the Yukon River, about 20 miles upstream from the Project. Construction of the Mainline Facilities would occur in the subsistence use areas of the village between April of Year 1 and June of Year 7. Pipeline construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Blasting would occur within 0.5 mile of Stevens Village's subsistence use areas. Construction of the Mainline Pipeline would overlap with nine resource use areas. In terms of edible weight, five resources (moose, birds, salmon, berries, and wood) are of high importance, two (small land mammals and non-salmon fish) are of moderate importance, and two are of low importance (furbearers and bear). Construction would temporarily affect access to and availability of these resources as a result of habitat loss, increased traffic and wildlife vehicle collisions, increased competition along access roads, and additional cost and effort to harvest resources. Limited impacts would extend into Project operation as a result of permanent habitat conversion in berry harvesting areas and impeded access to use areas due to restrictions on crossing locations for the permanent right-of-way.

Mainline Pipeline construction in the Stevens Village use areas that are crossed by the Project or in areas downstream from the community would occur between April of Year 1 and December of Year 5 and would be concurrent with spring waterfowl hunting, summer salmon and non-salmon fish harvesting, summer bear hunting, and fall moose hunting, as well as plants, berries, and wood harvesting. Construction could result in the temporary displacement of several terrestrial resources, including moose, disturb habitat through the removal of vegetation in harvest areas, and limit harvesters from accessing these use areas. Although Mainline Pipeline construction would occur during the upstream salmon migration in the Yukon River and non-salmon fish harvests, impacts on fish habitat and migration would be minimized because the river would be installed using the DMT method. Downstream contamination from an inadvertent release of drilling mud into the River would be localized as clean up measures would be implemented to minimize downstream impacts on fish resources.

Rampart

The community of Rampart is on the south bank of the Yukon River about 60 air miles to the northeast of Tanana, 46 air miles to the southwest of Stevens Village, and 85 miles to the northwest of Fairbanks. In the vicinity of Rampart, the Yukon River follows a broad depression passing through a low mountain range known as the Rampart Trough. Rolling hills between about 500 and 1,000 feet in elevation occur within the trough and around Rampart (Brown et al., 2016; Wahrhaftig, 1965).

The Euro-American settlement of Rampart was motivated by gold discoveries on Little Minook Creek, about 3.5 miles to the southeast of the modern community, in 1893 or 1894. The arrival of Euro-Americans was long predated by Koyukon Athabascans, who were settled in numerous locations around present-day Rampart (Brown et al., 2016).

Rampart was originally named Minook City in recognition of the Alaska Native who made the initial gold discovery in the region. In 1897, the community's name was changed to Rampart. The community grew quickly during the remainder of the 19th century as miners moved into the area. During this period of rapid growth, the community was home to Wyatt Earp and the American novelist Rex Beach (Brown et al., 2016)

A smallpox epidemic in 1900 caused the deaths of many Alaska Natives, and new gold discoveries soon drew many of the miners away. Nonetheless, the community continued to develop during the first half of the 20th century. The community was connected to telegraph lines in 1901 and an airstrip was built

in 1939. Gold mining in the area continued, and the local economy was further supported by a sawmill and salmon cannery (Brown et al., 2016).

In the 1990s, the population of Rampart saw a decline that led to the closing of the community's school. Some of this decrease appears to be the result of residents looking for winter employment outside the community. Although the school has since reopened, economic conditions in the community remain depressed. The community supports some facilities, including a tribal office, clinic, and landfill. However, residents must travel to other communities for shopping (Brown et al., 2016).

In 2015, the ADF&G conducted a study of the harvest and use of subsistence resources harvested in 2014 by Rampart residents (Brown et al., 2016). The ADF&G estimated that the 2014 population of Rampart consisted of 39 individuals, all of whom were Alaska Natives living in 13 households (Brown et al., 2016). Investigators from the ADF&G interviewed all 13 households in the community in 2015. One hundred percent of the households surveyed reported using subsistence resources, while 86 percent reported harvesting resources. Most households reported exchanging resources with other households in the community; i.e., receiving resources (100 percent) or giving resources to others (86 percent).

The ADF&G reported that all households in the community received cash income through employment. All the income earned by community members was provided through employment by local, including tribal, government.

Subsistence Use Areas

The Rampart subsistence use area is centered on the community and extends west along the Yukon River, south to the Elliot Highway, and intersects the Dalton Highway where it crosses the Yukon River. The Rampart subsistence use areas overlap with the Project in two locations: first, near where the Dalton Highway crosses the Yukon River; and second, about 10 miles to the south of the Yukon River (see figure 4.14.3-14).

Seasonal Round

Fishing begins in spring (April through May) when nets are set below the ice (see table 4.14.3-24). Residents also jig through holes in the ice for non-salmon fish. Occasionally, moose, caribou, and black bear are harvested in the spring, while small land mammals (e.g., hare and muskrat), game birds, waterfowl, and multiple types of non-salmon fish are the predominant species harvested during the spring.

The summer months (June through August) are focused on the upriver migration of salmon, one of the most important subsistence resources to the community. Beginning in June, Chinook salmon are harvested, followed by chum salmon, and finally coho salmon. Whitefish harvests continue throughout the salmon runs. Berry and plant harvests are also important gathering activities conducted in mid-summer and into fall.

Chum and coho salmon harvests continue into the fall (September through October). The harvest of large land mammals, including moose, black bear, and caribou, also occur during the fall. Small land mammals, including North American porcupine and hare, may be taken when available. Firewood is an important resource throughout the cold months of the year and is actively collected in the fall and into the winter months.

The winter months (November through March) are focused on harvesting furbearers and small land mammals. Moose harvests may occur in winter if meat is needed. Hibernating black bear may also be harvested during the winter. Arctic grayling are the only fish taken during the late winter month of March.

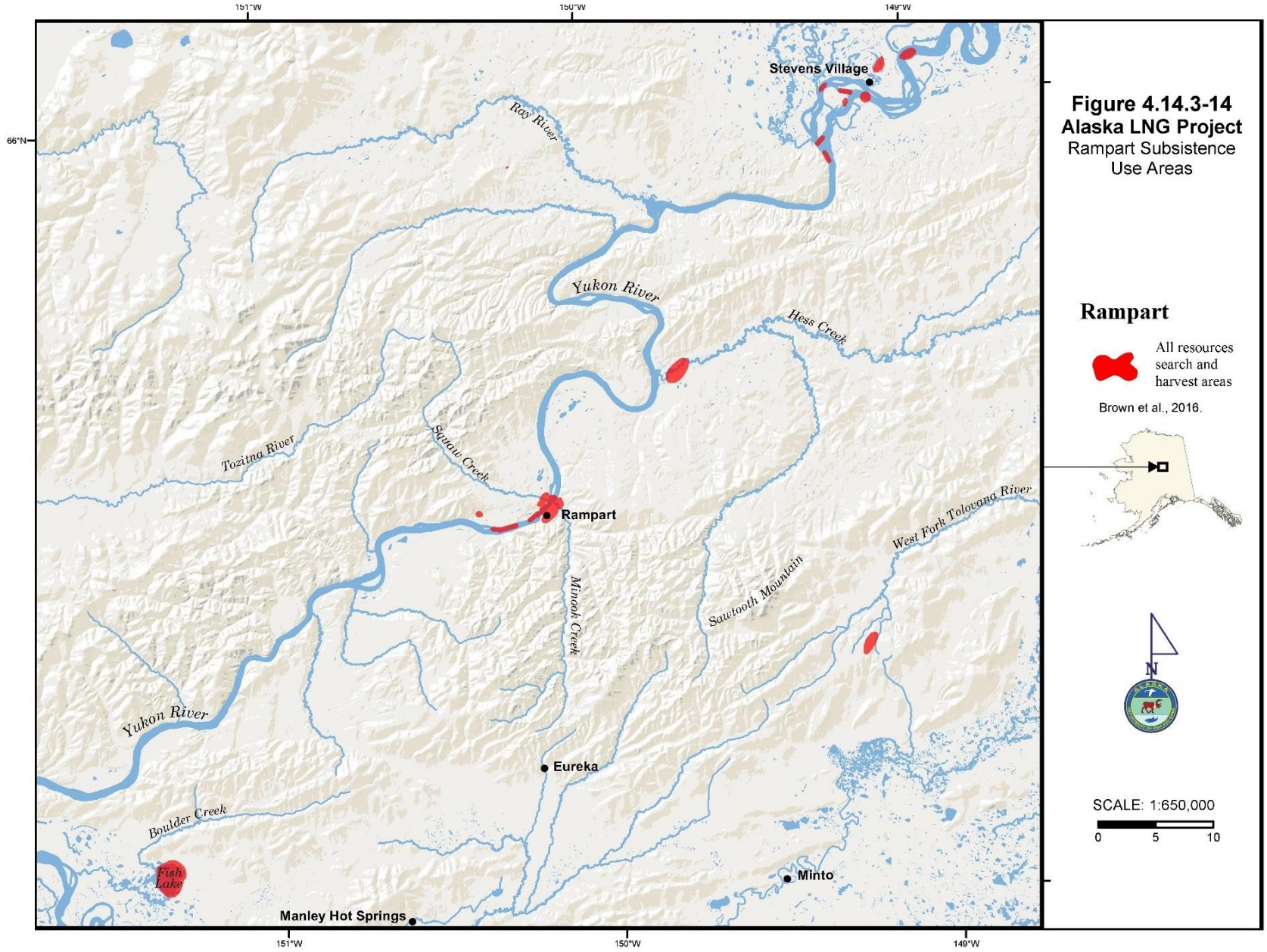

151°W
150°W
149°W
66°N
Stevens Village
Rosy River
Yukon River
Hess Creek
Tozitna River
Squaw Creek
Rampart
West Fork Tolovana River
Minook Creek
Sawtooth Mountain
Yukon River
Eureka
Boulder Creek
Fish Lake
Manley Hot Springs
Minto
Figure 4.14.3-14
Alaska LNG Project
Rampart Subsistence Use Areas
Rampart
All resources search and harvest areas
Brown et al., 2016.
N
SCALE: 1:650,000
0
5
10

TABLE 4.14.3-24

Rampart Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Caribou												
Moose												
Bear												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Plants and berries												
Wood												

Source: Braund, 2015

Harvest Data

Rampart households reported using a wide range of resources in 2014. All the households interviewed by the ADF&G reported the use of salmon, non-salmon fish, and vegetation. Large land mammals were used by 85.7 percent of households, and 57.1 percent of households made use of small land mammals, birds and eggs, and marine mammals.

Based on 2015 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2014 totaled 14,754.0 pounds, or 378.4 pounds per capita (Brown et al., 2016). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (230.6 pounds per capita), followed by large land mammals (102.9 pounds per capita), and non-salmon fish (31.3 pounds per capita). Far less use was made of small land mammals, birds and eggs, and vegetation. The per capita harvest weight for each of these three categories was below 10 pounds.

The most important subsistence resources were fall chum and coho salmon. The three most important resources—fall chum salmon, coho salmon, and moose—were harvested in quantities measuring over 100 pounds per capita (see table 4.14.3-25). Humpback whitefish, burbot, broad whitefish, sheefish, greater white-fronted goose, American beaver, and arctic grayling were harvested at far lower levels, with only one, humpback whitefish, reaching more than 10 pounds per capita (Brown et al., 2016).

Impacts on Subsistence

Rampart is on the Yukon River about 30 miles downstream from the Project. The eastern limits of Rampart's subsistence use area is crossed by the project at the Yukon River crossing. Potential impacts on Rampart subsistence would occur during Mainline Pipeline construction, which would temporarily impact the availability of resources as a result of displacement of moose or migratory birds; increased traffic and wildlife vehicle collisions; a temporary reduction in access to harvesters traveling upstream along the Yukon River; possible downstream effects on salmon and other non-salmon fish; and permanent habitat conversion of berry harvesting areas and wood harvesting areas. Limited impacts would extend into Project

operation as a result of permanent habitat conversion in berry harvesting areas resulting in more effort to harvest berries from other patches.

TABLE 4.14.3-25

Estimated Subsistence Harvest for Rampart

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	102.9	4,011.4
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	4.3	169.0
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	7.7	299.2
Upland birds	0.9	36.4
Eggs	–	–
Pacific salmon	230.6	8,991.5
Non-salmon fish	31.3	1,220.5
Berries	0.6	22.3
Plants	0.1	3.7
Wood	–	–
Other	–	–

Source: Brown et al., 2016
"–" = No harvest for this resource was reported.

Construction of the Project where it crosses the Yukon River would likely overlap with moose, migratory bird, and berry harvesting. Construction could result in the temporary displacement of terrestrial resources, including moose, and disturb habitat through the removal of vegetation in harvest areas. Although Mainline Pipeline construction would occur during the upstream salmon migration in the Yukon River and non-salmon fish harvests, impacts on fish habitat and migration would be minimized because the river crossing would be installed by DMT. Downstream contamination due to an inadvertent release of drilling mud into the river would be localized as cleanup measures would be implemented to minimize downstream impacts on fish resources.

4.14.3.3 Tanana River Region

The Tanana River Region includes nine communities: Tanana, Manley Hot Springs, Minto, Nenana, Four Mile Road CDP, Anderson, Ferry, Healy, and Denali Park CDP. The ADF&G conducted household harvest surveys for all but two of these communities (i.e., Manley Hot Springs and Minto).

The Tanana River Region encompasses the area from the Alaska Range to the foot of the Ray and White Mountains and includes a portion of the Tanana River floodplain. At the southern limits of the region, McKinley Park CDP, Healy, Ferry, Anderson, Four Mile Road CDP, and Nenana are situated along the Nenana River. At the confluence of the Tanana and Nenana Rivers, the region expands to the east and west following the Tanana River. Currently on the Tolovana River, Minto was historically on the Tanana River.

The Tanana River Region is rich in prehistoric archaeology, with some archaeological sites dating to more than 13,000 years ago in Ferry, Healy, and Nenana (Hoffecker, 2001; Pearson, 1999; Potter et al., 2007). Athabascan oral history documents salmon harvest and winter potlatch in Nenana (Shinkwin and Case, 1984). Prior to contact with Europeans, the confluence of the Tanana and Yukon Rivers was a periodic spring and summer trade, meeting, and ceremonial center for the Yukon, Koyukuk, and Tanana River Athabascans (Case and Halpin, 1990; McMahan, 1986; Stuck, 1917). At the time of Euro-American contact, semi-permanent residences were established in the Minto Flats area (Olson, 1981).

During the mining boom at the turn of the 20th century, permanent settlements were established to supply miners, including Manley Hot Springs, Tanana, Nenana, and Healy. Tanana expanded with multiple trading posts and a mission attracting people to build semi-permanent and permanent settlements (Case and Halpin, 1990). The population in Nenana grew due to the discovery of gold and increased again when the Alaska Railroad was built through the area in 1916 (Shinkwin and Case, 1984). The developments and population increase at Nenana spurred developments at Four Mile Road CDP less than 2.5 miles to the north. In Healy, coal and mineral mining began in 1906 and expanded further when the Alaska Railroad offered an option for more efficient transportation (Merritt, 1986). The demand for coal increased during World War II to the extent that the mining industry in Healy built residential housing to attract workers.

Anderson and Ferry were developed as railroad stations. Ferry supported gold mining with a section house and railroad station. The Alaska Railroad had a right-of-way planned through Anderson, but in 1918, the Nenana River changed course and destroyed 21 miles intended for railroad. Nearby, the current Denali Park and Preserve region was first made widely accessible with the completion of the Alaska Railroad, which reached Nenana to the north by 1923. In 1957, the Denali Highway opened the region to vehicle traffic and the area became an important tourist destination.

In the 1970s, Minto had to reestablish in a new location due to a history of flooding and erosion. Housing and a school were constructed at the new location on the Tolovana River 40 miles south of Old Minto on the Tanana River. Manley Hot Springs has nearly 100 year-round residents and remains a destination for visitors.

The majority (greater than 50 percent) of residents in Tanana, Minto, and Four Mile Road CDP are members of federally recognized tribes (U.S. Census Bureau, 2016). These tribes have traditional and current resource uses, including customary and traditional uses, in or near the Project area (see figure 4.14.3-15). Manley Hot Springs, Nenana, Anderson, Ferry, Healy, and McKinley Park CDP (also Denali Park CDP) have current subsistence resource use areas in or near the Project. A description of the nine communities and their subsistence use areas, harvest patterns, and seasonal round is provided in the following sections.

Spring (April through May) in the Tanana River Region is a transitional time when winter subsistence activities wane and summer activities begin (see table 4.14.3-26). Subsistence activity for upland birds and furbearers declines in early spring as residents of the region shift focus to non-salmon fish and waterfowl migrating through the area. Spring is a primary harvest time for bear in the region. Spring marks a decline of small land mammal harvests in general, though American beaver and North American porcupine subsistence activity continues.

Summer (June through August) in the Tanana River Region is characterized by intensified fishing activities. Salmon fishing begins in June and continues through the fall as different species navigate the region's watersheds. Non-salmon fish harvests, including whitefish and sheefish harvests, occur along with the summer salmon fishing. Waterfowl subsistence activity continues through the summer, as do harvests of small land mammals, namely squirrel. Subsistence activity for upland birds begins in late summer and continues into the spring. Residents of the region may target moose in late summer, but harvests at that time are only occasional. Vegetation emergence in the region allows for harvests of plants and berries.

TABLE 4.14.3-26

Tanana River Region Subsistence Harvest

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Moose												
Bear												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Plants and berries												
Wood												

Source: Braund, 2015

The focus on fishing continues into the fall (September through October) with harvests of coho salmon and non-salmon fish. Large land mammal harvests begin to intensify at this time. Moose subsistence activity is primarily in September and moose is the most common large land mammal resource harvested in the region. Bear subsistence activity continues and is particularly common in the fall in Tanana and Minto. Waterfowl subsistence activity intensifies to peak activity with the fall migration, particularly in Manley Hot Springs and Tanana. Berries are collected into early fall and wood collection begins at the end of fall.

The focus of subsistence activity shifts in the winter (November through March), with the end of salmon fishing and the slowing of non-salmon fishing. Residents primarily harvest small land mammals and upland birds for fresh meat over the winter season. Furbearer pelts are in prime condition over the winter, and residents report peak activity during this time. Moose subsistence activity may occur during December, during which time wood collection continues.

As part of the subsistence mapping and traditional knowledge study, each community in the Tanana River Region was asked to identify the three most important subsistence resources. At a regional level, moose was identified as the most important resource, berries were second, and wood was third. Salmon and non-salmon fish were mentioned in more than 10 percent of the responses, and all other resources were mentioned in fewer than 5 percent of the responses.

During subsistence mapping interviews in the Tanana River Region communities between 2014 and 2016, respondents were asked to comment on concerns about subsistence resources and their subsistence lifestyle. In particular, several respondents noted the increased use of Minto Flats, especially the Minto Lakes area, by outside hunters, and a corresponding avoidance of the area by local residents. Respondents commented that due to trails and access roads, the Minto Lakes area has become a key hunting area for people from other areas of the state. These trails and roads, used primarily by those not from Nenana, Minto, or Manley Hot Springs, cross the proposed Mainline Pipeline corridor. Respondents commented that the Minto Flats area attracts non-local hunters during peak regulated hunting seasons, such as moose season, and residents expressed concerns about potential impacts on resource populations in the area.

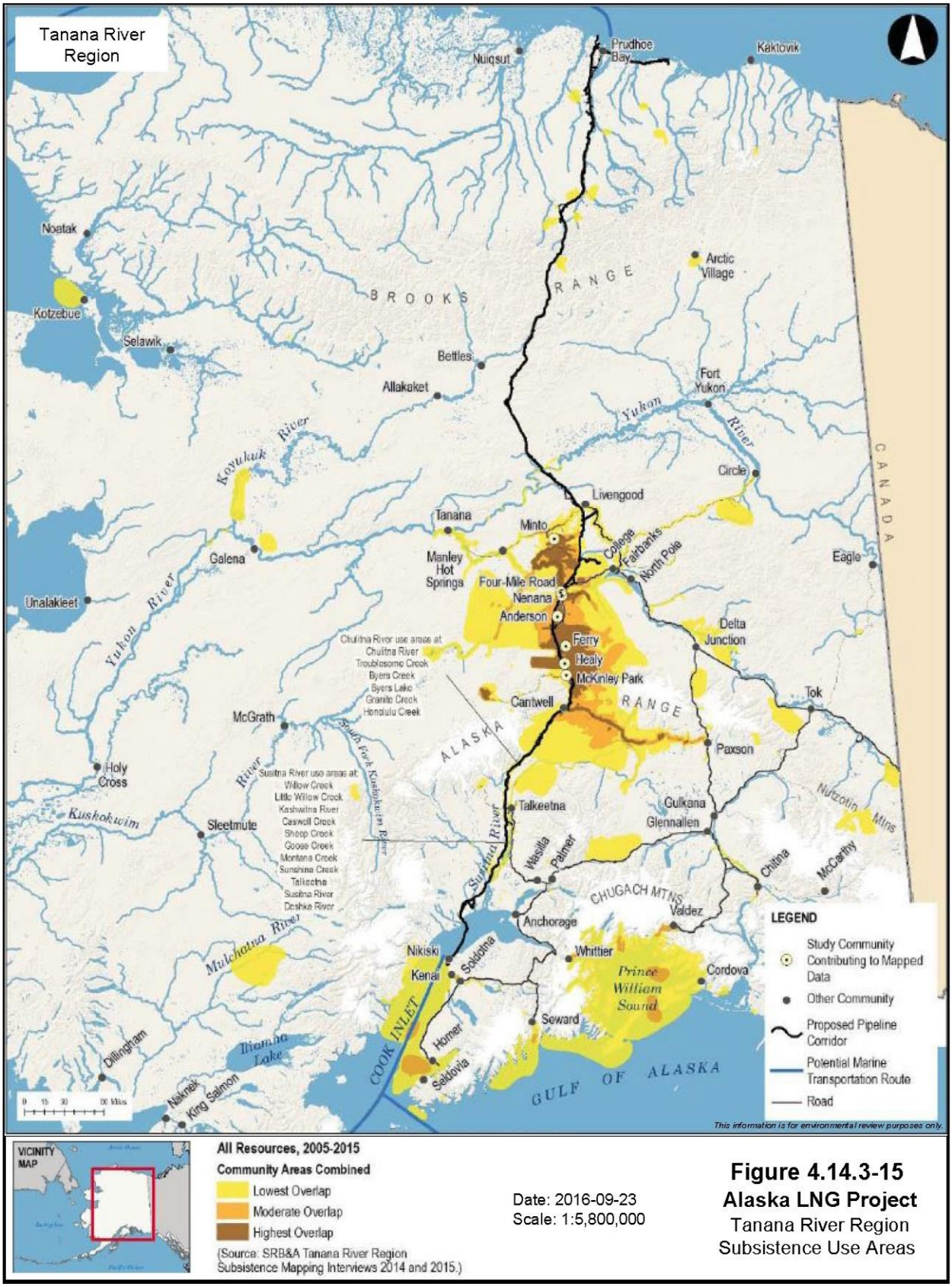


Figure 4.14.3-15
Alaska LNG Project
Tanana River Region
Subsistence Use Areas

Residents of Healy, Anderson, and Ferry mentioned a concern about increased hunting competition in recent years. The Denali Highway and Stampede Trail are heavily used by non-local hunters and present competition to the local subsistence users. Overall, the Tanana River Region respondents suggested there are fewer moose and birds in the area due to outside hunting pressure.

Comments specifically related to construction impacts by the Project include:

- downstream impacts where the Project crosses drainages that supply water to lakes and creeks in the Minto Flats area;
- creation of new access routes to subsistence use areas; and
- use of pesticides and herbicides along the Project that would affect plants and berries.

Tanana River Region Temporal Trends

Data for changes in subsistence activity over time are available only for land mammals and birds. Change in the timing of subsistence activity is characterized by a change in the number of months in which residents hunt or harvest resources, or a change in the time of year subsistence activity occurs. In the Tanana River Region, change in the timing of subsistence activity is evident for large land mammals, furbearers, small land mammals, and upland birds. Change over time for non-salmon fish is apparent for the community of Tanana, but not for the region as a whole.

A decline has occurred in the number of months of large land mammal harvests, including caribou in Tanana and moose and bear in all communities, but the season of harvesting these resources has not changed. Moose hunting primarily occurs in the fall with some winter activity, and bear hunting primarily occurs in the spring or fall.

A similar decline has occurred in the number of months of small land mammal and furbearer harvests; however, furbearer harvesting continues to occur during winter. Small land mammal harvests occur primarily over the winter, but a shift from a winter activity to a summer activity has occurred in Manley Hot Springs.

Change over time in the number of months during which bird subsistence activity occurs varies between communities (e.g., Minto and Manley Hot Springs). The number of months for upland bird harvests increased in Manley Hot Springs and decreased in Minto, but the peak season for upland bird subsistence activity continues to be the fall and early winter.

Tanana River Region Summary

Project construction activity and the Mainline Pipeline would affect subsistence for all communities in the Tanana River Region by reducing resource availability and access while increasing harvest cost and effort and potential resource competition. Subsistence use areas in the region tend to be focused in the Minto Flats State Game Refuge and along the Tanana River and Parks Highway, which run parallel to each other in the region. The Mainline Pipeline corridor intersects the eastern side of the Minto Flats State Game Refuge for its entire north to south extend, and parallels the Parks Highway and Nenana River from Nenana to Denali Park.

Tanana

The community of Tanana is about 3 miles downstream of the confluence of the Yukon and Tanana Rivers on the north bank of the Yukon River. The community is on a relatively flat terrace about 20 feet

above the river. Behind the community, low mountains rise to an elevation of 500 to 1,000 feet. Tanana is about 130 miles west/northwest of Fairbanks and 285 miles northwest of Anchorage.

The modern community of Tanana is only the most recent of numerous Alaska Native and Euro-American settlements near the confluence of the Yukon and Tanana Rivers. Prior to the arrival of Euro-Americans, the area was occupied by Koyukon-speaking Athabascans. After Euro-American settlement began in the region in 1863, a number of settlements were established. These included two trading posts downstream of the present-day location of Tanana and an Episcopal Mission about 1 mile upstream. The modern community of Tanana was established as Tanana Station by the Northern Commercial Company in 1897 (Brown et al., 2016).

Since the late 19th century, the U.S. military has had a presence in the Tanana vicinity. Between 1899 and 1923, the U.S. Army maintained Fort Gibbon a short distance downstream of the community. An airbase and radar station were operated during World War II and the Cold War, respectively, near the community (Brown et al., 2016; Orth, 1971).

Tanana has also played an important role in Alaska Native politics. In 1915, the community was the location of an important meeting between Alaska Native leaders and the federal government over concerns about encroachment on Alaska Native lands. This meeting ultimately led to the formation of the Tanana Chiefs Conference, a tribal consortium that remains in existence today (Brown et al., 2016).

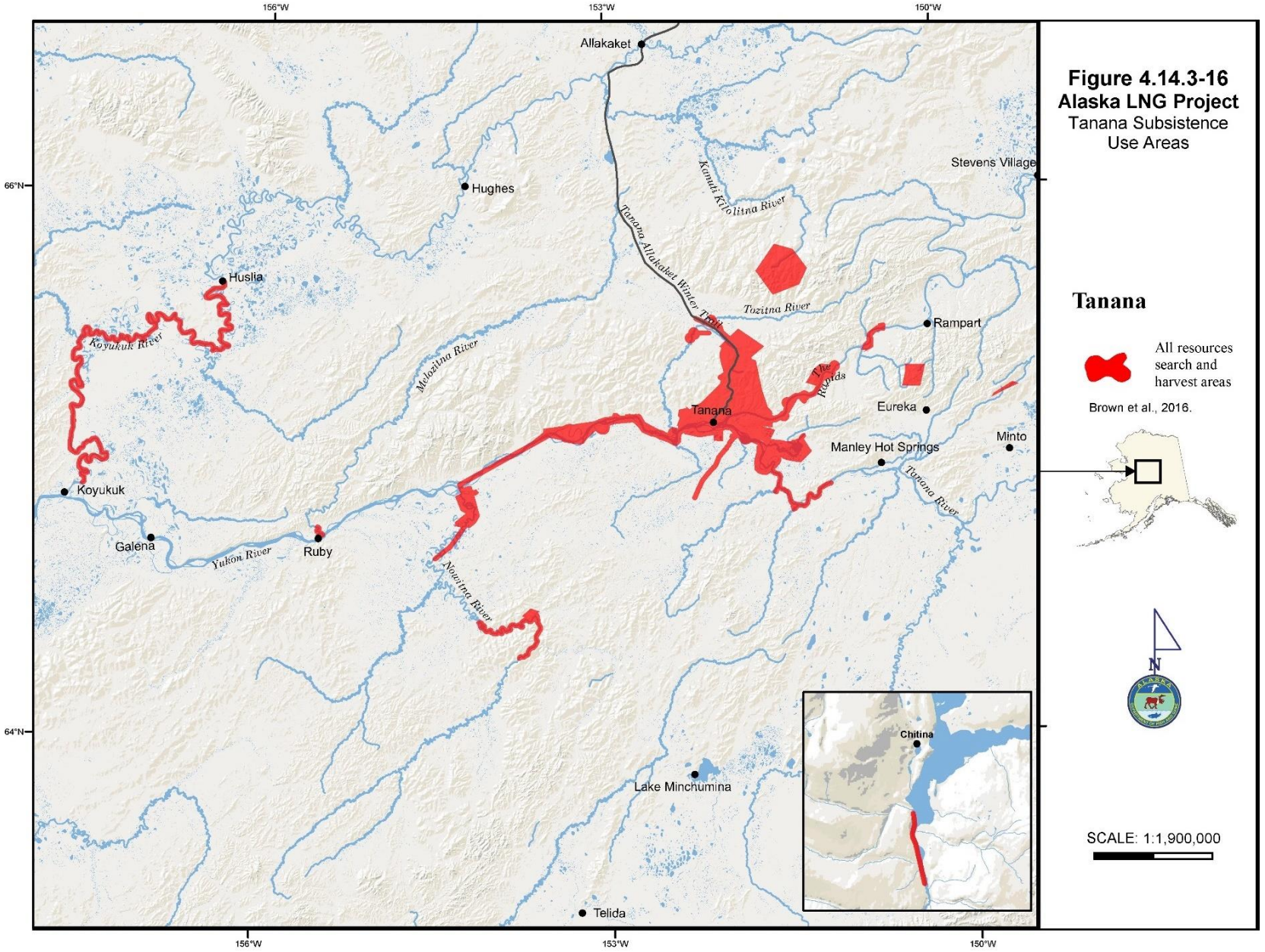
The Tanana municipality provides residents with electricity and well water. Some locations are served by municipal sewage treatment. The contemporary community of Tanana is reached by aircraft and the Yukon River. At the time the community was surveyed by the ADF&G, a road was under construction to connect Tanana with the Elliot Highway; however, the community was not yet on the road system (Brown et al., 2016).

In 2015, the ADF&G conducted a study of the harvest and use of subsistence resources in 2014 by Tanana residents (Brown et al., 2016). The ADF&G estimated that the 2014 population of Tanana consisted of 204 individuals living in 91 households. The Alaska Native population recorded by the ADF&G was 180 individuals (Brown et al., 2016). Investigators from the ADF&G interviewed 66 of the 91 households in the community. All the households surveyed by the ADF&G in 2015 reported using subsistence resources, while 86 percent reported harvesting resources. Most households reported exchanging resources with other households in the community; i.e., receiving resources (98 percent) or giving resources to others (82 percent) (Brown et al., 2016).

The ADF&G reported that about 91 percent of the households in the community received cash income through employment. Most of the income earned by community members was provided through employment by local, including tribal, government (54.3 percent); local service providers (19.9 percent); transportation, communication, and utilities (13.9 percent); and the federal government (10.0 percent) (Brown et al., 2016).

Subsistence Use Areas

Figure 4.14.3-16 depicts the extent of the Tanana subsistence use areas. The Tanana subsistence use areas center on the Yukon and Tanana Rivers and smaller tributaries, as well as inland areas to the north and south of the community. Use areas were reported as far west as Ruby, south along the Nowitna River, east beyond Rampart along the Yukon River, and past the Ray Mountains in the north. The Tanana subsistence use areas do not overlap with the Project.


156°W
153°W
150°W
66°N
64°N
Allakaket
Hughes
Stevens Village
Huslia
Rampart
Tanana
Eureka
Minto
Manley Hot Springs
Koyukuk
Galena
Ruby
Telida
Lake Minchumina
Chitina
Koyukuk River
Melozitna River
Kanuti Kilolitna River
Tozitna River
Tanana Allakaket Winter Trail
The Rapids
Yukon River
Nowitna River
Tanana River
Figure 4.14.3-16
Alaska LNG Project
Tanana Subsistence
Use Areas
Tanana
All resources
search and
harvest areas
Brown et al., 2016.
N
SCALE: 1:1,900,000

Seasonal Round

Tanana's location allows residents to take advantage of both terrestrial and freshwater resources. During spring (April through May), Tanana residents focus on trapping small mammals such as muskrat; hunting geese, ducks, and moose; and setting nets and lines for non-salmon fish (see table 4.14.3-27). Game birds such as ptarmigan are also harvested, as is wood for smoking meat and construction projects.

TABLE 4.14.3-27

Tanana Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon					■	■	■	■	■			
Pacific salmon						■	■	■	■	■		
Caribou								■				
Moose	■	■	■	■	■	■		■	■	■		■
Bear					■		■	■	■			
Furbearers	■	■	■								■	■
Small land mammals	■	■			■	■	■	■	■	■	■	■
Upland birds	■	■	■	■	■			■	■	■	■	■
Waterfowl				■	■	■	■	■	■	■		
Plants and berries							■	■	■	■		
Wood	■	■	■	■	■	■	■	■	■	■	■	■

Source: Braund, 2015

Chinook and chum salmon migrating past Tanana are harvested in the summer (June through August). Berry picking begins late in summer and continues into fall. Caribou, bear, waterfowl, and wood are occasionally harvested during the summer.

Fishing continues in the fall season (September through October). Salmon continue to run, and non-salmon fish populations become more plentiful. Harvest of large land mammals, such as bear and moose, also intensifies in the fall. Small mammals (e.g., hare and North American porcupine), waterfowl, upland game birds, berries, and wood are all harvested during the fall in preparation for the upcoming winter months. Moose hunting occurs during September, with opportunistic harvests throughout the rest of the year.

Winter (November through March) harvest of furbearers and other small mammals, including American beaver and hare, is common. Harvests of caribou and upland game birds and wood collection also occurs during the winter months.

Harvest Data

In the ADF&G survey, Tanana households reported using a wide range of resources in 2014 (see table 4.14.3-28). More than 90 percent of households made use of vegetation, and more than 80 percent used salmon and large land mammals. Non-salmon fish and birds and eggs were used by more than 60 percent of households. Small land mammals were used by just over 30 percent. Relatively small percentages of households made use of marine mammals (15.2 percent) and marine invertebrates (6.1 percent) (Brown et al., 2016).

Based on 2015 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2014 totaled 197,714.6 pounds, or 969.0 pounds per capita (Brown et al., 2016). The category of subsistence resource with the most use was salmon (691.7 pounds per capita), followed by non-salmon fish (168.1 pounds per capita), and large land mammals (93.8 pounds per capita). Far less use was made of small land mammals, birds and eggs, and vegetation. The per capita harvest weight for each of these three categories was well below 10 pounds. None of the residents of Tanana harvested marine mammals or marine invertebrates, though some used marine mammals or invertebrates obtained from other communities.

The most important subsistence resource measured in harvested pounds per capita was fish. Tanana residents harvested more than 500 pounds of fall chum salmon per capita in 2014. The second- and third-ranked resources were summer chum salmon (111.8 pounds per capita) and moose (87.6 pounds per capita). The remaining harvested resources consisted of two additional species of salmon and five species of non-salmon fish. The harvest of these resources ranged between 60.5 and 4.9 pounds per capita (Brown et al., 2016).

TABLE 4.14.3-28

Estimated Subsistence Harvest for Tanana

Resource	Per Capita (pounds)	Total (pounds)
Caribou	2.8	562.5
Moose	87.6	17,869.1
Bear	3.4	689.4
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	1.4	295.8
Marine mammals	–	–
Marine invertebrates	<0.1	2.1
Migratory birds	5.1	1,044.8
Upland birds	2.4	491.0
Eggs	0.1	10.3
Pacific salmon	691.7	141,140.2
Non-salmon fish	168.1	34,311.8
Berries	4.4	886.8
Plants	2.0	410.8
Wood	–	–
Other	–	–

Source: Brown, et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

The community of Tanana is at the union of the Tanana and Yukon rivers, downstream from the proposed Project at a distance of about 80 air miles. Tanana subsistence use areas would not be overlapped by the Project but would occur within 30 miles of the Project. Construction of the Project where it crosses the Yukon River would occur between April of Year 1 and December of Year 4. Construction at any single

point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. These timeframes may be concurrent with downstream fishing. Changes in resource access, availability, cost, and effort would not be anticipated during construction or operation of the Project.

Potential impacts on Tanana subsistence uses of concern to Tanana residents are downstream effects on fish. Downstream impacts on fish habitat and migration would be minimized because the Yukon River crossing would be installed using the DMT method. Downstream contamination due to inadvertent release of drilling mud into the River would be localized as cleanup measures would be implemented to minimize downstream impacts on fish resources.

Manley Hot Springs

The community of Manley Hot Springs is on Hot Springs Slough, a backwater of the Tanana River, about 5.5 river miles above the point at which the slough meets the Tanana River. The Hot Springs Slough is on the north side of the Tanana River and separates a broad, meander-scarred floodplain from the hills of the Yukon-Tanana Upland, which rises abruptly on the northern edge of the floodplain (Wahrhaftig, 1965). One of these hills is the Manley Hot Springs Dome, which rises to more than 2,600 feet, about 3.5 miles to the northwest of the community (Orth, 1971).

The geothermal springs, after which the community is named, are one of 36 known geothermal springs north of the Alaska Range (Boggs et al., 2016a) The springs emerge from the slopes of the hills on the north side of the slough, immediately to the north of the community (Newberry and Solie). The heat from the spring water is sufficient to prevent much of the slough from freezing during the winter (Brown et al., 2014).

The prehistory of the Manley Hot Springs vicinity is poorly known, a fact that may be the result of the relatively intensive historical development of the region and the consequent destruction of the archaeological record. However, based on the distribution of Alaska Native languages (Krauss et al., 2011), it is assumed that the residents of the region in late prehistory were Koyukon Athabascan people who lived in mobile, small bands (Brown et al., 2014).

The arrival of non-native travelers and traders created economic opportunities for Athabascan people living in the region. Native adaptations to these opportunities included settling closer to trading posts, trapping a wider range of fur-bearing animals, the use of new types of equipment such as fire arms and steel traps, the adoption of a more individual approach to trapping activities, and increased reliance on dog traction. The need to feed larger dog teams led to an increase in salmon harvests facilitated by the use of the fish wheel, which was adopted in the early 20th century (Brown et al., 2014).

The pace of Euro-American settlement around Manley Hot Springs increased after the discovery of gold and the establishment of the Rampart Mining District in 1896. As the mining industry grew, so did the need for a local service and supply center. Initially, these needs were met by the community of Baker, on the Tanana River, at the mouth of Baker Creek, about 10 river miles upstream of the entrance to Hot Springs Slough (Brown et al., 2014).

The first decade of the 20th century saw numerous important developments in the Manley Hot Springs vicinity. These included the development of a road and telegraph system, the establishment of a post office and hospital, and the beginning of agriculture for the local market. Numerous businesses and services also appeared at this time, including an Alaska Commercial Company store and a large resort hotel that made use of the geothermal springs at the site of the current community. With the establishment of the post office in 1907, the community was officially named Hot Springs. Although Alaska Natives were shut

out of the mining industry itself, they often found employment in support services, such as cutting wood and providing fish and game for mining communities (Brown et al., 2014).

By the 1920s, the mining industry was in decline and the resort hotel was destroyed by fire in 1913. Much of the population left the area; however, the community remained an important commercial location supporting fur trapping, agriculture, a school, and other services. In 1938, the airstrip was constructed (Brown et al., 2014). Although the Second World War led to another decline in population, the community rebounded in the 1950s as Alaska Native families moved into the community. That same decade, the hot springs were again developed for commercial purposes, heating greenhouses and indoor baths (Brown et al., 2014).

In the 1970s and 1980s, the salmon fishing industry was developed, and two fish processing plants were opened in the community; however, some community residents maintain that the industry has harmed the local salmon run. Ongoing environmental processes in the area include periodic wildfires and flooding. In the mid-20th century, changes in current patterns on the Tanana River led to the silting up of the mouth of Hot Springs Slough. As a result, the slough is now shallower and warmer than it was in the past and is less prone to freezing during the winter.

In 2013, the ADF&G conducted a study of the harvest and use of subsistence resources in 2012 by Manley Hot Springs residents (Brown et al., 2014). The ADF&G estimated that the 2013 population of Manley Hot Springs consisted of 123 individuals living in 58 households. In 2013, 28 residents of Manley Hot Springs were Alaska Natives. Investigators from the ADF&G interviewed 41 of the 58 households in the community. Of the 41 households surveyed by the ADF&G in 2013, 98 percent reported harvesting or attempting to harvest subsistence resources and 100 percent reported using subsistence resources. Seventy-one percent of the households reported sharing resources with other households in the community (Brown et al., 2014).

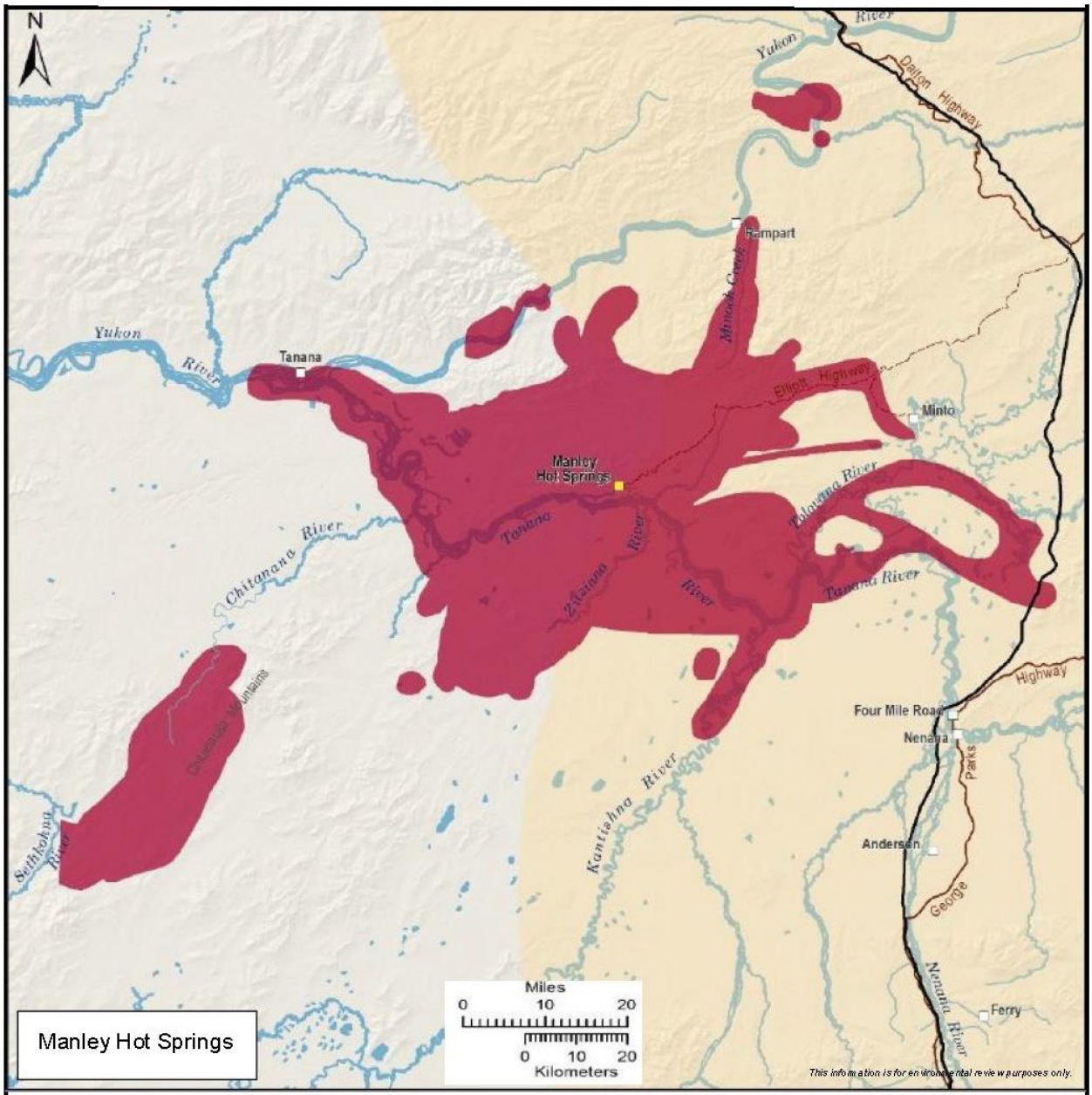
The ADF&G estimated that 93 percent of households in Manley Hot Springs received cash income through employment. The three primary sources of cash income were local government, construction, and the transportation, communication, and utilities industry. These industries respectively provided 25.0, 25.0, and 10.4 percent of the cash income earned by community members (Brown et al., 2014).

Subsistence Use Areas

The Manley Hot Springs subsistence use areas for all resources are between the community of Tanana in the west and the community of Minto in the east, and concentrated north and south of the Elliott Highway. The northernmost extent of the use areas is along the Yukon River just south of the Dalton Highway. A large use area near the Chitanatala Mountains represents the most southerly documented Manley Hot Springs use area. The Manley Hot Springs subsistence use areas overlap with the Project in an overland area north of the George Parks Highway (see figure 4.14.3-17).

Seasonal Round

Residents of Manley Hot Springs harvest terrestrial and fresh water species. Subsistence activity, in terms of number of resources hunted or harvested, is relatively stable year-round with a peak in activity in June and September and a slowdown in activity from December to April (see table 4.14.3-29). During spring (April through May), residents establish camps to harvest the spring migration of waterfowl and to net non-salmon fish either through the ice or in the free-flowing water after breakup. Wood is harvested in early spring and bears are harvested in late spring as they emerge from hibernation.





LEGEND

- Manley Hot Springs Use Areas
- Proposed Pipeline Corridor Buffer (50 miles)
- Proposed Pipeline Corridor
- Study Community
- Road

Date: 2014-12-03 Scale: 1:1,200,000

Figure 4.14.3-17
Alaska LNG Project
Manley Hot Springs
Subsistence Use Areas

TABLE 4.14.3-29

Manley Hot Springs Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon	■	■	■	■	■	■	■	■	■	■	■	■
Pacific salmon						■	■	■	■	■		
Moose									■			
Bear					■							
Furbearers	■	■	■								■	■
Small land mammals					■	■	■	■	■		■	
Upland birds	■	■	■	■	■	■	■	■	■	■	■	■
Waterfowl				■	■	■	■	■	■	■		
Plants and berries						■	■	■	■			
Wood	■	■	■	■						■	■	■

Source: Braund, 2015

Fish harvesting continues and intensifies during the summer months (June through August), and fishing camps are established along the Yukon River during season salmon runs. Plants and berries are collected in late summer. Waterfowl are occasionally harvested during the summer months. North American porcupine, hare, and squirrel are generally the only small land mammals taken during the summer.

During the fall months, Manley Hot Springs residents focus on moose as the fish harvest ends. American beaver harvests occur in the same locale and time frame as moose harvests. Upland birds and waterfowl are part of the fall harvest as well. Increased collection of firewood occurs in fall.

In addition to the continuation of harvesting non-salmon fish, upland game birds, and firewood, furbearers, including American marten, fox, American mink, Canadian lynx, otter, least weasel, gray wolf, and coyote, are a focus of winter activity. Manley Hot Spring residents harvest the largest number of American beaver for both fur and food in November.

Harvest Data

Most of the households contacted by the ADF&G reported both using (100 percent) and harvesting or attempting to harvest (98 percent) subsistence resources. Manley Hot Springs households reported using a wide range of resources in 2012 (see table 4.14.3-30). The most commonly used resource was vegetation, which was used by 100 percent of households in the community, followed by salmon (used by 93 percent of households), land mammals (used by 83 percent), non-salmon fish (used by 80 percent), birds and eggs (used by 54 percent), and marine invertebrates (used by 7 percent).

Based on 2013 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2012 totaled 52,437.6 pounds, or 426.2 pounds per capita (Brown et al., 2014). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (349.6 pounds per capita), followed by non-salmon fish (31.7 pounds per capita), large land mammals (21.4 pounds per capita), and vegetation (20.3 pounds per capita). The remaining resource categories, including small land animals, birds and eggs, and marine mammals and marine invertebrates, were all used at levels under 3 pounds per capita.

TABLE 4.14.3-30

Estimated Subsistence Harvest for Manley Hot Springs

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	20.7	2,546.3
Bear	0.7	82.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	0.9	116.3
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	0.6	76.1
Upland birds	1.6	196.5
Eggs	0.1	7.6
Pacific salmon	349.6	43,020.6
Non-salmon fish	31.7	3,894.4
Berries	16.6	2,043.8
Plants	3.7	453.9
Wood	–	–
Other	–	–

Source: Brown et al., 2014
"–" = No harvest for this resource was reported.

The most important subsistence resources measured in harvested pounds per capita were five types of salmon—fall chum (117.4 pounds per capita), Chinook (105.3 pounds per capita), coho (96.4 pounds per capita), summer chum (28.8 pounds per capita), and sockeye (1.7 pounds per capita)—followed by moose (20.7 pounds per capita). Northern pike, blueberry, humpback whitefish, lowbush cranberry, Bering cisco, and broad whitefish were all harvested in quantities lower than 10 pounds per capita (Brown et al., 2014).

Impacts on Subsistence

The community of Manley Hot Springs is at the end of the Elliot Highway, about 50 miles to the west of the Project. The Project overlaps a small portion of the eastern periphery of the community's subsistence use area along the edge of the Minto Flats. Mainline Pipeline construction near Minto Flats could displace moose during the winter construction season; however, moose harvests occur infrequently during winter. Moose displacement would be unlikely to continue into Project operation due to the community's distance from the Project and the community's seasonal use of the Minto Flats area.

Minto

The community of Minto is on a low rise above the west bank of the Tolovana River, about 24.5 air miles to the northeast of the confluence of the Tolovana and Tanana Rivers. Minto is also at the western edge of the Minto Flats, a complex of wetlands, ponds and oxbow lakes, lying between the escarpment of the Yukon-Tanana Uplands to the north and the Tanana River to the south (Wahrhaftig, 1965). The

wetlands of the Minto Flats are drained by five streams. In addition to the Tolovana River, these streams include the Tatalina and Chatanika Rivers and Goldstream and Washington Creeks. The Minto Flats are situated at the northern end of the Tanana-Kuskokwim Lowland, a lowland trough that follows the northern margin of the Alaska Range (Wahrhaftig, 1965).

Minto is about 50 air miles to the northwest of Fairbanks and 40 miles north of Nenana. The community can be reached from the Elliot Highway via the 11-mile Minto Spur road. The Tolovana River and an airstrip provide access by water and air.

Prior to the arrival of Euro-American travelers and settlers, much of the Tanana River Drainage was occupied by the Tanana Athabascans. It is assumed that in the Minto Flats vicinity prior to the arrival of Euro-Americans, Athabascan people lived in small mobile groups (Brown et al., 2014).

The Euro-American presence along the Tanana River increased in the early 20th century after gold was discovered in the nearby Rampart mining district and the Tolovana River Drainage. These discoveries were followed by increased settlement and supported by steamboat traffic on the Tanana River, construction of a telegraph line, and the establishment of roadhouses and trading posts (Brown et al., 2014).

In response to these changes, increasing numbers of local Athabascan people began participating in the cash economy by supplying wood fuel for steamboats, investing increasing effort in the fur trade, and making greater use of purchased foods. Greater participation in the fur trade encouraged the use of larger dog teams, which were fed by harvesting increasing numbers of salmon. Larger harvests of salmon were facilitated by the use of fish wheels, which were introduced in the early 1900s (Brown et al., 2014).

In 1915, increasing numbers of Tanana people began building cabins on the Tanana River to take advantage of trading and employment opportunities along the river and to send their children to the missionary school in the nearby community of Nenana. Although not occupied year-round until the 1940s, this settlement became known as Minto (Brown et al., 2014). In the 1970s, recurrent flooding and the advantages of highway access led to the relocation of Minto to its current location. The original location is now known as Old Minto (Brown et al., 2014).

In 2013, the ADF&G conducted a study of the harvest and use of subsistence resources in 2012 by Minto residents (Brown et al., 2014). The ADF&G estimated that the 2013 population of Manley Hot Springs consisted of 176 individuals living in 61 households. In 2013, 95 residents of Minto were Alaska Natives. Investigators from the ADF&G interviewed 46 of the 61 households in the community in 2013. Most households reported harvesting (94 percent) or using (98 percent) subsistence resources. Seventy-four percent of households reported sharing resources with other households in the community (Brown et al., 2014).The ADF&G estimated that 81.4 percent of households received cash income through employment. The five primary sources of cash income were local government, construction, mining, local service providers, and "other" employers. These sources respectively provided 30.9, 13.1, 8.9, 8.7, and 5.3 percent of the cash income earned by community members. Employment by the federal or state government, in retail trade, or the transportation, communication, and utilities sector, each accounted for less than 5 percent of the cash income earned by community members (Brown et al., 2014).

Subsistence Use Areas

The Minto subsistence use areas are centered on the Minto Flats State Game Refuge. The subsistence range extends between the communities of Tanana in the west, Stevens Village in the north, and Fairbanks in the east. The southernmost use area is along the Kantishna River (see figure 4.14.3-18). The Project intersects with Minto's subsistence use areas between its intersections with the Alaska Railroad in the south and the Tolovana River in the north.

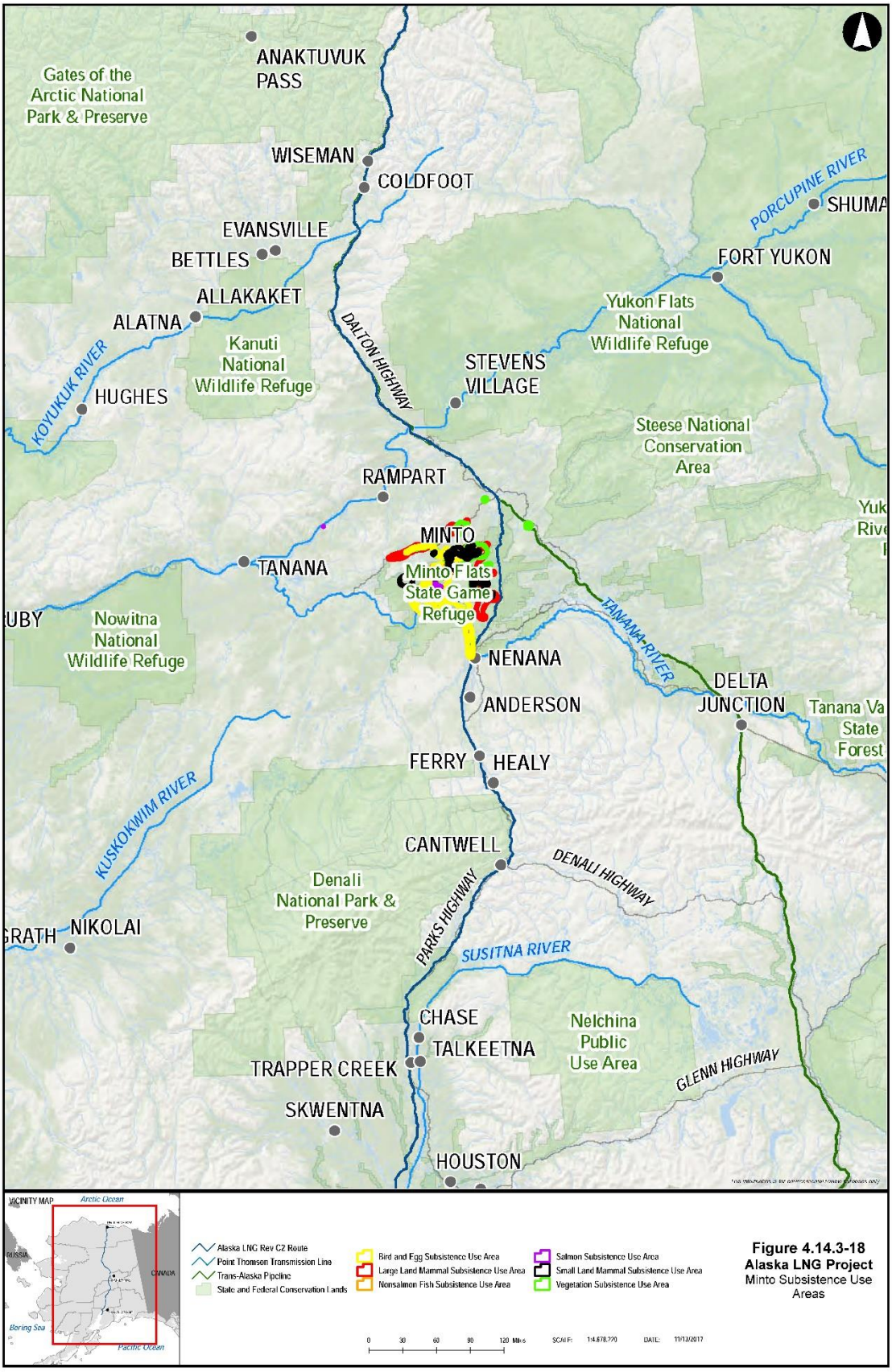


Figure 4.14.3-18
Alaska LNG Project
Minto Subsistence Use Areas

Seasonal Round

Minto residents harvest terrestrial and freshwater subsistence resources in and around the Minto Flats throughout the year (see table 4.14.3-31). Subsistence activity peaks in the fall and remains relatively even throughout the rest of the year. During the spring season (April through May), particularly in May, Minto harvesters focus on fishing and processing non-salmon fish from the Minto Flats and Tanana River. Muskrat harvests and the spring migration of waterfowl augment spring subsistence resources for residents of Minto. The last of the winter wood gathering also occurs in April.

Throughout the summer months (June through August), Minto subsistence activities focus primarily on salmon. Non-salmon fish harvests, including sheefish, northern pike, and whitefish, occur incidentally to the salmon set net fishing. Moose are a particularly important resource, providing up to 95 percent of the total land mammal harvest (Brown et al., 2014). Moose subsistence activities begin in late summer commonly as a multi-family activity. Muskrat harvests occur primarily during the early summer months as residents paddle around the lakes of the Minto Flats. Residents also harvest plants and berries as they ripen over the summer months.

Salmon and other fish continue to be harvested during fall (September through October). Upland game birds such as ptarmigan and grouse, as well as migratory waterfowl, are harvested as fishing declines. In addition to late spring and early summer harvests of whitefish, September and October harvest also occurs. September is the peak timing for large land mammal harvests such as moose and black bear.

The winter months (November through March) shift to the harvest of furbearers and small land mammals. Residents continue to pursue moose in early winter, occasionally harvest Dall sheep in December, and harvest wood throughout the winter.

TABLE 4.14.3-31

Minto Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon			■	■	■	■	■	■	■	■	■	
Pacific salmon							■	■	■	■		
Moose								■	■		■	■
Bear									■	■		
Dall sheep												■
Furbearers	■											■
Small land mammals	■	■	■		■	■						■
Upland birds									■	■		
Waterfowl				■	■				■	■		
Plants and berries						■	■	■				
Wood	■	■	■	■						■	■	■

Source: Braund, 2015

Harvest Data

Minto households reported using a wide range of resources in 2012 (see table 4.14.3-32). The most commonly used resource was vegetation (used by 98 percent of households in the community), followed by large land mammals (used by 96 percent of households), salmon (used by 91 percent), birds and eggs (used by 78 percent), non-salmon fish (used by 54 percent), and marine invertebrates (used by 2 percent).

TABLE 4.14.3-32

Estimated Subsistence Harvest for Minto

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	84.6	14,918.5
Bear	1.3	230.7
Dall sheep	0.6	–
Deer	–	–
Other large land mammals	–	106.1
Small land mammals	2.1	370.8
Marine mammals	–	–
Marine invertebrates	–	0.2
Migratory birds	9.2	1,621.7
Upland birds	0.9	161.9
Eggs	–	–
Pacific salmon	96.8	17,074.7
Non-salmon fish	20.7	3,651.5
Berries	8.8	1,541.9
Plants	0.5	91.1
Wood	–	–
Other	<0.1	3.1

Source: Brown et al., 2014
"–" = No harvest for this resource was reported.

The ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2012 totaled 39,772.2 pounds, or 225.5 pounds per capita (Brown et al., 2014). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (96.8 pounds per capita), followed by large land mammals (86.5 pounds per capita), non-salmon fish (59.8 pounds per capita), birds and eggs (10.1 pounds per capita), vegetation (9.3 pounds per capita), and small land mammals (2.1 pounds per capita).

The most important subsistence resources measured in harvested pounds per capita were moose (84.6 pounds per capita) followed by a variety of salmon, including coho (25.3 pounds per capita), fall chum (21.9 pounds per capita), summer chum (20.4 pounds per capita), Chinook (20.1 pounds per capita) and sockeye (9.2 pounds per capita). The remaining resources consisted of blueberry (5.2 pounds per capita) and three species of non-salmon fish, including northern pike (8.7 pounds per capita), broad whitefish (3.9 pounds per capita), and sheefish (3.5 pounds per capita) (Brown et al., 2014).

Impacts on Subsistence

The community of Minto is on the western edge of the Minto Flats, about 20 miles west of the Project. Subsistence use areas that are crossed by the Project or in areas upstream from the community would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. The Project would overlap nine subsistence resource use areas. Six of these (moose, migratory birds, salmon, non-salmon fish, berries, and wood) are of high importance; two (small land mammals and upland game

birds) are of moderate importance; and one (bear) is of low resource importance. Use areas for eggs and plants are within 2 miles of the Project. Construction would temporarily impact access to resources and availability of these resources as a result of habitat loss, increased competition from non-local harvesters, and additional cost and effort to harvest these resources. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads constructed in undeveloped areas.

Minto subsistence harvesters rely heavily on rivers and creeks crossed by the Project. Participants in traditional knowledge workshops reported that salmon are not very abundant in the Minto Flats area, but northern pike, sheefish, and arctic grayling are common and the Tolovana River near Minto Flats is a key salmon spawning area and a whitefish and salmon migration corridor. Downstream effects were a key concern raised during subsistence mapping and traditional knowledge workshops. In general, construction of stream and river crossings upriver from the community would occur during the winter. Construction impacts on fish would not be anticipated from winter construction as fish would not be present due to the frozen condition.

Summer construction in the northern portion of the Minto Flats could cause indirect impacts on non-salmon fish harvesting and moose, waterfowl, and upland bird hunting. Winter construction could affect winter furbearer hunters and trappers in addition to moose hunters.

During subsistence interviews and traditional knowledge workshops, Minto residents cited the increasing presence of non-local hunters in their traditional areas and concerns about future rights-of-way worsening these issues. Competition from non-local hunters would continue into Project operation as a result of new access to the Minto Flats area.

Nenana

The community of Nenana is on the south bank of the Tanana River, immediately upstream of the confluence of the Tanana and Nenana Rivers. Nenana is about 15 miles northeast of Anderson and 43 miles southwest of Fairbanks.

Nenana is situated on a low, north-facing point of land, created by a meander of the Tanana River to the east and the Nenana River to the west. In contrast to the low, marshy south bank of the Tanana River, the north bank immediately north of the community rises abruptly from the river to more than 1,200 feet above the surrounding terrain (Brown and Kostick, 2017).

Archaeological evidence indicates that the human occupation of the region extends more than 10 millennia into the past. The occupation of the region by the Athabascan people is well documented by early Euro-American travelers in the region who noted Native settlements near the confluence in the late 19th and early 20th centuries. The confluence also appears to be the location of a large, seasonally occupied Athabascan village. The seasonal importance of the area is suggested by the meaning of the name Nenana, which translates from Tanana Athabascan as "stopping-while-migrating-stream" (Brown and Kostick, 2017).

The confluence retained its geographic importance after the arrival of Euro-Americans in the late 19th and early 20th centuries. Some Native families built cabins near the confluence to gain access to non-Native trade goods passing through the area, or to take advantage of economic opportunities provided by commercial traffic on the Tanana River (Brown and Kostick, 2017). Gold discoveries and the subsequent development of the Pedro mining district in 1902 led to additional development and a growing population in the early 20th century. Telegraph and mail service and the arrival of the Alaska Railroad provided reliable interactions with other communities. In 1923, Nenana had a population of 800. By 1930,

the population had decreased to less than 300, due partly to an influenza epidemic and the end of construction activities on the Alaska Railroad (Brown and Kostick, 2017).

Nenana's population remained low, with significant seasonal fluctuations until the middle of the 20th century. Military activity in the region during the Second World War and road construction in the 1960s and 1970s brought additional traffic to the area. At the present time, Nenana is an important transportation hub and offers a variety of medical, legal, and educational opportunities to its residents (Brown and Kostick, 2017).

In 2016, the ADF&G conducted a study of the harvest and use of subsistence resources in 2015 by Nenana residents (Brown and Kostick, 2017). The ADF&G estimated that the 2015 population of Nenana consisted of 583 individuals living in 243 households. In 2015, 203 residents of Nenana were Alaska Natives. Investigators from the ADF&G interviewed 134 of the 243 households in the community in 2016. Of the 134 households surveyed, 84 percent reported harvesting subsistence resources and 97 percent reported using subsistence resources. Most households reported exchanging resources with other households in the community, with 87 percent receiving subsistence resources from others and 54 percent giving subsistence resources to others (Brown and Kostick, 2017).

The ADF&G estimated that 84 percent of households in Nenana received cash income through employment. The three primary sources of cash income were local services; local, including tribal, government; and the transportation, communication, and utilities industry. Employers in these sectors respectively provided 29.2, 13.7, and 10.4 percent of the cash income earned by community members (Brown and Kostick, 2017).

Subsistence Use Areas

Nenana subsistence activities are centered on the rivers and road systems near the community, as well as some overland areas. Nenana subsistence use areas for all resources extend north of the community along the Tanana River and tributaries (Tolovana and Kantishna Rivers), south along the George Parks Highway, and east along the Tanana River and George Parks Highway, in addition to large overland areas east of the Parks Highway as shown on figure 4.14.3-19. The general limits of the community's use areas include the Muddy River and Lake Minchumina in the west, south along the George Parks Highway, north along the entire length of the Elliott Highway, and in large overland areas north and southeast of the community. Some Nenana subsistence harvesters reported use areas near the Project farther south along the George Parks Highway toward Talkeetna and near proposed shipping routes in Cook Inlet near Homer and Seldovia. More distant use areas include the Koyukuk River west of Galena, north near Arctic Village, and east in the mountains at the headwaters of the Chisana River. The Project overlaps with Nenana use areas along the George Parks Highway and north near where the Project intersects with the Tolovana River.

Seasonal Round

Early spring is when arctic ground squirrels, Alaska wild rhubarb (*Polygonum alpinum*), and wild potatoes (*Hedysarum alpinum*) are gathered and hunting migratory waterfowl begins. During the spring migration, ducks are hunted and set nets are placed for whitefish. Summer fishing begins with the river breakup and continues into fall. Fall and winter are dominated by hunting moose; trapping red fox, North American river otter, gray wolf, wolverine, American beaver, muskrat, and Canadian lynx; and plant root and berry collection.

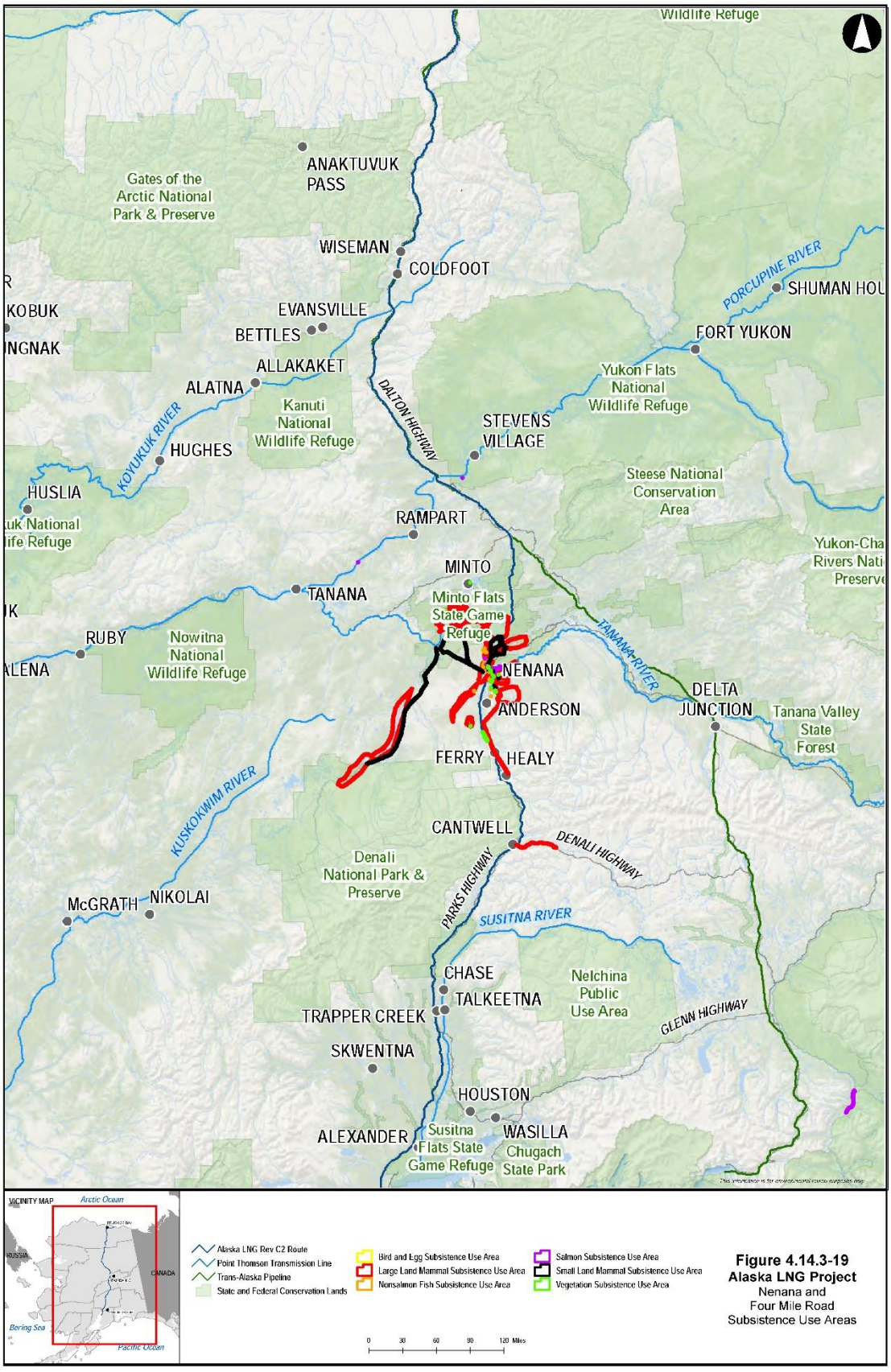


Figure 4.14.3-19
Alaska LNG Project
Nenana and
Four Mile Road
Subsistence Use Areas

Harvest Data

Nenana households reported using a wide range of resources in 2015. The most commonly used resource was vegetation, which was used by 86.6 percent of households in the community, followed by large land mammals (used by 78.4 percent of the community), salmon (used by 76.1 percent), non-salmon fish (used by 64.9 percent), birds and eggs (used by 42.5 percent), and small land mammals (used by 21.6 percent). Marine mammals and invertebrates were used by the fewest households, at 13.4 and 6.7 percent, respectively (Brown and Kostick, 2017).

Based on 2016 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2015 totaled 64,963.9 pounds, or 111.4 pounds per capita (Brown and Kostick, 2017). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (45.8 pounds per capita), followed by large land mammals (37.1 pounds per capita), non-salmon fish (13.4 pounds per capita), birds and eggs (6.8 pounds per capita), and vegetation and small land mammals (8.3 pounds per capita). The least use, as measured in pounds per capita, was made of marine invertebrates (0.1 pounds per capita) (see table 4.14.3-33).

TABLE 4.14.3-33

Estimated Subsistence Harvest for Nenana and Four Mile Road Census Designated Place

Resource [a]	Per Capita (pounds)	Total (pounds)
Caribou	1.7	986.5
Moose	35.1	20,488.2
Bear	0.3	181.3
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	2.3	1,326.5
Marine mammals	–	–
Marine invertebrates	0.1	36.3
Migratory birds	5.2	3,058.3
Upland birds	1.5	881.0
Eggs	<0.1	11.2
Pacific salmon	45.8	26,722.2
Non-salmon fish	13.4	7,796.1
Berries	5.4	3,174.2
Plants	0.5	302.8
Wood	–	–
Other	–	–

Source: Brown and Kostick, 2017

"–" = No harvest for this resource was reported.

[a] Resources for Four Mile Road include moose, caribou, small land mammals, migratory birds, upland game birds, salmon, non-salmon fish, berries, and wood.

The most important subsistence resources measured in harvested pounds per capita were moose (35.1 pounds per capita), coho salmon (16.5 pounds per capita), and fall chum salmon (10.5 pounds per capita). Seven resources (sockeye salmon, Chinook salmon, summer chum salmon, blueberry, humpback

whitefish, American beaver, and arctic grayling) were all harvested in quantities lower than 10 pounds per capita (Brown and Kostick, 2017).

Seven percent of the households in Nenana reported food insecurity in 2015 compared to a 13-percent statewide average between 2013 and 2015 (Brown and Kostick, 2017). Insufficient quantities of subsistence resources likely played a role in causing food insecurity, as 68 percent of Nenana residents reported that subsistence resources did not last as long as needed (Brown and Kostick, 2017).

Impacts on Subsistence

Nenana is situated at the union of the Tanana and Nenana Rivers, less than a mile east of the Project. Construction of the Project where it crosses Nenana's primary subsistence use area, from the Minto Flats in the north to Healy in the south, would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. In addition, several camps and access roads would be within Nenana's subsistence use area. Blasting would occur within 0.5 mile of Nenana's subsistence use areas. The Project would overlap subsistence uses for 10 subsistence resources, including three resources of high material and cultural importance (moose, salmon, and berries), two resources of moderate importance (birds and non-salmon fish), and five resources of low importance (small land mammals, bear, eggs, plants, and wood). Construction would temporarily impact access to resources and availability of these resources as a result of habitat loss, increased competition from non-local harvesters, increased traffic, and additional cost and effort to harvest. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads constructed in undeveloped areas, permanent habitat conversion in vegetation harvesting areas, and impeded access to use areas due to restrictions on crossing locations for the permanent right-of-way.

Construction activity could temporarily displace moose, bear, small land mammals and birds; temporarily block harvester access to hunting and harvesting areas; and remove previously used vegetation harvesting areas. The Tanana River crossing, the primary drainage from which residents harvest fish, would be constructed using the DMT method, which would minimize impacts on fish. Although Nenana is along the Parks Highway in a developed area, their subsistence use area extends to the largely undeveloped Minto Flats. The Project would introduce new roads and permanent right-of-way that allow access by non-local hunters to the use area. This potential influx of non-local hunters would result in competition for resources that would continue through Project operation.

Four Mile Road Census Designated Place

Four Mile Road CDP is just north of Nenana, in interior Alaska, about 50 miles southwest of Fairbanks on the George Parks Highway. Four Mile Road is in the western-most portion of Tanana Athabascan territory. The area has growth from development in Nenana.

Subsistence Use Areas

The Four Mile Road CDP subsistence use areas occur primarily along the Tanana and Kantishna Rivers north of the community, in overland areas east of the community, and along the Parks Highway as shown on figure 4.14.3-19. Additional use areas are along the Kenai River near the proposed Nikiski terminal and along Moose Creek off Petersville Road. Other use areas on the map include areas near Chitina.

Seasonal Round

The ADF&G (Brown and Kostick, 2017) household surveys for Nenana extended beyond the city limits and included all households along the Dalton Highway, including Four Mile Road CDP households. Therefore, the seasonal round for this community is the same as Nenana.

Harvest Data

Unlike the subsistence mapping for Nenana, which includes the harvest of marine mammals and marine invertebrates, Four Mile Road CDP subsistence mapping documented the use of nine resources: moose, caribou, small land mammals, migratory birds, upland game birds, salmon, non-salmon fish, berries, and wood (see table 4.14.3-33).

Impacts on Subsistence

Four Mile Road CDP is along the Parks Highway north of where it crosses the Tanana River. The Project would overlap three resource areas of high importance (moose, salmon, and berries), three of moderate importance (birds and non-salmon fish), and two of low importance (small land mammals and wood). Similar to Nenana, construction would temporarily impact access to, and availability of, resources due to habitat loss, increased competition from non-local harvesters, increased traffic, and additional cost and effort to harvest resources. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads constructed in undeveloped areas, permanent habitat conversion in vegetation harvesting areas, and impeded access to use areas due to restrictions on crossing locations for the permanent right-of-way.

Anderson

The community of Anderson is on the east bank of the Nenana River, about 15 miles south of the confluence of the Nenana and Tanana Rivers, 4 miles north of Clear Air Force Base, 23 miles north of the community of Ferry, and 55 miles to the southwest of Fairbanks.

In the vicinity of Anderson, the Nenana River divides into a complex system of small braided channels cutting across a broad floodplain, known as Lost Slough. Anderson is situated on the north end of a low ridge that runs parallel to the east bank of the river.

While human occupation of the region extends more than 10 millennia into the past, the community of Anderson was not established until the 1950s when Arthur Anderson and other homesteaders settled in the area (Brown and Kostick, 2017). During the late 1950s, the U.S. Air Force established Clear Air Force Base about 4 miles to the south of Anderson's property. In 1958, Anderson subdivided and sold his holdings to civilians working at the base (Brown and Kostick, 2017).

Continued growth of the community led to the incorporation of the city in 1962. Construction of a bridge of the Tanana River in 1968 and the completion of the Parks Highway in 1971 connected the community to the state road system. Although Clear Air Force Base is still used by the Air Force, the end of the Cold War and changes in the base's mission led to a loss of population in the community. Despite this, Anderson still offers its residents a variety of services, including a kindergarten through grade 12 school, post office, and landfill. However, residents must travel to larger communities, such as Nenana or Fairbanks, for other services and shopping (Brown and Kostick, 2017).

In 2016, the ADF&G conducted a study of the harvest and use of subsistence resources in 2015 by Anderson residents (Brown and Kostick, 2017). The ADF&G estimated that the 2015 population of

Anderson consisted of 186 individuals living in 79 households. In 2015, three residents of Anderson were Alaska Natives. Investigators from the ADF&G interviewed 50 of the 79 households in the community in 2016. Of the 50 households surveyed, 78 percent reported harvesting subsistence resources and 94 percent reported using subsistence resources (Brown and Kostick, 2017).

The ADF&G estimated that 68 households in Anderson received cash income through employment. The four primary sources of cash income were the federal government; the transportation, communication, and utilities industry; local government; and local service providers. These employers provided 27.0, 16.0, 14.0, and 10.2 percent, respectively, of the cash income earned by community members (Brown and Kostick, 2017).

Subsistence Use Areas

The Anderson community's subsistence use areas are primarily west and east of the Parks Highway as shown on figure 4.14.3-20. To the west, use areas border the DNPP and occur in overland areas between the highway and the Teklanika River. Other areas include the flats and hills east of the Parks Highway; along Rex Trail, Ferry area, and Healy Creek; as well as portions of the Parks Highway north of the community and the Denali Highway. Anderson residents reported use areas outside their community along the Project. These areas occur as far north as the Brooks Range along the Dalton Highway and as far south as the marine waters of Cook Inlet. Other areas shown include those east to the Canadian Border along the Alaska Highway, south in the bays and coastal areas of Kodiak Island, and west in areas near Galena and along the Mulchatna River north of Iliamna Lake. Other large use areas include Prince William Sound and other areas in the GOA. The majority of the residents reported hunting near the Project area between Anderson and the Alaska Range.

Seasonal Round

Based on survey data for 2015 from the ADF&G (Brown and Kostick, 2017), most households in Anderson participate in subsistence activities. However, participation by most households in the cash economy (more than 80 percent) makes subsistence "occasional events rather than a seasonal practice" (Brown and Kostick, 2017). Nonetheless, seasonal patterns in subsistence behaviors are apparent (see table 4.14.3-34).

TABLE 4.14.3-34

Anderson Subsistence Harvest Timing

Resource	Spring	Summer	Fall	Winter
Non-salmon fish				
Pacific salmon				
Marine invertebrates				
Large land mammals				
Birds				
Small land mammals				
Berries				
Plants				

Source: Brown and Kostick, 2017

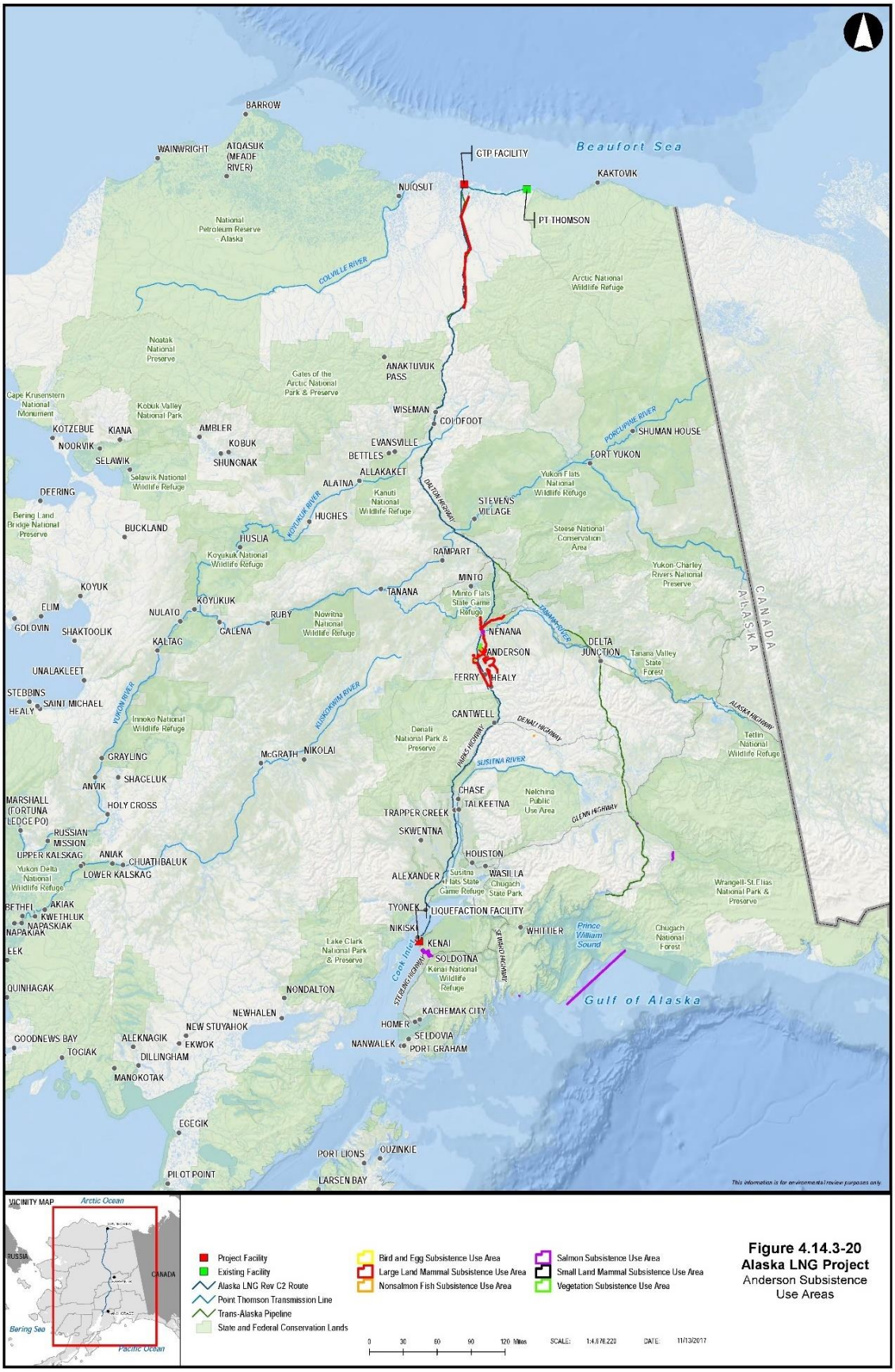


Figure 4.14.3-20
Alaska LNG Project
Anderson Subsistence Use Areas

The greatest variety of subsistence resources are harvested by Anderson residents in the summer. Salmon, the most important subsistence resource used by Anderson residents in terms of pounds per capita and percentage of households, is harvested at that time. While some salmon is obtained locally, the most commonly used species, sockeye salmon, is not available locally. Many residents travel to south-central Alaska or Prince William Sound to harvest salmon during the summer. Rod and reel was the most common method of catching salmon, although dip nets and fishwheels were also used, primarily for sockeye. Salmon plays an important role in social interactions in Anderson, with significant percentages of residents reporting sharing salmon.

Marine and freshwater non-salmon fish are also harvested during the summer. In 2015, Pacific halibut comprised most of the non-salmon harvest although other marine species, including starry flounder and skates were also harvested. Freshwater species include arctic grayling, rainbow trout, and northern pike. Some residents of Anderson reported traveling to coastal locations to harvest marine invertebrates in the summer.

Vegetation is another important category of resource harvested during the summer. The majority of vegetation harvested by Anderson residents are berries, primarily blueberries and lowbush cranberries. Other plants and plant products collected by Anderson residents include greens, mushrooms, and wood. Although wood is used as a fuel by some Anderson residents, most households in the community are not heated with firewood. Some small mammals, primarily furbearers, are harvested during the summer. Some households harvested marine invertebrates during the summer.

During the fall, the focus of subsistence activities turns from fishing to hunting large land mammals and birds. Moose are the most common target of fall hunting. Moose are locally available, and in 2015, made up 90 percent of the large land mammal harvest. Other large land mammals targeted by Anderson residents include black and brown bear, caribou, and mule deer (*Odocoileus hemionus*).

The majority of upland game birds and migratory waterfowl (e.g., spruce grouse, mallards) harvested by Anderson residents are hunted in the fall. The harvest of berries and wood continues into the fall and some small mammals are harvested at this time as well.

The variety of subsistence resources harvested by Anderson residents drops during the winter. The hunting of upland game birds continues during this season. Some residents harvest small mammals, primarily furbearers, during the winter and into the spring. The pelts of some species are in prime condition in early winter. Harvested species include fox, otter, least weasel, American mink, American marten, wolverines, and American beaver. Snowshoe hare are harvested for both fur and meat. The sale of pelts to craftspeople in other communities provides additional income to some residents. Freshwater fish species, e.g., rainbow trout, are harvested by ice fishing.

Harvest Data

Anderson households reported using a wide range of resources in 2015. The most commonly used resource was vegetation, which was used by 78 percent of households in the community. Salmon, large land mammals, non-salmon fish, and birds and eggs were used by 74, 62, 60, and 38 percent of households, respectively. Small land mammals, marine mammals, and invertebrates were used by much smaller percentages of the households (10, 2, and 2 percent, respectively) (Brown and Kostick, 2017).

Based on 2016 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2015 totaled 15,045.3 pounds, or 80.7 pounds per capita (Brown and Kostick, 2017). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (36.7 pounds per capita), followed by large land mammals

(25.4 pounds per capita), non-salmon fish (10.2 pounds per capita), vegetation (5.9 pounds per capita), and birds and eggs (2.3 pounds per capita). Far less use, as measured in pounds per capita, was made of marine invertebrates (0.1 pound per capita). No households reported harvesting caribou or marine mammals in 2015 (see table 4.14.3-35).

TABLE 4.14.3-35

Estimated Subsistence Harvest for Anderson

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	22.8	4,250.2
Bear	1.5	290.7
Dall sheep	–	–
Deer	1.1	204.8
Other large land mammals	–	–
Small land mammals	<0.1	7.1
Marine mammals	–	–
Marine invertebrates	0.1	15.8
Migratory birds	0.1	12.6
Upland birds	2.2	412.7
Eggs	–	–
Pacific salmon	36.7	6,847.7
Non-salmon fish	10.2	1,901.8
Berries	3.9	729.6
Plants	2.0	372.3
Wood	–	–
Other	–	–

Source: Brown and Kostick, 2017
"–" = No harvest for this resource was reported.

The most important subsistence resources measured in harvested pounds per capita was sockeye salmon (24.5 pounds per capita), followed by moose (22.8 pounds per capita). Pacific halibut, coho salmon, Chinook salmon, pink salmon, blueberry, mule deer, lowbush cranberry, and spruce grouse were all harvested in quantities lower than 1 pound per capita (Brown and Kostick, 2017).

Impacts on Subsistence

Anderson is a community on the eastern bank of the Nenana River, about 5 miles east of the Parks Highway and 3 miles east of the Project. Construction of the Project where it extends through Anderson's subsistence use area (from the Tanana River in the north to the Denali Highway in the south) would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Additionally, a construction camp and access roads would be constructed near Anderson's subsistence use area. Blasting would occur within 0.5 mile of Anderson's subsistence use areas. The Project would overlap subsistence use areas for 11 subsistence resources, including four of moderate resource importance (moose, birds, salmon, and non-salmon fish) and seven of low resource importance (caribou, Dall sheep, bear, small land mammals, berries, plants, and wood). Additionally, subsistence use areas for salmon and non-salmon fish

overlap the vessel route in Cook Inlet. The Project crosses use areas for Dall sheep, but only in a state nonsubsistence area.

Construction would temporarily impact access to and availability of resources due to habitat loss, increased competition from non-local harvesters, increased traffic, and additional cost and effort to harvest resources. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads constructed in undeveloped areas, permanent habitat conversion in vegetation harvesting areas, and impeded access to use areas due to restrictions on crossing locations for the permanent right-of-way.

Ferry

The community of Ferry is on the east and west banks of the Nenana River where the river is crossed by the Alaska Railroad about 38 air miles to the south of the confluence of the Nenana and Tanana Rivers, 28 miles northwest of Denali Park, 11 miles northwest of Healy, and 70 miles southwest of Fairbanks. The community shares its name with the Ferry CDP. The Ferry CDP encompasses an irregular area that follows the east bank of the Nenana River for about 4 miles and extends about 15 miles to the east.

The community of Ferry is about 1,000 feet above sea level within a sloping environmental transition zone between the boreal forest to the north and the alpine ecosystems of the Alaska Range to the south (Brown and Kostick, 2017). In the vicinity of Ferry, the Nenana River follows a braided course. On either side of the floodplain, terraces rise abruptly to between 100 and 300 feet above the river. On both sides of the river, the community is situated slightly above the active floodplain.

The Nenana River valley was occupied by Athabascan peoples at the time of Euro-American contact, and the human occupation of the region extends more than 10,000 years into the past. The origins of the community, however, date to the beginning of the 20th century and the arrival of Euro-American miners. One of the earliest residents of the community was Tom Strand, who worked as a market hunter providing meat to miners working in the Bonnifield and Kantishna mining districts near Ferry. Strand's gravesite is in the community and his descendants reportedly lived there until the 1980s (Brown and Kostick, 2017).

Increased development of the community followed the construction of the Alaska Railroad in the 1920s. In 1922, Ferry was the site of a railroad station (Orth, 1971), and a post office was established in 1925. Additional developments included a roadhouse and grocery store (Brown and Kostick, 2017). More recent settlement occurred in the 1970s, and in 1971, construction of the Parks Highway connected Ferry to the state road system. Construction of the Eva Creek Wind Farm brought additional traffic to Ferry, and its completion in 2012 has provided electric power to the community (Brown and Kostick, 2017). At the present, the community of Ferry offers few amenities and services. Most residents travel to Healy for shopping and services.

In 2016, the ADF&G conducted a study of the harvest and use of subsistence resources by Ferry residents in 2015 (Brown and Kostick, 2017). The ADF&G estimated the population of Ferry to be 41 individuals living in 18 households. In 2015, no residents of Ferry were Alaska Natives. Investigators from the ADF&G interviewed 14 of the 18 households in the community in 2016 (Brown and Kostick, 2017). Of the 14 households surveyed, all reported using and harvesting subsistence resources. The ADF&G estimated that 77 percent of households received cash income through employment. The two primary sources of cash income were the transportation, communication, and utilities industry and the federal government, which respectively provided 55.7 and 19.9 percent of the cash income earned by community members (Brown and Kostick, 2017).

Subsistence Use Areas

Ferry's community subsistence use areas are east of the Parks Highway and Nenana River between the Yanert River to the south and Rex Trail to the north, as well as along the George Parks Highway north to Nenana as shown on figure 4.14.3-21. Additional use areas are farther south along the Denali Highway and at several creeks along the George Parks Highway, including Honolulu, Byers, Troublesome, Montana, and Goose Creeks. To the north, a few isolated areas occur along the Tanana River and near Chena Hot Springs Road. Several respondents identified additional use areas close to the Project, including locations along Cook Inlet and the Kenai River. Other areas farther from the Project included an overland area surrounding Lake Minchumina, an area along the Taylor Highway near Chitina, and the waters of Prince William Sound. The residents of Ferry reported hunting near the community in the vicinity of the Project area.

Seasonal Round

Residents of the community of Ferry commonly harvest and use subsistence resources. In 2015, 100 percent of the interviewed households reported the harvest and/or use of subsistence resources. Subsistence activities take place throughout the year (see table 4.14.3-36).

TABLE 4.14.3-36

Ferry Subsistence Harvest Timing

Species	Spring	Summer	Fall	Winter
Non-salmon fish				
Pacific salmon				
Marine invertebrates				
Large land mammals				
Birds				
Small land mammals				
Berries				
Plants				

Source: Brown and Kostick, 2017

During the summer, residents of Ferry harvest the widest variety of subsistence resources, including salmon, non-salmon fish, greens, and berries. Salmon is the most important resource used by Ferry residents in terms of pounds per capita. Most salmon are caught locally using nets or rod and reel. Four species are harvested by Ferry residents, but the most commonly used species is sockeye salmon. Non-salmon fish harvested during the summer consist of a mix of marine and freshwater species including arctic grayling, Pacific halibut, and burbot.

During the summer, Ferry residents collect 20 different types of plants, including berries, greens, mushrooms, and wood. In 2015, all Ferry households harvested plants. Most households in Ferry used firewood, although they did not rely on wood as their sole fuel. Collection of marine invertebrates also occurs during the summer. In 2015, however, marine invertebrates made up a very small percentage of subsistence resources used by Ferry residents.

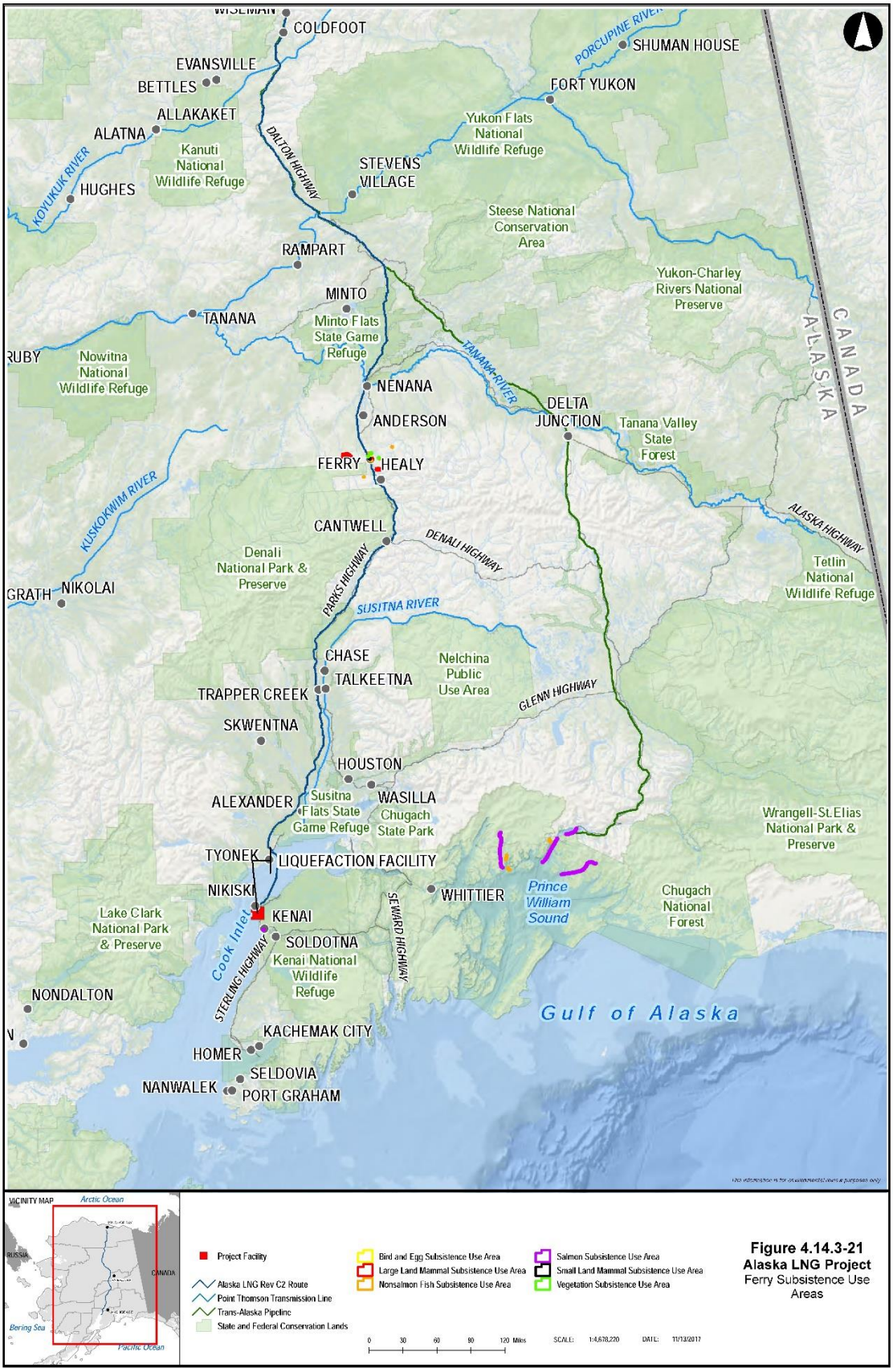


Figure 4.14.3-21
Alaska LNG Project
Ferry Subsistence Use Areas

In the fall, subsistence activities focus on hunting large land mammals and birds. Moose is the most commonly hunted large land mammal and the most important as measured in pounds harvested per capita. Other large land mammals hunted by Ferry residents include black and brown bear, Dall sheep, and caribou. Large land mammals are an important resource for the community with almost all households using them. Sharing between households is an important part of large mammal use in Ferry. Upland game birds, such as spruce and sharp-tailed grouse are also hunted in the fall.

The hunting of upland game birds continues into the winter, although the emphasis shifts to ruffed grouse and rock and willow ptarmigan. Ferry residents make limited use of small land mammals during the winter, all of which are harvested for their fur. Furbearing animals targeted by Ferry residents include gray wolf, American beaver, Canadian lynx, and coyote.

Relatively few Ferry residents participate in subsistence activities during the spring, although the collection of firewood and birch sap does occur.

Harvest Data

Ferry households reported using a wide range of resources in 2015. The most commonly used resource was vegetation, which was used by all households in the community. Salmon, non-salmon fish, large land mammals, and birds and eggs were used by 78.6, 64.3, 93.0, and 64.3 percent of households, respectively. Small land mammals and marine invertebrates were used by much smaller percentages of Ferry households (14.3 and 7.1 percent, respectively).

Based on 2016 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2015 totaled 4,572.8 pounds, or 111.3 pounds per capita (Brown and Kostick, 2017). The category of subsistence resource receiving the most use, measured in pounds harvested per capita, was salmon (63.5 pounds per capita), followed by vegetation (14.8 pounds per capita), large land mammal (16.8 pounds per capita), and non-salmon fish (10.6 pounds per capita). Far less use, as measured in pounds per capita, was made of birds and eggs (2.3 pounds per capita) and marine invertebrates (1.6 pounds per capita) (see table 4.14.3-37).

The most important subsistence resources measured in harvested pounds were sockeye salmon (49.7 pounds per capita), followed by moose (16.8 pounds per capita) and coho salmon (11.8 pounds per capita). Lowbush cranberry, arctic grayling, blueberry, raspberry, spruce grouse, burbot, and shrimp were harvested in quantities lower than 1 pound per capita (Brown and Kostick, 2017).

Impacts on Subsistence

Ferry is a small community on the eastern bank of the Nenana River, within 1 mile of the Parks Highway and the Project. The Project would overlap Ferry's subsistence use areas for nine subsistence resources. Of these subsistence resources, five are of high importance (moose, salmon, berries, plants, and wood), two are of moderate importance (birds and non-salmon fish), and two are of low importance (bear and small land mammals). Construction would primarily occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Construction would include a few access roads. Construction would temporarily displace subsistence resources, such as moose, bear, small land mammals, and upland game birds along the Project corridor, temporarily limit access to hunting and harvesting areas, and result in permanent habitat conversion in vegetation harvest areas. Permanent habitat conversion would continue into Project operation.

TABLE 4.14.3-37

Estimated Subsistence Harvest for Ferry

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	16.8	691.7
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	–	–
Marine mammals	–	–
Marine invertebrates	1.6	64.3
Migratory birds	–	–
Upland birds	2.3	94.9
Eggs	–	–
Pacific salmon	63.5	2,610.9
Non-salmon fish	10.6	434.7
Berries	10.9	448.7
Plants	3.9	158.5
Wood	–	–
Other	1.7	69.1

Source: Brown and Kostick, 2017
"–" = No harvest for this resource was reported.

Healy

The community of Healy occupies the west bank of the Nenana River immediately downstream of the confluence of the Nenana River and Dry Creek. The Parks Highway passes through the community and connects Healy to other communities on the road system, as well as the larger centers of Fairbanks and Anchorage. Healy is about 11 miles south of Ferry, 18 miles north of Denali Park, and 78 air miles to the southwest of Fairbanks. Healy is in the northern foothills of the Alaska Range, a region characterized by east to west oriented ridges reaching elevations of 2,000 to 4,500 feet separated by broad lowlands (Wahrhaftig, 1965).

Archaeological research indicates that by the time Euro-American settlement began in the late 19th century, Athabascan peoples had been living in the region for more than a millennium (Brown et al., 2016). Euro-American settlement of the area was motivated by a variety of economic opportunities, including logging, mining, and the construction of the Alaska Railroad (Brown et al., 2016).

One of the most important industries for Healy residents was, and continues to be, coal mining. Early settlers in the region recognized the economic potential of local coal deposits, and by the early 20th century, coal mining was well established. Mines in the Healy vicinity supplied coal for the Alaska Railroad and U.S. military bases, as well as Fairbanks and Anchorage. At the time the ADF&G surveyed the community of Healy in 2015, about 15 percent of working-age residents were employed by the mining industry (Brown et al., 2016).

Increasing concerns over the effects of big game hunting in the region led to the establishment of Mt. McKinley (now Denali) National Park in 1917. Despite the proximity of the town to the DNPP, it was not designated a resident zone community, making its residents ineligible to harvest resources in the national park (Brown et al., 2016).

Because of its location on the Parks Highway and proximity to the DNPP, Healy receives a considerable amount of commercial and tourist traffic. Healy supports a variety of private commercial and public facilities including a local school, Alaska State Trooper Post, and Department of Transportation facilities (Brown et al., 2016).

In 2015, the ADF&G conducted a study of the harvest and use of subsistence resources in 2014 by Healy residents (Brown et al., 2016). Based on the study, the population of Healy in 2014 consisted of 1,005 individuals living in 366 households, with 25 residents being Alaska Natives. Investigators from the ADF&G interviewed 127 of the 366 households in the community in 2015. Of the 127 households surveyed, 92 percent reported using subsistence resources, while 78 percent reported harvesting subsistence resources (Brown et al., 2016). The ADF&G estimated that 343 households received cash income through employment. The majority of community cash income was provided by employment in the mining sector (32.8 percent), followed by the federal government (14.4 percent) and local service providers (9.2 percent) (Brown et al., 2016).

Subsistence Use Areas

Healy's community subsistence use areas are primarily concentrated east of the Parks Highway in a continuous area from the Susitna and Chulitna Rivers in the south to Minto in the north as shown on figure 4.14.3-22. Additional use areas near the Project range from as far north as the North Slope and the Brooks Range to numerous rivers and creeks along the Parks Highway south of the community toward Wasilla, and farther south to use areas within Cook Inlet. Other areas not near the Project include various rivers on the North Slope, areas along the Alaska Highway between Tok and Delta Junction, and bays and coastal areas of Kodiak Island and Prince William Sound in the south. The Project overlaps the Healy subsistence use areas along the George Parks Highway from the Four Mile Road CDP south to the Chulitna River.

Seasonal Round

Healy residents' harvest of wild resources typically occurs within the open seasons of general hunting, trapping, and sport and personal fishing (Brown et al., 2016). Healy residents participate in subsistence activities throughout the year (see table 4.14.3-38). During the winter months, residents hunt large land mammals (moose) and upland ground birds. Winter is also the time when most of the small land mammals harvested by community members are obtained. About 87 percent of small land mammals were harvested during the winter by Healy residents. The most commonly harvested species were arctic ground squirrel, red squirrel, and snowshoe hare.

During the late winter and early spring, subsistence users from Healy harvest freshwater fish through the ice on interior lakes. Fish species harvested during this time include lake trout, Dolly Varden, and burbot. Other subsistence resources targeted by Healy residents in the spring include black and brown bear, small land mammals, and upland ground birds.

Participation in subsistence activities by Healy residents is most intense during the summer. During this time, subsistence efforts are focused heavily on harvesting salmon. Community members used all five species of salmon, although sockeye makes up the majority of salmon harvested by the community. Community members harvested salmon throughout south-central Alaska as well as Prince William Sound and the Kenai Peninsula.

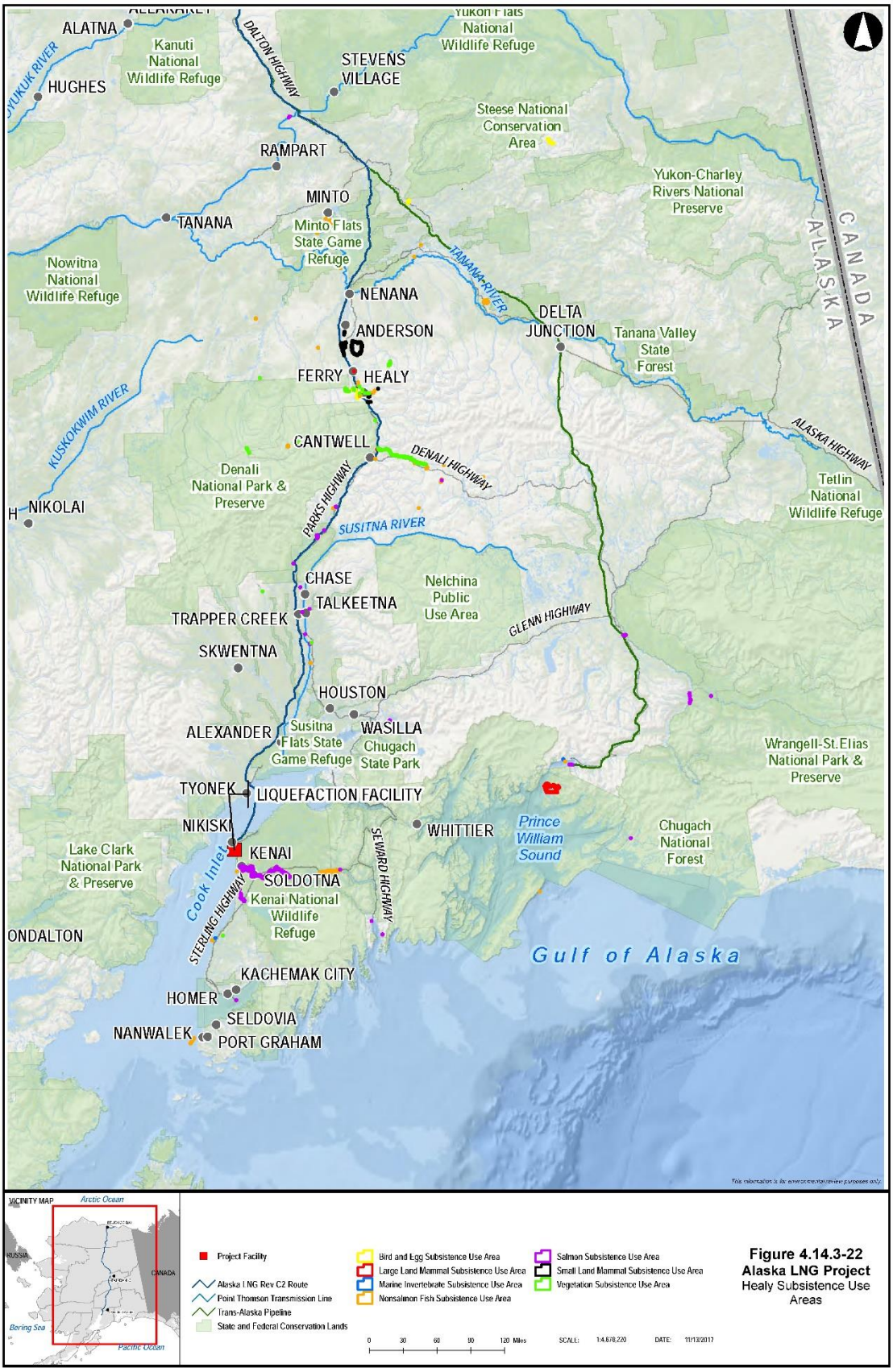


Figure 4.14.3-22
Alaska LNG Project
Healy Subsistence Use Areas

TABLE 4.14.3-38

Healy Subsistence Harvest Timing

Species	Spring	Summer	Fall	Winter
Non-salmon fish				
Pacific salmon				
Marine invertebrates				
Large land mammals				
Birds				
Small land mammals				
Berries				
Plants				

Source: Brown et al., 2016

Subsistence users from Healy also harvested marine and freshwater non-salmon fish during the summer. The most important marine species is Pacific halibut. Freshwater non-salmon fish harvested during the summer include arctic grayling and trout. Summer sport fish species include arctic grayling, rainbow trout, Dolly Varden, and northern pike. Caribou, black bear, and small amounts of upland game birds and small land mammals were also harvested during the summer.

Vegetation is another important summer subsistence resource. Most plant resources harvested by Healy residents during the summer are berries, with blueberry being the most important in terms of pounds harvested per capita. Healy residents also collect a variety of greens, mushrooms, and firewood. More than half of households in Healy harvested firewood. However, only a small percentage rely solely on wood as a source of fuel.

During the fall, the focus of subsistence efforts by Healy residents shifts to large land mammals, upland game birds, and migratory waterfowl. Large land mammal species targeted at this time include moose, caribou, brown bear, Sitka black-tailed deer (*Odocoileus hemionus sitkensis*), and mountain goat (*Oreamnos americanus*).

American beaver, fox, American marten, Canadian lynx, coyotes, gray wolves, and wolverines are taken by trappers in the winter. Healy residents participate in winter moose hunts. Fish are harvested in late winter and early spring. Fishing continues into summer when sockeye and Chinook salmon, Pacific halibut, rockfishes, and lingcod are harvested.

Harvest Data

Healy households reported using a wide range of resources in 2014. More than half of the households interviewed by the ADF&G reported the use of salmon, non-salmon fish, large land mammals, and vegetation. About 30 percent reported the use of birds and eggs. Less than 10 percent of households reported the use of small land mammals and marine invertebrates (Brown et al., 2016).

Based on 2015 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2014 totaled 51,996.2 pounds, or 51.3 pounds per capita (Brown et al., 2016). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was large land mammal (33.9 pounds per capita), followed by salmon (9.3 pounds per capita), and non-salmon fish (5.3 pounds per capita). Far less use, as measured in pounds per capita, was

made of vegetation (1.9 pounds per capita), birds and eggs (0.7 pound per capita), small land mammals (0.1 pound per capita), and marine invertebrates (0.1 pound per capita). No households reported harvesting marine mammals in 2014 (see table 4.14.3-39).

Of the 10 most important subsistence resources measured in harvested pounds per capita, the most important, and the only resource harvested in quantities larger than 10 pounds per capita, was moose (29.4 pounds per capita). The second-, third-, and fourth-ranked resources were sockeye salmon, Pacific halibut, and caribou. The remaining six resources (blueberry, brown and black bear, Sitka black-tailed deer, arctic grayling, and pink salmon) were all harvested in quantities lower than 1.0 pound per capita (Brown et al., 2016).

Four percent of households in Healy were assessed as having low or very low food security in 2014 compared to a 12-percent statewide average between 2012 and 2014 (Brown et al., 2016). A lack of subsistence foods appears to be an important contributor to food insecurity, with 25 percent of households reporting that subsistence foods did not last as long as needed (Brown et al., 2016).

TABLE 4.14.3-39

Estimated Subsistence Harvest for Healy

Resource	Per Capita (pounds)	Total (pounds)
Caribou	2.7	2,743.6
Moose	29.4	29,568.2
Bear	1.0	1,389.1
Dall sheep	–	–
Deer	0.5	489.9
Other large land mammals	0.2	208.9
Small land mammals	0.1	138.3
Marine mammals	–	–
Marine invertebrates	0.1	131.1
Migratory birds	0.2	168.2
Upland birds	0.5	534.0
Eggs	–	–
Pacific salmon	9.3	9,362.4
Non-salmon fish	5.3	5,341.7
Berries	1.5	1,521.6
Plants	0.4	399.2
Wood	–	–
Other	–	–

Source: Brown et al., 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Healy is a community on the Parks Highway, less than 2 miles east of the Project. Mainline Pipeline construction would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Blasting would occur within 0.5 mile of Healy's subsistence use areas. The Project overlaps

12 resource areas, including four with resources of high material and cultural importance (moose, salmon, non-salmon fish, and berries), four with resources of moderate importance (caribou, small land mammals, upland game birds, and wood), and four with resources of low importance (Dall sheep, bear, migratory birds, and plants). Construction would temporarily displace subsistence resources, temporarily limit access to hunting and harvesting areas, increase competition, and result in permanent habitat conversion in vegetation harvest areas. Permanent habitat conversion would continue into Project operation.

Denali Park Census Designated Place

The Denali Park CDP is in the northern foothills of the Alaska Range and follows, for the most part, the eastern bank of the Nenana River for about 25 miles from the confluence of the Nenana River and Coyote Creek in the north to the confluence of the Nenana and Jack Rivers in the south. The Denali Park CDP encompasses the community of Denali Park Village, including numerous private residences along the Parks Highway parallel to the Nenana River, and NPS employee housing a short distance inside the DNPP (Brown and Kostick, 2017).

At the time of Euro-American arrival, the region was occupied by Athabascan peoples, including speakers of the Tanana, Ahtna, and Dena'ina languages. However, the modern settlement in what is now the Denali Park CDP was largely driven by the establishment of Denali (previously McKinley) National Park (Brown and Kostick, 2017).

The designation of McKinley (now Denali) National Park in 1917 was the result of concerns that the construction of the Alaska Railroad through the region would lead to overexploitation of natural resources. After its completion in 1923, the railroad was instrumental in bringing visitors to the park (Brown and Kostick, 2017).

Over time, businesses supporting the tourist industry, including the McKinley Park Hotel in 1939 and roadhouses, were established near the park entrance. Road construction, including completion of the Denali Highway in 1958 and the Parks Highway in 1970, and the construction of an airstrip in 1960, increased public access to the park and surrounding area. This infrastructure led to additional development. In 1985, a state land sale created a residential subdivision known as the McKinley Park Village. This subdivision was renamed Denali Park Village in 2015 when the Mount McKinley and McKinley National Park were renamed (Brown and Kostick, 2017).

The Denali Park CDP supports a number of services and amenities including a fire station, community hall, and electric service for Denali Park Village. Although a large number of businesses are clustered near the entrance to the park, these are closed seasonally. Most Denali Park residents travel to Healy for shopping and other services (Brown and Kostick, 2017).

In 2016, the ADF&G conducted a study of the harvest and use of subsistence resources in 2015 by Denali Park residents (Brown and Kostick, 2017). The population of Denali Park consisted of 172 individuals living in 92 households. In 2015, no residents of Denali Park were Alaska Natives (Brown and Kostick, 2017). Investigators from the ADF&G interviewed 69 of the 92 households in the community. Of the 69 households surveyed, 99 percent reported using subsistence resources, while 93 percent reported harvesting subsistence resources.

The ADF&G estimated that 94 percent of households received cash income through employment. The two primary sources of cash income were the federal government, which provided 40.2 percent of the cash income earned by community members, and local service providers, which provided 27.7 percent (Brown and Kostick, 2017).

Subsistence Use Areas

Due to its proximity to the DNPP where hunting is restricted, the subsistence use areas for all resources primarily occur east of the community between the Yanert and Nenana River Drainages and areas along the Denali Highway as far east as Tangle Lakes as shown on figure 4.14.3-23. The southernmost use areas occurred along the George Parks Highway adjacent to the Chulitna River. Overland use areas extend west to the Kantishna area and to the east near the terminus of the Denali Highway near Paxson. Another use area is centered on Wonder Lake in the DNPP, primarily for berries, plants, and fishing. The Project bisects the community use area along the George Parks Highway.

Seasonal Round

Although the majority of households in Denali Park CDP engage in subsistence activities, participation in the cash economy limits time spent in subsistence pursuits. Denali Park's location on the road systems facilitates travel to other locations to participate in subsistence activities. Such travel is limited by income, however.

Most of the subsistence resources harvested by Denali Park CDP residents, as measured in pounds per capita, are harvested during the summer. The summer months are also when community residents make use of the widest variety of resources (see table 4.14.3-40). Salmon is the most important resource used by the community as measured in both percentage of use and weight. However, salmon are not locally available. Denali Park CDP residents making use of salmon frequently travel to locations in south-central Alaska, including the Kenai Peninsula, Prince William Sound, and the Chulitna and Susitna river systems. The most commonly harvested species is sockeye salmon, which is mostly harvested with dip nets.

TABLE 4.14.3-40

Denali Park Census Designated Place Subsistence Harvest Timing

Species	Spring	Summer	Fall	Winter
Non-salmon fish				
Pacific salmon				
Marine invertebrates				
Large land mammals				
Birds				
Small land mammals				
Berries				
Plants				

Source: Brown and Kostick, 2017

Denali Park CDP residents also make use of a variety of non-salmon fish during the summer. The most important non-salmon fish species as measured by edible weight or pounds per capita is Pacific halibut, which like salmon is not locally available. Locally available species include arctic grayling, trout, and char.

Summer subsistence activities also include the harvesting of plants. Vegetation is the most widely used and harvested category of subsistence resource among Denali Park CDP residents. Thirty-four different types of plants are used by community residents, although the most common in terms of pounds per capita are blueberries and lowbush cranberries. Other plants and plant products used by residents include greens, mushrooms, and firewood. Plant resources are widely shared among community residents, and some plant products are used in the manufacture and sale of craft items.

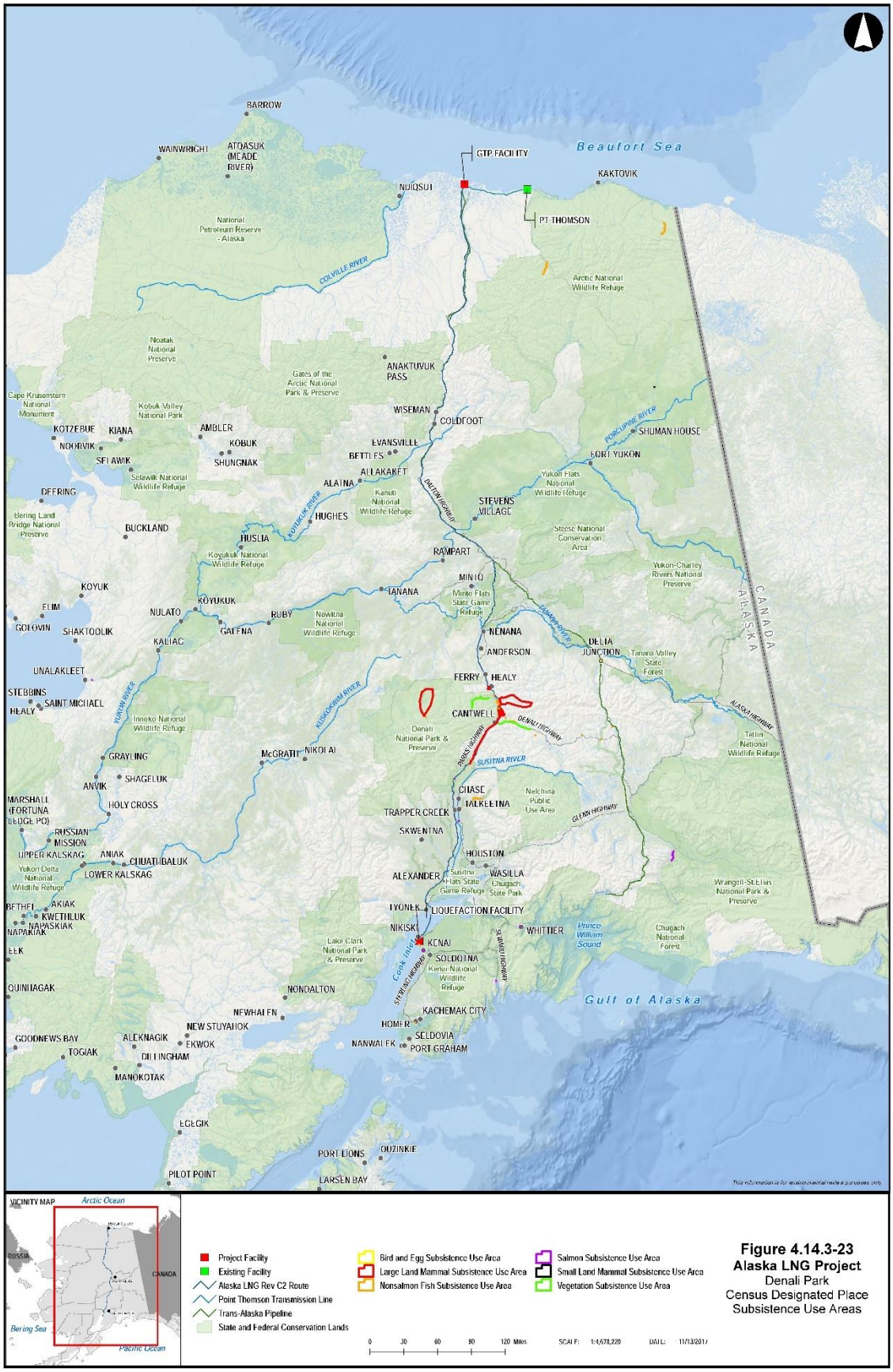


Figure 4.14.3-23
Alaska LNG Project
Denali Park
Census Designated Place
Subsistence Use Areas

A limited amount of hunting of large and small land mammals and upland ground birds also occurs during the summer. Some households harvested marine invertebrates during the summer.

During the fall, the focus of subsistence behavior shifts from fishing and the collection of plants to the hunting of birds and large land mammals. Large land mammals are an important resource used by the majority of Denali Park residents. In fall 2015, the most commonly harvested land mammal was caribou, which are hunted locally. The most commonly used large land mammal was moose, although none was harvested in 2015. This reveals the importance of sharing and barter networks in the use of large land mammals among community members. Denali Park CDP's location on the road system also enables residents to obtain meat through the roadkill salvage program. Upland game birds, primarily grouse, and migratory waterfowl are hunted in the fall.

Community members continue subsistence activities during the winter, although the rate of community participation declines. During the winter months, the focus shifts to upland game birds (ptarmigan and grouse) and small mammals. Small land mammals are harvested for both meat and fur, with most harvesting occurring during the winter and early spring. Species targeted by community members include snowshoe hare, red squirrel, and red fox.

The harvest and use of large and small land mammals and upland game birds continues into the spring although the level of community participation and the amount of subsistence products obtained are generally low.

Harvest Data

Denali Park CDP households use a wide range of resources. The most commonly used resource was vegetation, which was used by 97.1 percent of households. Salmon, non-salmon fish, and large land mammals were used by 78.3, 65.2, and 72.5 percent of households, respectively. Small land mammals, birds and eggs, and marine invertebrates were used by much smaller percentages of Denali Park households (5.8, 14.5, and 13.0 percent, respectively) (Brown and Kostick, 2017).

Based on 2016 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2015 totaled 9,835.7 pounds, or 57.3 pounds per capita (Brown and Kostick, 2017). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (25.7 pounds per capita), followed by vegetation (11.9 pounds per capita), large land mammal (9.6 pounds per capita), and non-salmon fish (8.7 pounds per capita). Far less use was made of birds and eggs (0.6 pounds per capita) and marine invertebrates (0.8 pound per capita) (see table 4.14.3-41).

Of the ten most important subsistence resources measured in harvested pounds per capita, the most important, and the only resource harvested in quantities larger than 10 pounds per capita, was sockeye salmon (22.2 pounds per capita). The second through seventh-ranked resources (Pacific halibut, blueberry, caribou, lowbush cranberry, bison [*Bison bison*], and coho salmon), were harvested in quantities less than 10 pounds per capita.

None of the households in Denali Park CDP reported having low or very low food security in 2015. Despite the apparent food security, 43 percent of households reported that subsistence foods did not last as long as needed (Brown and Kostick, 2017).

TABLE 4.14.3-41

Subsistence Harvest for Denali Park Census Designated Place

Resource	Per Capita (pounds)	Total (pounds)
Caribou	5.3	906.7
Moose	–	–
Bear	–	–
Dall sheep	0.8	138.7
Deer	–	–
Other large land mammals	3.5	599.9
Small land mammals	<0.1	6.0
Marine mammals	–	–
Marine invertebrates	0.8	136.3
Migratory birds	<0.1	1.7
Upland birds	0.6	100.4
Eggs	–	–
Pacific salmon	25.7	4,413.9
Non-salmon fish	8.7	1,494.1
Berries	11.2	1,930.9
Plants	0.6	107.1
Wood	–	–
Other	–	–

Source: Brown and Kostick, 2017
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Denali Park CDP is on the Parks Highway near the entrance to Denali National Park. The Project would overlap subsistence use areas for 11 resources, including two of high importance (berries and wood), three of moderate importance (moose, salmon, and non-salmon fish), and six of low importance (caribou, Dall sheep, bear, small land mammals, birds, and plants). A portion of the use area from the entrance to the DNPP to near Cantwell is in the Fairbanks nonsubsistence area. Construction would occur between April of Year 1 and December of Year 4, and at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Blasting would occur within 0.5 mile of Denali Park CDP's subsistence use areas. A construction camp and several small access roads would be constructed in the subsistence use area.

Construction activity could temporarily displace subsistence resources, such as moose, caribou, small land mammals, and birds; disrupt fish availability in streams crossed by the Project (including several salmon streams to the south of the community accessible along the Parks Highway); temporarily block harvester access to subsistence use areas; increase competition; and permanently convert vegetation within the subsistence areas. Competition for resources could continue during Project operation.

4.14.3.4 South-Central Region

The South-Central Region includes eight study communities (Cantwell, Chase, Talkeetna, Trapper Creek, Skwentna, Alexander Creek/Susitna, Beluga, and Tyonek) within the Susitna River Drainage,

extending to Upper Cook Inlet, and east to include the Matanuska River Drainage system. The region is bounded to the north and west by the Alaska Range, to the north and east by the Talkeetna Range, and to the south and east by the Chugach Range. The South-Central Region is bordered at its southern extreme by the Upper Cook Inlet.

The communities in the South-Central Region are within traditional Dena'ina and Ahtna territory. Cantwell, the northernmost community in the region, was traditionally used as Ahtna hunting and fishing grounds. Ahtna village sites were in the vicinity of both Susitna North and Chickaloon. To the east, Glacier View was on the traditional interregional exchange route between Ahtna and Dena'ina. Evidence of traditional seasonal Dena'ina use areas have been identified in Talkeetna, Alexander Creek, and Beluga. Skwentna is an important location on the Iditarod Trail. The Dena'ina traditionally controlled trade through Rainy Pass near Dena'ina Chunilna Village site, near Chase, reflecting long-term Athabascan use of the South-Central Region. Trapper Creek and Beluga are in traditional Dena'ina territory, and at contact, Tyonek had a resident Dena'ina community.

Due to their location in western Cook Inlet, Tyonek and Beluga were less affected by the gold rush at the turn of the 20th century compared to their counterpart communities in upper and eastern Cook Inlet. Beluga residents engaged in commercial fishing, and by 1960, gas deposits in Beluga were developed. The infrastructure is now largely owned by utility and gas companies. The Dena'ina community of Tyonek, which had served as a longtime Russian trading locality during the 1800s, became an Indian reservation in 1915 (ADCCED, 2017a). The passage of ANCSA in 1971 extinguished the reservation; however, the community continues to occupy the area and is now a federally recognized tribe.

Today, the majority (greater than 50 percent) of residents in Tyonek are part of a federally recognized tribe (U.S. Census Bureau, 2016). Tyonek residents have traditional and current resource uses, including customary and traditional uses, in or near the Project area (see figure 4.14.3-24). Cantwell, Chase, Talkeetna, Trapper Creek, Skwentna, Alexander Creek/Susitna, and Beluga have current subsistence resource use areas in or near the Project area. A description of the eight communities and their subsistence use areas, harvest patterns, and seasonal round is provided in the following sections.

Spring (April through May) in the South-Central Region is characterized by bear and freshwater non-salmon fish subsistence activities (see table 4.14.3-42). Bear harvests occur as early as March as bears emerge from their dens to feed. Residents harvest freshwater fish (e.g., rainbow trout, arctic grayling, whitefish, and eulachon/hooligan) in the region through ice fishing in local watersheds and/or with nets or rod-and-reel after breakup in open waters. In Cook Inlet, spring marks the harvest of clams. American beaver, snowshoe hare, and muskrat are common small land mammals harvested in the spring. Mushrooms and early plants such as fiddlehead ferns (*Dryopteris* spp.) are collected. Early Chinook salmon harvests begin in late spring, either offshore in Cook Inlet or in the Susitna River tributaries. Bird harvests occur during the spring; however, both waterfowl and upland bird subsistence activity is more common in other times of the year.

During the summer months (June through August), residents continue fishing for freshwater non-salmon fish, and harvests of salmon intensify as they migrate through the watersheds of the region. Ducks and geese are commonly harvested in late August as well as large land mammals, including caribou, moose, and Dall sheep. Upland bird and small land mammal harvests decline through summer. Residents continue to hunt bear during the summer months.

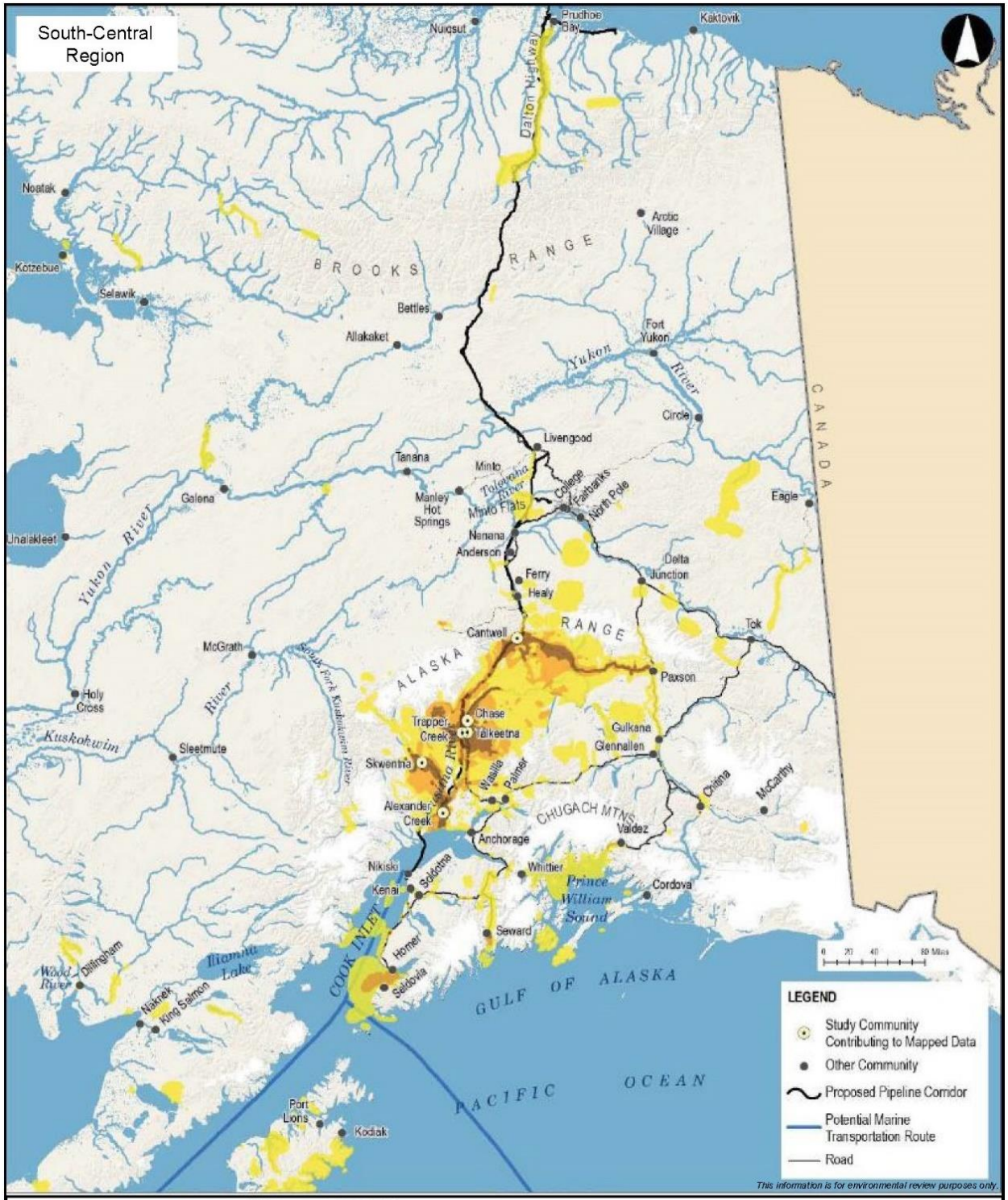

South-Central Region
Nuiqsut
Prudhoe Bay
Kaktovik
Dalton Highway
Noatak
Arctic Village
BROOKS RANGE
Kotzebue
Selawik
Bettles
Allakaket
Fort Yukon
Yukon River
CANADA
Circle
Livengood
Tanana
Minto
Tolovana River
Manley Hot Springs
Minto Flats
College
Fairbanks
North Pole
Eagle
Galena
Unalakleet
Yukon River
Nenana
Anderson
Ferry
Healy
Delta Junction
Cantwell
ALASKA RANGE
Tok
McGrath
Paxson
Holy Cross
Kuskokwim River
Sleetmute
Trapper Creek
Chase
Talkeetna
Gulkana
Glennallen
Skwentna
Willow
Wasilla
Palmer
Chitina
McCarthy
Alexander Creek
CHUGACH MTNS
Valdez
Anchorage
Nikiski
Soldotna
Whittier
Kenai
Prince William Sound
Cordova
COOK INLET
Seward
Homer
Dillingham
Wood River
Iliamna Lake
Naknek
King Salmon
Seldovia
GULF OF ALASKA
Port Lions
Kodiak
PACIFIC OCEAN
LEGEND
Study Community Contributing to Mapped Data
Other Community
Proposed Pipeline Corridor
Potential Marine Transportation Route
Road
This information is for environmental review purposes only.
VICINITY MAP
All Resources, 2005-2015
Community Areas Combined
Lowest Overlap
Moderate Overlap
Highest Overlap
(Source: SRB&A Southcentral Region Subsistence Mapping Interviews 2014, 2015 and 2016.)
Date: 2016-09-26
Scale: 1:6,509,800
Figure 4.14.3-24
Alaska LNG Project
South-Central Region
Subsistence Use Areas

TABLE 4.14.3-42

South-Central Region Subsistence Harvest

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Marine non-salmon												
Pacific salmon												
Caribou												
Moose												
Bear												
Dall sheep												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Marine invertebrates												
Plants and berries												
Wood												

Source: Braund, 2015

Fall (September through October) harvest intensifies for large land mammals, waterfowl, and upland birds. The timing of moose hunting in the region varies by community. Typically, moose is hunted in September, but some communities (e.g., Skwentna and Alexander Creek) have a winter moose harvest. Caribou harvests occur more commonly in the northern communities in the region due to herd proximity. Beluga and Tyonek do not regularly harvest caribou. Marine non-salmon fish harvests occur during the fall by residents along Cook Inlet and by those who travel south for these resources. Salmon fishing continues with the fall run of coho salmon, as well as non-salmon fishing and harvests of small game. Residents continue to collect clams into the early fall as well as the last of the berries for the season.

During winter (November through March) in the South-Central Region, residents focus on trapping furbearers and small land mammals and harvesting caribou and moose. Freshwater non-salmon fish continue to be harvested through the ice, and upland birds remain a small game target. Wood collection occurs year-round and is an important source of heat for many South-Central Region residents.

As part of the subsistence and traditional knowledge study, each community in the South-Central Region was asked to identify the three most important subsistence resources. At a regional level, moose was identified as the most important resource, wood was second, and salmon was third. Non-salmon fish, caribou, plants, and other land mammals were mentioned less frequently.

During subsistence mapping interviews in the South-Central Region communities in 2013, respondents were asked to comment on concerns about subsistence resources and their subsistence lifestyle. A common observation among workshop participants was the increase in sport hunting as well as non-local people hunting in their village's traditional subsistence areas.

Comments specifically related to construction impacts by the Project included the following concerns about increased competition for resources:

- employment opportunities associated with the Project could bring outsiders into the area during construction and operation;
- cleared right-of-way would create a new access corridor both for local residents and outsiders who are in the area for hunting and recreation; and
- construction workers could affect fish and game resources outside of work hours.

South-Central Region Temporal Trends

In the South-Central Region, changes in the timing of subsistence activities are not evident for non-salmon fish, small land mammals, birds, plants and berries, and wood, although data regarding changes over time for these resources is limited to Beluga and Tyonek. In contrast, large land mammals and furbearers reflect a change in the timing of subsistence activities in Cantwell, Chase, and Trapper Creek.

Changes in the timing of large land mammal hunting are evident in the South-Central Region. The changes vary by resources and community. The most substantial are associated with the timing of bear subsistence activities in Cantwell from late winter and spring to summer and fall; a change in timing of moose subsistence activities in Chase from the fall hunting season to hunting both in fall and winter; a decrease in the number of months used per year for subsistence activity for all large land mammals in Skwentna; and an increase in subsistence activity months for large land mammals in Tyonek. Other changes in the region are evident, including a decrease in Dall sheep subsistence activity months in Cantwell, a shift in the timing of caribou subsistence activity in Chase, and a decrease in bear subsistence activity months in Chase.

A decrease in furbearer subsistence activity months is evident for the northern communities of Skwentna and Chase. The southern communities of Tyonek and Beluga, however, have reported no change over time for these resources.

Data regarding salmon activity months are available for the community of Tyonek and Beluga. These data indicate a change in the timing of Tyonek salmon harvesting over time. The most recent data report salmon subsistence activity occurring year-round in contrast to a May through October season, as reported in earlier studies. May through October continues to remain the peak season for salmon fishing, with winter salmon harvests occurring less frequently in lakes. The neighboring community of Beluga is the only other community with comparative temporal data for salmon and does not report a similar change in the resource over time.

South-Central Region Summary

Project construction activity and operation of the Mainline Pipeline would affect subsistence for many communities in the South-Central Region by reducing resource availability and access while increasing harvest cost and effort and potential resource competition. Subsistence use areas in the region tend to be focused along the Susitna River in the vicinity of Chase, Talkeetna, and Trapper Creek, along the Susitna River and Susitna River delta in the vicinity of Alexander Creek, and along the Denali and Parks Highways in the vicinity of Cantwell. The Project corridor in the region runs parallel to the Parks Highway and Susitna River, and intersects, or runs parallel to areas used by residents of several communities, including Cantwell, Chase, Trapper Creek, Talkeetna, and Alexander Creek.

The project corridor directly intersects subsistence use areas for the communities of Cantwell, Chase, Trapper Creek, Talkeetna, and Alexander Creek. In addition, for all communities in the region the construction schedule for the Project coincides with the harvest of resources that are highly ranked in terms of pounds per capita or user preference.

Because the Mainline Pipeline corridor intersects or parallels the subsistence use areas of Cantwell, Chase, Trapper Creek, Talkeetna and Alexander Creek for much of their lengths, it is likely that operation of Project facilities would continue to have effects on subsistence.

Cantwell

The community of Cantwell is at the intersection of the Parks and Denali Highways, in the Broad Pass Depression, a glaciated valley between the Talkeetna Mountains to the south and the central portion of the Alaska Range to the north. Cantwell is about 100 miles to the southwest of Fairbanks on the opposite side of the Alaska Range, and about 150 miles north of Anchorage.

The Broad Pass Depression extends about 50 miles to the southwest of Cantwell, where it opens onto the broad lowland surrounding the Susitna River. At its northern end, the depression is drained by the Nenana River, which flows northward through a canyon in the Alaska Range. In the Cantwell vicinity, the floor of the Broad Pass Depression is flat and marshy and is drained by meandering streams that eventually join the Nenana River (Wahrhaftig, 1965).

Cantwell is within the Ahtna Athabascan language region. Prior to the Euro-American settlement of the region, the Ahtna made seasonal use of the Valdez Creek Drainage, about 50 miles to the east of Cantwell. The discovery of gold at Valdez Creek in 1903 led some Ahtna families to establish more permanent residences in the area (Holen et al., 2014).

In 1916, as the Alaska Railroad was extended toward Fairbanks through the Broad Pass Depression, the community of Cantwell was established as a railroad construction camp. Employment opportunities drew settlers to the community, including Ahtna from the Valdez Creek vicinity. The community spread eastward from its original location along the railroad toward the Parks Highway when the opening of the highway in 1971 brought automobile traffic to Cantwell. Cantwell is only 28 miles south of the DNPP, and much of the community's income is generated by the tourism industry. The community supports numerous businesses, a public school, state and federal government offices, and a community center operated by the Native Village of Cantwell (Holen et al., 2014).

In 2012, the ADF&G estimated a population of 196 individuals living in 83 households. The Alaska Native population recorded by the ADF&G was 35 individuals (Holen et al., 2014). In 2013, ADF&G investigators interviewed 55 of the 83 households in the community. Most of the households surveyed by the ADF&G reported harvesting (85.5 percent) and using (94.5 percent) subsistence resources. The ADF&G reported that 82 percent of households in the community received cash income through employment. Most of the income earned by community members was provided through employment by state government (23.6 percent), local government (19.3 percent), and local service providers (20.7 percent) (Holen et al., 2014).

Subsistence Use Areas

Figure 4.14.3-25 depicts the extent of the Cantwell subsistence use areas. Cantwell community's subsistence use areas extend from Healy Creek in the north to the Susitna River in the south, with additional isolated use areas further south on Kosina Creek. The subsistence use areas expand to the Clearwater Mountains in the east and to the West Fork of the Chulitna River in the west. Smaller isolated areas occur

west of the Parks Highway along Ohio Creek and east of the highway in the Talkeetna Mountains. The Project would follow the George Parks Highway in this region and intersect with Cantwell subsistence use areas along the highway from just south of Denali Park to the upper reaches of the Chulitna River. Additional Cantwell use areas were reported in the western Brooks Range, throughout Cook Inlet and Prince William Sound, and as far south as the southern region of Kodiak Island. The Project would overlap the Cantwell use areas along the George Parks Highway from the Yanert Fork south to where the Chulitna River parallels the Susitna River.

Seasonal Round

Subsistence activity in Cantwell, in terms of number of resource categories hunted or harvested, varies from month to month, with more activity in August and September and less activity in November when no resources are targeted according to current data (see table 4.14.3-43). Prior studies report caribou harvests occurring in November. During the spring (April through May), residents of Cantwell hunt for bear, ice fish in nearby streams and lakes, and harvest wood. Species of fish harvested from April through June include Dolly Varden, trout, arctic grayling, and char.

During the summer months (June through August), residents continue fishing for non-salmon fish and begin travelling outside the community to harvest salmon. According to the most recent data, berry picking occurs in August and continues through mid-September. Large land mammal harvests, including caribou, moose, bear, and Dall sheep begin in late summer.

Cantwell residents continue to harvest large land mammals into the fall (September through October), particularly moose. Caribou hunting begins in the middle of September and continues into winter. Waterfowl are harvested during the fall migration in September through mid-October. Other fall activities include ptarmigan and grouse hunting, coho salmon fishing, and the continued harvest of wood.

Hunting of caribou and upland game birds, trapping, and wood harvesting are winter activities (November through March). Cantwell residents begin trapping for furbearing animals and harvesting wood in early December. Trapping declines in February. Wood is harvested until mid-summer. Residents hunt for ptarmigan and grouse starting in late December through mid-January.

TABLE 4.14.3-43

Cantwell Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon				■	■	■						
Pacific salmon						■	■	■				
Caribou	■	■						■	■	■		■
Moose								■	■			■
Bear				■		■	■	■	■	■		
Dall sheep								■	■			
Furbearers			■									
Upland birds	■											■
Waterfowl									■	■		
Plants and berries								■	■			
Wood	■	■	■	■	■	■	■					■

Source: Braund, 2015

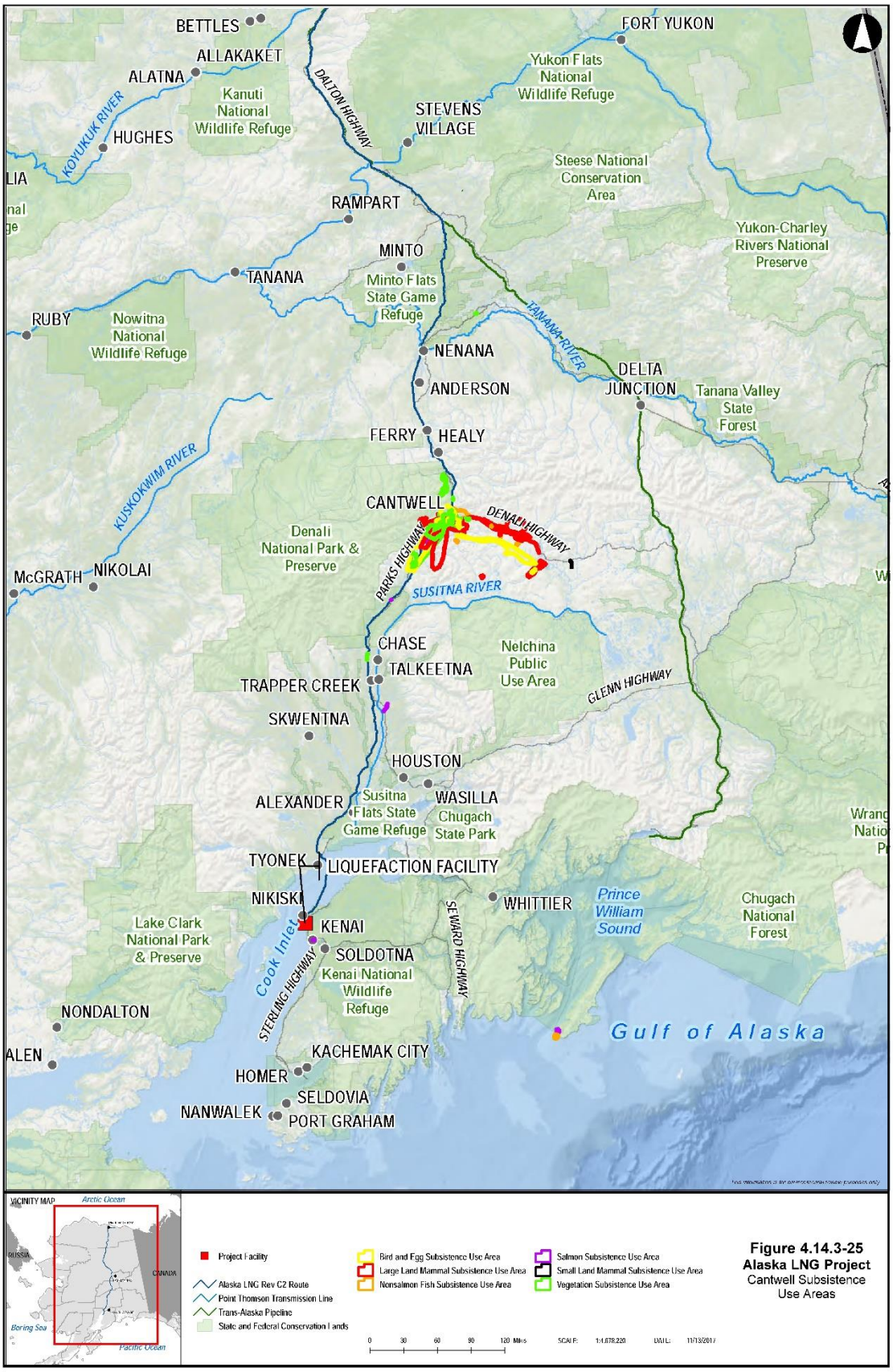


Figure 4.14.3-25
Alaska LNG Project
Cantwell Subsistence Use Areas

Harvest Data

Cantwell households reported using a wide range of resources in 2012. More than 80 percent of households made use of large land mammals and vegetation. More than 70 percent made use of salmon, and 60 percent used non-salmon fish. Small land mammals and birds and eggs were used by 21.8 and 30.9 percent of households, respectively. Considerably smaller percentages of households made use of marine mammals (1.8 percent) and marine invertebrates (3.6 percent) (Holen et al., 2014).

Based on 2013 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community totaled 19,759.8 pounds, or 121.4 pounds per capita (Holen et al., 2014). Large land mammals had the most use (72.0 pounds per capita), followed by salmon (35.9 pounds per capita), non-salmon fish (6.5 pounds per capita), and vegetation (5.2 pounds per capita). Far less use, as measured in pounds per capita, was made of small land mammals and birds and eggs (see table 4.14.3-44).

TABLE 4.14.3-44

Estimated Subsistence Harvest for Cantwell

Resource	Per Capita (pounds)	Total (pounds)
Caribou	13.0	2,550.4
Moose	51.9	10,186.4
Bear	7.1	1,394.4
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land Mammals	0.8	163.3
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	0.5	102.7
Upland birds	0.5	98.8
Eggs	–	–
Pacific salmon	35.9	2,978.3
Non-salmon fish	6.5	1,274.6
Berries	4.9	953.9
Plants	0.3	57.0
Wood	–	–
Other	–	–

Source: Holen et al, 2014
"–" = No harvest for this resource was reported.

The most important subsistence resources measured in harvested pounds per capita were terrestrial resources, including moose and caribou, followed by salmon and non-salmon fish (Holen et al., 2014).

Impacts on Subsistence

Cantwell is a community at the intersection of the Parks and Denali highways. Construction within the Cantwell subsistence use area would occur between April of Year 1 and December of Year 4.

Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. A construction camp would be constructed in Cantwell and several access roads would be built between the Project mainline and Parks Highway in Cantwell's subsistence use area. Blasting would occur within 0.5 mile of Cantwell's subsistence use areas. The Project would overlap Cantwell subsistence use areas for 12 resources, including five resources of high material and cultural importance (moose, caribou, salmon, non-salmon fish, and berries), three resources of moderate importance (small land mammals, upland game birds, and wood), and four resources of low importance (Dall sheep, bear, migratory birds, and plants). The subsistence use areas for non-salmon fish are also overlapped by the Project shipping route in Cook Inlet.

Construction activity could temporarily displace subsistence resources, such as moose, caribou, bear, small land mammals, and birds along the Project corridor; reduce the availability of fish in streams and rivers crossed by the Project; temporarily block harvester access to subsistence use areas; and permanently convert vegetation within the subsistence areas. An increase in Project employees in the area could result in competition for resources during Project construction. Data on the timing of subsistence for Cantwell indicate that summer construction activities could conflict with summer salmon and non-salmon fish harvests; moose, caribou, bear, and waterfowl hunting; and harvests of plants and berries. Residents' use areas are concentrated along the existing highway corridor at distances of under 1 mile where competition has been noted by residents. Competition would continue during Project operation.

Chase

The community of Chase is on the eastern side of the Susitna River on the western edge of the Talkeetna Mountains. In the Chase vicinity, the Alaska Railroad follows the eastern side of the Susitna River and passes between the community and the river. Chase is about 88 miles north of Anchorage and 9 miles north of Talkeetna.

While Chase is in a region long occupied by Dena'ina Athabascans, the history of the community began in 1919 when a railroad station was established. The station was named after Nancy Chase, the daughter of a representative of the Alaskan Engineering Commission. In 1927, a creamery was established in the vicinity; however, it was out of business by 1933. The current community was established when the state government began selling land in the area. The modern community has no school, local businesses, or government services. It is not on the road system but is connected to Talkeetna by an all-terrain vehicle trail. Access to the community is also provided by the Alaska Railroad (Holen et al., 2014).

In 2012, the ADF&G estimated a population of 35 individuals, none of whom were Alaska Natives, living in 18 households (Holen et al., 2014). ADF&G investigators interviewed 16 of the 18 households in the community. All the households surveyed reported harvesting and using subsistence resources.

The ADF&G reported that 14 of the 18 households in the community received cash income through employment. More than 75 percent of the income earned by community members was provided through employment by local service providers (50.0 percent) and mining (25.5 percent) (Holen et al., 2014).

Subsistence Use Areas

Figure 4.14.3-26 depicts the extent of the Chase subsistence use areas. Chase community's subsistence use areas follow the Susitna River and expands to the east over land and along drainage systems. Chase subsistence users follow the Susitna River from the Talkeetna area as far north as the confluence with Portage Creek. The use areas extend to the east along the Talkeetna River and into the Talkeetna Mountains. Isolated use areas occur on the Chulitna River, Susitna River, and near the junction of the Parks Highway and Talkeetna Spur Road. The Project would intersect with one use area where the Parks Highway crosses the Susitna River.

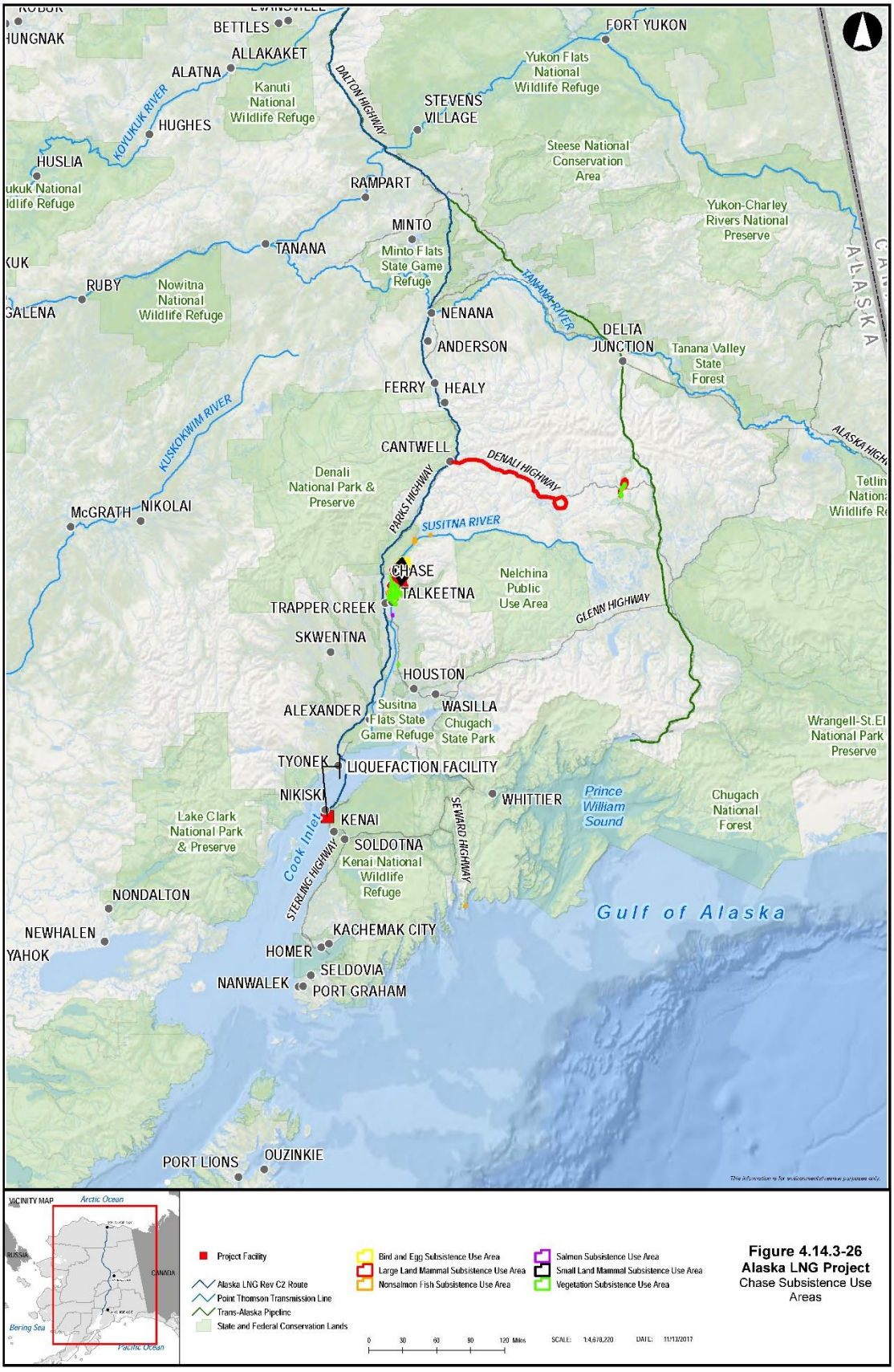


Figure 4.14.3-26
Alaska LNG Project
Chase Subsistence Use Areas

Seasonal Round

The number of resource categories hunted or harvested is relatively stable year-round with more activity in August and September and less activity in December and March (see table 4.14.3-45). Spring (April and May) harvests of non-salmon fish are common, as is bear hunting in late May. Non-salmon fish harvested during the spring include rainbow trout, Dolly Varden, arctic grayling, whitefish in local watersheds, and Pacific halibut from Cook Inlet or Prince William Sound. Additional subsistence activities include digging clams, likely from Cook Inlet or Prince William Sound, collecting wood, and harvesting upland game birds and American beavers.

TABLE 4.14.3-45

Chase Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon	■	■	■	■	■	■	■	■	■	■	■	■
Marine non-salmon					■	■	■	■	■			
Pacific salmon						■	■	■	■	■		
Caribou								■	■	■	■	
Moose		■							■		■	
Bear					■			■				
Furbearers	■											
Small land mammals	■	■	■	■							■	■
Upland birds	■	■	■	■							■	■
Waterfowl								■	■	■		
Marine invertebrates				■	■	■	■	■	■			
Plants and berries								■	■	■		
Wood	■	■	■	■	■	■	■	■	■	■	■	■

Source: Braund, 2015

During summer (June through August), residents continue to harvest many of the same subsistence resources until the salmon begin to run in the Susitna and Talkeetna Rivers. In late summer and into fall, caribou harvests occur to the north; harvests are primarily from the Nelchina caribou herd near the Denali Highway. Additionally, late summer marks the beginning of harvesting ducks and geese, bear, moose, hare, and berries. Chase residents also begin to harvest upland game birds during the late summer.

During the fall (September through October), Chase residents continue to harvest salmon, non-salmon fish, marine invertebrates, caribou, and black bear. Fall activities also include berry picking, and moose, ptarmigan, grouse, and duck hunting. Residents also harvest wood in fall.

During the winter (November through March), Chase residents trap and hunt small game and furbearers and take advantage of snow machines to transport wood. Residents continue to harvest caribou into early winter as well as upland birds. Residents ice fish specifically for trout and burbot during the winter, with an occasional moose harvest.

Harvest Data

Chase households reported using a wide range of resources in 2012. All households reported using vegetation, and more than 80 percent reported using salmon and large land mammals. Almost 70 percent

reported using non-salmon fish and birds and eggs. Twenty-five percent reported using small land mammals. Much smaller percentages, 6.3 and 12.5 percent, respectively, reported using marine mammals and marine invertebrates (Holen et al., 2014).

Based on 2013 survey data, the ADF&G estimated that the total weight of subsistence resources harvested by the community was 6,834.6 pounds, or 195.8 pounds per capita (Holen et al., 2014). Large land mammals and salmon were used the most, accounting for weights of 97.5 and 44.8 pounds per capita. Residents of Chase harvested 30.3 pounds of vegetation and 13.1 pounds of non-salmon fish per capita. Other resources, i.e., small land mammals, birds, and eggs, received much less use (see table 4.14.3-46).

The most important subsistence resources measured in harvested pounds per capita included moose, caribou, blueberry, highbush cranberry, American beaver, and black bear. Of these six resources, moose and caribou were ranked number one and two, respectively. Three additional species, including salmon, one non-salmon fish, and Pacific halibut, also made the top ten list (Holen et al., 2014).

TABLE 4.14.3-46

Estimated Subsistence Harvest for Chase

Resource	Per Capita (pounds)	Total (pounds)
Caribou	50.3	1,755.0
Moose	43.5	1,518.8
Bear	3.7	130.5
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	4.8	168.9
Marine mammals	–	–
Marine invertebrates	–	–
Migratory birds	0.2	5.6
Upland birds	5.1	176.7
Eggs	–	–
Pacific salmon	44.8	1,561.2
Non-salmon fish	13.1	456.5
Berries	26.9	939.9
Plants	3.5	121.5
Wood	–	–
Other	–	–

Source: Holen et al., 2014
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Construction of the Project where it extends through Chase's subsistence use area along the Parks Highway (from the Denali Highway in the north to the northern boundary of the state nonsubsistence area in the south) would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Two construction camps and several access roads would be constructed along the Parks

Highway, but at a distance from the community. Blasting would occur within 0.5 mile of Chase's subsistence use areas. The Project would overlap use areas for seven resources, including five of high material and cultural importance (moose, upland game birds, salmon, non-salmon fish, and berries), one of moderate importance (caribou), and one of low importance (bear).

Construction activity could temporarily displace subsistence resources such as moose, caribou, bear, and upland birds; reduce the availability of fish in streams and rivers crossed by the Project; temporarily limit harvester access to subsistence use areas; and permanently convert vegetation (berries) within the subsistence areas. An increase in Project employees in the area could result in competition for resources during Project construction. Data on the timing of subsistence for Chase indicate that summer construction activities could conflict with summer salmon and year-round non-salmon fish harvests, and moose, caribou, bear, and waterfowl harvests. Residents' use areas are concentrated along the existing highway corridor at distances of under 1 mile where competition has been noted by residents. Competition would continue during Project operation.

Talkeetna

The community of Talkeetna is on the east side of the Susitna River, immediately downstream of its confluence with the Talkeetna River and about 2 miles downstream from the confluence of the Susitna and Chulitna Rivers. Talkeetna is on the northeastern edge of the Cook Inlet-Susitna Lowland, a region encompassing the Susitna River valley and Cook Inlet, consisting primarily of Quaternary sediments.

Talkeetna can be reached by the Talkeetna Road, a 13-mile-long spur highway connecting the community with the George Parks Highway. Talkeetna is about 70 miles southeast of the DNPP and about 80 miles north of Anchorage.

Although the region had been long occupied by Dena'ina Athabascans, the history of the contemporary community extends back to the 1890s when a mining boom on the lower Susitna River drew Euro-American settlers to the region. The town itself was established in 1919 as the headquarters for construction of the Alaska Railroad between Seward and Fairbanks (Holen et al., 2014).

The influenza epidemic of 1918, the end of railroad construction, and the decline of mining in the area led to reductions in the local population. After the Second World War, however, settlement in the area resumed. More recently, the community has emerged as a popular tourist destination for visitors to the Alaskan interior and DNPP. Today, Talkeetna supports a wide variety of government services and private businesses (Holen et al., 2014).

In 2012, the ADF&G estimated a population of 788 individuals living in 374 households in Talkeetna. The Alaska Native population recorded by the ADF&G was 29 individuals (Holen et al., 2014). Most of the 102 households contacted by the ADF&G in 2013 reported harvesting (90.2 percent) and using (96.1 percent) subsistence resources.

The ADF&G reported that 83 percent of households in the community received cash income through employment. Most of the income earned by community members was provided through local service providers (36.6 percent), local government (17.4 percent), and the transportation, communication, and utility industry (14.1 percent) (Holen et al., 2014).

Subsistence Use Areas

Figure 4.14.3-27 depicts the extent of the Talkeetna subsistence use areas. The Talkeetna community's use areas have only been documented in one previous study (Holen et al., 2014). The use

areas are mostly within the Susitna River Drainage along the George Parks and Denali Highways from the Clearwater Mountains south to the Talkeetna Mountains near the Knik Arm. Concentrations of subsistence use occur near Talkeetna both to the east and west along Petersville Road. Isolated use areas also occur in the Clearwater Mountains, at Deadman and Big Lakes, several areas along the upper Susitna River, and other areas throughout the Matanuska-Susitna Valley. Additionally, fish and marine invertebrate harvest areas are in several locations throughout the Cook Inlet waters. The Project would intersect the Talkeetna use area along various portions of the George Parks Highway.

Seasonal Round

Limited data are available for Talkeetna subsistence seasonal rounds; therefore, a subsistence harvest calendar is not provided. The ADF&G study documented monthly harvest data for large land mammals and gray wolf, of which only caribou (August through November) and moose (September) were taken during the 2012 study period. Holen et al. (2014) report Talkeetna residents ice fish and collect plants in the spring. The summer season is focused on fishing, either in the local watersheds or by travelling south to the Kenai Peninsula. During fall, Talkeetna residents harvest large land mammals, including moose and caribou. Caribou harvests occur from late summer and continue into the winter. Trapping furbearers and small game is the main subsistence activity in the winter, accompanied by some ice fishing and harvests of upland birds.

Harvest Data

Talkeetna households reported using a wide range of resources in 2012. More than 80 percent reported using salmon and vegetation. More than half reported using non-salmon fish and large land mammals. Almost a quarter reported the use of birds and eggs, and more than 15 percent reported the use of marine invertebrates.

Based on 2013 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 42,020.1 pounds, or 53.3 pounds per capita (Holen et al., 2014). The most important subsistence resource measured in harvested pounds per capita is salmon (23.7 pounds per capita), followed by berries (8.9 pounds per capita), caribou (7.3 pounds per capita), and non-salmon fish (4.9 pounds per capita). Far less use, as measured in pounds per capita, was made of small land mammals, marine invertebrates, and plants (see table 4.14.3-47).

Impacts on Subsistence

Talkeetna is on the Talkeetna Spur Road off of the Parks Highway, at the union of the Susitna and Talkeetna Rivers within a state nonsubsistence area. Talkeetna is about 5 miles east of the Project. The closest area of the Project where residents could conduct subsistence activities under state and/or federal law is about 20 air miles to the northwest of the community and farther by road. Outside of and within the nonsubsistence area, the Project overlaps Talkeetna subsistence use areas for 11 resources, including five of high material and cultural importance (moose, salmon, non-salmon fish, berries, and wood), four of moderate importance (caribou, small land mammals, upland game birds, and plants), and two of low importance (bear and migratory birds). Construction would temporarily impact access to and availability of resources as a result of habitat loss, increased competition, and additional cost and effort to harvest resources. Residents' use areas are concentrated along the existing highway corridor at distances of under 1 mile where competition has been noted by residents. Competition for resources would continue during Project operation.

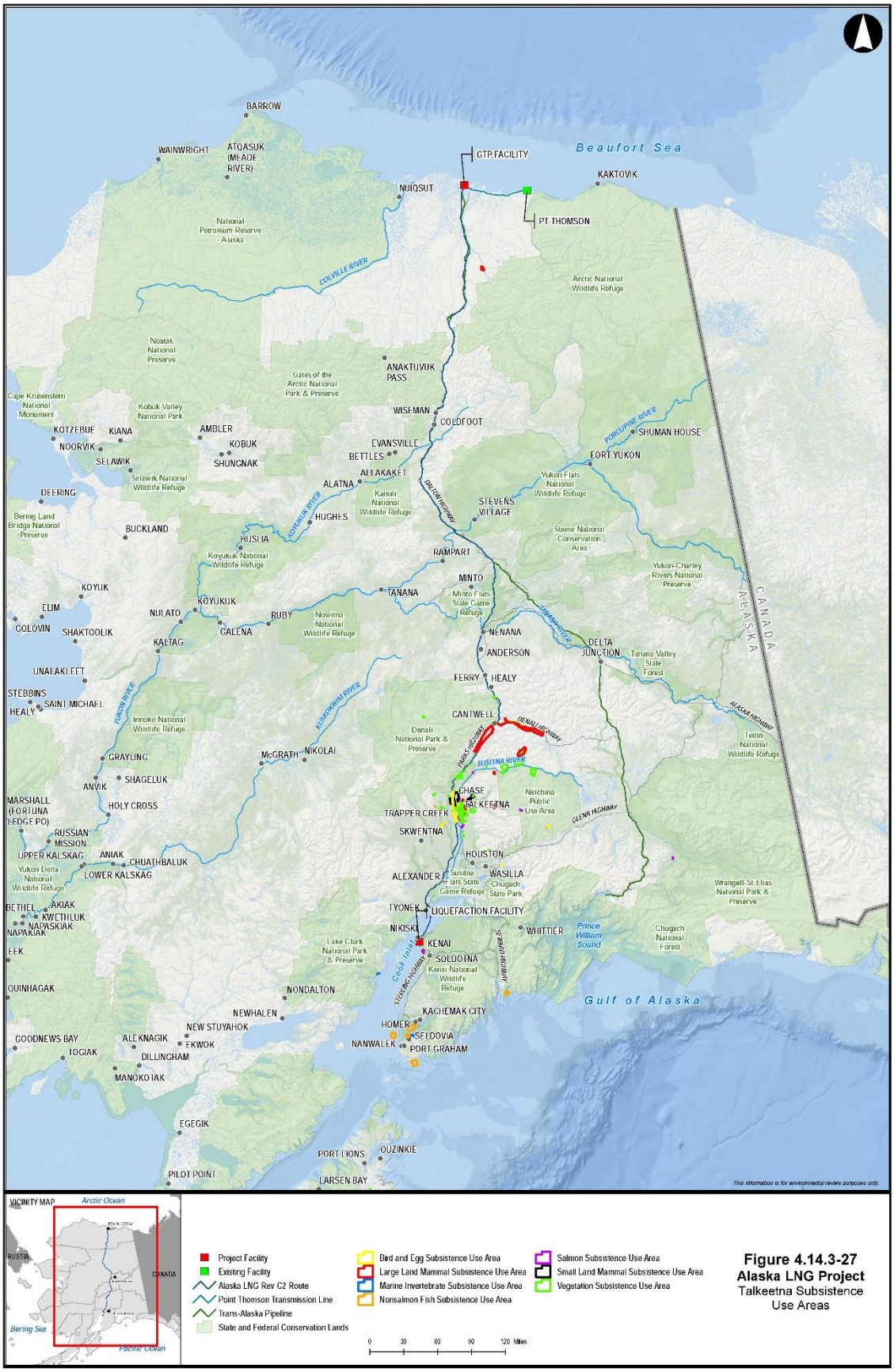


Figure 4.14.3-27
Alaska LNG Project
Talkeetna Subsistence Use Areas

TABLE 4.14.3-47

Estimated Subsistence Harvest for Talkeetna

Resource	Per Capita (pounds)	Total (pounds)
Caribou	7.3	5,720.0
Moose	4.2	3,300.0
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	2.9	2,255.0
Marine mammals	–	–
Marine invertebrates	0.6	476.5
Migratory birds	<0.1	11.4
Upland birds	0.3	261.1
Eggs	–	–
Pacific salmon	23.7	18,709.6
Non-salmon fish	4.9	3,891.1
Berries	8.9	6,994.0
Plants	0.5	396.9
Wood	<0.1	4.6
Other	–	–

Source: Holen et al., 2014
"–" = No harvest for this resource was reported.

Construction of the Project within Talkeetna's subsistence use area along the Parks Highway (from the Denali Highway in the north to the northern boundary of the state nonsubsistence area in the south) would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Two construction camps and several access roads would be constructed along the Parks Highway, but at a substantial distance from the community of Talkeetna. Talkeetna subsistence use areas occur along the Dalton Highway on the North Slope, where construction would take place during winter. Summer construction could displace caribou and moose hunting, and winter construction activities could displace caribou and furbearers, and limit access for ice fishing.

Trapper Creek

The community of Trapper Creek is in the Cook Inlet-Susitna Lowland on the western side of the Susitna River about 3 miles southwest of the confluence of the Susitna and Chulitna Rivers. The community of Talkeetna is on the opposite side of the Susitna River about 4 miles to the east. Trapper Creek is an unincorporated community that consists of residences within about 14 miles of the intersection of the George Parks Highway and the Petersville Road (Holen et al., 2014).

Archaeological work suggests that the occupation of the Trapper Creek area dates to at least 11,000 to 9,000 years ago. At the beginning of the historic era, the Cook Inlet-Susitna Lowland was occupied by Dena'ina Athabascans, although use of the region by the Dena'ina tended to focus on areas south of the Trapper Creek area (Holen et al., 2014).

During the first half of the 20th century, the economy of the area was focused on mining and trapping. The late 1960s brought more settlement to the area with the construction of the George Parks Highway and state land sales that encouraged homesteading. Many of the newer residents began small-scale agriculture. Today, in addition to residences, Trapper Creek supports a fire station, gas station, elementary school, and numerous summer cabins (Holen et al., 2014).

In 2012, the ADF&G estimated a population of 335 individuals living in 148 households. The Alaska Native population recorded by the ADF&G was 19 individuals (Holen et al., 2014). Investigators from the ADF&G interviewed 69 of the 148 households in the community. Most of the households surveyed by the ADF&G in 2013 reported harvesting (95.6 percent) and using (98.5 percent) subsistence resources.

The ADF&G reported that 74 percent of households in the community received cash income through employment. Most of the income earned by community members was provided through employment by local service providers (36.9 percent). Other occupations provided small contributions to community income, including local government (10.5 percent), construction (11.6 percent), and transportation, communication, and utilities (12.4 percent) (Holen et al., 2014).

Subsistence Use Areas

Trapper Creek community's subsistence use areas extend north to Cantwell, south to the confluence of the Deshka and Susitna Rivers, west of Peters Creek, and east near the Nelchina River (see figure 4.14.3-28). The subsistence use areas primarily follow the Chulitna and Susitna Rivers and associated tributaries. Trapper Creek residents use an isolated portion of the Denali Highway corridor, including areas west of the Susitna River. Additionally, Trapper Creek subsistence use areas were also reported in Cook Inlet waters for salmon, non-salmon fish, and marine invertebrates. The Project would intersect with Trapper Creek residents' subsistence use areas along the George Parks Highway from the Chulitna River area to just south of Trapper Creek, and then again intermittently until the confluence of the Deshka and Susitna Rivers. The Project would overlap with Trapper Creek use areas along the George Parks Highway, Petersville Road, and Susitna River.

Seasonal Round

Limited data are available for Trapper Creek subsistence seasonal rounds; therefore, a subsistence harvest calendar is not provided. The ADF&G study documented monthly harvest data for large land mammals and gray wolf, of which only caribou (September and November), moose (September), and bear (May and June) were taken during the 2012 study period (Holen et al., 2014). Spring subsistence activities are not explicitly addressed in the ADF&G study. Bear harvests occur in late spring and early summer. Trapper Creek residents harvest salmon from the Susitna River and its tributaries in the late summer. Large land mammal harvests, particularly moose, occur in the fall; however, some residents travel north to hunt caribou off the Denali Highway. Furbearer harvest occurs in the winter months along with non-salmon fish and wood harvests.

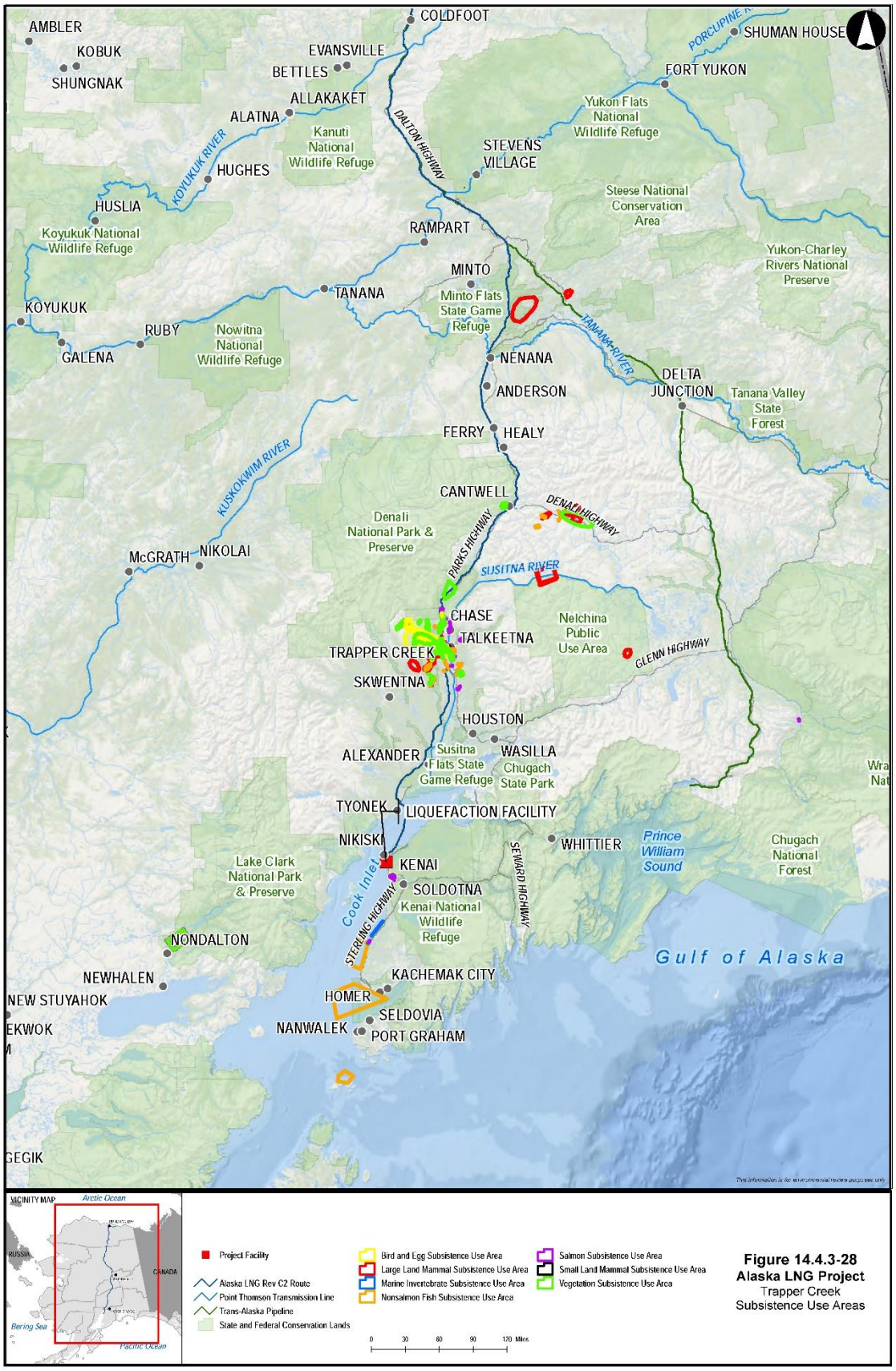


Figure 14.4.3-28
Alaska LNG Project
Trapper Creek
Subsistence Use Areas

Harvest Data

Trapper Creek households reported using a wide range of resources in 2012 (see table 4.14.3-48). The most commonly used resource was vegetation, which 94.1 percent of households reported using. Fish were the next most commonly used resource, with 82.4 percent reporting the use of salmon and 67.6 percent reporting use of non-salmon fish. Large land mammals, birds and eggs, and small land mammals were used by 66.2, 38.2, and 13.2 percent of Trapper Creek residents, respectively. Considerably smaller percentages of households made use of marine mammals (4.4 percent) and marine invertebrates (7.4 percent) (Holen et al., 2014).

TABLE 4.14.3-48

Estimated Subsistence Harvest for Trapper Creek

Resource	Per Capita (pounds)	Total (pounds)
Caribou	2.5	836.5
Moose	11.5	3,860.9
Bear	0.7	248.8
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	1.5	496.6
Marine mammals	–	–
Marine invertebrates	0.8	282.1
Migratory birds	0.1	16.4
Upland birds	1.6	545.2
Eggs	–	–
Pacific salmon	25.0	8,351.5
Non-salmon fish	9.7	3,241.1
Berries	6.8	2,266.1
Plants	0.8	258.7
Wood	<0.1	2.6
Other	–	–

Source: Holen et al., 2014
"–" = No harvest for this resource was reported.

Based on 2013 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 20,406.5 pounds, or 60.9 pounds per capita (Holen et al., 2014). Salmon were most heavily harvested, with Trapper Creek residents harvesting 25.0 pounds per capita. Large land mammals were the next most heavily harvested resource (14.7 pounds per capita), followed by non-salmon fish (9.7 pounds per capita), and vegetation (7.5 pounds per capita). Considerably smaller per capita harvests were reported for small land mammals (1.5 pounds) and birds and eggs (1.7 pounds). Only a small per capita harvest was reported for marine invertebrates (0.8 pound). The most important subsistence resource measured in harvested pounds per capita was salmon, followed by moose (Holen et al., 2014).

Impacts on Subsistence

Trapper Creek is on the Parks Highway, west of the Susitna River along the Mainline Pipeline. The community is within a state nonsubsistence area. The closest area of the Project where residents could conduct subsistence activities under state and/or federal law is about 20 miles to the north of the community. Trapper Creek use areas are crossed by the Project outside and within the nonsubsistence use area. Construction near and within Trapper Creek's subsistence use area along the Parks Highway (from the Denali Highway in the north to the northern boundary of the state nonsubsistence area in the south) would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Two construction camps and several access roads would be constructed along the Parks Highway, but at a distance from Trapper Creek.

The Project would overlap subsistence use areas for eight resources, including five of high material and cultural importance (moose, salmon, non-salmon fish, berries, and wood), two of moderate importance (caribou and plants), and one of low importance (bear). The Project overlaps with use areas for small land mammals, migratory birds, and upland game birds, but only in the state nonsubsistence area. In addition to the Mainline Pipeline, subsistence use areas for non-salmon fish are crossed by the shipping route in Cook Inlet. Summer construction activities could conflict with caribou, moose, and bear hunting, in addition to summer salmon harvesting.

Construction would temporarily impact access to and availability of resources as a result of habitat loss, increased competition, and additional cost and effort to harvest these resources. Residents' use areas are concentrated along the existing highway corridor at distances of under 1 mile where competition has been noted by residents. Competition would continue during Project operation.

Skwentna

Skwentna is a 450-square-mile CDP in the Cook Inlet-Susitna Lowlands, centered on the confluence of the Skwentna and Yentna Rivers. Both the Skwentna and Yentna Rivers are heavily braided streams, and the riverine lowland surrounding the confluence is characterized by numerous meander scars. The Skwentna CDP encompasses 35 year-round residences spread throughout the CDP, as well as numerous seasonal homes (Holen et al., 2014).

The CDP is within the Dena'ina Athabascan language region. Numerous historic villages and fish camps have been documented in the vicinity of the Skwentna CDP and demonstrate intensive use of the area by the Dena'ina. Archaeological work in the vicinity suggests that the human occupation of the area extends at least 3,600 years into the past (Holen et al., 2014).

In 1908, the Alaska Road Commission built the Iditarod Trail, which crosses the Skwentna River about 10 miles upstream of its confluence with the Yentna. Shortly after the completion of the trail, the Skwentna Roadhouse was established to provide services to travelers on the trail. In 1937, a post office was opened, and after the Second World War, an airstrip was built and a military radar station was established. In the 1960s, the population of the Skwentna area increased as a result of state land sales that encouraged homesteading (Holen et al., 2014).

Today, Skwentna proper is defined by the roadhouse and airstrip. Skwentna proper is at the confluence of the Skwentna River and Eight Mile Creek, which in turn is a short distance upstream of the confluence of the Skwentna and Yentna Rivers. Although the post office remains open, the Skwentna CDP does not possess a school, store, or government offices (Holen et al., 2014).

In 2013, the ADF&G conducted a study of the harvest and use of subsistence resources in 2012 by Skwentna residents (Holen et al., 2014). The ADF&G estimated a population of 62 individuals living in 35 households. The Alaska Native population recorded by the ADF&G was two individuals. Investigators from the ADF&G interviewed 30 of the 35 households in the community. All households surveyed by the ADF&G in 2013 reported harvesting and using subsistence resources (Holen et al., 2014).The ADF&G reported that 57 percent of households in the community received cash income through employment. Most of the income earned by community members (74.3 percent) was provided through employment by local service providers (Holen et al., 2014).

Subsistence Use Areas

Figure 4.14.3-29 depicts the extent of the Skwentna subsistence use areas. Skwentna community's subsistence use areas extend from the northern shore of Cook Inlet into the Yentna and Skwentna drainage systems of the Alaska Range. The use areas span an area along the eastern flanks of the Alaska Range to the flats east of the Kahiltna and Yentna Rivers. Use areas occur as far north as the headwaters of the Yentna River and south into overland areas just north of Beluga Lake. Isolated use areas also occur at the mouth of the Susitna River and upriver locations, including the Big Lake area and Turnagain Arm. Additional use areas were reported for marine invertebrates in Cook Inlet waters as well as for deer on Kodiak Island. The Project would overlap an isolated, small subsistence use area along the Susitna River.

Seasonal Round

Skwentna community's subsistence activity is highest in the fall and declines in late winter, with the fewest resources targeted in March (see table 4.14.3-49). The harvest of non-salmon fish, bear, muskrat, and plants occurs during spring (April through May). Residents also occasionally harvest upland birds, waterfowl, American beaver, and snowshoe hare at this time. Fishing in the Upper Yentna area begins when rivers start to melt and continues throughout summer and into fall. Fish species harvested in the spring include rainbow trout, arctic grayling, whitefish, northern pike, sucker, and eulachon (local name is "hooligan"). American beaver and muskrat, which are trapped during the spring, are used primarily for dog food and fur. Bear is considered a nuisance, but black bear are sometimes harvested for subsistence purposes (Fall et al., 1983). Skwentna residents begin to harvest the first plants of the season in late spring.

Summer (June through August) subsistence activities in the Upper Yentna area include the continued harvest of non-salmon fish species, bears, plants, and muskrats. Skwentna residents begin to harvest salmon in the summer in the Yentna, Skwentna, Susitna, and Talachulitna Rivers, and in Lake Creek. Additional summer resources include North American porcupine, berries, and spruce grouse. During August, residents begin to harvest caribou and Dall sheep.

Primary fall (September through October) subsistence activities include hunting large land mammals, such as deer, caribou, and Dall sheep; ducks and geese; and snowshoe hare. Moose are typically harvested in the winter, but residents occasionally participate in the fall moose hunt. Residents continue to harvest a number of resources including wood, bear, several species of salmon, berries, and spruce grouse.

Winter (November through March) harvests include fish such as burbot and lake trout through the ice, furbearers, and small land mammals including red squirrels, coyotes, Canadian lynx, wolverine, American beavers, and an occasional gray wolf. Residents continue to harvest moose through the winter by snow machine along the frozen waterways. Wood is harvested year-round and provides an important heating source for Skwentna residents.

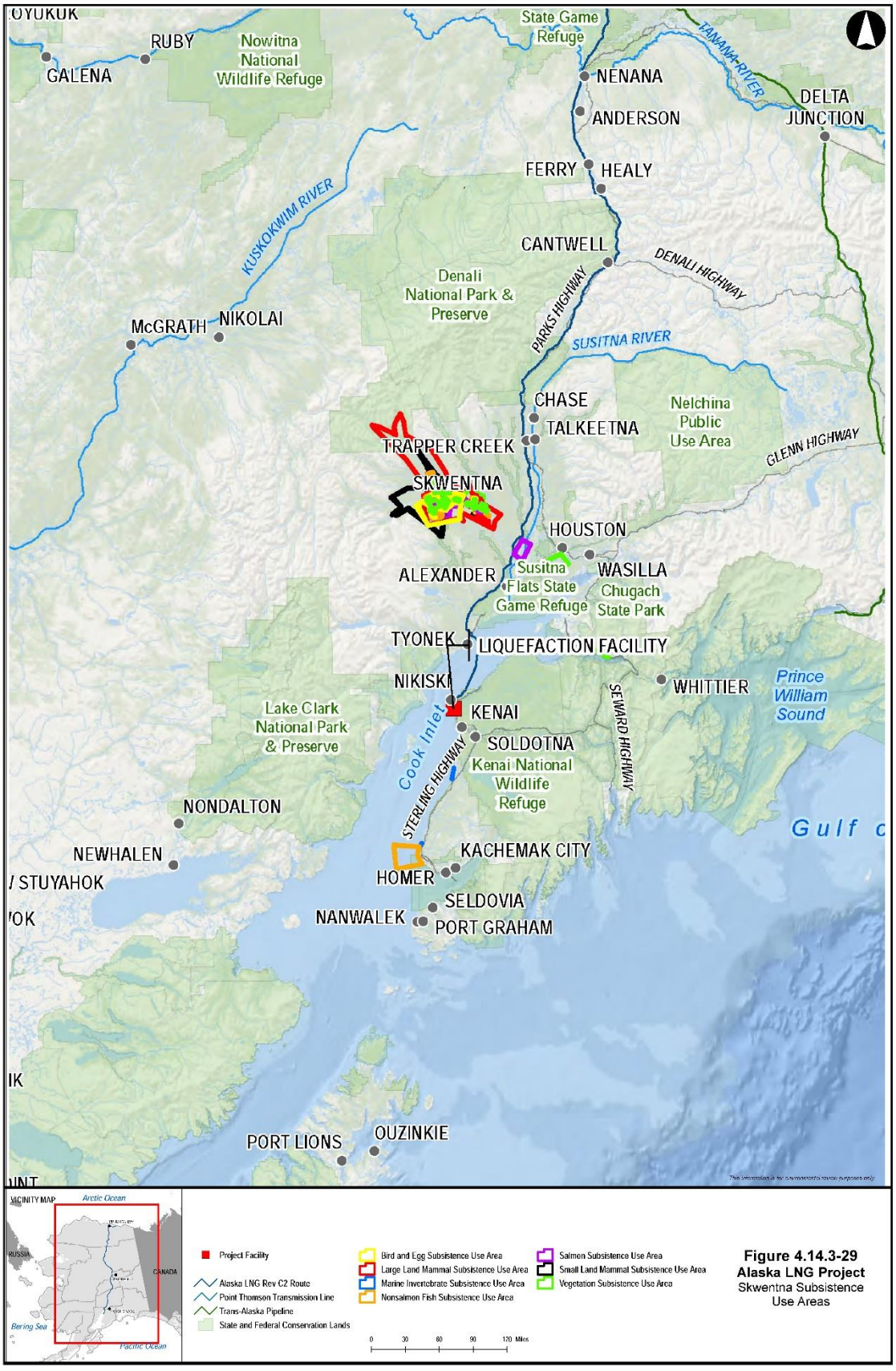


Figure 4.14.3-29
Alaska LNG Project
Skwentna Subsistence Use Areas

TABLE 4.14.3-49

Skwentna Subsistence Harvest Timing

Resource	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon	■	■	■	■	■	■	■	■	■	■	■	■
Pacific salmon						■	■	■	■	■		
Caribou								■	■	■		
Moose	■	■							■			■
Bear					■	■	■					
Deer										■		
Dall sheep								■	■			
Furbearers	■	■	■								■	■
Small land mammals	■	■	■	■	■	■	■	■	■	■	■	■
Upland birds	■	■	■	■	■	■	■	■	■	■	■	■
Waterfowl				■	■	■		■	■	■	■	
Plants and berries				■	■	■	■	■	■	■		
Wood	■	■	■	■	■	■	■	■	■	■	■	■

Source: Braund, 2015

Harvest Data

Skwentna households reported using a wide range of resources in 2012 (see table 4.14.3-50). Ninety percent or more of households reported using salmon and vegetation. The use of non-salmon fish, large land mammals, birds and eggs, and small land mammals was reported by 80, 73.3, 66.7, and 26.7 percent of households, respectively. Only 16.7 percent reported the use of marine invertebrates (Holen et al., 2014).

Based on 2013 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 9,965.7 pounds, or 161.2 pounds per capita (Holen et al., 2014). Large land mammal was the category of subsistence resource receiving the heaviest use (71.8 pounds harvested per capita), followed by salmon (54.3 pounds per capita), non-salmon fish (19.5 pounds per capita), and vegetation (7.9 pounds per capita). Far less use, as measured in pounds per capita, was made of small land mammals, birds and eggs, and marine invertebrates.

The most important subsistence resource measured in harvested pounds per capita was moose, which consisted of twice the amount of the second most harvested resource by weight, coho salmon. Four of the top ten resources were salmon species (Holen et al., 2014).

Impacts on Subsistence

The community of Skwentna is on the Skwentna River near its union with the Yentna River, about 30 miles west of the Project. The Project crosses a nonsubsistence area to the southeast of the community near the Yentna River crossing. Construction would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, and terrain. The Project would overlap Skwentna subsistence use areas for two resources, including one of high material and/or cultural importance (moose) and one of low importance (bear). The Project would overlap use areas for salmon, a resource of high importance, but only in state

nonsubsistence areas. Construction would temporarily impact access to and availability of resources as a result of habitat loss, increased competition from non-local harvesters, and additional cost and effort to harvest these resources. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads in a previously undeveloped area used for subsistence west of the Susitna River.

TABLE 4.14.3-50

Estimated Subsistence Harvest for Skwentna

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	59.4	3,675.0
Bear	11.6	716.0
Dall sheep	–	–
Deer	0.8	49.6
Other large land mammals	–	–
Small land mammals	1.4	87.5
Marine mammals	–	–
Marine invertebrates	2.1	131.3
Migratory birds	1.4	87.9
Upland birds	2.8	172.4
Eggs	–	–
Pacific salmon	54.3	3,356.0
Non-salmon fish	19.5	1,203.4
Berries	6.5	401.0
Plants	1.4	85.6
Wood	–	–
Other	–	–

Source: Holen et al., 2014
"–" = No harvest for this resource was reported.

Construction activity could cause temporary displacement of land mammals, such as moose and bear, in areas crossed by the Project as well as temporarily limit harvest access to use areas downstream from the community. The Yentna River crossing would be open cut during the winter. Due to frozen conditions, habitat alteration, sedimentation, and decreased fish availability for upriver harvesters is not anticipated.

Alexander Creek/Susitna

The communities of Alexander and Susitna are encompassed within the 160-square-mile Susitna CDP, whose population consists of 24 individuals (including 2 Alaska Natives) living in 13 households. Twelve households are in Alexander Creek. Today, only one permanent household is in Susitna (Holen et al., 2014). Neither community supports any government or commercial services. Susitna and Alexander Creek are not on the road system. Access to the communities is provided by boat, aircraft, or snow machine (Holen et al., 2014).

The community of Susitna is on the southeast bank of the Susitna River, about 3 miles downstream of the confluence of the Susitna and Yentna Rivers. The community of Alexander is on the western side of the Susitna River and the western bank of Alexander Creek, just upstream of its confluence with the

Susitna River. Alexander is about 9 miles to the southwest of Susitna. The two communities are within the Cook Inlet-Susitna Lowland, a broad low-lying area composed largely of Quaternary sediments surrounding Cook Inlet and the Susitna River (Wahrhaftig, 1965).

Although their modern populations are predominately non-Native, both communities were important Dena'ina villages in the past. As a Dena'ina village, the community of Susitna may have had a population as large as 600 individuals. During the Russian occupation of Alaska, the economy of the region was closely tied to the fur trade, and Susitna was probably the location of a Russian Orthodox church during the late 19th century (Holen et al., 2014; Stanek et al., 2007). By this time, the local economic focus had shifted to mining, and the community was known as Susitna Station (Holen et al., 2014; Stanek et al., 2007). Three disease epidemics, including the 1918 influenza epidemic, drastically reduced the Dena'ina population in the early 20th century. By the 1930s, most of the Dena'ina residents of Susitna moved to Tyonek.

Alexander Creek was also an important traditional Dena'ina village. Like Susitna, the Dena'ina population decreased after the arrival of Euro-Americans. The disease epidemics that reduced the population of Susitna probably also affected Alexander as well, and by 1920, only two individuals were living in the community. After the Second World War, the population of Alexander Creek increased as the area became a popular destination for salmon fishing. The region now supports numerous fishing lodges. After the passage of ANCSA, the community sought recognition as a native village. In 1976, the village was recognized as a member of Cook Inlet Region Incorporated and was conveyed 1,686 acres of state land (Holen et al., 2014).

In 2013, the ADF&G conducted a study of the harvest and use of subsistence resources in 2012 by Alexander/Susitna residents. Investigators from the ADF&G interviewed 11 of the 13 households in the community. All of the households reported both harvesting and using subsistence resources (Holen et al., 2014).The ADF&G reported that 44 percent of households in the community received cash income through employment. Most of the income earned by community members was provided through employment by local service providers (67.2 percent), retail trade (20.2 percent), and the agriculture, forestry, and fishing sector (12.6 percent) (Holen et al., 2014).

Subsistence Use Areas

Figure 4.14.3-30 depicts the extent of the Alexander Creek subsistence use areas. Alexander Creek community's subsistence use extends from the mouth of the Susitna River to the confluence with the Kashwitna River in the north. From Red Shirt Lake in the east, the subsistence use areas encompass overland areas around Alexander Lake down to Theodore River in the west. An isolated use area was reported inland of Cook Inlet along the McArthur River. The Project would intersect the Alexander Creek use areas near the Susitna River.

Seasonal Round

Limited data are available for Alexander Creek subsistence seasonal rounds (Holen et al., 2014); therefore, a subsistence harvest calendar is not provided. The ADF&G study documented monthly harvest data for large land mammals and gray wolf, of which only caribou (August), moose (September and December), and bear (June) were taken during the 2012 study period. During spring (April through May), Alexander Creek residents catch freshwater fish from the McArthur River. In late spring, Chinook salmon are harvested in the McArthur and Susitna Rivers. Salmon fishing continues through the summer. Cod and Pacific halibut from Cook Inlet and Prince William Sound are also harvested in the summer season. Bear harvest begins in the summer and continues into the fall. Fall harvests of migratory birds and caribou also occur. Fall moose hunting is less common for Alexander Creek residents than is the winter moose hunt. Plant and berry harvests occur during the growing season in late spring, summer, and fall.

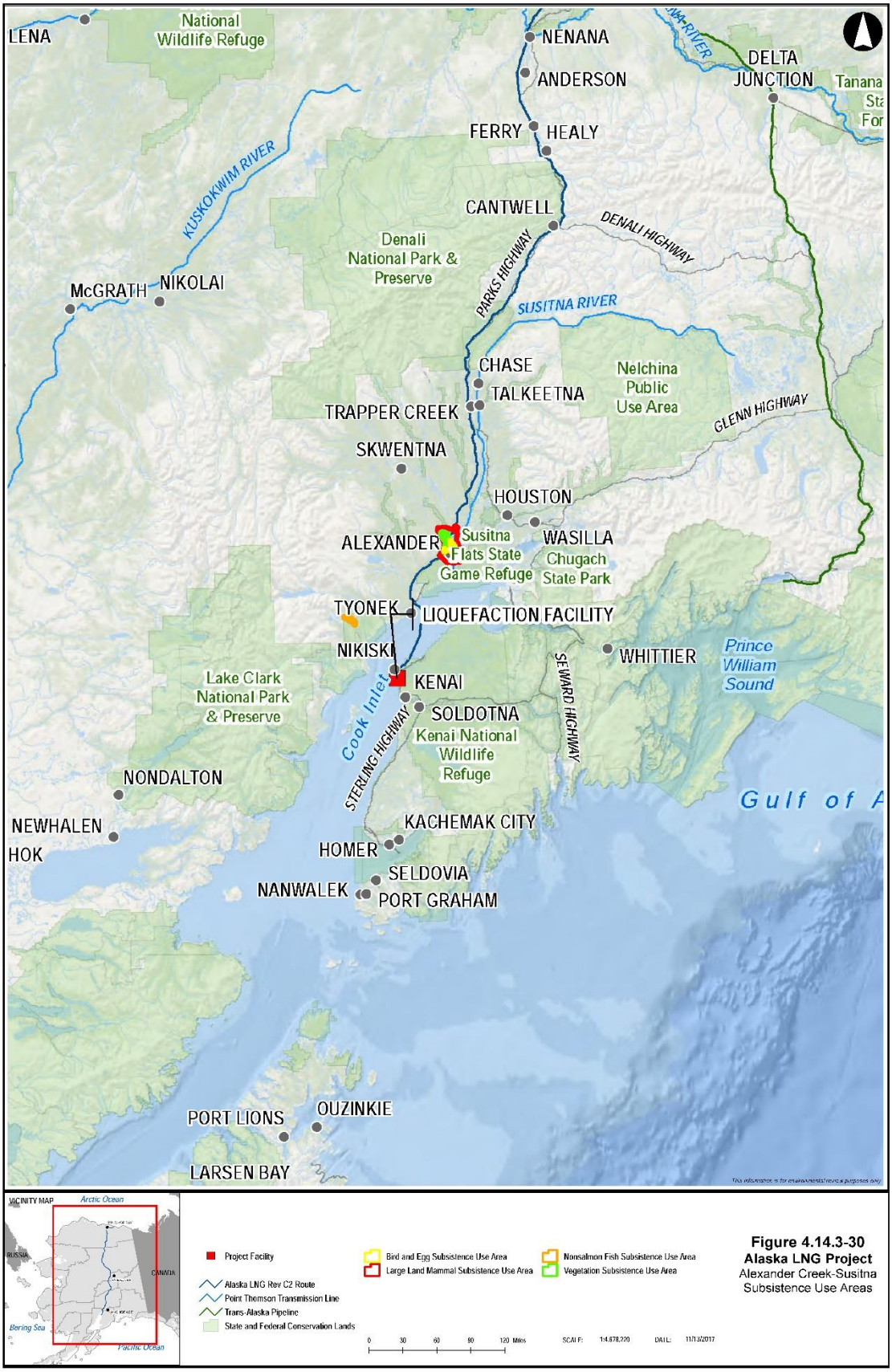


Figure 4.14.3-30
Alaska LNG Project
Alexander Creek-Susitna Subsistence Use Areas

Harvest Data

Alexander Creek/Susitna households reported using a wide range of resources in 2012 (see table 4.14.3-51). All households reported using salmon, large land mammals, and vegetation. The use of non-salmon fish and birds and eggs was reported by 81.8 and 63.6 percent of households, respectively. Only 9.1 percent of households reported using either small land mammals or marine invertebrates (Holen et al., 2014).

TABLE 4.14.3-51

Estimated Subsistence Harvest for Alexander Creek/Susitna

Resource	Per Capita (pounds)	Total (pounds)
Caribou	6.5	153.6
Moose	135.0	3,190.9
Bear	5.8	137.1
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	0.2	4.7
Marine mammals	–	–
Marine invertebrates	0.5	10.6
Migratory birds	0.3	7.1
Upland birds	2.1	50.8
Eggs	1.5	35.8
Pacific salmon	44.3	1,047.5
Non-salmon fish	4.0	95.4
Berries	17.1	410.7
Plants	1.3	31.0
Wood	–	–
Other	–	–

Source: Holen et al, 2014
"–" = No harvest for this resource was reported.

Based on 2013 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 5,175.2 pounds, or 218.6 pounds per capita (Holen et al., 2014). The category of subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was large land mammals (147.3 pounds per capita), followed by salmon (44.3 pounds per capita), and vegetation (18.4 pounds per capita). Far less use, as measured in pounds per capita, was made of non-salmon fish, small land mammals, birds and eggs, and marine invertebrates.

The most important subsistence resource measured in harvested pounds per capita was moose. Alexander Creek/Susitna residents harvested 135.0 pounds of moose per capita in 2012. The second and third-ranked resources were both species of salmon harvested in quantities of slightly over 20 pounds per capita. The remaining seven resources were harvested at much lower levels, at less than 10 pounds per capita (Holen et al., 2014).

Impacts on Subsistence

The community of Alexander Creek is on the west bank of Alexander Creek near its union with the Susitna River, near the base of Susitna Mountain. Construction would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. The Project would overlap with 12 subsistence resource areas, including five of high material and/or cultural importance (moose, salmon, non-salmon fish, berries, and wood), four of moderate importance (caribou, bear, upland game birds, and plants), and three of low importance (small land mammals, migratory birds, and marine invertebrates). In addition to the Mainline Facilities, the Project shipping route overlaps Alexander Creek use areas for non-salmon fish and marine invertebrates. Construction would temporarily impact access to and availability of resources as a result of habitat loss, increased competition from non-local harvesters, and additional cost and effort to harvest resources. Competition would likely extend into Project operation due to new access along the permanent right-of-way and access roads.

Beluga

The community of Beluga is on the western shore of Cook Inlet, about 4 miles southwest of the mouth of the Beluga River, 35 miles west of Anchorage, and 8 miles northeast of the Native Village of Tyonek. The community lies within the Cook Inlet-Susitna Lowland, a region of low-lying glaciated topography on both sides of Cook Inlet that extends from the Susitna River Drainage at the head of the inlet to Tuxedni Bay on the western shore, and Kachemak Bay on the eastern shore (Wahrhaftig, 1965). Most of the community is situated on comparatively high ground that follows the Cook Inlet shoreline for about 2 miles between the southwestern end of the Beluga airstrip and the mouth of Three Mile Creek.

Beluga is within the traditional territory of the Upper Inlet Dena'ina. Oral history notes the presence of a native village in the approximate location of the modern community. Russian Orthodox priests traveling in the area during the mid- to late 19th century made no mention of a community in this location (Stanek et al., 2007). However, a map produced by the 1895 Dall expedition recorded a location named Beluga on the Beluga River about 5 miles from its mouth. A map produced in 1933 by the USGS recorded the location of a community in about the same location. This location was further corroborated in 2006, when personnel from the ADF&G interviewed a local resident who recounted information provided by a fisherman who lived in the area in the 1930s (Stanek et al., 2007).

By the first half of the 20th century, fishermen were living seasonally in the area near Three Mile Creek. Structures in this location were documented on USGS topographic maps in 1958. The development of gas deposits in the vicinity of Beluga was followed by the establishment of permanent residences under the Federal Homestead Act and land purchases from the State of Alaska.

The present-day community offers few services, although a lighted, gravel airstrip at the northeastern end of the community is maintained through a public-private partnership. The Chugach Electrical Association and the Municipality of Anchorage operate a large, gas-powered electrical generating plant at Beluga and provide electrical power to residents. In addition to the airstrip, access to the community is provided by a barge-landing on Cook Inlet, and a road network connects Beluga to the village of Tyonek.

In 2006, the ADF&G conducted a study of the harvest and use of subsistence resources from 2005 to 2006 by Beluga residents (Stanek et al., 2007). The ADF&G estimated that the 2006 population of Beluga consisted of 40 individuals living in 15 households. In 2006, three residents of Beluga were Alaska Natives (Stanek et al., 2007).

Investigators from the ADF&G interviewed 14 of the 15 households in the community in 2006 (Stanek et al., 2007). Of the 14 households surveyed, 100 percent reported harvesting and using subsistence

resources. Additionally, all the interviewed households reported sharing resources with other households in the community, i.e., giving or receiving subsistence resources (Stanek et al., 2007).

The ADF&G estimated that 71 percent of households received cash income through employment (Stanek et al., 2007). The three primary sources of cash income were the transportation, communication, and utilities industry; local service providers; and agriculture, forestry, and fishing. These sources respectively provided 41, 30, and 10 percent of the cash income earned by community members. Other employers combined accounted for less than 20 percent of the cash income earned by community members (Stanek et al., 2007).

Subsistence Use Areas

Figure 4.14.3-31 depicts the extent of the Beluga subsistence use areas. Beluga community's subsistence use areas are documented along the northern shore of Cook Inlet from the mouth of the Susitna River to west of Tyonek. From the shore of Cook Inlet, the use areas extend to the north along the Chuit, Beluga, and Theodore Rivers. Overland use areas span across the river systems from the western banks of the Susitna River to the Chakachatna River. Isolated use areas are documented to the north near Beluga Mountain, along the Skwentna and Hayes Rivers, and near Flat Horn Lake. The Project corridor would overlap with Beluga residents' use areas from Mount Susitna to the south near Tyonek.

Seasonal Round

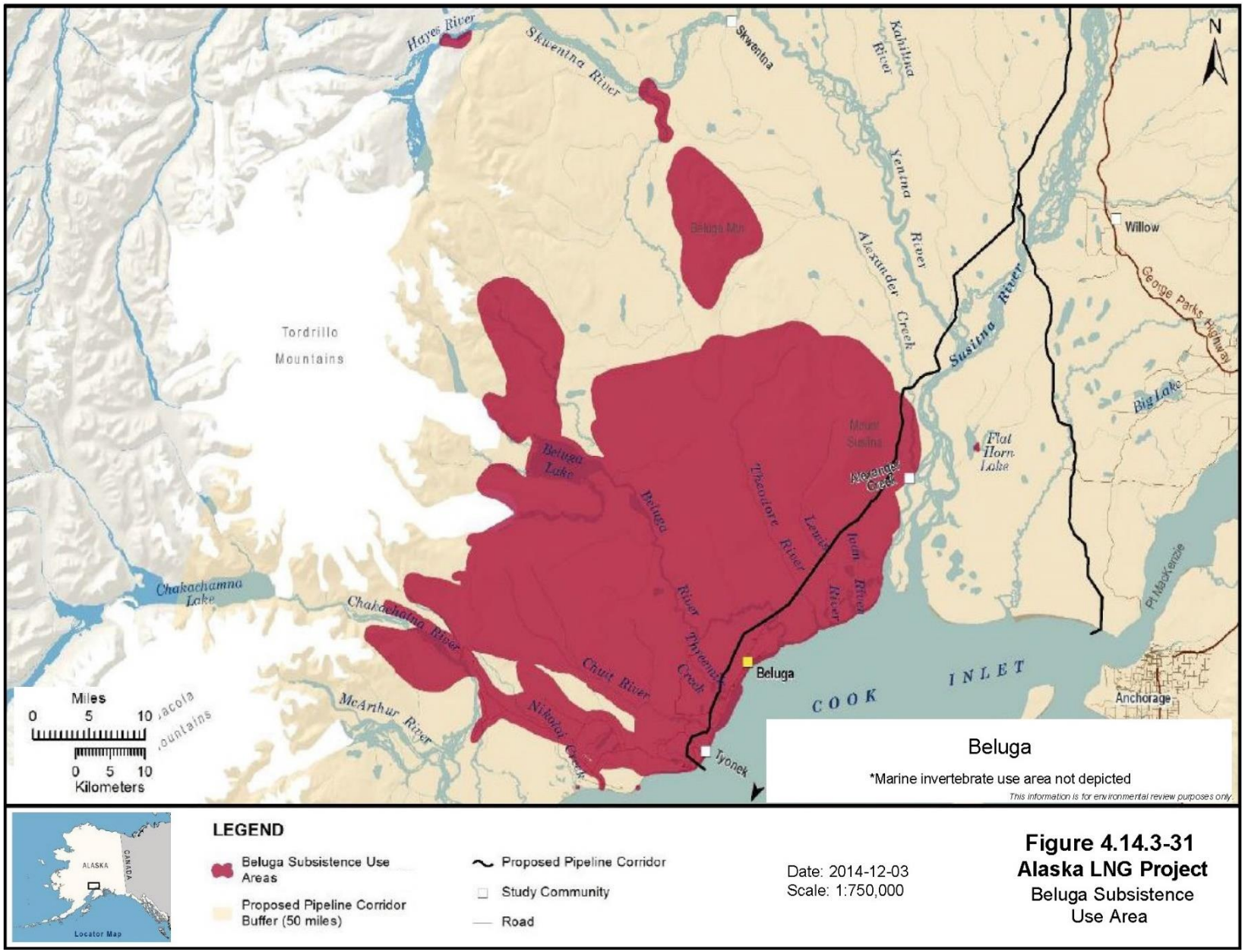
Beluga residents rely on a variety of marine, freshwater, and terrestrial resources (see table 4.14.3-52). The number of resource categories hunted or harvested is the highest in the fall and decreases during the summer with the fewest resources targeted in June. Spring (April through May) harvests begin with the breakup of lake and river ice, when residents harvest eulachon/hooligan with dip nets as they arrive to spawn in the Beluga and Susitna Rivers. Residents may also harvest other non-salmon fish such as trout during the early spring months, although ice-fishing activities cease once the lakes and rivers thaw. Hunting for brown and black bears also occurs during the spring as they emerge from hibernation. Mushrooms and wild plants, including fiddlehead ferns, are harvested in the spring. In late May, both commercial and subsistence salmon harvests occur using set nets from local beaches.

TABLE 4.14.3-52

Beluga Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Pacific salmon												
Moose												
Bear												
Furbearers												
Small land mammals												
Upland birds												
Waterfowl												
Marine invertebrates												
Plants and berries												
Wood												

Source: Braund, 2015


Hayes River
Skwentna River
Skwentna
Kahiltna River
Yentna River
Alexander Creek
Willow
George Parks Highway
Susitna River
Big Lake
Flat Horn Lake
Beluga Mtn
Tordrillo Mountains
Beluga Lake
Beluga River
Theodore River
Lewis River
Ivan River
Chakachamna Lake
Chakachatna River
Chuit River
Threemile Creek
McArthur River
Nikolai Creek
Beluga
Tyonek
COOK INLET
Anchorage
Pt MacKenzie
N
Miles
0 5 10
0 5 10
Kilometers
ALASKA
CANADA
Locator Map
LEGEND
Beluga Subsistence Use Areas
Proposed Pipeline Corridor Buffer (50 miles)
Proposed Pipeline Corridor
Study Community
Road
Beluga
*Marine invertebrate use area not depicted
This information is for environmental review purposes only.
Date: 2014-12-03
Scale: 1:750,000
Figure 4.14.3-31
Alaska LNG Project
Beluga Subsistence Use Area

Summer (June through August) marks the beginning of the harvest of Chinook, coho, and other salmon, as well as non-salmon fish species such as northern pike and rainbow trout. Salmon fishing efforts increase in mid-June and decline by the end of August. Residents may also travel to coastal areas in the summer (June through July) to harvest marine invertebrates. Plant and berry harvests and upland game bird hunting begin in mid-August, and the moose hunting season begins at the end of August.

The month of September is a peak time for harvesting moose, berries, upland birds, waterfowl, and non-salmon fish. Spruce and ruffed grouse are mainly taken in September and October. The waterfowl season begins in September and continues through mid-to-late October, at which time most waterfowl have migrated out of the area.

As the ground and waters of the area freeze, allowing overland travel, fur trapping begins (typically in November) and continues through March. Winter to spring harvests also include freshwater fish taken through holes in the ice. Trapping and hunting for American beaver and muskrat begin in the winter and continue into spring. Opportunistic harvesting of ptarmigan occurs when residents travel local roads or check trap lines.

Harvest Data

All the households contacted by the ADF&G in 2006 reported both using (100 percent) and harvesting (100 percent) subsistence resources. Beluga households reported using a wide range of resources in 2005 through 2006 (see table 4.14.3-53). The most commonly used resource was large land mammals, which were used by 100 percent of households in the community, followed by salmon and vegetation (both used by 92.9 percent of households), non-salmon fish (used by 85.7 percent), birds and eggs (used by 78.6 percent), marine invertebrates (used by 50 percent), and small land mammals (used by 42.9 percent) (Stanek et al., 2007).

Based on 2006 survey data, the ADF&G estimated that the total harvest weight of subsistence resources harvested by the community during 2005 to 2006 totaled 8,086.0 pounds, or 202.2 pounds per capita (Stanek et al., 2007). The subsistence resource receiving the heaviest use, measured in pounds harvested per capita, was salmon (86.8 pounds per capita), followed by large land mammals (60.1 pounds per capita), non-salmon fish (35.7 pounds per capita), vegetation (11.0 pounds per capita), birds and eggs (6.8 pounds per capita), marine invertebrates (1.6 pounds per capita), and small land mammals (0.1 pound per capita).

Of the 10 most important subsistence resources measured in harvested pounds per capita, the highest ranked resource was moose (43.4 pounds per capita). Four of the top 10 ranked resources were species of salmon: coho (second rank, 38.7 pounds per capita), Chinook (third rank, 32.1 pounds per capita), sockeye (sixth rank, 12.4 pounds per capita), and chum (tenth rank, 2.8 pounds per capita). The fourth and fifth ranked resources, respectively accounting for 15.0 and 13.9 pounds per capita, were rainbow trout and northern pike. The seventh through ninth-ranked resources were black bear, berries, and spruce grouse, respectively accounting for 9.4, 8.2, and 3.9 pounds (Stanek et al., 2007).

TABLE 4.14.3-53

Estimated Subsistence Harvest for Beluga

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	43.4	1,736.0
Bear	9.4	373.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	7.4	294.0
Small land mammals	0.1	5.0
Marine mammals	–	–
Marine invertebrates	1.6	64.0
Migratory birds	2.3	90.0
Upland birds	4.5	180.0
Eggs	–	–
Pacific salmon	86.8	3,472.0
Non-salmon fish	35.7	1,429.0
Berries	8.2	326.0
Plants	2.9	114.0
Wood	–	–
Other	0.1	3.0

Source: Stanek et al., 2007
"–" = No harvest for this resource was reported.

Impacts on Subsistence

The community of Beluga is on the western shore of Cook Inlet near the Project crossing of Cook Inlet. The Project would overlap with subsistence use areas for eight resources with high user overlap, including five of high material and/or cultural importance (moose, upland game birds, salmon, non-salmon fish, and berries), and three of moderate importance (small land mammals, migratory birds, and plants). Construction would occur between April of Year 1 and December of Year 4. Construction at any single point would last about 6 to 12 weeks or longer, depending upon the rate of progress, weather, terrain, and other factors. Several access roads, coastal access, and a construction camp would occur within the community's subsistence use area. Construction would temporarily impact access to resources, permanently change vegetation within the right-of-way, increase competition from non-local harvesters, and result in additional cost and effort to harvest these resources. Competition would likely extend into Project operation due to new access along the coast and access roads.

Construction activity could cause temporary displacement of resources, such as moose, bear, small land mammals, waterfowl, and upland game birds; temporarily block harvesters from accessing use areas; and remove previously used vegetation harvest areas. Subsistence activities that would most likely be affected occur during the fall/early winter (August through November) when residents target the greatest number of resources, including moose, bear, upland birds, waterfowl, and berries.

Tyonek

The community of Tyonek is on the north side of North Foreland, a short and wide point of land on the northwestern shore of Cook Inlet. Tyonek is between the mouth of the Beluga River, about 12 miles to the north, and Granite Point, about 8 miles to the southwest. Granite Point marks the northern end of Trading Bay, a long, shallow bay on the western shore of the inlet. Tyonek is across the inlet, 44 miles southwest of Anchorage and 60 miles north of Nikiski.

This western side of Cook Inlet consists of Quaternary sediments that slope gradually from the mountains of the Alaska Range to the shore of the inlet. The region is dotted with small lakes and wetlands and cut by meandering streams that empty into the inlet. The community of Tyonek is situated on the edge of an approximately 50-foot bluff directly overlooking the water.

The majority of the residents of Tyonek have cultural and ancestral ties to the Dena'ina, an Athabaskan people occupying the lands surrounding Cook Inlet. Oral traditions and archaeological and linguistic evidence suggest that Dena'ina have been present in the Upper Cook Inlet area for at least a millennium. The earliest interaction between Europeans and Dena'ina peoples occurred in 1778 in Trading Bay when James Cook's ships briefly entered Cook Inlet. The Dena'ina, who traded with Cook's men, may have come from a village in the vicinity of modern-day Tyonek. A Russian fur trading post was established near Tyonek sometime before 1794.

By 1875, after Alaska had been purchased by the United States, a permanent Alaska Commercial Company trading post was present at Tyonek (Stanek et al., 2007). During the 19th and early 20th century, epidemic disease struck many Dena'ina communities in the Upper Inlet. In the early 20th century, survivors from many of these communities resettled in Tyonek (Stanek et al., 2007).

Since the late-19th century, three communities in the vicinity of North Forelands have been named Tyonek. The current location, referred to as "New Tyonek," has been occupied since 1932 (Jones et al., 2015b).

Mining, commercial fishing, and the development of the Alaska Railroad brought non-natives into the Cook Inlet region and provided some opportunities for Tyonek residents to participate in the cash economy. However, the 1930s through the 1950s are generally remembered as a time of poverty caused by poor returns from commercial fishing and trapping and scarce wild resources. The production of oil and gas in Cook Inlet in the 1950s and 1960s brought additional changes to the area. Residents of Tyonek received more than 11 million dollars in the 1960s for drilling rights to gas deposits on Tyonek lands (Stanek et al., 2007).

Today, the community has a health center and an elementary/high school and is served by water, sewer, electrical, and telephone services. Tyonek is not on the road system and is typically accessed by boat or aircraft using the community's airstrip (Jones et al., 2015b).

In 2014, the ADF&G conducted a study of the harvest and use of subsistence resources by Tyonek residents in 2013 (Jones et al., 2015b). The ADF&G estimated a population of 142 individuals living in 63 households. The Alaska Native population recorded by the ADF&G was 136 individuals (Jones et al., 2015b). Investigators from the ADF&G interviewed all 63 households in the community. All the households surveyed reported harvesting and using subsistence resources (Jones et al., 2015b).The ADF&G reported that all households in the community received cash income through employment. Most of the income earned by community members was provided through employment by local government (45.9 percent), construction (17.6 percent), and local service providers (17.9 percent) (Jones et al., 2015b).

Subsistence Use Areas

Tyonek community's subsistence use areas cover a large portion of the marine environment on the west side of Cook Inlet from Tuxedni Bay in the south to the Little Susitna River in the north as shown on figure 4.14.3-32. The eastern side of Cook Inlet along the shore from Anchor Point to Clam Gulch is also used for subsistence purposes. The subsistence use areas extend to the north from Cook Inlet along the McArthur and Chakachatna Rivers and overland between the Beluga and Chakachatna Rivers just south of Beluga Lake. Inland areas occur to the east of Beluga River as well as about 10 to 20 miles from the Cook Inlet shoreline as far as the Susitna River. The Project would cross through Tyonek subsistence use areas from Alexander Creek through Beluga and into Tyonek along the north side of Cook Inlet.

Seasonal Round

Subsistence activities are highest in the spring, summer, and fall, with peak activity in April, June, and September (see table 4.14.3-54). During the winter, harvests decline with the fewest resources targeted in January and February. In spring (April through May), Tyonek residents harvest resources when winter ice clears from local streams and lakes. Marine mammals, fish, marine invertebrates, grouse, and some furbearing animals are harvested in spring. Razor, butter, and redneck (*Mactromeris polynyma*) clams are harvested in April and May. Chinook salmon, harbor seal, beluga whale, and freshwater fish (e.g., rainbow trout and Dolly Varden) are harvested in spring. Other resources occasionally harvested in the spring include sockeye salmon, North American porcupine, black bear, ducks, and geese.

During the spring, residents pursue two different methods of trout fishing: 1) prior to the breakup of ice, residents fish through the ice in lakes; and 2) after the ice breaks, residents travel the region by skiff for rod and reel fishing. Eulachon is the first fish that becomes available in Cook Inlet in the spring and it is harvested using gill nets. Marine invertebrates must be harvested after the ice breaks. Beluga whale (when authorized) and harbor seals are available spring through fall. American beaver is primarily harvested for their fur in winter, but are also harvested in spring. Black bear is harvested in spring when they first emerge from their dens. In addition to using the meat, the fur is valued clothing.

In early summer (June), marine invertebrates are harvested as the Chinook salmon harvest decreases. Tyonek residents transition to harvest sockeye, pink, chum, and coho salmon. The peak harvest of harbor seal, beluga whale (when authorized), and freshwater fish continue throughout the summer. Berry harvests begin in July and include blueberries, currants (*Ribes* spp.), and highbush cranberry. In late summer (August), Tyonek residents harvest spruce grouse, snowshoe hare, and black bear. North American porcupine and brown bear are occasionally harvested during the summer.

In the fall (September through October), Tyonek residents conclude harvesting many of the resources taken throughout the spring and summer, including harbor seal, beluga whale, black bear, chum and coho salmon, and berries and plants. With the closing of the productive summer season, Tyonek residents target ducks, geese, and moose. The majority of moose hunting occurs during September, although moose hunting has recently begun starting in late August. The peak harvest for brown bear and North American porcupine is September. Other fall resources include American beaver and marine invertebrates. Wood, which can be harvested year-round, is collected during the fall in preparation for winter.

During the winter months, Tyonek residents begin harvesting ptarmigan, Dolly Varden, and furbearers, including American mink, American marten, fox, coyote, American beaver, and otter. Tyonek residents continue to harvest spruce grouse during the winter along with snowshoe hares, rainbow trout, and wood. After the winter solstice, longer daylight hours allow harvest of trout, Dolly Varden, and northern pike.

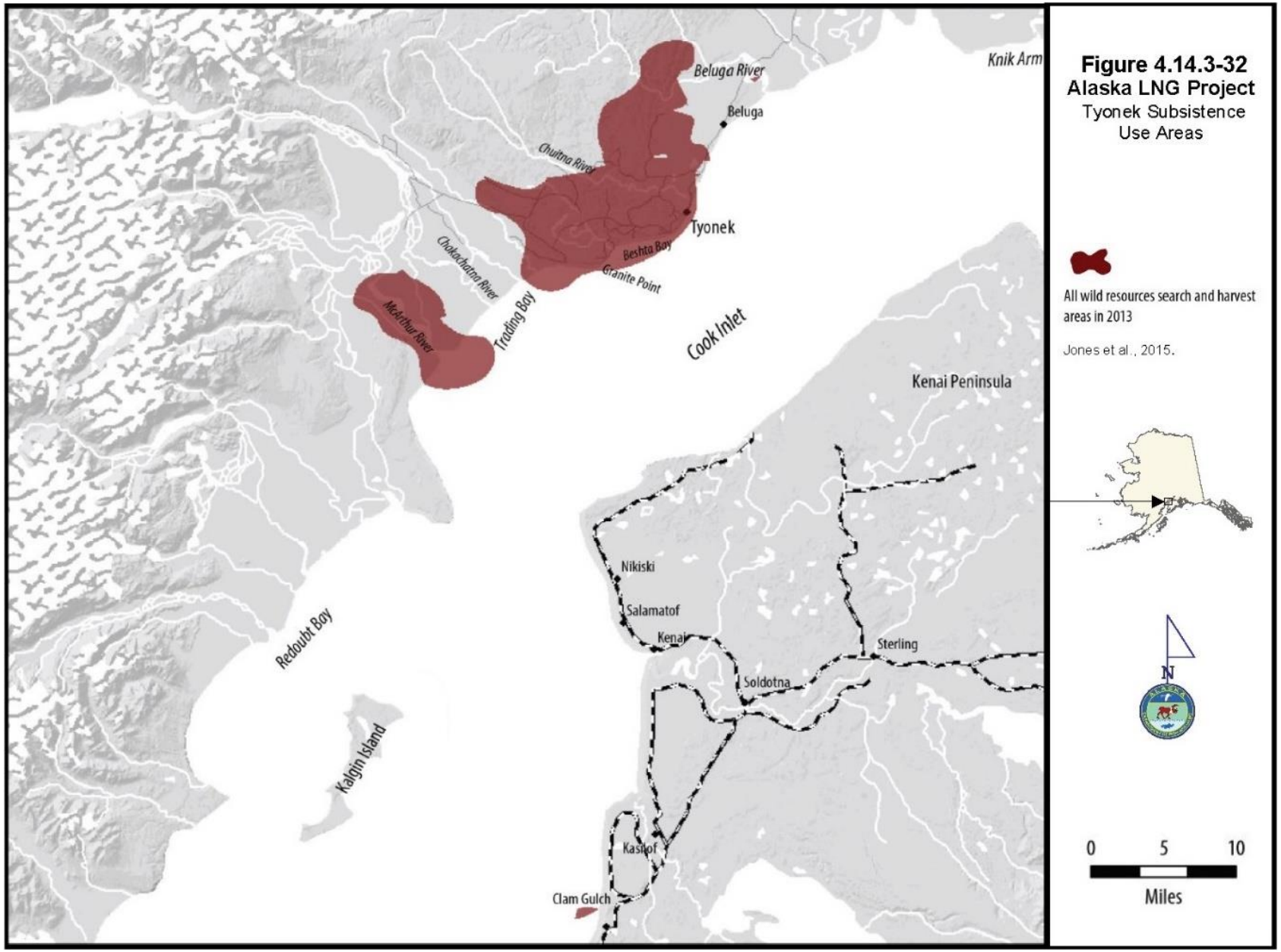

Knik Arm
Beluga River
Beluga
Chuitna River
Tyonek
Beshta Bay
Granite Point
Chokochatona River
McArthur River
Trading Bay
Cook Inlet
Kenai Peninsula
Nikiski
Salamatof
Kenai
Sterling
Soldotna
Redoubt Bay
Kalgin Island
Kasilof
Clam Gulch
Figure 4.14.3-32
Alaska LNG Project
Tyonek Subsistence Use Areas
All wild resources search and harvest areas in 2013
Jones et al., 2015.
N
0
5
10
Miles

TABLE 4.14.3-54

Tyonek Subsistence Harvest Timing

Species	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Freshwater non-salmon												
Marine non-salmon												
Pacific salmon												
Moose												
Bear												
Furbearers												
Small land mammals												
Marine mammals												
Upland birds												
Waterfowl												
Marine invertebrates												
Plants and berries												
Wood												

Source: Braund, 2015

Harvest Data

Tyonek households reported using a wide range of resources in 2013 (see table 4.14.3-55). More than 97 percent of households reported using salmon and vegetation. Three quarters or more of households reported using non-salmon fish, marine mammals, and marine invertebrates. More than 68 percent reported using large land mammals. Thirty-nine percent reported using birds and eggs, and 14.6 percent reported using small land mammals (Jones et al., 2015b).

Based on 2013 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 24,248.8 pounds, or 170.7 pounds per capita (Jones et al., 2015b). Salmon received the heaviest use (117.5 pounds per capita), followed by large land mammals (24.3 pounds per capita), non-salmon fish (13.1 pounds per capita), and vegetation (9.5 pounds per capita). Far less use, as measured in pounds per capita, was made of the remaining resource categories: marine mammals (harbor seals), birds and eggs, small land mammals, and marine invertebrates.

The most important subsistence resource measured in harvested pounds per capita was Chinook salmon. Only three terrestrial resources were within the 10 most harvested resources, including moose, blueberries, and highbush cranberries. Six of the 10 most harvested resources were salmon or non-salmon fish. One species of marine mammal, harbor seal, also made the top 10 list (Jones et al., 2015b).

Impacts on Subsistence

The community of Tyonek is on the western shore of Cook Inlet, south of the community of Beluga and about 4 miles south of where the Project corridor crosses Cook Inlet. The Project would overlap Tyonek subsistence uses areas for 11 resources including four of high material and/or cultural importance (moose, salmon, berries, and wood), three of moderate importance (marine mammals, migratory birds, and non-salmon fish), and four of low importance (bear, small land mammals, upland game birds, and plants). Marine mammals, consisting exclusively of harbor seal, are harvested along 20 miles of the coast between Beluga and McArthur River. No impacts on marine mammal harvest would be anticipated.

TABLE 4.14.3-55

Estimated Subsistence Harvest for Tyonek

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	24.3	3,471.4
Bear	–	–
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	1.0	139.5
Marine mammals	2.5	360.0
Marine invertebrates	0.9	131.9
Migratory birds	0.8	112.8
Upland birds	0.4	52.2
Eggs	0.8	0.8
Pacific salmon	117.5	16,765.5
Non-salmon fish	13.1	1,863.2
Berries	9.0	1,281.4
Plants	0.5	70.1
Wood	–	–
Other	–	–

Source: Jones et al., 2015b
"–" = No harvest for this resource was reported.

Construction activity could cause temporary displacement of resources, such as moose, bear, small land mammals, waterfowl, and upland game birds, in areas crossed by the Project; temporarily limit access to use areas; and remove previously used vegetation harvest areas. Impacts on Tyonek subsistence uses could continue after construction into Project operation as a result of new access roads, both inland and coastal, within their subsistence use area. Increased access into the lands west of Cook Inlet could cause higher incidences of trespassing onto Tyonek Native Corporation land.

4.14.3.5 Kenai Peninsula Region

The Kenai Peninsula Region includes four communities: Nikiski, Seldovia, Port Graham, and Nanwalek. The eastern portion of the peninsula contains the Kenai Mountains with large ice fields and jagged coastlines. Most of the western half of the Kenai Peninsula is heavy with glacial silt overlying volcanic ash and glacial till. Forests here can be mixed broadleaf and needleleaf with low scrub in boggy areas. The eastern reaches of the Kenai Peninsula contains glaciers and exposed bedrock. The lowlands are often covered with a layer of silt over glacial till. Vegetation consists of dwarf or low scrub with some areas of needleleaf forests. The southern and western reaches of the lower Kenai Peninsula contain gravelly and stony moraine deposits with silts and clays in the floodplains and river deltas. The vegetation consists of broadleaf and needleleaf forests with a long growing season. High, low, and dwarf shrubs are common, with wetlands containing low scrub.

The Kenai River corridor is an important salmon harvest area with numerous archaeological sites along the river documenting a long history of Dena'ina use of the area for its wealth of salmon and other

subsistence resources. The salmon runs of Deep Creek and the Ninilchik River were also attractive resources to the Dena'ina and provided a transportation route to the Caribou Hills. To the south in Kachemak Bay, Sugpiat and Athabascan use of the area has been documented (de Laguna, 1975; Workman et al., 1980). The southern end of the Kenai Peninsula near Port Graham, Nanwalek, and Seldovia has long been used by Sugpiat people with a number of prehistoric villages along the southern tip of the Kenai Peninsula.

Russian communities initially developed the Kenai Peninsula beginning in the late 18th century with fur trading posts in Kenai, Seldovia, Port Graham, and Nanwalek. Later, the discovery of gold on the north side of the Kenai Peninsula in 1890 initiated the Cook Inlet gold rush, driving prospectors to the streams of Turnagain Arm in search of placer deposits of gold. Homesteaders settled plots of land in Nikiski in the 1940s, preceding an oil and gas boom in the 1960s.

Commerce from fish traps, canneries, and harbors supported many of the southern communities through the 20th century. Fish traps in Salamatof operated in the mid-century (Ringsmuth, 2005), and canneries in Kenai, Ninilchik, and Port Graham supported the residents in the area.

The majority (greater than 50 percent) of residents in the communities of Port Graham and Nanwalek are members of federally recognized tribes (U.S. Census Bureau, 2016). These tribes have traditional and current resource uses, including customary and traditional uses, in or near the Project (see figure 4.14.3-33). Nikiski and Seldovia have current subsistence resource use areas in or near the Project. A description of the four communities and their subsistence use areas, harvest patterns, and seasonal round is provided in the following sections.

Data on the timing of subsistence activity, for all resources, are only available for Nanwalek and Port Graham, and thus no regional description of the timing of subsistence activities for the Kenai Peninsula is included. Additionally, due to a lack of comparative temporal data, change over time in the timing of subsistence activities is not addressed for the Kenai Peninsula Region.

Data are available for the timing of fish subsistence activities in the communities of Nanwalek, Port Graham, and Seldovia. Fishing in the Kenai Peninsula Region occurs year-round. Salmon harvests may occur offshore throughout the year; however, fishing intensifies over the summer and fall months as the salmon begin to make their runs to inland watersheds. Freshwater non-salmon fish harvests occur year-round, but like salmon subsistence activity, intensifies in the summer and fall. Marine non-salmon fishing is moderate over the winter and picks up once the weather warms in spring, making boating conditions more favorable.

As part of the subsistence and traditional knowledge study, each community in the Kenai Peninsula Region was asked to identify the three most important subsistence resources. At a regional level, salmon was identified as the most important resource, moose was second, and berries were third. Pacific halibut, non-salmon fish, and wood were mentioned in about 10 percent of the responses, and all other resources were mentioned less frequently.

During subsistence mapping interviews in the Kenai Peninsula Region communities between 2014 and 2015, respondents were asked to comment on concerns about subsistence resources and their subsistence lifestyle. Specific concerns pertained to lingering contamination from the Exxon Valdez oil spill and other sources of contamination, changes in resource availability, the effects of a poor economy on subsistence, and the impact of climate change on subsistence practices and resources.

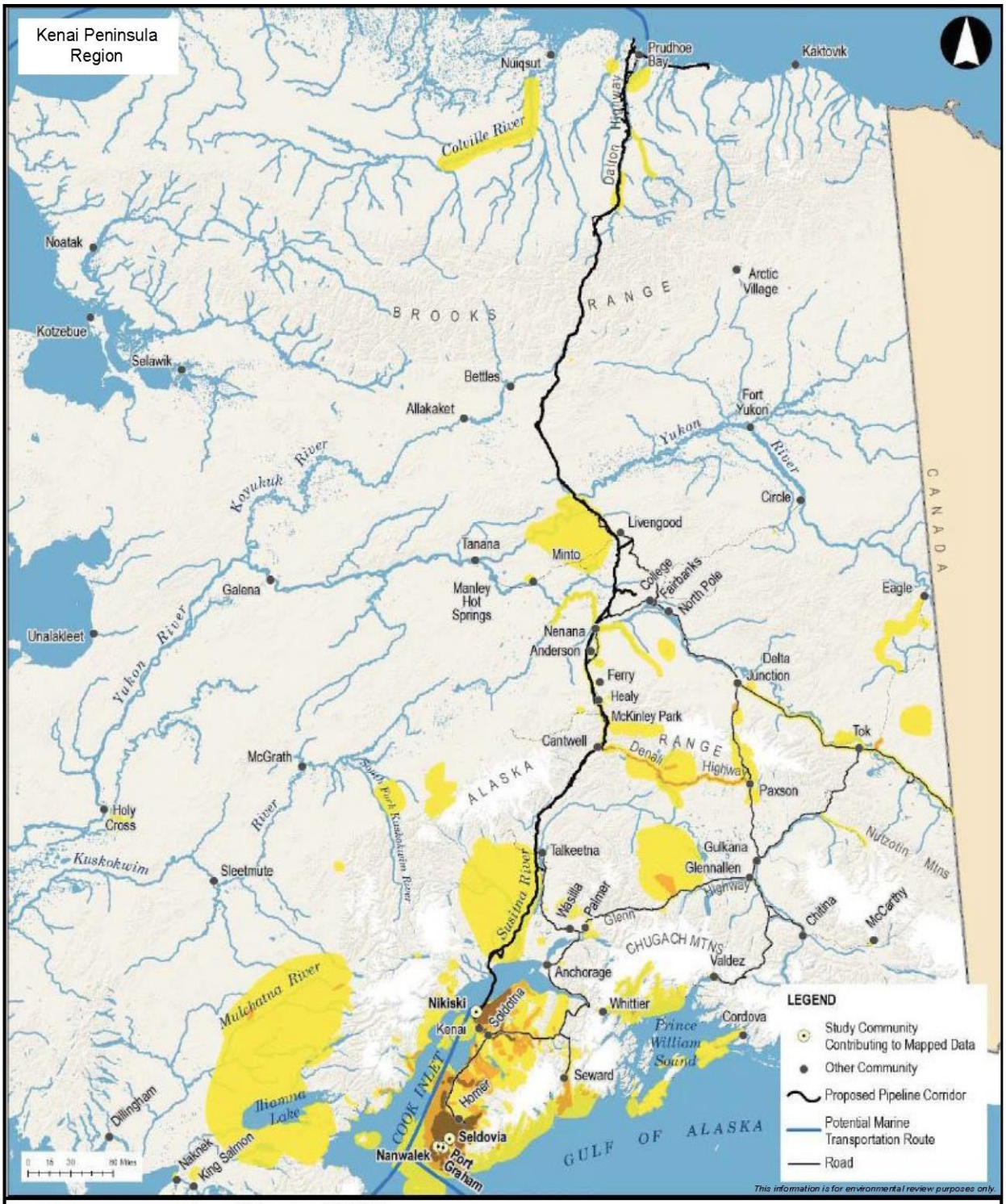


Figure 4.14.3-33
Alaska LNG Project
Kenai Peninsula Region
Subsistence Use Areas

The Exxon Valdez oil spill occurred on March 24, 1989. Since that time, communities in Lower Cook Inlet have observed and experienced the environmental repercussions of the crude oil spilled into Prince William Sound and spread around the area by tidal currents. The crude oil that washed onto the beach throughout the region affected wildlife and altered the ecosystem. The negative effects of the oil on the region's coastal and marine resources caused many residents to abandon traditional subsistence practices and economic pursuits, such as commercial fishing. The residents of the Kenai Peninsula Region communities, specifically those in Lower Cook Inlet, are concerned about the impact the spill had on subsistence resources.

Contamination from any source is a primary concern for subsistence users in the region. Respondents often reported checking all resources for contamination (e.g., tumors) prior to processing and consuming them.

Resource availability, particularly fish, was a concern. Several respondents described sport fishing, including fishing charters, as stressors on the fish population in Cook Inlet. Respondents also commented that Pacific halibut is an important resource in Cook Inlet and that the overuse of halibut in sport fisheries has caused a decrease in the abundance and size of halibut. Diminished salmon runs in Cook Inlet, in part due to commercial fishing, was noted.

During workshops in Lower Cook Inlet communities, such as Seldovia, Port Graham, and Nanwalek, respondents discussed a decrease in marine invertebrate species. Dungeness, tanner, and king crabs were common in Cook Inlet as well as marine invertebrate species such as sea urchins, clams, and cockles. Respondents in Seldovia also commented on the decrease in the availability of clams. Today, due to overharvest, environmental issues, and the increase in predator populations (e.g., sea otter), marine invertebrate populations have suffered, and some species, like the king crab, seem to have disappeared.

Respondents also expressed concern about the availability of certain terrestrial resources. During workshops, participants commented that as the human population increases on the Kenai Peninsula, subsistence resources decrease as a result of habitat loss and a disruption to migration patterns. In addition to the increased population, economic pursuits such as oil and gas development and logging have created roads to areas, including hunting grounds that were once difficult to access. One respondent commented that logging roads, seismic trails, and exploration activities have negatively affected moose populations by allowing access to areas that should be difficult to reach.

Comments specifically related to construction impacts by the Project included the following concerns about increased competition for resources:

- impacts on marine habitats where resources such as fish, marine mammals, and marine invertebrates are harvested;
- pollution from normal operations or a disaster that would affect subsistence resources;
- increased human access along the right-of-way that could decrease the number of animals and/or species present; and
- increased competition for subsistence resources due to the presence of outsiders hired by the Project.

In comments on the draft EIS, CIRI identified moose–vehicle collisions due to Project traffic as a concern given the importance of moose as a subsistence resource for the people of the Cook Inlet region. CIRI asked that AGDC work with local communities to establish a process to distribute moose killed as a

result of vehicle accidents to local villages. AGDC said that under ADF&G regulations, wildlife killed by a vehicle belongs to the state; therefore, AGDC cannot develop a process separate from the Alaska State Wildlife Troopers' Wildlife Salvage Program for the distribution of animals killed in vehicle accidents. AGDC said that it would work with the public to inform them of the enrollment process for receiving moose roadkill through the Wildlife Savage Program, provide notification of moose incidents that occur in construction areas, and implement measures outlined in the Wildlife Avoidance and Interaction Plan to reduce moose–vehicle collisions.

In its comments on the draft EIS, CIRI additionally asked that AGDC work with local communities to make felled timber available for use as firewood. AGDC said that timber felled on public and private lands (including CIRI lands) would be managed based on landowner or land management agency requirements. For clearing on state lands, as a requirement of the state right-of-way lease, AGDC said it would prepare a Timber Clearing, Salvage, and Utilization Plan, which would identify opportunities for residents and local communities to access salvaged timber. AGDC anticipates that a similar process would be required for timber cleared on BLM lands.

Kenai Peninsula Region Temporal Trends

Comparison of harvest data from previous years makes it possible to identify temporal trends in subsistence activities by residents of the Kenai Peninsula communities. At the present time, data for the community of Nikiski is only available for 2014 (Jones and Kostick 2016, making it impossible to identify temporal trends in subsistence behavior for community residents. However, comparable harvest data for multiple years has been compiled for the remaining three communities of Seldovia, Nanwalek, and Port Graham.

The estimated per capita harvest for all resources for Nanwalek and Port Graham show similar patterns. For both communities, the estimated per capita harvest for all resources combined remained relatively stable between 1987 and 2014. Over that period, the estimated per capita harvest for all resources by Nanwalek ranged from a low of 253.0 pounds in 2014 to a high of 304.9 pounds in 1993 (Jones and Kostick, 2016.). Over the same period, the estimated per capita harvest for all resources by Port Graham residents ranged from a low of 212.3 pounds in 1993 to a high of 466.3 pounds in 2003 (Jones and Kostick 2016).

For both communities, the relative stability in per capita harvest for all resources shows two disruptions over the recorded period. Both communities show a marked decrease in combined subsistence returns that is possibly related to the Exxon Valdez oil spill that occurred in 1989. For Nanwalek residents, there was a 51-percent decrease from 1987 levels in 1989 and a 36-percent decrease from 1987 levels in 1990. Port Graham residents experienced a similar decrease of 47 percent from 1987 harvest levels in 1989 (Jones and Kostick 2016).

Both communities also showed a marked increase in per capita harvest for all resources in 2003 as compared to 1997. Nanwalek residents experienced a 55-percent increase between 1997 and 2003. Port Graham residents experienced an 84-percent increase over the same period (Jones and Kostick 2016). The cause of this increase is unclear and the gaps in the data coverage make it impossible to determine how abrupt the increases were in each community.

The comparable record of total per capita harvest for Seldovia begins in 1991 and does not appear to show a decrease due to the Exxon Valdez oil spill. Between 1991 and 2014, the estimated per capita harvest for all resources combined for Seldovia shows an overall decline from a high of 205.5 pounds per capita in 1991 to 138.3 pounds per capita in 2014. No subsistence harvest data was collected from Seldovia

for the period of 1997 and 2003, making it impossible to determine if a marked increase in per capita harvest occurred during that time as it did at Nanwalek and Port Graham (Jones and Kostick 2016).

Comparable harvest data from the three communities indicate that salmon and non-salmon fish are the most important resource categories as measured as a proportion of the total harvest. For the communities of Nanwalek and Port Graham, salmon represents a greater proportion of the total harvest than it does for Seldovia. As a proportion of the annual subsistence harvest of Nanwalek and Port Graham, the importance of salmon increased between 1987 and 2014.

For all three communities, the remaining general resource categories (land mammals, marine mammals, birds and eggs, marine invertebrates and vegetation) make up a much smaller proportion of the harvest. The harvest of minor resource categories by residents of Nanwalek and Port Graham was fairly steady at low percentages with several subtle exceptions. Among subsistence users from Port Graham, the categories of land mammals and vegetation showed slight increases between 1987 and 2014, and in 1989, the proportion of land mammals showed a marked increase in Nanwalek's subsistence harvest, perhaps reflecting adjustments required by the Exxon Valdez oil spill.

Changes in the importance of minor resource categories was more apparent among residents of Seldovia. Land mammals make up a larger proportion of the harvest for residents of Seldovia than for residents of Nanwalek or Port Graham, and marine invertebrates were harvested in higher proportions among Seldovia residents than among residents of the other two communities. However, the proportion of marine invertebrates in the Seldovia harvest decreased sharply in 2014 relative to 1993. In contrast, vegetation showed a marked increase in importance among Seldovia residents in 2014.

Kenai Peninsula Region Summary

Project construction activity and operation of the Mainline Pipeline and Liquefaction Facilities could have impacts on subsistence for many communities in the region by reducing resource availability and access while increasing harvest cost and effort and potential resource competition. Subsistence impacts would be likely for the community of Nikiski. North of Nikiski, the Project corridor generally follows the Cook Inlet coastline of the Kenai Peninsula. South of Nikiski, the Project corridor follows shipping lanes in Cook Inlet, and is unlikely to directly impact the subsistence practices of the communities of Seldovia, Port Graham, and Nanwalek.

Nikiski

The community of Nikiski is on the eastern shore of Cook Inlet, on the western side of the Kenai Peninsula, about 120 air miles northeast of the entrance to the inlet, 60 air miles to the southwest of Anchorage, and 14 road miles north of the community of Kenai. Nikiski is immediately to the east of East Foreland, one of two points of land on the eastern and western shores of the inlet that reduce the width of Cook Inlet at that point to about 10 miles. The region is poorly drained and underlain by proglacial lake bottom sediments with relatively low relief. Elevations in the Nikiski vicinity range between about 100 and 200 feet above Cook Inlet.

Prior to Russian and Euro-American settlement, the residents of what is today Nikiski were the Athabascan-speaking Dena'ina, who occupied a horseshoe-shaped territory around Cook Inlet, from Kachemak Bay on the eastern shore to the northeastern end of Lake Iliamna on the western side. Historic records indicate the presence of three Dena'ina villages in the vicinity of Nikiski in the 19th century, although the Dena'ina presence extends much further into the past (Jones and Kostick, 2016).

Euro-American homesteaders, working in the fishing, trapping, or fur farming industries, began settling in the area in the early 20th century. Important developments after the Second World War led to population increases on the Cook Inlet shore of the Kenai Peninsula. In 1950, the Wildwood Air Force Base was constructed on the eastern shore of Cook Inlet to the south of Nikiski. In 1957, oil was discovered on the Swanson River, which drains the region to the northeast of Nikiski (Jones and Kostick, 2016).

At the time of the discovery, the area that is today occupied by the community of Nikiski was called North Kenai. Infrastructure supporting the petroleum industry, including pipelines, refineries, and shipping facilities quickly developed in North Kenai. Four petroleum companies—Unocal Chemical, Phillips LNG, Chevron, and Tesoro—had operations in North Kenai by 1964 (Jones and Kostick, 2016).

Until 1974, the upper Kenai Peninsula produced most of the crude oil extracted in Alaska. Today, the economy of Nikiski is still closely tied to petroleum extraction, refining, and shipping. ConocoPhillips, Tesoro, and other petroleum companies have operations in the area.

In addition to the oil industry, Nikiski supports a wide variety of other business, government, and medical services. In 2010, the U.S. Census Bureau reported a population of 4,493 in Nikiski, including 522 Alaska Natives, and 1,689 households. In 2014, ADF&G conducted a study of the harvest and use of subsistence resource in Nikiski. Researchers from the ADF&G estimated a population of 4,263 living in 1,568 households. The ADF&G estimated an Alaska Native population of 511 (Jones and Kostick, 2016). Despite the relatively large population and heavy industrial presence, Nikiski offers access to natural areas, public lands, and a wide variety of marine and terrestrial resources.

In 2014, the ADF&G conducted a study of the harvest and use of subsistence resources in Nikiski. Investigators from the ADF&G interviewed 203 of the estimated 1,568 households in the community. Ninety-five percent of the 203 households contacted by the ADF&G in 2014 reported using subsistence resources, while 78.7 percent of households reported harvesting subsistence resources. Most households additionally reported exchanging resources with other households in the community, with 64.4 percent receiving resources and 51 percent giving resources (Jones and Kostick, 2016).

The ADF&G reported that 1,284 households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local, state, and federal government (13.2 percent); mining (29.2 percent); and local service providers (30.4 percent) (Jones and Kostick, 2016).

Subsistence Use Areas

Historical data documenting the areas used by Nikiski residents for resource search and harvest have not been collected. However, the subsistence use areas of Nikiski residents has been documented for 2014 by the ADF&G (Jones and Kostick, 2016). These areas encompass numerous, smaller discontinuous locations in which Nikiski residents have conducted subsistence activities. Jones and Kostick (2016) mapped most of these locations between the Turnagain Arm of Cook Inlet and Lake Tustumena on the glaciated lowland of the Kenai Peninsula that lies between Cook Inlet to the west and the Kenai Mountains to the east as shown on figure 4.14.3-34.

In addition to the core subsistence use area between Turnagain Arm and Lake Tustumena, in 2014 residents of Nikiski practiced subsistence activities on the eastern and western shores of Cook Inlet, the shores of Turnagain Arm and Kachemak Bay, in the Kenai Mountains, Prince William Sound, and the open waters of Cook Inlet.

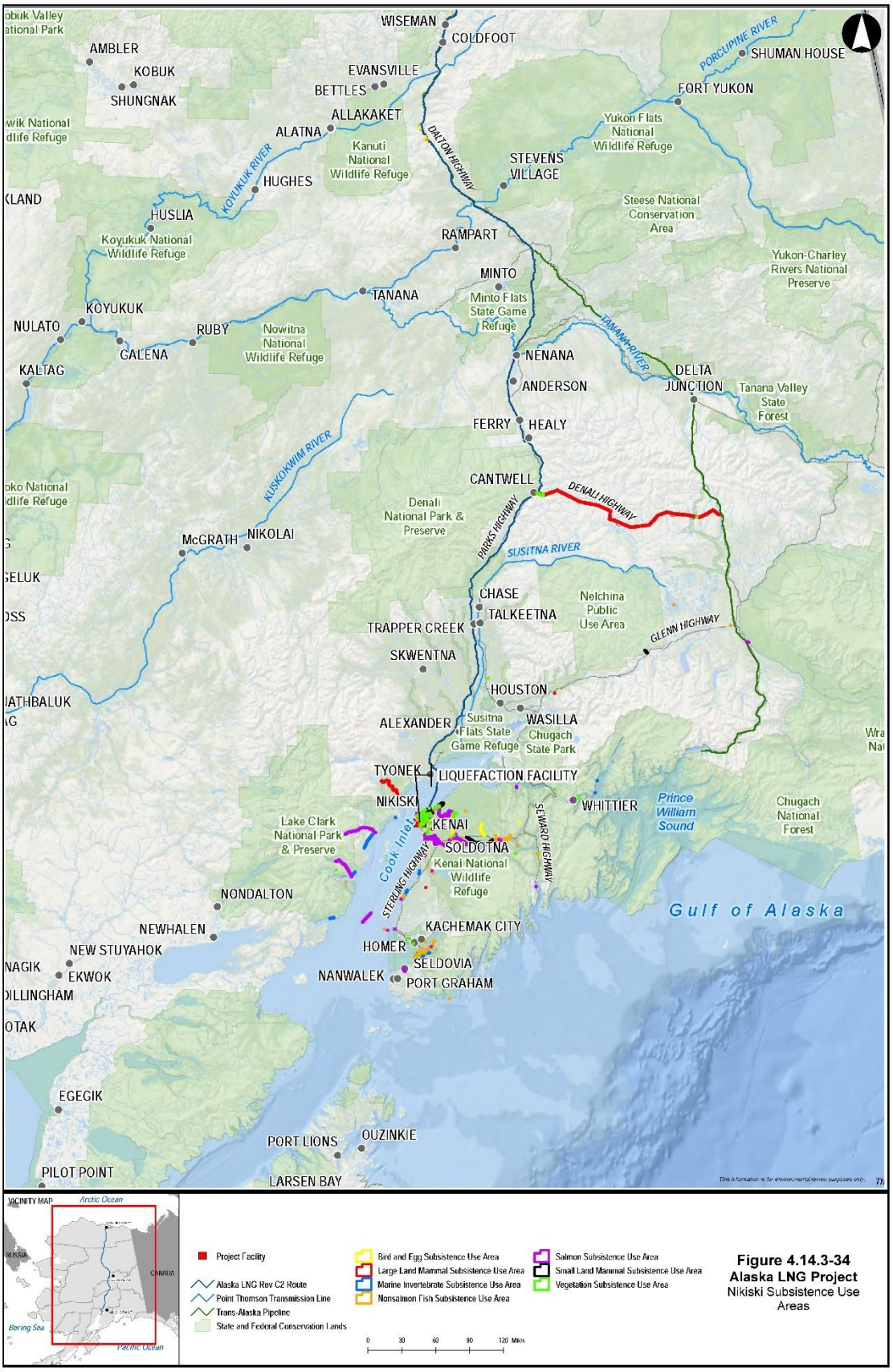


Figure 4.14.3-34
Alaska LNG Project
Nikiski Subsistence Use Areas

Seasonal Round

Nikiski residents harvest a wide variety of subsistence resources throughout the year (see table 4.14.3-56). In the early spring, residents harvest freshwater fish through the ice on local lakes and trap a variety of small mammals. After ice breakup, residents begin fishing with rod and reel and making preparations for the salmon harvest. Hunting of black bear occurs in the spring and extends into the summer.

During the summer, Nikiski residents harvest the widest variety of subsistence resources. Salmon is the focus of much of the subsistence efforts during this season. All five species of Pacific salmon are targeted by local subsistence users, but the majority of harvested salmon is sockeye. Most salmon are caught with dip nets or rod and reel. Marine and freshwater non-salmon fish species are also harvested during the summer. The most important of these by weight is Pacific halibut. Some community members harvest marine invertebrates. Species obtained by residents include crabs, clams, and shrimp.

Vegetation is another important category of subsistence resource harvested during the summer. The majority of households in Nikiski participate in the subsistence harvest of vegetation. Berries are the most important species of vegetation harvested, with blueberries being the most important. In addition to berries, community members harvest species of greens, mushrooms, and seaweed. Wood is also harvested. Most of the harvest of vegetation occurs in close proximity to the road system on the Kenai Peninsula.

TABLE 4.14.3-56

Nikiski Subsistence Harvest Timing

Resource	Spring	Summer	Fall	Winter
Non-salmon fish	■	■		
Pacific salmon		■		
Marine invertebrates		■		
Large land mammals		■	■	
Birds	■	■	■	■
Small land mammals	■	■	■	■
Berries		■		
Plants		■		■

Source: Jones and Kostick, 2016

The hunting of large land mammals, caribou, and moose, begins in late summer and extends into the fall. The search and harvest of large land mammals takes place mainly in the vicinity of Nikiski in the northwestern quarter of the Kenai Peninsula. Harvesting of upland game birds and migratory waterfowl occurs primarily in the fall, although upland game birds are hunted throughout the year.

Hunting of upland game birds continues into the winter. Winter is also the season when the largest harvest of small land mammals occurs. More than half of small land mammals harvested by community members are obtained at this time. The three most important species are snowshoe hare, American marten, and American beaver. Most of the small land mammal harvest occurs in the vicinity of Nikiski.

Harvest Data

Nikiski households reported using a wide range of resources in 2014. The most commonly used resources were salmon and vegetation, both of which were used by slightly more than 80 percent of households. Non-salmon fish were used by 55 percent of households, large land mammals by 32.7 percent, marine invertebrates by 19.3 percent, and birds and eggs by 16.3 percent. The resources used by the fewest households were small land mammals and marine mammals, which were used by 7.9 and 2.5 percent, respectively (Jones and Kostick, 2016).

Based on 2014 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 292,421.0 pounds, or 68.4 pounds per capita (Jones and Kostick, 2016). The estimated pounds per capita of general subsistence resource categories are shown below (see table 4.14.3-57). The resources harvested at the highest levels were salmon (31.7 pounds per capita), large land mammals (17.0 pounds per capita), and non-salmon fish (12.5 pounds per capita). No marine mammals were harvested.

The most important subsistence resources based on estimated per capita harvest weight was sockeye salmon. Three other species of salmon were within the 10 most harvested species by weight, although at lower quantities. Moose was the most important large land mammal, followed by caribou and black bear. Pacific halibut and rainbow trout were the most important non-salmon fish. Blueberries were the most important plant resource (Jones and Kostick, 2016).

TABLE 4.14.3-57

Estimated Subsistence Harvest for Nikiski

Resource	Per Capita (pounds)	Total (pounds)
Caribou	2.4	10,427.6
Moose	13.7	58,394.5
Bear	0.9	4,032.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	0.6	2,705.4
Marine mammals	–	–
Marine invertebrates	1.7	7,258.2
Migratory birds	0.1	363.8
Upland birds	0.3	1,362.5
Eggs	<0.1	55.6
Pacific salmon	31.7	135,314.5
Non-salmon fish	12.5	53,278.3
Berries	3.7	15,861.9
Plants	0.8	3,366.7
Wood	–	–
Other	–	–

Source: Jones and Kostick, 2016
"–" = No harvest for this resource was reported.

Impacts on Subsistence

Nikiski subsistence use areas, including use areas for four resources of moderate importance (moose, salmon, non-salmon fish, and wood) and six resources of low importance (caribou, bear, small land mammals, birds, berries, and plants) are overlapped by the Project. Additionally, the shipping route for the Project overlaps with use areas for salmon and non-salmon fish, resources of moderate importance, outside the state nonsubsistence area.

Nikiski is a non-rural community; the closest areas where residents could conduct subsistence activities on state land would be across Cook Inlet to the west of the Susitna River, or in lower Cook Inlet where residents' fishing areas are overlapped by the shipping route, which would be unlikely to introduce new impacts.

Impacts on the community's subsistence uses would occur primarily during construction, related to the displacement of subsistence resources along the Mainline Pipeline farther north. Project operation is unlikely to result in subsistence impacts because the Project is in a highly developed area and most of the subsistence use areas (i.e., areas outside the state nonsubsistence area) are at a substantial distance from the community.

Seldovia

Seldovia is on the eastern shore of Seldovia Bay, a deep fjord on the rugged southern side of the entrance to Kachemak Bay. Seldovia is 15 air miles to the southwest of Homer and 135 miles to the southwest of Anchorage. Mountains rise steeply on the eastern and western sides of Seldovia Bay, which are drained by steep creeks running into the short Seldovia River that flows northwestward through a broad valley into Seldovia Bay. Seldovia is not connected to the road system and is accessible only by boat or aircraft (Jones and Kostick, 2016).

During the pre-contact period, people ancestral to speakers of both Sugpiak and Dena'ina languages were present in Kachemak Bay. However, by AD 500, ancestors of Sugpiak-speakers had apparently abandoned the inner reaches of Kachemak Bay, which were subsequently occupied by the Dena'ina (Workman and Workman, 1988). During the historic period, the inner portion of Kachemak Bay and the western side of the Kenai Peninsula to the north of the bay were occupied by Dena'ina-speakers. The southern entrance to Kachemak Bay, including Seldovia Bay, the southern coast of the Kenai Peninsula, and Prince William Sound, were occupied by the Sugpiak-speaking Chugach (Crowell and Mann, 1998).

Historic records of Seldovia first appear with the U.S. Census of 1880 (Jones and Kostick, 2016). However, it is unclear if it originated as a Russian or Alaska Native community. By the 1800s, Seldovia residents were heavily involved in the commercial fishing and fur industries. In the early 1900s, fish canneries were established in Seldovia as the importance of the commercial fishing industry grew. Much of the population of Seldovia at this time could trace their ancestry to Alaska Natives or peoples of Russia and Scandinavia.

Seldovia's population continued to grow into the 1980s until the collapse of the commercial crab fishing industry. Today Seldovia's economy is based heavily on the logging and tourism industries. The contemporary community of Seldovia offers a wide range of commercial and governmental services (Jones and Kostick, 2016). The U.S. Census of 2010 reported a population of 420 people living in 195 households. One hundred twenty-one individuals were reported to be Alaska Natives. In 2014, the ADF&G estimated a population of 278 individuals living in 126 households. The Alaska Native population recorded by the ADF&G was 64 individuals (Jones and Kostick, 2016).

In 2014, the ADF&G conducted a study of the harvest and use of subsistence resources in Seldovia (Jones and Kostick, 2016). Investigators from the ADF&G interviewed 95 of the 126 households in the community. The majority (98.9 percent) of the 95 households contacted by the ADF&G reported using subsistence resources, while 93.7 percent of households reported harvesting subsistence resources. The ADF&G reported that 100 households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local, state, and federal government (52.4 percent); agriculture, forestry, and fishing (17.9 percent); and construction (9.3 percent) (Jones and Kostick, 2016).

Subsistence Use Areas

Residents of Seldovia obtained subsistence resources from locations throughout Alaska. In 2014, community members carried out subsistence harvests as far north as Delta Junction, west to Cold Bay on the Alaska Peninsula, and southeast to Sitka. However, most subsistence activities take place near Seldovia, including the Kenai Mountains surrounding the community and the waters and southern shore of Kachemak Bay (see figure 4.14.3-35). Other areas in which Seldovia residents practiced subsistence behavior include the waters of upper and lower Cook Inlet and the GOA.

Seasonal Round

The seasonal round for Seldovia residents begins in the early spring as snow melts (see table 4.14.3-58). Early spring subsistence activities include the gathering of plants (fiddlehead ferns and mushrooms) and kelp for use as a garden fertilizer.

As summer begins, salmon becomes the focus of subsistence activities by community members. Salmon is the most commonly harvested subsistence resource among Seldovia residents. All five species of Pacific salmon are used, but the most commonly harvested species is sockeye. Salmon are harvested from both marine and freshwater. However, Seldovia residents tend to focus the harvesting of salmon from marine waters of Cook Inlet to the west of Seldovia. Salmon used for subsistence purposes are harvested by rod and reel and dip and set nets, and are removed from commercial catch. Participation in commercial salmon fishing also occurs at this time and may compete with subsistence activities.

Non-salmon fish are also targeted during the summer and are the second most harvested resource category. The most important non-salmon fish is Pacific halibut, followed by a variety of other marine fish. Most non-salmon fish are harvested with rod and reel, but some are obtained with dip and set nets or removed from commercial catch. A variety of marine invertebrates such as clams, mussels, shrimp, crab, and octopus, are also harvested during the summer primarily from beaches near Seldovia.

Vegetation is another important summer subsistence resource. Berries were the most important categories of vegetation harvested by Seldovia residents, with more than ten species being collected. In addition to berries, members of the community harvested a variety of other plants including fern fiddleheads, mushrooms, greens, and seaweed. Wood was also commonly collected by residents.

The hunting of large land mammals begins in late summer and extends into the fall. Residents of Seldovia harvest moose, caribou, black bear, and mountain goat. Most residents who hunted large land mammals did so in the Kenai Mountains in the vicinity of the community. However, some residents traveled to other parts of the state. In 2014, all large land mammals were harvested in August and September.

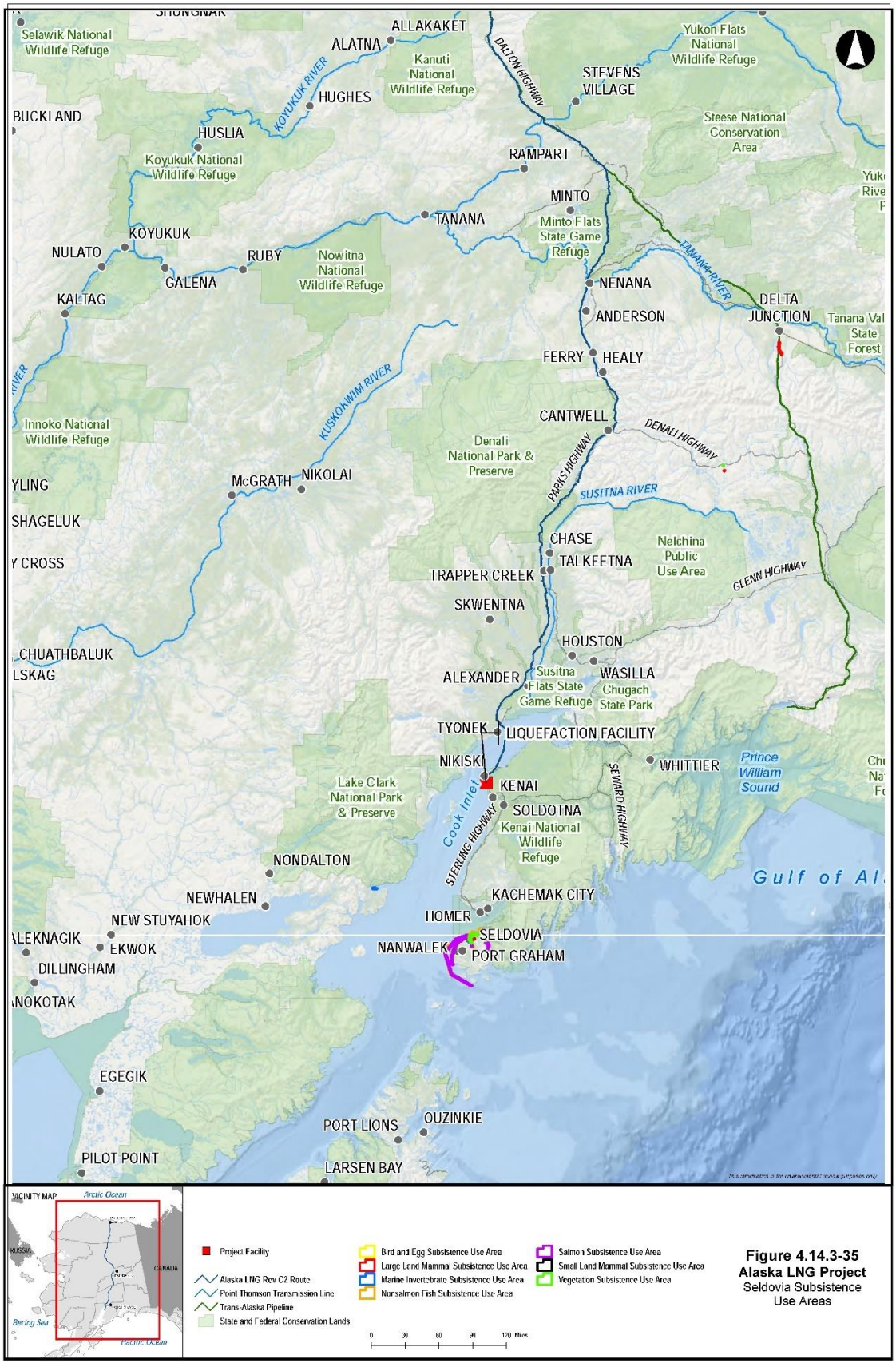


Figure 4.14.3-35
Alaska LNG Project
Seldovia Subsistence Use Areas

TABLE 4.14.3-58

Seldovia Subsistence Harvest Timing

Species	Spring	Summer	Fall	Winter
Non-salmon fish				
Pacific salmon				
Marine invertebrates				
Marine mammals				
Large land mammals				
Birds				
Small land mammals				
Berries				
Plants				

Source: Jones and Kostick, 2016

Most of the harvest of birds by community members also occurs during the fall. Birds targeted by community members primarily include upland ground birds and migratory waterfowl, although a small number of other categories were used as well. Most birds were harvested near Seldovia.

During the winter, Seldovia residents harvest firewood, marine invertebrates, and seaweed in the vicinity of the community. The harvesting of small land mammals also occurs during the winter and extends into early spring. Species targeted by community residents include snowshoe hare, North American porcupine, and least weasel. Alaska Natives in Seldovia also harvested marine mammals. In 2014, these consisted of harbor seals and sea otters.

Harvest Data

Seldovia households reported using a wide range of resources in 2014 (see table 4.14.3-59). About 90 percent or more of the households interviewed by the ADF&G made use of salmon (93.7 percent), vegetation (94.7 percent), and non-salmon fish (89.5 percent). More than 50 percent of households used large land mammals (61.1 percent) and marine invertebrates (68.4 percent). Smaller percentages of households used birds and eggs (23.2 percent), small land mammals (5.3 percent), and marine mammals (1.1 percent) (Jones and Kostick, 2016).

Based on 2014 survey data, the weight of subsistence resources harvested by the community totaled 38,455.1 pounds, or 138.4 pounds per capita (Jones and Kostick, 2016). The estimated pounds per capita of general subsistence resource categories are shown below. The resources harvested at the highest levels were salmon (47.5 pounds per capita), non-salmon fish (36.0 pounds per capita), vegetation (30.1 pounds per capita), and large land mammals (17.3 pounds per capita).

The most important subsistence resources based on estimated per capita harvest weight was Pacific salmon. Seven of the ten most important resources harvested (by weight) by Seldovia residents were salmon and non-salmon fish. The most important large land mammal was moose. The most important plant resources were blueberries and salmonberries (*Rubus spectabilis*) (Jones and Kostick, 2016).

TABLE 4.14.3-59

Estimated Subsistence Harvest for Seldovia

Resource	Per Capita (pounds)	Total (pounds)
Caribou	0.7	200.5
Moose	15.6	4,331.4
Bear	0.6	155.1
Dall sheep	–	–
Deer	–	–
Other large land mammals	0.4	96.9
Small land mammals	0.1	13.4
Marine mammals	1.1	299.5
Marine invertebrates	5.5	1,537.1
Migratory birds	0.6	164.5
Upland birds	0.3	86.2
Eggs	–	–
Pacific salmon	47.5	13,203.9
Non-salmon fish	36.0	10,013.8
Berries	21.5	5,964.6
Plants	8.6	2,388.2
Wood	–	–
Other	–	–

Source: Jones and Kostick, 2016
"–" = No harvest for this resource was reported.

In Seldovia, 5 percent of households reported low or very low food security in 2014 compared to a 12-percent statewide average between 2012 and 2014. A lack of subsistence foods played a role in food insecurity. Fifteen percent of the households reported that their subsistence foods did not last as long as needed (Jones and Kostick, 2016).

Impacts on Subsistence

Seldovia is on the lower Kenai Peninsula, about 80 miles south of the Project terminus and Liquefaction Facilities, and about 20 miles from the shipping route. The Project would overlap Seldovia subsistence use areas for salmon and non-salmon fish, both resources of high importance to Seldovia residents. The Project overlaps moose and caribou use areas where it intersects with the Denali Highway, in addition to other caribou hunting areas along the Parks Highway north to the Tanana River. However, the construction timing is not concurrent with the timing of harvest of these terrestrial mammals.

Construction would require about 200 barge shipments during the summer shipping season. Because the additional traffic would occur in an already established shipping lane, impacts on fish harvests would be unlikely during construction or operation due to the presence of large non-salmon use areas outside of the shipping lane.

Marine mammals, including harbor seal and northern sea otter, are harvested in low numbers about 70 miles south of the Project. Project impacts on the subsistence use of these resources would not be anticipated.

Port Graham

The community of Port Graham is near the southwestern point of the Kenai Peninsula, about 20 miles to the southwest of the entrance to Kachemak Bay, on the southern side of a deep fjord also named Port Graham. Port Graham is about 3 air miles to the east of the community of Nanwalek, which is near the entrance to the fjord of Port Graham. The community of Port Graham is 7 miles southwest of Seldovia and 140 air miles southwest of Anchorage. Port Graham is not on the road system and is accessible only by boat or aircraft. Homer, the closest community on the Alaska road system, is on the opposite, or north side, of Kachemak Bay, and is 28 air miles to the northeast.

Port Graham is within the Kenai Mountain range, which extends from Prince William Sound to Cook Inlet along the southern margin of the Kenai Peninsula. Although the highest parts of the Kenai Mountains reach 13,000 feet, elevations are mostly below 3,000 feet in the vicinity of Port Graham. The local topography is characteristic of heavily glaciated mountains with rounded peaks and broad U-shaped valleys (Wahrhaftig, 1965).

The site of Port Graham was historically occupied by the Sugpiak-speaking Chugach, whose territory extended from the entrance of Kachemak Bay to the eastern side of Prince William Sound. Most archaeological sites on the southern coast of the Kenai Peninsula are less than 1,000 years old. This short archaeological record appears to reflect the destruction of the archaeological record by tectonic activity (Crowell and Mann, 1998). The actual occupation of the area by people ancestral to the Chugach undoubtedly extends further into the past (Jones and Kostick, 2016).

Archaeological evidence, as well as local oral traditions, indicate that a Native settlement was established at the Port Graham community site "prior to the 1880s" (Jones and Kostick, 2016). This Alaska Native community was one of at least 11 Alaska Native settlements between Seldovia and Day Harbor during the historic era (Crowell and Mann, 1998). About 100 years earlier in 1786, Russian fur traders established Fort Alexandrovsk, the second permanent Russian settlement in Alaska, at the nearby site of Nanwalek. Coercion by Russian fur traders and later the presence of Russian Orthodox missionaries drew many Sugpiak-speakers to the area (Jones and Kostick, 2016).

By the late 19th century, the commercial fishing industry surpassed the fur trade in the local economy. In 1910, the Fidalgo Island Company began developing fish processing facilities at Port Graham (Jones and Kostick, 2016). The fishing industry continued to attract settlement throughout the first half of the 20th century. By 1950, the population of Port Graham was 92 people (Jones and Kostick, 2016). Beginning in the 1950s, however, the salmon fishery began to decline, and during the second half of the 20th century, the fortunes of the commercial fishing industry fluctuated. The 1964 Good Friday earthquake, fires at cannery facilities, and the Exxon Valdez oil spill also negatively affected the commercial fishing industry. In 2014, the reopening of a salmon hatchery run by the Port Graham Village Council raised hopes of a revitalized commercial fishing industry (Jones and Kostick, 2016).

In 2014, the ADF&G conducted a study of the harvest and use of subsistence resources in Port Graham (Jones and Kostick, 2016). The ADF&G estimated a population of 148 individuals living in 58 households. The Alaska Native population recorded by the ADF&G was 133 individuals (Jones and Kostick, 2016). Investigators from the ADF&G interviewed 41 of the 58 households in the community. All 41 households reported using subsistence resources, while 97.6 percent of households reported harvesting subsistence resources.

The ADF&G reported that 37 households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were state

and local government (61.5 percent); agriculture, forestry and fishing (24.3 percent); and local service providers (8.1 percent) (Jones and Kostick, 2016).

Subsistence Use Areas

Port Graham's subsistence use areas between 2006 and 2015 are centered around the community and are more expansive in the waters of the region than on land, as shown on figure 4.14.3-36. The use areas extend offshore from Koyuktolik Bay to near Seldovia. Residents of Port Graham reported additional use areas in Kachemak Bay, including Tutka and China Poot Bays. Other offshore use areas include an almost continuous area from Kachemak Bay to Nuka Passage and the Kenai Fjords. Overland areas occur along a travel corridor through the Kenai Mountains from Port Graham to Rocky and Windy Bays. Offshore marine use areas would be crossed by the Project's vessel routes.

Seasonal Round

Port Graham residents make use of a variety of resources throughout the year (see table 4.14.3-60). Because the community is at the southwestern end of the Kenai Peninsula and lacks connection to the state's road system, however, the subsistence activities of community members emphasize marine resources. Community members also do not travel as far to practice subsistence as residents of communities on the road system.

In the spring, Port Graham residents make use of resources close to the community including sea gull eggs, spruce grouse, and small land mammals. Terrestrial vegetation, such as spruce tips and fiddlehead ferns, and seaweed, which is used as a flavoring, are also harvested.

Salmon arrive in the late spring and early summer, although some species are available all year in marine waters near the community. Port Graham residents harvest all five species of Pacific salmon, although the most important species is sockeye. Most of the salmon harvest occurs in marine waters along the Kenai Peninsula coast from Port Graham Bay to Chatham Bay. Most salmon are caught with set nets or other types of net, although smaller amounts are harvested with rod and reel or removed from commercial catch. Salmon are widely shared among community members. The harvest of salmon continues through the summer and into the fall.

Non-salmon fish are another important summer resource. The most important of these species is Pacific halibut. A variety of additional marine and freshwater non-salmon fish are also harvested, although Port Graham subsistence users tend to emphasize marine species. Non-salmon species are harvested from the same general region as salmon and are obtained using seine nets, set nets, and rod and reel.

Port Graham residents also harvest vegetation during the summer. The vast majority of plant resources used by community members (about 96 percent in 2014) are berries whose harvest extends into the fall. However, other edible, medicinal, and non-edible plant resources are also harvested at this time, including yarrow (*Achillea millefolium*), wild celery (*Angelica lucida*), wild chive (*Allium schoenoprasum*), seaweed, and firewood.

Large land mammals, upland game birds, and migratory waterfowl are hunted in the fall. Community residents hunting large land mammals do so primarily on the southwestern tip of the Kenai Peninsula in the regions surrounding the community. Species targeted by Port Graham residents include black bear, moose, and mountain goat. Migratory waterfowl harvested by community residents consist of a variety of ducks hunted in Port Graham Bay and in the vicinity of Dangerous Cape. Upland game birds, exclusively spruce grouse in 2014, are hunted in uplands to the south of the community. Although most upland game birds are hunted in the fall, community residents harvest them throughout much of the year.

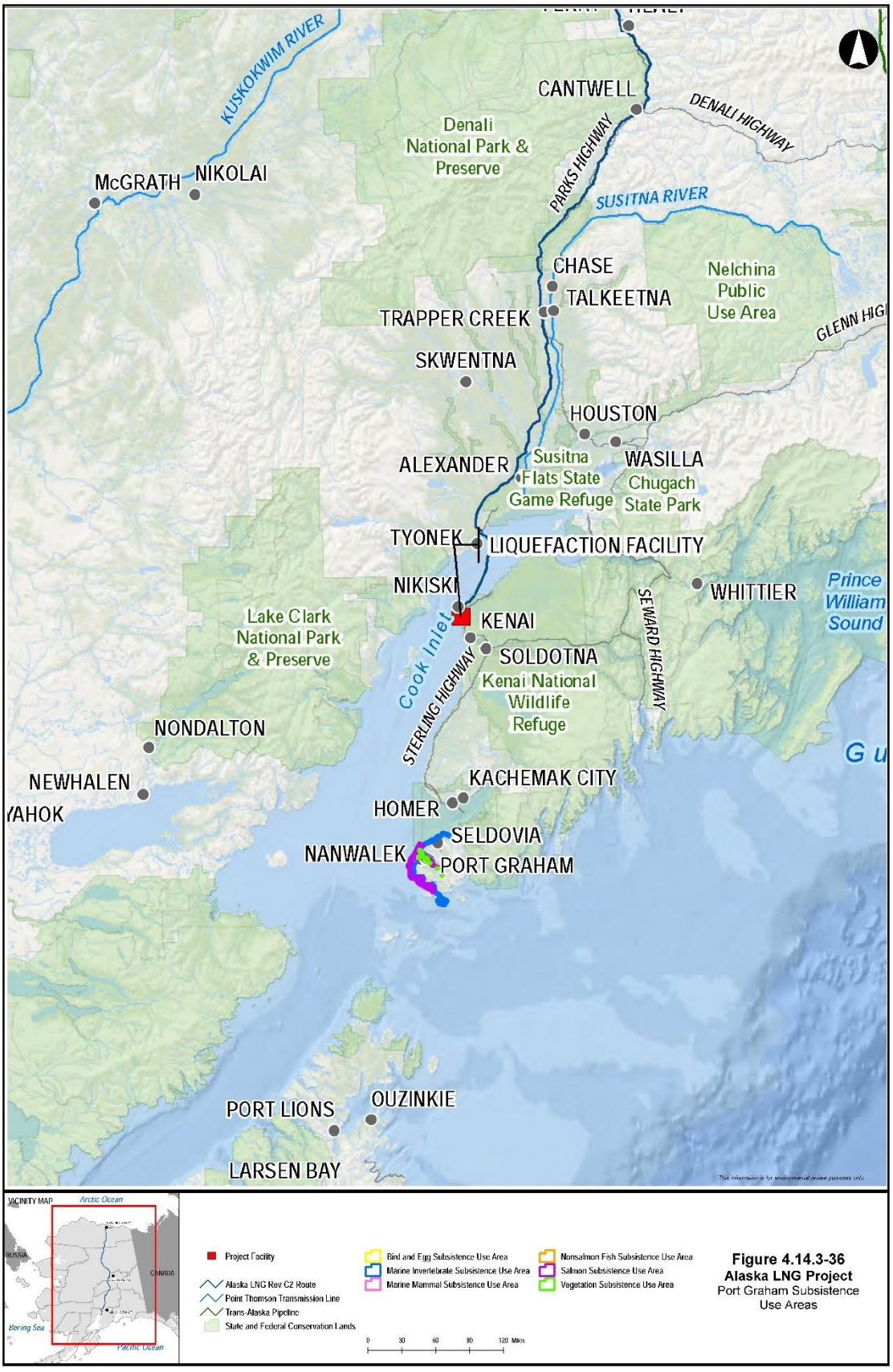


Figure 4.14.3-36
Alaska LNG Project
Port Graham Subsistence
Use Areas

TABLE 4.14.3-60

Port Graham Subsistence Harvest Timing

Species	Spring	Summer	Fall	Winter
Non-salmon fish	■	■		
Pacific salmon	■	■	■	
Marine invertebrates	■	■	■	■
Marine mammals			■	■
Large land mammals		■	■	
Birds and eggs	■			
Small land mammals	■			■
Berries		■	■	
Plants	■	■		

Source: Jones and Kostick, 2016

During the winter, a second peak in the use of small land mammals occurs, as subsistence users hunt furbearers for their white winter pelts. Small land mammal species used for subsistence purposes include snowshoe hare, North American porcupine, arctic ground squirrel, red squirrel, and least weasel.

Marine mammals and marine invertebrates can be harvested by community members throughout the year. Harbor seal is the most important marine mammal, although residents also harvest Steller sea lion and sea otter. The most important marine invertebrate used by Port Graham residents is octopus, although a variety of other species including snails, chitons, and clams are also harvested. Subsistence harvesters obtain marine mammals and marine invertebrates along the coastline of the southwestern tip of the Kenai Peninsula between Kasitsna Bay and Perl Island.

Harvest Data

Port Graham households reported using a wide range of resources in 2014 (see table 4.14.3-61). More than 97 percent of households reported using salmon and vegetation. Three quarters or more of households reported using non-salmon fish, marine mammals, and marine invertebrates. More than 68 percent reported using large land mammals. Thirty-nine percent reported using birds and eggs, and 14.6 percent reported using small land mammals (Jones and Kostick, 2016).

Based on 2014 survey data, the ADF&G estimated that the weight of subsistence resources harvested by the community totaled 32,429.0 pounds, or 218.2 pounds per capita (Jones and Kostick, 2016). Salmon was the category of subsistence resource receiving the heaviest use (107.5 pounds per capita), followed by non-salmon fish (63.3 pounds per capita). Sixteen and a half pounds of vegetation were used per capita. Large land mammals and marine invertebrates received similar levels of use at 10.9 and 11.3 pounds per capita, respectively. Use of marine mammals was 7.8 pounds per capita. The categories with the lowest levels of use (ranging from 0.3 to 0.7 pound per capita) were small land mammals and birds and eggs.

TABLE 4.14.3-61

Estimated Subsistence Harvest for Port Graham

Resource	Per Capita (pounds)	Total (pounds)
Caribou	–	–
Moose	10.3	1,527.8
Bear	0.6	82.0
Dall sheep	–	–
Deer	–	–
Other large land mammals	–	–
Small land mammals	0.3	49.5
Marine mammals	7.8	1,154.3
Marine invertebrates	11.3	1,680.4
Migratory birds	0.3	44.3
Upland birds	0.4	52.5
Eggs	<0.1	2.5
Pacific salmon	107.5	15,974.9
Non-salmon fish	63.3	9,406.1
Berries	15.8	2,351.6
Plants	0.7	98.7
Wood	–	–
Other	<0.1	4.4

Source: Jones and Kostick, 2016
"–" = No harvest for this resource was reported.

The most important subsistence resource measured in harvested pounds per capita was sockeye salmon. Only two terrestrial resources were within the 10 most harvested resources by weight: moose and blueberries. Other important resources harvested by Port Graham residents were various salmon and non-salmon fish. Octopus was the tenth most harvested resource by weight (Jones and Kostick, 2016).

Impacts on Subsistence

Port Graham is on the lower Kenai Peninsula, about 90 miles south of the Liquefaction Facilities and about 20 miles from the Project shipping route. The community's marine use areas are overlapped by the Project shipping route near the mouth of Cook Inlet.

Construction would require about 200 barge shipments during the summer shipping season. However, because the additional traffic would occur in an already established shipping lane, impacts on fish harvests would be unlikely during construction or operation due to the presence of large non-salmon use areas outside of the shipping lane.

Marine mammals, including harbor seal, Steller sea lion, and northern sea otter are harvested in low numbers about 70 miles south of the Project. Project impacts on the subsistence use of these resources would not be anticipated.

Nanwalek

The community of Nanwalek is near the southwestern-most point of the Kenai Peninsula and on the southern side of the entrance to a deep fjord named Port Graham. Nanwalek is about 3 air miles to the west of the community of Port Graham, 9 miles to the southwest of Seldovia, and 145 air miles southwest of Anchorage. Nanwalek is on the north shore of English Bay, a small bay and lagoon fed by the English Bay River. Immediately to the west of the community, steep slopes rise to mountain peaks of more than 2,700 feet. The community of Nanwalek, which is unincorporated, was previously known as English Bay. It is not on the road system and is accessible only by boat or aircraft.

The site of Nanwalek was historically occupied by the Sugpiak-speaking Chugach, whose territory extended from the entrance of Kachemak Bay to the eastern side of Prince William Sound. Most archaeological sites on the southern coast of the Kenai Peninsula are less than 1,000 years old. This short archaeological record appears to reflect the destruction of the archaeological record by tectonic activity (Crowell and Mann, 1998). The actual occupation of the area by people ancestral to the Chugach undoubtedly extends further into the past (Jones and Kostick, 2016).

In 1786, Russian fur traders established Fort Alexandrovsk, the second permanent Russian settlement in Alaska, at the site of Nanwalek. Coercion by Russian fur traders and later the presence of Russian Orthodox missionaries drew many Sugpiak-speakers to Nanwalek and the nearby community of Port Graham. By the late 1800s, the focus of the local economy was commercial fishing rather than fur trading. By the early 21st century, rising costs, stagnant fish prices, and the closure of local waters to commercial fishing, led to the end of most commercial fishing at Nanwalek (Jones and Kostick, 2016).

In 2014, the ADF&G conducted a study of the harvest and use of subsistence resources in Nanwalek (Jones and Kostick, 2016). The ADF&G estimated a population of 231 individuals living in 58 households. The Alaska Native population recorded by the ADF&G was 212 individuals. Investigators from the ADF&G interviewed 56 of the 58 households in the community. A majority (89.3 percent) of the 56 households reported using subsistence resources. The same percentage of households reported harvesting subsistence resources. The mean number of resources harvested by households was 11.5.

The ADF&G reported that 46 households in the community received cash income through employment. The three most important sources of income, as a percentage of wage earnings, were local, state, and federal government (76.6 percent); local service providers (18.2 percent); and retail trade (2.0 percent) (Jones and Kostick, 2016).

Subsistence Use Areas

Nanwalek subsistence use areas are centered in the coastal waters of the lower Kenai Peninsula as shown on figure 4.14.3-37. Nanwalek residents harvest resources in Cook Inlet and Kachemak Bay along the Kenai Peninsula's south tip. Important marine waters include China Poot Bay, Tukta Bay, Seldovia Bay, Koyuktolik Bay, Jakolof Bay, Port Graham Bay, and waters around Yukon Island. The English Bay River and its tributary lakes, and adjacent mountains within this watershed, are used by Nanwalek residents. Offshore marine use areas would be crossed by the Project's vessel routes.

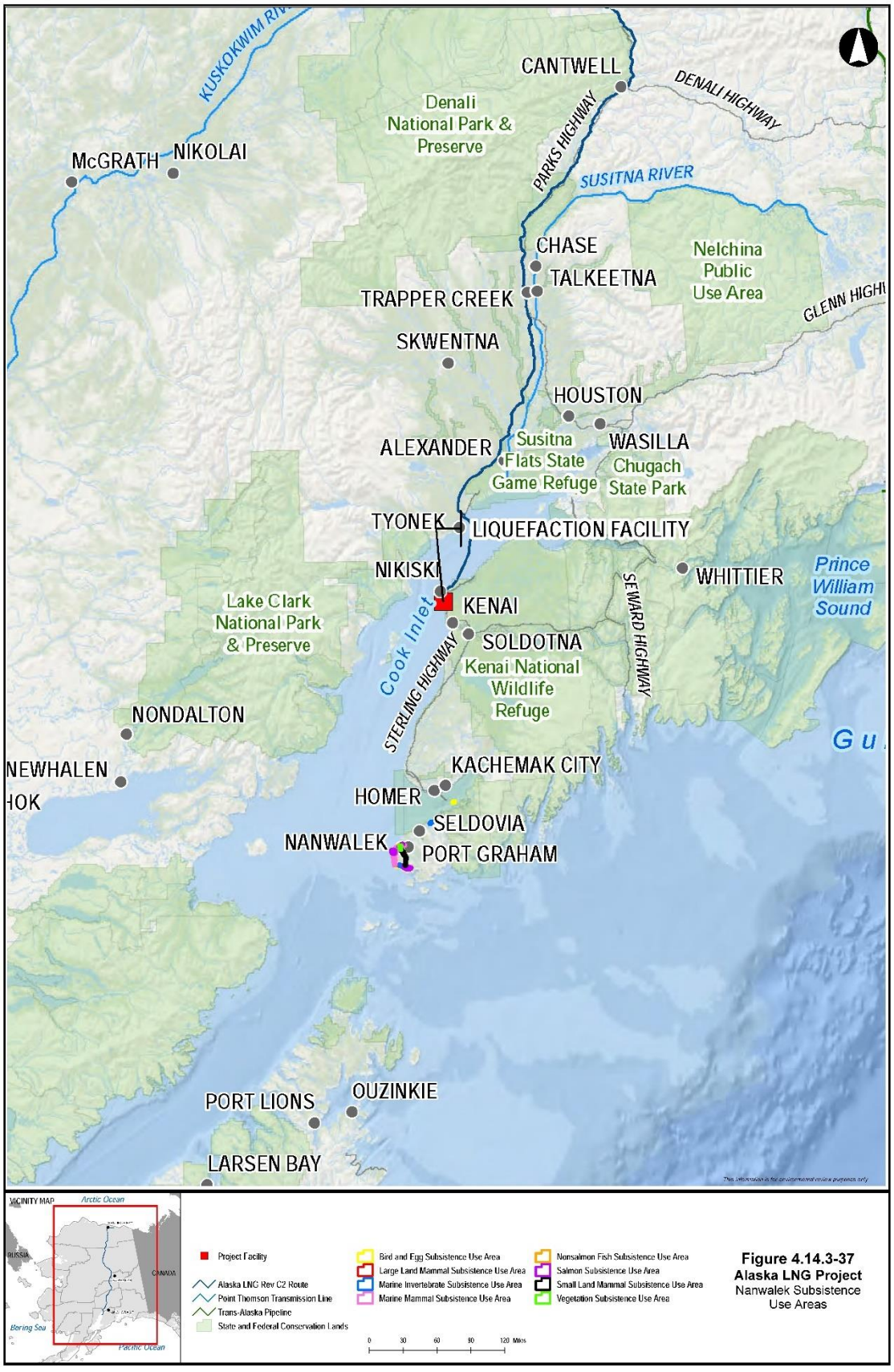


Figure 4.14.3-37
Alaska LNG Project
Nanwalek Subsistence
Use Areas

Seasonal Round

During spring and summer, fishing by rod and reel for salmon occurs in English Bay Lagoon and Port Graham Bay. Sockeye, chum, and pink salmon are harvested in June and July by rod and reel, and set net. Coho salmon arrive in late July and continue to return through mid-September. During the majority of the year, Chinook salmon are caught in offshore marine waters.

Lake, rainbow, and cutthroat (*Oncorhynchus clarkii*) trout are harvested in the English Bay River system during summer, fall, and winter. Marine non-salmon fish, including kelp greenling (*Hexagrammos decagrammus*), lingcod, Pacific cod, Pacific tomcod, sea bass (*Sebastes* spp.), and starry flounder, are harvested in Cook Inlet.

Black bear is harvested during spring, summer, and fall along the road from Nanwalek along the English Bay River and into Koyuktolik Bay. Mountain goat hunting occurs during a limited timeframe regulated by the State of Alaska between August 10 and October 15 by permit. Mountain goats are hunted in the mountains in the English Bay River Watershed and along Koyuktolik Bay. Moose are also hunted by permit from August 25 to September 30 along the road to Koyuktolik Bay along the English Bay River.

Grouse are harvested during the summer and fall along the English Bay River road. Migratory birds are hunted during summer, fall, and winter along the shores of Cook Inlet between Nanwalek and Koyuktolik Bay.

Harbor seals and Steller sea lions are harvested form late winter through fall at China Poot Bay, Tukta Bay, Seldovia Bay, Koyuktolik Bay, Port Chatham, waters around Yukon Island, and in Cook Inlet near Nanwalek. Octopus is hunted year-round along the Cook Inlet shoreline from about 1.5 miles east of Nanwalek to the mount of Koyuktolik Bay.

Black chiton (*Katharina tunicata*), snails, mussels, and cockles are gathered along the Cook Inlet shoreline from about 1.5 miles east of Nanwalek to the south and west to the mouth of Koyuktolik Bay in the late summer, fall, and winter. Clams are gathered in the tidal flats of China Poot Bay, at the far end of Tukta Bay, and in Jakolof Bay.

Mushrooms, berries, and seaweeds are harvested in spring, summer, and fall. Alaska wild rhubarb, fiddlehead fern shoots, fireweed shoots, wild celery, and willow leaves are gathered in the spring. Beach greens (*Honckenya peploides*), goose tongue (*Plantago maritima*), Labrador tea, nettles (*Urtica* spp.), wild chives, wild parsley (*Pastinaca sativa*), and yarrow are collected in summer. Blueberries, currants, highbush cranberries, mushrooms, nagoonberries (*Rubus arcticus*), rose hips (*Rosa* spp.), salmonberries, and watermelon berries (*Streptopus amplexifolius*) are harvested in the fall. Firewood collection is a year-round activity.

Harvest Data

Nanwalek households reported using a wide range of resources in 2014 (see table 4.14.3-62). More than 85 percent of households reported using salmon and vegetation. Three quarters or more of households reported using non-salmon fish and marine invertebrates. Fifty percent or more of households reported using marine mammals and birds or eggs. About 34 and 2 percent reported using large land mammals and small land mammals, respectively (Jones and Kostick, 2016).

Based on 2014 survey data, the weight of subsistence resources harvested by the community totaled 58,443.0 pounds, or 253.0 pounds per capita (Jones and Kostick, 2016). Salmon was the category of subsistence resource receiving the heaviest use (173.5 pounds per capita), followed by non-salmon fish (41.8 pounds per capita). Marine mammals, marine invertebrates, and vegetation all received similar levels of use ranging between 10.7 and 11.8 pounds per capita. The categories with the lowest levels of use (ranging from 2.5 to 0.1 pounds per capita) were large and small land mammals and birds and eggs.

TABLE 4.14.3-62

Estimated Subsistence Harvest for Nanwalek

Resource	Per Capita (pounds)	Total (pounds)
Caribou	0.7	155.4
Moose	–	–
Bear	0.5	120.1
Dall sheep	–	–
Deer	–	–
Other large land mammals	1.3	300.4
Small land mammals	0.1	16.6
Marine mammals	10.7	2,468.2
Marine invertebrates	11.3	2,617.3
Migratory birds	0.2	44.1
Upland birds	0.1	13.8
Eggs	1.0	235.4
Pacific salmon	173.5	40,082.9
Non-salmon fish	41.8	9,665.0
Berries	9.6	2,223.2
Plants	2.2	498.1
Wood	–	–
Other	<0.1	2.5

Source: Jones and Kostick, 2016
"–" = No harvest for this resource was reported.

The most important subsistence resource measured in harvested pounds per capita was sockeye salmon. The only terrestrial resource of the 10 most used resources was blueberries. The majority of resources harvested by Nanwalek residents were salmon and non-salmon fish. These were followed by black chitons (a marine invertebrate), and two pinniped species: Steller sea lions and harbor seals (Jones and Kostick, 2016).

Impacts on Subsistence

Nanwalek is on the lower Kenai Peninsula, about 90 miles south of the Liquefaction Facilities, and about 20 miles from the Project shipping route. The Mainline Pipeline would overlap use areas for five resources of low importance (moose, caribou, bear, small land mammals, and upland game birds). The Project shipping route in Cook Inlet would directly overlap Nanwalek subsistence use areas for non-salmon fish, a resource of high importance. The shipping route would also overlap salmon use areas in a state nonsubsistence area.

Nanwalek subsistence use areas for caribou, moose, bear, upland birds, and small land mammals have been documented in a single use area near the Yukon River, which is a substantial distance from the community (over 400 miles). Most of these resources are available in areas closer to Nanwalek. Therefore, the likelihood of construction activities affecting Nanwalek subsistence harvests of large terrestrial mammals is low.

Construction would require about 200 barge shipments during the summer shipping season. Because the additional traffic would occur in an already established shipping lane, however, impacts on

fish harvests would be unlikely during construction or operation due to the presence of large non-salmon use areas outside the shipping lane.

Marine mammals, including harbor seal, Steller sea lion, and northern sea otter are harvested in low numbers about 70 miles south of the Project. Project impacts on the subsistence use of these resources would not be anticipated.

4.14.4 Conclusion

We assessed potential impacts on subsistence for 33 communities. The subsistence data analyzed for 32 of the 33 communities are less than 10 years old and almost half of these are 5 years old or less. Only one survey is older than 10 years. The subsistence use areas for 29 of the communities have active use areas that would be directly affected by the Project. Project construction and operation would result in temporary, long-term, and permanent effects on the abundance and availability of subsistence resources used by these communities. These Project effects would vary depending on construction timing, wildlife presence and migration, and community harvest strategies. We note that AGDC has agreed to implement our recommendation from section 4.14 of the draft EIS to file a Project Local Subsistence Implementation Plan and a signed Conflict Avoidance Agreement (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

Construction activities such as clearing, grading, trenching, pile driving, and the presence of construction equipment and workers would cause the temporary displacement of terrestrial, avian, and marine resources, particularly moose, caribou, and bowhead whales. Based on the temporary and limited nature of construction activities in a given area, construction impacts on resource availability and access would be short term and would not be significant. AGDC would minimize subsistence impacts by coordinating with local communities through the employment of subsistence representatives and by limiting or avoiding construction activities that could reduce resource availability or user access. To minimize impacts on whale harvests, AGDC would coordinate with the AEWC to reduce or halt barge traffic during peak harvests and would require vessel operators to enter negotiations for a Conflict Avoidance Agreement. In Cook Inlet and Prudhoe Bay, AGDC would employ marine mammal monitors (protected species observers) to reduce the potential for harassment of protected marine mammals.

Habitat loss, conversion, or fragmentation as a result of construction would be localized and have short- and long-term impacts on resource availability for subsistence users. These impacts would not be significant due to the availability of adjacent suitable habitat. Of note, vegetation clearing could affect the availability of local berry patches, which are important to several communities along the Mainline Pipeline (Wiseman, Coldfoot, Nenana, Anderson, Healy, Denali Park CDP, Cantwell, and Trapper Creek). AGDC would minimize habitat impacts implementing the Project Revegetation Plan and Fugitive Dust Plan.

Operational effects of linear infrastructure would be long term or permanent. The pipeline rights-of-way and access roads could alter caribou migration patterns, resulting in a reduction in caribou availability for the residents of Utqiagvik, Nuiqsut, and Anaktuvuk Pass. New access roads that would be constructed to support pipeline operation would provide access to non-local hunters that could increase competition for subsistence resources and affect the availability and abundance of resources, particularly for the communities of Minto, Nenana, Four Mile Road, Alexander Creek/Susitna, and Beluga where access roads would be constructed in undeveloped areas. AGDC would minimize access to undeveloped areas by installing fencing, berms, and/or signs at access points to prevent or deter use of access roads and the right-of-way. To reduce the potential for increased competition, AGDC would prohibit their employees from hunting, fishing, and gathering resources while housed at camps. However, these measures would not eliminate competition.

Between Prudhoe Bay and Livengood, the Project is generally parallel to TAPS and the Dalton Highway. Between Healy and Willow, the Project is generally parallel to the Parks Highway. These

highways currently provide access to non-local hunters into areas used by subsistence hunters. Increased access and competition would not be anticipated to significantly change the abundance and availability of subsistence resources for the communities of Wiseman and Coldfoot, which have subsistence use areas that would be crossed by the access roads.

4.15 AIR QUALITY

This section describes the air quality conditions that would directly or indirectly be affected by construction and operation of the Project and summarizes the federal and state air quality regulations that are applicable to the Project. The section also characterizes and quantifies the existing air quality and describes the potential impacts that construction and operation of Project facilities could have on air quality in general and on the air quality of nationally designated protected areas under federal law (e.g., units of the National Park System, National Wilderness Areas, and NWRs).

The term *air quality* refers to the relative concentrations of pollutants in the ambient air. The subsections below describe well-established air quality concepts that are applied to characterize air quality and determine the significance of increases in air pollution. This includes metrics for specific air pollutants known as criteria pollutants, in terms of ambient air quality standards (AAQS), regional designations to manage air quality known as Air Quality Control Regions (AQCR), and the on-going monitoring of ambient air pollutant concentrations under state and federal programs.

Combustion of natural gas, diesel, and other fossil fuels would produce criteria air pollutants such as ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), and inhalable particulate matter ($PM_{2.5}$ and PM_{10}). $PM_{2.5}$ includes particles with an aerodynamic diameter less than or equal to 2.5 micrometers, and PM_{10} includes particles with an aerodynamic diameter less than or equal to 10 micrometers. Combustion of fossil fuels also produces VOCs, a large group of organic chemicals that have a high vapor pressure at room temperature, and nitrogen oxides (NO_x). VOCs react with NO_x, typically on warm summer days, to form O_3; therefore, NO_x and VOCs are often referred to as O_3 precursors. Other discussed byproducts of combustion are GHGs and hazardous air pollutants (HAP). HAPs are chemicals known to cause cancer and other serious health impacts.

GHGs produced by human activity, like fossil-fuel combustion, are primarily carbon dioxide (CO_2), CH_4, and nitrous oxide. The status of GHGs as a pollutant is not related to toxicity. GHGs are non-toxic and non-hazardous at normal ambient concentrations. Elevated levels of GHGs are considered the cause of accelerated warming of the global climate system since the 1950s. GHGs are typically expressed in terms of carbon dioxide equivalent (CO_{2e}) based on the Global Warming Potential (GWP) of each GHG. The GWP represents the ability of each different GHG to trap heat in the atmosphere. The GWP of GHGs are determined based on the heat-absorbing ability of each gas relative to that of CO_2 as well as the rate of decay, or rate of removal from the atmosphere, of each gas over a given number of years. GWPs are used to define the impact GHGs have on global warming over different time periods. Because each of the gases remains in the atmosphere for a different amount of time and has a varying ability to absorb solar radiation, the calculated GWP for each gas in relation to CO_2 can vary greatly. For example, for the 100-year GWP, CO_2 has a GWP of 1, while CH_4 has a GWP of 25 and nitrous oxide a GWP of 298. We use the 100-year GWP for the analysis throughout because the EPA used the same for the Greenhouse Gas Reporting rule.

Other Project-related pollutants not produced by combustion are fugitive dust and fugitive emissions. Fugitive dust is a mix of $PM_{2.5}$, PM_{10}, and larger particles thrown up by vehicles, earth movement, or wind erosion. Fugitive emissions, in the context of this EIS, would mainly be fugitive emissions of CH_4 from operational pipelines and aboveground facilities.

4.15.1 Regional Climatology

Alaska's diverse climate is characterized by widely varying temperature ranges and weather phenomena due to the state's size, highly variable topographical features, and location within the high latitudes. Climatic and meteorological variability would influence Project design and operation, as well as dispersion of air pollutants emitted by Project facilities.

NOAA has classified 13 climate divisions for Alaska. Four are relevant to the Project:

- North Slope;
- Central Interior;
- Cook Inlet; and
- Northwest Gulf.

The number of discrete climatic zones has sometimes been expanded to include two smaller, transitional alpine regions between the Central Interior and Cook Inlet zones (the Alaska Range) and between the North Slope and Central Interior zones (the Brooks Range). The climatic zones of Alaska relevant to this Project and the applicable regions within these zones are described below.

- North Slope: The North Slope region, north of the Brooks Range, is within the Beaufort Coastal Plain Subregion. It is dominated by an arctic climate characterized by very cold winters, persistent high wind episodes, and frequent fog conditions influenced by wind flow from the ice shield, especially in the warmer months.

- Brooks Range: The Brooks Range, with elevations reaching 4,800 feet at Atigun Pass, is partially within both the North Slope and Central Interior climatic divisions in the Project area. Local elevation and topography, especially at locations in narrow valleys, leads to unique climate features in this region, including an abundance of precipitation, mainly snow, and rapidly changing weather.

- Central Interior of Alaska: The Central Interior of Alaska, between the Brooks Range and the Alaska Range, is dominated by a continental climate characterized by very cold, stable air episodes in the winter, with a warmer growing season in the summer and occasional periods of high temperature and dry, stable atmospheric conditions in the summer.

- Alaska Range: The Alaska Range is partially within both the Central Interior and Cook Inlet climatic divisions in the Project area. Local elevation and topographic features lead to a unique climate in the region, including an abundance of precipitation, mainly snow, and rapidly changing weather.

- Cook Inlet: The south-central portion of Alaska, south of the Alaska Range and including lands around Cook Inlet, is dominated by a traditionally described maritime climate, with a transitional zone in the region's southern foothills. Elevations along the Project corridor range from about 1,000 feet in the Alaska Range foothills to sea level along Cook Inlet.

- Northwest Gulf: The climate conditions in and around Kodiak Island and over open waterbodies, including Shelikof Strait and the Kennedy Entrance to Cook Inlet, are characterized by moderate temperatures with lower precipitation than other areas within the Alaskan panhandle. Maximum precipitation occurs in late autumn and winter (Bieniek et al., 2011).

Figure 4.15.1-1 shows the climatic divisions in the Project area.

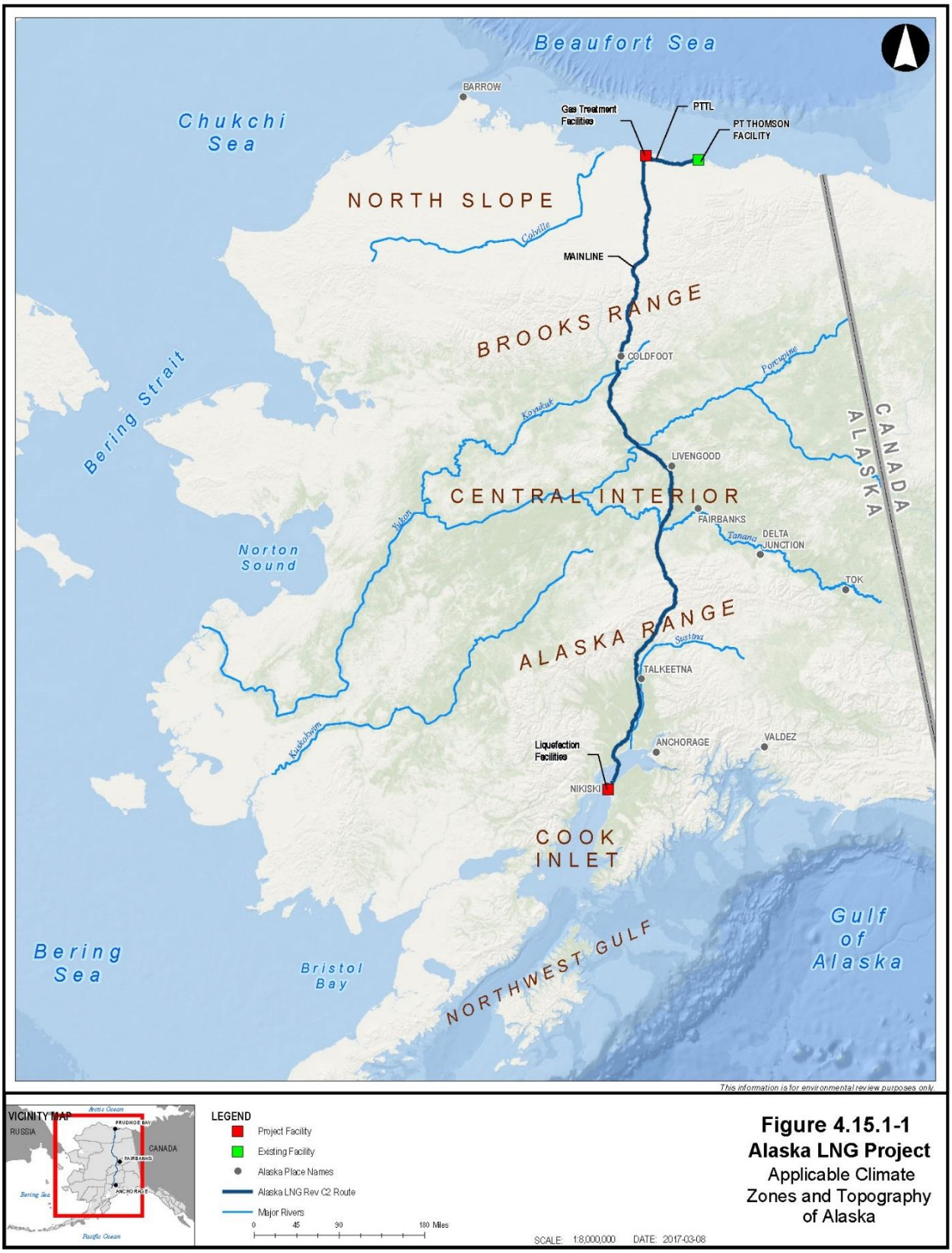


Figure 4.15.1-1
Alaska LNG Project
Applicable Climate Zones and Topography of Alaska

4.15.1.1 Gas Treatment Facilities

The Gas Treatment Facilities would be in the North Slope climatic zone. Project facilities on the North Slope would be exposed to cold arctic weather temperatures and associated wind flow patterns. Average daily maximum temperatures range from about -11°F in January to 60°F in July, and average daily minimum temperatures range from about -25°F in January to 40°F in July. Average monthly precipitation is less than 1 inch per month in the spring, fall, and winter months. Average monthly precipitation peaks in the summer, with maximum average monthly precipitation of about 1 inch in August.

4.15.1.2 Mainline Facilities

The Mainline Facilities would cross multiple climatic zones, including the North Slope, Brooks Range, Central Interior of Alaska, Alaska Range, and Cook Inlet. Regional climate for the North Slope climatic zone is described above. Temperatures within the Brooks Range are typically 5 to 10 degrees warmer than the North Slope, and average monthly precipitation is typically higher than the North Slope, especially in the summer months. The Brooks Range and areas just south have a relatively high amount of snowfall (70 inches or more annually).

The Central Interior of Alaska exhibits the largest seasonal and daily range in temperatures. Extremely cold weather can persist during the winter months, with occasional 2- or 3-week periods of temperatures below -40°F. In the summer months, average high temperatures are above 70°F, with occasional days above 90°F. As a location representative of the Central Interior of Alaska, Fairbanks receives 65 inches of snow per year, on average. Total annual precipitation generally averages more than 10 inches per year, with the bulk of that amount occurring as rainfall during the summer months.

In the Cook Inlet region, temperature ranges are more moderate, with average summer temperatures in the 60°F range and winter temperatures in the 20°F range. Precipitation in the Cook Inlet region ranges from a peak of about 3.5 inches in the summer months, to a low of about 1 inch per month in the spring months.

4.15.1.3 Liquefaction Facilities

The Liquefaction Facilities would be within the Cook Inlet climatic zone. Regional climate for the Cook Inlet climatic zone is described above.

LNG carriers would pass through the Cook Inlet climatic zone and Northwest Gulf climatic zone on their route to and from the Liquefaction Facilities. The Northwest Gulf climatic zone has the mildest temperature conditions of the regions in which the Project would be located, with average wintertime daily temperatures ranging from about 25 to 40°F, and average summertime daily temperatures ranging from 50 to 60°F. Precipitation in the Northwest Gulf region is heavier and more frequent than in the other areas, generally occurring throughout the year. Average monthly precipitation ranges from a peak of 8.5 inches per month in the fall and winter months, to a low of about 5 inches per month in the late summer months.

4.15.2 Existing Ambient Air Quality

4.15.2.1 Ambient Air Quality Standards

The EPA, as required by the CAA, has established National Ambient Air Quality Standards (NAAQS) to protect public health (primary standards) and public welfare (secondary standards). Standards have been set for six principal pollutants called "criteria pollutants." These criteria pollutants are ground-

level O_3; CO; NO_2, which is one of the group of gases called NO_x; SO_2; PM_{10}; $PM_{2.5}$; and airborne lead (EPA, 2018b). The NAAQS, which are codified in 40 CFR 50, are summarized in table 4.15.2-1.

The Alaska Ambient Air Quality Standards (AAAQS) are similar to the federal NAAQS for criteria pollutants, but ADEC has retained the 24-hour and annual standards for SO_2 that were previously part of the NAAQS. ADEC has also established an 8-hour AAAQS for ammonia. The AAAQS are summarized in table 4.15.2-1.

TABLE 4.15.2-1

National Ambient Air Quality Standards and Alaska Ambient Air Quality Standards

Air Pollutant	Primary/Secondary	Averaging Period	NAAQS	AAAQS
Ammonia	—	8-hour [a]	—	2.1 mg/m^3
CO	Primary	1-hour [a]	35 ppmv	40 mg/m^3 (35 ppmv)
		8-hour [a]	9 ppmv	10 mg/m^3 (9 ppmv)
Lead	Primary and secondary	Rolling 3-month average	0.15 µg/m^3	0.15 µg/m^3
NO_2	Primary	1-hour [b]	100 ppbv	188 µg/m^3 (100 ppbv)
	Primary and secondary	Annual	53 ppbv	100 µg/m^3 (53 ppbv)
O_3	Primary and secondary	8-hour [c]	0.070 ppmv	0.070 ppmv
PM_{10}	Primary and secondary	24-hour [a]	150 µg/m^3	150 µg/m^3
$PM_{2.5}$	Primary and secondary	24-hour [d]	35 µg/m^3	35 µg/m^3
		Annual	12 µg/m^3	12.0 µg/m^3
SO_2	Primary	1-hour [e]	75 ppbv	196 µg/m^3 (75 ppbv)
	Secondary	3-hour [a]	0.5 ppmv	1,300 µg/m^3 (0.5 ppmv)
	—	24-hour [a]	—	365 µg/m^3
	—	Annual	—	80 µg/m^3

Sources: EPA, 2018b; ADEC, 2016a

"—" = not promulgated; µg/m^3 = micrograms per cubic meter; ppbv = parts per billion by volume; ppmv = ppm by volume

[a] Not to be exceeded more than once in a year.

[b] Standard is attained when the 3-year average of the annual, 98th percentile, daily maximum, 1-hour concentration is less than or equal to 100 ppbv, or 188 µg/m^3.

[c] Standard is attained when the 3-year average of the annual fourth-highest daily maximum 8-hour average O_3 concentration is less than or equal to 0.070 ppmv.

[d] Standard is attained when the 3-year average of the annual 98th percentile 24-hour concentration is less than or equal to 35 µg/m^3.

[e] Standard is attained when the 3-year average of the annual, 99th percentile, daily maximum, 1-hour concentration is less than or equal to 75 ppbv, or 196 µg/m^3.

4.15.2.2 Air Quality Control Regions and Attainment Status

An AQCR is defined under 42 USC 7407(c) as "...any interstate area or major intrastate area which [the Administrator of the EPA] deems necessary or appropriate for the attainment and maintenance of ambient air quality standards." Each AQCR, or portion(s) of an AQCR, may be classified as either attainment, nonattainment, or maintenance with respect to the NAAQS.

Areas where ambient air concentrations of the criteria pollutants are below the levels listed in the NAAQS are considered in attainment. If ambient air concentrations of criteria pollutants are above the NAAQS levels, then the area is considered to be in nonattainment. Areas that have been designated nonattainment but have since demonstrated compliance with the NAAQS are classified as maintenance for

that pollutant. Maintenance areas are treated similarly to attainment areas for the permitting of stationary sources, but specific provisions may be incorporated through the state's approved maintenance plan to ensure that air quality would remain in compliance with the NAAQS for that pollutant. Maintenance areas retain the classification for 20 years before being reclassified as attainment areas. Areas where air quality data are not available are considered to be unclassifiable and are treated as attainment areas.

The Project facilities would be in areas classified as attainment for all criteria pollutant standards. The nearest nonattainment area to the Project facilities would be the Fairbanks $PM_{2.5}$ Nonattainment Area, which is in the Fairbanks North Star Borough and is approximately 25 miles by 16 miles in size.[122] While no Project facilities would be within this nonattainment area, some air emission generating activities, including Project construction support and transportation of equipment, would occur within this nonattainment area, as well as two CO maintenance areas (Fairbanks and Anchorage) and one PM_{10} maintenance area (Eagle River) during Project construction.[123] These air emissions are further addressed in section 4.15.3.1.

Although the EPA maintains jurisdiction over portions of the outer continental shelf within the GOA (40 CFR 55), attainment status does not apply in offshore areas. Therefore, LNG vessels transiting the GOA would not pass through nonattainment or maintenance areas.

4.15.2.3 Air Quality Monitoring and Background Concentrations

AGDC gathered and filed publicly available ambient air quality data from local, state, and federal agencies, as well as private entities. In addition, AGDC established an ambient air quality monitoring station, in consultation with ADEC, to characterize background air quality in the vicinity of the Liquefaction Facilities. Data was collected from January 1, 2015 to June 30, 2016. Ambient air quality monitoring data was separated by region and Project component. Tables 4.15.2-2 to 4.15.2-4 summarize the available ambient air quality data, including the estimated representative background levels for Project facilities, and a comparison to the associated NAAQS/AAAQS applicable to the Project area. Estimated background air quality for the compressor stations is presented in section 4.15.5.2.

The background air quality concentrations presented in table 4.15.2-2 represent estimated background air pollutant concentrations for the Gas Treatment Facilities and portions of the Mainline Facilities within the North Slope.[124] The majority of the data collected demonstrates that existing air quality is in compliance with AAQS. While some isolated exceedances of the 1-hour NO_2 AAQS threshold were observed, the design concentrations indicate compliance with the NO_2 standard. The estimated representative background level for Project facilities was approved for use by ADEC along with the Project modeling protocol developed for the Gas Treatment Facilities.

Participants in traditional knowledge workshops on the North Slope remarked that air quality has worsened due to development in the area, particularly oil and gas development. Several participants, particularly those from the Nuiqsut and Kaktovik communities, commented that visible haze was noticeable in the vicinity of Prudhoe Bay. Participants also noted that the air quality impacts tended to be particularly noticeable during winter months and that local residents reported breathing difficulties they believed were connected to airborne contaminants (Braund, 2016). These impacts can result from fine particulate, NO_x, and VOC emissions associated with oil and gas development, processing, and transport.

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122 Further details regarding the size and location of the Fairbanks $PM_{2.5}$ Nonattainment Area are available at the following location: https://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip//.

123 Further details regarding the size and location of the Fairbanks and Anchorage CO Maintenance Areas and the Eagle River PM_{10} Maintenance Area are available at the following location: https://dec.alaska.gov/air/anpms/sip/contents/.

124 Monitored air quality data were included as appendix B to AGDC's Resource Report 9 (Accession No. 20170417-5345), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 in the "Numbers: Accession Number" field.

TABLE 4.15.2-2

Monitored Air Quality Data from the North Slope

Air Pollutant	Averaging Period	Representative Background Concentration at the GTP	NAAQS/AAAQS
SO_2	1-hour [b]	9.39 µg/m^3	196 µg/m^3
	3-hour	20.96 µg/m^3	1,300 µg/m^3
	24-hour	8.12 µg/m^3	365 µg/m^3
	Annual	1.8 µg/m^3	80 µg/m^3
CO	1-hour	1.15 mg/m^3	40 mg/m^3
	8-hour	1.15 mg/m^3	10 mg/m^3
NO_2	1-hour [c]	61.69 µg/m^3	188 µg/m^3
	Annual	6.0 µg/m^3	100 µg/m^3
O_3	8-hour [d]	0.056 ppmv	0.070 ppmv
PM_{10}	24-hour	50.0 µg/m^3	150 µg/m^3
$PM_{2.5}$	24-hour [e]	15 µg/m^3	35 µg/m^3
	Annual	3.7 µg/m^3	12 µg/m^3

µg/m^3 = micrograms per cubic meter; ppmv = ppm by volume

[a] Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in table 4.15.2-1.

[b] The 1-hour SO_2 average shown in the table reflects the annual 99th percentile of the daily maximum 1-hour SO_2 concentration averaged over the specified monitoring period, and is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[c] The 1-hour average shown in the table reflects annual 98th percentile of the daily maximum 1-hour NO_2 concentration averaged over the specified monitoring period and is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[d] The annual fourth-highest daily maximum 8-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[e] The annual 98th percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

Background air quality concentrations presented in table 4.15.2-3 represent background air pollutant concentrations for portions of the Mainline Facilities within Interior Alaska and the Alaska Range. The majority of the data collected demonstrate that existing air quality is in compliance with the AAQS. While some exceedances of the $PM_{2.5}$ standard were observed, these are associated with the Fairbanks $PM_{2.5}$ nonattainment area and are not representative of air quality in the Project vicinity.

Participants in traditional knowledge workshops remarked that the Interior Alaska and the Alaska Range areas have generally good air quality, with seasonal changes noted during years where wildfires occurred. Several participants said that dust and traffic contribute to poorer air quality along the Dalton Highway and other highways and local roads (Braund, 2016).

Background air quality concentrations presented in table 4.15.2-4 represent background air pollutant concentrations for portions of the Mainline Facilities within the south-central Alaska and Cook Inlet climate regions and the Liquefaction Facilities/LNG Plant. The majority of the data collected demonstrate that the existing air quality is in compliance with AAQS. While some isolated exceedances of the short-term NO_2, PM_{10}, and $PM_{2.5}$ AAQS thresholds were observed, the design concentrations indicate compliance with the NO_2, PM_{10}, and $PM_{2.5}$ standards. As previously noted, AGDC installed a background air quality monitoring station to establish representative background concentrations for the Liquefaction Facilities. The background air quality information presented for the Liquefaction Facilities was gathered by this station.

TABLE 4.15.2-3

Monitored Air Quality Data from Interior Alaska and the Alaska Range

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations [a]	NAAQS/AAAQS
SO_2	1-hour [b]	146.5 µg/m^3	196 µg/m^3
	3-hour	5.33 – 131 µg/m^3	1,300 µg/m^3
	24-hour	5.33 – 85.9 µg/m^3	365 µg/m^3
	Annual	1.33 – 33.2 µg/m^3	80 µg/m^3
CO	1-hour	0.7 – 5.41 mg/m^3	40 mg/m^3
	8-hour	0.3 – 3.21 mg/m^3	10 mg/m^3
NO_2	1-hour [c]	26.32 µg/m^3	188 µg/m^3
	Annual	1.91 µg/m^3	100 µg/m^3
O_3	8-hour [d]	0.054 – 0.064 ppmv	0.070 ppmv
PM_{10}	24-hour	15 – 111 µg/m^3	150 µg/m^3
$PM_{2.5}$	24-hour [e]	11.2 – 83.2 [f] µg/m^3	35 µg/m^3
	Annual	1.45 – 13.2 [f] µg/m^3	12 µg/m^3

µg/m^3 = micrograms per cubic meter; ppmv = ppm by volume

[a] Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in table 4.15.2-1.

[b] The 1-hour SO_2 average shown in the table reflects the annual 99th percentile of the daily maximum 1-hour SO_2 concentration averaged over the specified monitoring period and is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[c] The 1-hour average shown in the table reflects annual 98th percentile of the daily maximum 1-hour NO_2 concentration averaged over the specified monitoring period and is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[d] The annual fourth-highest daily maximum 8-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[e] The annual 98th percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[f] Includes measured concentrations from the Fairbanks urban $PM_{2.5}$ nonattainment area.

A number of participants in the traditional knowledge workshops for the south-central Alaska and Cook Inlet areas remarked that the area has good air quality due to vegetation and good air flow. Other participants noted that dust due to vehicle and air traffic, as well as fire-related and other naturally-occurring air pollution, has caused temporary air quality issues in the region. Some participants also felt that development in the area, including industrial development, had negatively affected the air quality, especially in the Kenai Peninsula region (Braund, 2016).

4.15.3 Air Quality Regulatory Requirements

State air quality rules govern the issuance of air permits for construction and operation of a stationary emission source. The state air quality rules are part of the EPA-approved SIP, developed in accordance with Section 110 of the CAA. The EPA retains enforcement and oversight authority to provide assurance the state complies with CAA requirements. ADEC is the lead air permitting authority for the Project. ADEC's air quality regulations are codified in 18 AAC 50, which incorporates the federal program requirements and establishes permit review procedures for facilities that emit pollutants to the ambient air. New facilities are required to obtain an air quality permit prior to initiating construction.

TABLE 4.15.2-4

Monitored Air Quality Data from South-Central Alaska and Cook Inlet

Air Pollutant	Averaging Period	Representative Background Concentration at the Liquefaction Facilities	NAAQS/AAAQS
SO_2	1-hour [a]	5.0 µg/m^3	196 µg/m^3
	3-hour	5.0 µg/m^3	1,300 µg/m^3
	24-hour	2.4 µg/m^3	365 µg/m^3
	Annual	0.0 µg/m^3	80 µg/m^3
CO	1-hour	1.145 mg/m^3	40 mg/m^3
	8-hour	1.145 mg/m^3	10 mg/m^3
NO_2	1-hour [b]	32.3 µg/m^3	188 µg/m^3
	Annual	2.6 µg/m^3	100 µg/m^3
O_3	8-hour [c]	0.047 ppmv	0.070 ppmv
PM_{10}	24-hour	40 µg/m^3	150 µg/m^3
$PM_{2.5}$	24-hour [d]	12 µg/m^3	35 µg/m^3
	Annual	3.7 µg/m^3	12 µg/m^3

µg/m^3 = micrograms per cubic meter; ppmv = ppm by volume

[a] The 1-hour SO_2 average shown in the table reflects the annual 99th percentile of the daily maximum 1-hour SO_2 concentration averaged over the specified monitoring period. This average is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[b] The 1-hour average shown in the table reflects annual 98th percentile of the daily maximum 1-hour NO_2 concentration averaged over the specified monitoring period. This average is provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[c] The annual fourth-highest daily maximum 8-hour O_3 concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

[d] The annual 98th percentile $PM_{2.5}$ concentrations averaged over the specified monitoring period are provided for informational purposes and for PSD-quality determination purposes for future permitting projects.

4.15.3.1 Federal Air Quality Requirements

New Source Review and Prevention of Significant Deterioration

Congress established the New Source Review (NSR) pre-construction permitting program as part of the 1977 CAA amendments. Federal pre-construction review under NSR is conducted under separate procedures for sources in attainment areas and sources in nonattainment areas. Nonattainment NSR applies to sources in nonattainment areas. Since the Project is not in any nonattainment areas, this process does not apply to the Project and is not discussed further.

The PSD regulations, codified in 40 CFR 52.21, apply to new major sources or major modifications at existing sources in attainment areas or in areas that are unclassifiable. PSD is intended to keep new air emission sources from causing the existing air quality to deteriorate beyond acceptable levels. Under PSD regulations, a major source is any source type belonging to a list of 28 named source categories that emit or have the potential to emit (PTE) 100 tpy or more of any regulated pollutant. Source categories not named on this list are considered major if the facility emits or has the PTE 250 tpy or more of any criteria pollutant. None of the Project facilities are included in the list of 28 named source categories.

PSD can also apply to an existing major source when physical modifications are made to the source that result in increased emissions above the "major modification" or significant emission rate for the respective pollutant. Additionally, a minor NSR permit is required for a new source when the PTE exceeds

the minor NSR thresholds. Minor source NSR thresholds are generally developed on a state level and can vary from state to state.

New Source Review Requirements

Table 4.15.3-1 presents the major stationary source, major modification, and minor NSR threshold levels applicable to the Project. The GTP and Liquefaction Facilities would be considered new major stationary sources because each of these new sources have potential emissions that exceed the Major Stationary Source Threshold Levels. Existing major stationary sources require a major NSR permit when a modification or addition to the facility results in a net emission increase that exceeds the Significant Net Increase thresholds. The compressor stations and heater station would be considered new minor sources with respect to PSD.

TABLE 4.15.3-1

New Source Review: Major Stationary Source/Major Modification Emission Thresholds

Pollutant	Major Stationary Source Threshold Level (tpy)	Major Modification Significant Net Increase (tpy)	Alaska Minor NSR Threshold Level (tpy)
O_3/VOC/NO_X	250	40	40
CO	250	100	100 [a]
SO_2	250	40	40
PM	250	25	25
PM_{10}	250	15	15
$PM_{2.5}$	250	10	10
lead	250	0.6	0.6
GHG	N/A	N/A	N/A

N/A = Not applicable

[a] Threshold applies within 6.2 miles (10.0 km) of a CO nonattainment area.

Prevention of Significant Deterioration Requirements

Once a facility is subject to PSD, the following requirements apply:

- determination of Best Available Control Technology (BACT);
- air quality monitoring and modeling analyses to ensure that a project's emissions will not cause or contribute to a violation of any NAAQS or PSD increment;
- notification to the Federal Land Manager (FLM) of nearby Class I areas that could be affected by the facility and of Class I area Air Quality Related Values (AQRV) impacts; if applicable, conduct a Class I AQRV impact assessment;
- an additional impacts analysis that evaluates the effects of regional growth associated with the facility, as well as the impacts on soil, vegetation with substantial economic or recreation value, and visibility within the affected region; and
- public involvement for the permit, including a public comment period, public hearings or meetings, and appeal procedures.

BACT is a case-by-case emissions limitation based on the maximum degree of control that can be achieved in practice after accounting for the degree of control at similar facilities as well as the energy,

environmental, and economic impact. BACT can be based on add-on control equipment or modification of the production processes or methods. This includes fuel cleaning or treatment and innovative fuel combustion techniques. BACT may be a design, equipment, work practice, or operational standard if imposition of an emissions standard is infeasible.

The air quality monitoring and modeling analysis involves an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and predictions, using dispersion modeling, of ambient concentrations that would result from the Project and future growth associated with the Project.

Under the CAA, federal Class I areas are areas in existence as of August 7, 1977 that meet one of the following criteria: 1) national wilderness areas or national memorial parks that exceed 5,000 acres in size, 2) national parks that exceed 6,000 acres in size, or 3) international parks. Such areas fall under the provisions of the PSD regulations. The United States has 158 mandatory Class I areas. If a new source or major modification of an existing source is subject to the PSD program requirements, the facility is required to notify the appropriate federal officials whose areas could be affected and, if applicable, assess the impacts of the proposed project on the Class I area. Under the CAA, if a nationally designated protected area, like a unit of the National Park System, does not meet the criteria to be a Class I area, it is automatically a Class II area. Impacts on protected Class II areas should be considered under the "additional impacts analysis" provisions of the PSD regulations.

In addition to the CAA requirements, NEPA also serves as an independent basis for requiring an evaluation of air quality impacts on nationally designated protected areas in the "environmental consequences" section of an EIS (see 1502.16(c) and (f)). Such areas include, but are not limited to, units of the National Park System, NWRs, National Wilderness Areas, WSRs, and National Historic Trails. The national designation for these areas identifies a variety of special purposes for which the areas are to be managed. For example, under the NPS Organic Act of 1916, Congress directed that units of the National Park System be managed "unimpaired for the enjoyment of future generations." Figure 4.15.3-1 illustrates the location of Class I and other nationally protected areas in proximity to the Project.

The GTP and Liquefaction Facilities would be subject to PSD permitting because each facility exceeds the 250 tpy emission threshold. The compressor stations and heater station would be subject to minor NSR permitting and require an operating permit under the Title V provisions because they each exceed 100 tpy of a regulated pollutant. AGDC submitted a PSD permit application for the GTP on December 29, 2017 and for the Liquefaction Facilities on May 1, 2018. The applications are currently under review by ADEC.

Title V Operating Permits

The Part 70 Operating Permit program, as described in 40 CFR Part 70, requires major stationary sources of air emissions to submit an operating permit application prior to initial facility startup. Part 70 operating permits are more commonly referred to as "Title V" permits. The Title V permit is a legally-enforceable document used to clarify what facilities must do to comply with air quality and emissions regulations. In Alaska, the EPA has delegated the authority to issue Title V permits to ADEC, which has incorporated the program in 18 AAC 50.236. The threshold levels for determining the applicability for a Title V permit are:

- 100 tpy of any criteria air pollutant;
- 10 tpy of any individual HAP;
- 25 tpy of any combination of HAPs; or
- named minor source category.

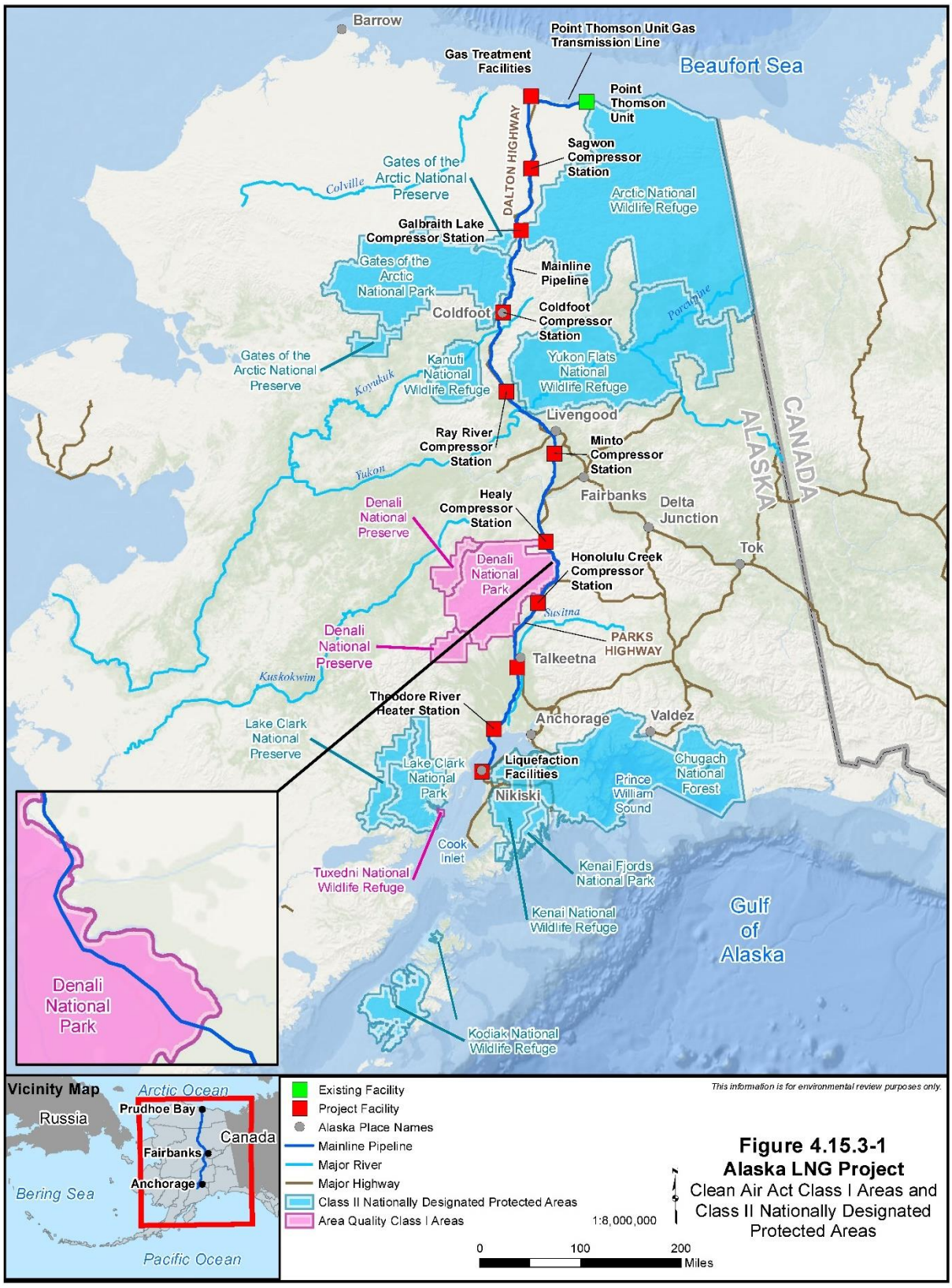


Figure 4.15.3-1
Alaska LNG Project
Clean Air Act Class I Areas and Class II Nationally Designated Protected Areas

Based on the current estimated PTE calculations, the GTP, compressor stations, heater station, and Liquefaction Facilities would be required to obtain Title V permits.

New Source Performance Standards

Section 111 of the CAA authorized the EPA to develop technology-based standards that apply to specific categories of stationary sources. These standards, referred to as New Source Performance Standards (NSPS), are found in 40 CFR 60. The NSPS apply to new, modified, and reconstructed affected facilities in specific source categories. We have determined that the following NSPS would be applicable to one or more of the Project facilities.

Subpart A – General Provisions

The general provisions listed in Subpart A include broader definitions of applicability and various methods for maintaining compliance with requirements listed in subsequent subparts of 40 CFR 60. Subpart A also specifies the state agencies to which the EPA has delegated authority to implement and enforce standards of performance. Any Project facilities subject to a NSPS subpart listed below would be subject to Subpart A.

Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Subpart Db applies to steam-generating units constructed after June 19, 1984 that have a maximum *heat input capacity* of 100 million British thermal units (MMBtu/hour). Three utility heaters at the GTP would have a heat input capacity of 225 MMBtu/hour each. These units would be subject to Subpart Db.

Subpart Dc – Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units

Subpart Dc applies to steam-generating units constructed after July 9, 1989 that have a maximum heat input capacity of 100 MMBtu/hour or less but greater than or equal to 10 MMBtu/hour. The Rabideux Creek Compressor Station would have five indirect-fired gas heaters, and the Theodore River Heater Station would have nine indirect-fired gas heaters. Based on current Project design, each heater would have a maximum heat input capacity of 28 MMBtu/hour and would, therefore, be subject to Subpart Dc.

Subpart CCCC – Standards of Performance for Commercial and Industrial Solid Waste Incineration Units

Subpart CCCC applies to owners and operators of commercial and industrial solid waste incineration units constructed after June 4, 2010 or reconstructed after August 7, 2013. Subpart CCCC requires a pre-construction siting analysis, waste management plan, operational training, emission limits, performance testing, recordkeeping, and reporting. Each of the compressor stations and the heater station would have a waste incineration unit subject to Subpart CCCC.

Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII applies to owners and operators of stationary compression ignition internal combustion engines (CI ICE) that commence construction after July 11, 2005, where the stationary CI ICE are: 1) manufactured after April 1, 2006, and are not fire pump engines, or 2) are manufactured as a certified NFPA fire pump engine after July 1, 2006.

Subpart IIII specifies emission standards, fuel requirements, compliance requirements, and testing requirements for CI ICE, some of which vary by model year, engine power, and displacement, and also

specifies notification, reporting, and recordkeeping requirements for owners and operators of CI ICE subject to this subpart.

The GTP would have two power generator CI ICEs, three fire water pump CI ICEs, and one emergency generator CI ICE that would be subject to the requirements of Subpart IIII. If any of the three fire water pump CI ICEs meets the emission limit requirements of Subpart IIII, a non-resettable hour meter would be installed prior to startup to ensure compliance with this NSPS.

The Liquefaction Facilities would have one non-emergency CI ICE air compressor drive and one fire water pump that would be subject to the requirements of Subpart IIII. If the fire water pump CI ICE does not meet the emission limit requirements of Subpart III, a non-resettable hour meter would be installed prior to startup to ensure compliance with this NSPS.

Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

Subpart JJJJ provides requirements for stationary spark ignition internal combustion engines that are constructed, modified, or reconstructed after June 12, 2006. Subpart JJJJ limits emissions of NO_x, CO, and VOCs. Each of the compressor stations and the heater station would have spark ignition ICEs, which would be subject to Subpart JJJJ.

Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

Subpart KKKK applies to owners and operators of stationary combustion turbines with a heat input peak load equal to or greater than 10 MMBtu/hour that commenced construction, modification, or reconstruction after February 18, 2005. Subpart KKKK regulates emissions of NO_X and SO_2. Subject turbines must meet the applicable emission limits and operational requirements as well as recordkeeping and reporting requirements of this subpart.

The 18 natural-gas-fired turbines at the GTP would be subject to Subpart KKKK. The turbines would meet the emission limitations with the low NOx emission controls and the low sulfur content of the gas burned. The Liquefaction Facilities would have six simple cycle natural-gas-fired combustion turbines and four natural-gas-fired combined cycle turbines, which would be subject to Subpart KKKK. The turbines would meet the emission limitations with the low NOx emission controls and the low sulfur content of the gas burned. Each of the compressor stations would have natural-gas-fired combustion turbines that would be subject to Subpart KKKK. The turbines would meet the emission limitations with the low NOx emission controls and the low sulfur content of the gas burned.

Subpart OOOOa – Standards of Performance for Crude Oil and Natural Gas Facilities

Subpart OOOOa regulates emissions of GHGs and VOCs from certain new and modified sources in the oil and natural gas sector. Subpart OOOOa would apply to the following equipment proposed to be installed at aboveground facilities associated with the Project:

- centrifugal compressors using wet seals;
- single continuous-bleed, natural-gas-driven pneumatic controllers;
- storage vessels with potential VOC emissions equal to or greater than 6 tpy;
- pneumatic pumps that are natural-gas-driven diaphragm pumps;
- all equipment within certain process units associated with natural gas processing; and
- certain fugitive emission components associated with natural gas facilities.

The GTP, compressor stations, heater station, and Liquefaction Facilities would have equipment subject to Subpart OOOOa. Meter stations could also be subject to Subpart OOOOa.

Subpart OOOOa requires implementation of leak detection and repair programs at applicable natural gas compressor stations, requirements to limit GHG and VOC emissions from compressors and pneumatic controllers used at natural gas facilities, and requirements for recordkeeping and annual reporting. AGDC would be required to implement the applicable portions of Subpart OOOOa at the aboveground facilities subject to this subpart, including the fugitive emissions monitoring requirements.

National Emissions Standards for Hazardous Air Pollutants

Section 112 of the CAA authorized the EPA to develop technology-based standards that apply to specific categories of stationary sources that emit HAPs. These standards are referred to as National Emission Standards for Hazardous Air Pollutants (NESHAP) and are found in 40 CFR 61 and 63. Eight hazardous substances are regulated by 40 CFR 61: asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride. NESHAPs can apply to major and/or area (minor) sources of HAPs. The EPA develops national priorities for NESHAPs that focus on significant environmental risks and noncompliance patterns.

The 1990 CAA amendments established a list of 189 HAPs, resulting in the promulgation of Part 63, also known as the Maximum Achievable Control Technology standards. Part 63 regulates HAPs from major sources of HAPs and specific source categories emitting HAPs. Some NESHAPs may apply to area (minor) sources of HAPs. Major source thresholds for NESHAPs are 10 tpy of any single HAP or 25 tpy of total HAPs.

The GTP and Liquefaction Facilities would be classified as major sources of HAPs because the facilities would emit greater than 10 tpy of formaldehyde and ethylbenzene, both of which are regulated HAPs. The compressor stations, heater station, and meter stations would be classified as area sources of HAPs. The following NESHAP subparts apply to the Project facilities.

Subpart A – NESHAP General Provisions

The general provisions listed in Subpart A include broader definitions of applicability and various methods for maintaining compliance with requirements listed in subsequent subparts of 40 CFR 63. This subpart also addresses the delegation of NESHAP authority to the states. Subpart A regulates flares if operated as a control device for NESHAP-regulated units. The flares at the GTP and Liquefaction Facilities would be subject to the flare design and operating requirements of Subpart A.

Subpart H – NESHAP for Organic Equipment Leaks

Subpart H regulates component leaks from equipment in contact with a liquid or gas that contains at least 5-percent total organic HAPs on an annual basis. Subpart H requires leak detection and repair for components operating 300 hours or more on an annual basis. Subpart H may be applicable to the compressor stations, heater station, and Liquefaction Facilities depending on the composition of the natural gas condensate stored at these facilities.

Subpart HH – NESHAP for Oil and Natural Gas Production Facilities

Subpart HH regulates glycol dehydrators, storage vessels with potential flash emissions, and ancillary equipment at facilities that process, upgrade, or store natural gas or hydrocarbon liquids. Subpart HH would be applicable to the GTP based on current facility design.

Subpart HHH – NESHAP for Natural Gas Transmission and Storage Facilities

Subpart HHH regulates new and existing glycol dehydrators at natural gas transmission and storage facilities that transport or store natural gas at major sources of HAPs. Subpart HHH requires emission controls monitoring, recordkeeping, and reporting. The GTP is anticipated to have three glycol dehydrators that would be subject to Subpart HHH requirements.

Subpart EEEE – NESHAP from Organic Liquids Distribution (Non-gasoline)

Subpart EEEE regulates emissions from organic liquid distribution operations at major sources of HAPs. Organic liquid distribution operations include the operation of storage tanks, loading and unloading of transport vehicles or containers, and equipment leaks. Organic liquid distribution operations subject to Subpart HH or HHH are not subject to Subpart EEEE. Subpart EEEE would apply to operations at the Liquefaction Facilities based on current facility design.

Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ regulates HAP emissions from reciprocating internal combustion engines (RICE) at major and area sources. The GTP, compressor stations, heater station, and Liquefaction Facilities would have multiple RICE engines subject to Subpart ZZZZ. The RICE engines with a horsepower rating of less than 500 hp at the GTP and Liquefaction Facilities would maintain compliance with Subpart ZZZZ by demonstrating compliance with NSPS Subpart IIII. The RICE engines at the compressor stations and heater station would maintain compliance with Subpart ZZZZ by demonstrating compliance with NSPS Subpart JJJJ. One of the RICE engines at the GTP would have a rating greater than 500 hp and would be subject to the emission limitations of Subpart ZZZZ.

Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Subpart DDDDD regulates boilers and process heaters at major sources of HAPs. The GTP would have three natural-gas-fired utility heaters subject to the initial notification and work practice standards of Subpart DDDDD.

Mandatory Greenhouse Gas Reporting

Subpart W of 40 CFR 98 requires petroleum and natural gas facilities that emit 25,000 MTPA or more of CO_2e to report annual emissions of specified GHGs from various processes within the facility. The GTP and Liquefaction Facilities would be required to report GHG emissions because annual emissions of GHGs would be above 25,000 MTPA.

Compressor stations are also subject to GHG reporting requirements under Subpart W. Reporting is required for CO_2e from reciprocating compressor rod packing venting, centrifugal compressor venting, transmission storage tanks, blowdown vent stacks, natural gas pneumatic device venting, and equipment leaks from valves, connectors, open-ended lines, pressure relief valves, and meters. AGDC would comply with the mandatory GHG reporting requirements for regulated facilities associated with the Project.

General Conformity

A General Conformity applicability analysis is required for any part of a project occurring in nonattainment or maintenance areas for criteria pollutants. Section 176(c) of the CAA requires federal

agencies to ensure that federally approved or funded projects conform to the applicable approved SIP. Such activities must not:

- cause or contribute to any new violation of any standard in any area;
- increase the frequency or severity of any existing violation of any standard in any area; or
- delay timely attainment of any standard or any required interim emission reductions or other milestones in any area.

None of the direct Project emissions would occur within a nonattainment or maintenance area. The Project would generate a small amount of indirect emissions within the Fairbanks $PM_{2.5}$ Nonattainment Area, the Fairbanks Area CO Maintenance Area, the Anchorage CO Maintenance Area, and the Eagle River PM_{10} Maintenance Area from construction support and equipment transportation. Table 4.15.3-2 summarizes the annual emissions generated in each nonattainment or maintenance area compared to the General Conformity applicability thresholds.

As presented in table 4.15.3-2, the maximum annual emissions generated by the Project in the nonattainment and maintenance areas would not exceed General Conformity applicability thresholds. Therefore, a General Conformity Analysis would not be required.

TABLE 4.15.3-2

General Conformity Applicability Analysis

Air Pollutant	Maximum Annual Emissions (tpy)	General Conformity Applicability Threshold
Fairbanks $PM_{2.5}$ Nonattainment Area		
$PM_{2.5}$	3.8	70
SO_2 [a]	<0.1	70
NO_X [a]	4.8	70
Fairbanks CO Maintenance Area		
CO	1.9	100
Anchorage CO Maintenance Area		
CO	0.4	100
Eagle River PM_{10} Maintenance Area		
PM_{10}	<0.1	100

[a] SO_2 and NO_X are $PM_{2.5}$ precursor pollutants.

4.15.3.2 Alaska Air Quality Requirements

The Project facilities are subject to Alaska's air quality regulations codified in 18 AAC 50. The portions of 18 AAC 50 that would apply to each of the Project facilities would be summarized in the air permits issued by ADEC. Many of the applicable state regulations directly adopt federal regulations, but some state specific standards that may be applicable to the Project include:

- visibility protection standards (50.025);
- waste incinerator emission standards (50.050);
- industrial processes and fuel burning equipment (50.055);
- open burning (50.065);

- marine vessel visible emission standards (50.070);
- non-road engine emission standards (50.100); and
- minor construction permit requirements (50.502).

4.15.4 Construction Emissions Impacts and Mitigation

This section describes impacts and mitigation plans associated with construction of the Project as a whole as well as by each Project facility. Construction of the Mainline Facilities, PTTL, and PBTL would result in temporary increases in air pollutant emissions. Construction of the GTP and Liquefaction Facilities would result in multi-year increases in air pollutant emissions. Air emissions generated during construction would result from construction vehicles, marine traffic, air traffic, vehicles driven by construction workers commuting to and from Project sites, open burning, and fugitive dust.

Combustion emissions were calculated using emission factors from sources such as vendor-provided emission factors, EPA's MOVES2014[125] for on-road vehicles, EPA's AP-42 emission factors, EPA's Emission Factors for Locomotives, and diesel engine tier standards codified in 40 CFR 89 and 1039.

Construction equipment would use the following control measures:

- sulfur content of gasoline would be limited to 10 ppm and onshore diesel limited to 15 ppm; and

- construction camp electrical generators would comply with NSPS IIII and would be Tier 4 diesel-fired engines.

Particulate emissions would result from fugitive dust generated by construction-related activities, the quantity of which would depend on several factors, including:

- size of the area disturbed;
- nature and intensity of construction activity;
- surface properties (such as the silt and moisture content of the soil);
- wind speed; and
- speed, weight, and volume of vehicular traffic.

Emission calculations for fugitive dust were completed using methodologies from EPA's AP-42 emission factors. Fugitive emissions were assumed to be reduced 100 percent when temperatures would be below freezing in certain portions of the Project area (e.g., the GTP, PTTL, and Mainline Spreads 1 and 2) during the 6-month winter period and reduced by 50 percent using wet suppression during the summer.[126]

AGDC developed a Project Fugitive Dust Control Plan. As outlined in this plan, watering would be the primary means of dust abatement. Additional measures outlined in the Fugitive Dust Control Plan include:

- limiting vehicles from tracking off designated roads;

- keeping traffic to designated roads and workspaces;

[125] Motor Vehicle Emission Simulator 2014.

[126] The assumption of 100-percent fugitive dust emission control is consistent with the assumptions included in the Greater Mooses Tooth 1 Supplemental EIS prepared by the BLM in 2014 and the Point Thomson EIS prepared by the COE in 2012.

- reducing vehicle speeds on unpaved surfaces;
- cleaning up track-out and/or carry-out areas at paved road access points;
- covering open-body haul trucks;
- applying dust suppressants such as water mixed with magnesium chloride or calcium chloride in areas where sensitive vegetation is not present; and
- recordkeeping related to fugitive dust control including weather conditions and fugitive dust control measures applied.

AGDC indicated that it would require the construction contractors to comply with the methods outlined in the Fugitive Dust Control Plan. EIs would be responsible for inspecting, monitoring the effectiveness of measures, and recordkeeping associated with fugitive dust control. We have reviewed the Fugitive Dust Control Plan and find it acceptable. With the implementation of this plan, we conclude that the effects from fugitive dust would have a minor temporary impact on air quality in the Project area.

AGDC developed a Project Open Burning Plan, which would be used to manage open burning activities to ensure that emissions generated during open burning do not create a health hazard or public nuisance. The Project Open Burning Plan includes the following details:

- regulations, guidance, and permits that would be applicable to open burn activities and establish who would be responsible for obtaining the applicable permits;
- areas where, or conditions during which, open burn activities would not be permitted;
- activities that would be conducted prior to an open burn, including developing a plan and drawing to detail open burn areas and controls, notifications that would be conducted, and measures that would be implemented to ensure a controlled burn; and
- monitoring requirements during the open burn activities and emergency measures that would be implemented in the event of an uncontrolled burn.

The Project Open Burning Plan identifies who is responsible for the various activities described in the plan. We have reviewed the Project Open Burning Plan and find it acceptable. With the implementation of the Project Open Burning Plan, we conclude that the effects from open burning activities would have a minor temporary impact on air quality in the Project area.

4.15.4.1 Gas Treatment Facilities

Based on the Project schedule, construction of the Gas Treatment Facilities would occur over 90 months (7 years, 6 months).

GTP

Construction emission sources for the GTP include heavy-duty trucks, pickup trucks, buses, non-road equipment, electrical generators, heaters, crushers, ships, barge tugs, and harbor assist tugs. Marine emissions would also be generated for receiving modules associated with the GTP. No charter flights are planned for GTP construction; therefore, aircraft emissions are not included in construction emission

calculations. Estimated construction emissions for the GTP are detailed in table 4.15.4-1 by construction year.

AGDC would implement the following construction emission mitigation measures on construction equipment and stationary sources associated with the installation of the GTP:

- gasoline limited to 10 ppm sulfur and onshore diesel limited to 15 ppm sulfur;
- electric generators in compliance with NSPS Subpart IIII; and
- rock crushers equipped with wet dust suppression controls operational during non-frozen conditions.

These emissions control measures have been incorporated into the emission estimates detailed in table 4.15.4-1.

AGDC identified the following GTP construction equipment that would likely require air permits:

- two rock crushers at the GTP and gravel mine quarry (permit applications to be submitted to ADEC in the 4th quarter of 2020);
- one waste incinerator at the construction camp (permit application to be submitted to ADEC in the 3rd quarter of 2020); and
- stationary generators at the construction camp (permit application to be submitted to ADEC in the 3rd quarter of 2020).

AGDC would obtain air permits from ADEC for these equipment units/activities prior to installation. Both the waste incinerator and the stationary generators at the construction camp would also require Title V operating permits, which AGDC would obtain based on the timing specified within the construction permits to be issued by ADEC.

TABLE 4.15.4-1

GTP Construction Emission Estimates

Construction Year [a]	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)	GHG (metric tons CO_{2e})
Year 1	21.6	481.3	70.8	370.9	47.9	9.6	<0.1	29,573
Year 2	84.5	613.8	679.2	2,830.3	308.1	6.7	1.6	127,048
Year 3	142.2	1,143.2	1,113.4	5,140.5	557.0	21.7	3.6	195,981
Year 4	126.6	1,001.8	1,085.1	4,556.7	492.8	28.5	4.2	123,889
Year 5	85.2	438.4	803.0	4,231.1	449.8	12.8	3.4	75,780
Year 6	43.8	163.2	439.6	3,522.2	368.6	4.3	2.0	43,018
Year 7	33.4	113.4	398.2	2,120.1	222.0	3.4	1.6	27,082
Year 8	0	0	0	0	0	0	0	0
Total	**537.3**	**3,955.1**	**4,589.3**	**22,771.8**	**2,446.2**	**87.0**	**16.4**	**622,371**

PTTL

Based on the current Project schedule, the PTTL would be constructed in two spreads simultaneously over a period of 12 months. Construction emission sources would include heavy-duty vehicles, light-duty trucks, buses, non-road equipment, marine equipment, and charter flights. Estimated construction emissions for the PTTL are detailed in table 4.15.4-2 by construction year.

TABLE 4.15.4-2

PTTL Construction Emission Estimates

Construction Year [a]	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)	GHG (metric tons CO_2e)
Year 2	0.1	1.6	0.5	0.7	0.1	0	0.0	168
Year 3	12.7	57.4	53.6	394.3	49.1	0.7	0.2	15,084
Year 4	14.6	52.5	84.7	373.3	51.6	1.5	0.9	21,860
Year 5	0.2	2.2	0.5	23.9	2.4	0	0.0	352
Total	**27.6**	**113.7**	**139.3**	**792.2**	**103.2**	**2.2**	**1.1**	**37,464**

A rock crusher used for PTTL construction would require an air permit. AGDC would submit an air permit application to ADEC in the 3rd quarter of 2020 and obtain an air permit prior to installation of the rock crusher.

PBTL

Based on the current Project schedule, PBTL construction would occur over 20 months. The emission sources for construction would be similar to those listed above for the PTTL; however, no charter flights are planned for PBTL construction. Estimated construction emissions for the PBTL are detailed in table 4.15.4-3 by construction year.

TABLE 4.15.4-3

PBTL Construction Emission Estimates

Construction Year [a]	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)	GHG (metric tons CO_2e)
Year 3	<0.1	<0.1	<0.1	2.1	0.2	<0.1	<0.1	11
Year 4	0.5	3.5	1.6	11.3	1.9	<0.1	<0.1	940
Total	**0.5**	**3.5**	**1.6**	**13.4**	**2.1**	**<0.1**	**<0.1**	**951**

Gas Treatment Facilities Conclusions

Based on the above discussions and tables, construction of the GTP would have a temporary moderate impact and construction of the PTTL and PBTL would have a temporary minor impact on air quality in the Project area during construction.

4.15.4.2 Mainline Facilities

Based on the current Project schedule, construction of the Mainline Pipeline and associated facilities would occur over about 6 years. Construction emission sources would include heavy-duty vehicles, light-duty trucks, buses, pilot vehicles, non-road equipment, tugs, supply boats, barges, dredges, survey vessels, railroad locomotives, marine vessels, aircrafts, and open burning activities. Estimated construction emissions for the Mainline Facilities are detailed in table 4.15.4-4 by construction year.

AGDC would implement the following construction emission mitigation measures, which have been incorporated into the emission estimates provided in table 4.15.4-4, on construction equipment and stationary sources associated with Mainline Facilities installation:

- gasoline limited to 10 ppm sulfur and onshore diesel limited to 15 ppm sulfur;
- electric generators in compliance with NSPS Subpart IIII; and
- four rock crushers (one for each construction spread) equipped with wet dust suppression controls operational during non-frozen conditions.

TABLE 4.15.4-4

Mainline Facilities Construction Emission Estimates

Construction Year [a]	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)	GHG (metric tons CO_2e)
Year 1	46.3	280.7	282.3	1490.1	217.6	6.4	2.1	77,597
Year 2	98.3	558.5	628.9	3,857.0	555.4	12.6	3.8	184,676
Year 3	110.3	862.0	625.4	4,733.9	108.5	18.3	3.5	209,093
Year 4	305.5	5,781.0	1,033.8	5,067.2	692.9	167.3	4.8	448,528
Year 5	50.1	467.8	228.5	2,887.2	348.2	7.0	1.0	112,045
Year 6	13.8	96.2	58.3	735.1	77.4	0.5	0.4	32,124
Year 7	4.3	30.4	10.6	222.8	23.6	0	0.1	9,883
Preliminary open burning emissions [a]	157.0	74.0	1,393.0	187.0	15.0	0.0	129.0	66,837
Estimated GHG emissions from permafrost degradation [b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1,938
Total	**785.6**	**8,150.6**	**4,260.8**	**19,180.3**	**2,038.6**	**212.1**	**144.7**	**1,142,721**

N/A Not applicable.

[a] Open burn emissions are presented for the entire pipeline route and are not divided by construction year. Open burning activities would occur in Spreads 3 and 4.

[b] Permafrost degradation GHG emissions are presented for the entire pipeline route and are not divided by construction year (see section 4.2.5).

AGDC has identified the following equipment units/activities associated with Mainline Facilities construction that would require air permits from ADEC prior to their installation:

- four rock crushers (one for each construction spread; permit applications to be submitted to ADEC in the 1st quarter of 2021);
- one waste incinerator at each of the construction camps (permit applications to be submitted to ADEC in the 4th quarter of 2020); and
- open burn activities on Spreads 3A to 3C and 4A to 4E (permit application to be submitted to ADEC in the 1st quarter of 2021).

ADEC is responsible for issuing these air quality permits, including those for rock crushers that could be operated within the DNPP. AGDC would obtain air permits from ADEC for these equipment units/activities prior to installation. The waste incinerators at the construction camps would also require

Title V operating permits, which AGDC would obtain based on the timing specified within the construction permits to be issued by ADEC.

Based on the above discussion and table, construction of the Mainline Facilities would have a minor temporary impact on air quality in the Project area during construction.

4.15.4.3 Liquefaction Facilities

Based on the current Project schedule, construction of the Liquefaction Facilities would occur over about 7 years. Construction activities would include:

- construction and operation of a camp;
- LNG Plant and storage facilities construction; and
- Marine Terminal construction including a PLF and MOF.

Construction emission sources include heavy-duty trucks, work trucks, pickup trucks, passenger vehicles, non-road equipment, buses, electrical generators, waste incinerators, and marine equipment. Estimated construction emissions for the Liquefaction Facilities are detailed in table 4.15.4-5 by construction year.

TABLE 4.15.4-5

Liquefaction Facilities Construction Emission Estimates

Construction Year	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)	GHG (metric tons CO_2e)
Year 1	21.6	481.3	70.8	370.9	47.9	9.6	<0.1	29,573
Year 2	84.5	613.8	679.2	2,830.3	308.1	6.7	1.6	127,048
Year 3	142.2	1,143.2	1,113.4	5,140.5	557.0	21.7	3.6	195,981
Year 4	126.6	1,001.8	1,085.1	4,556.7	492.8	28.5	4.2	123,889
Year 5	85.2	438.4	803.0	4,231.1	449.8	12.8	3.4	75,780
Year 6	43.8	163.2	439.6	3,522.2	368.6	4.3	2.0	43,019
Year 7	33.4	113.4	398.2	2,120.1	222.0	3.4	1.6	27,082
Total	**537.3**	**3,955.1**	**4,589.3**	**22,771.8**	**2,446.2**	**87.0**	**16.4**	**622,372**

AGDC would implement the following construction emission mitigation measures, which have been incorporated into the emission estimates provided in table 4.15.4-5, on construction equipment and stationary sources associated with installation of the Liquefaction Facilities:

- gasoline limited to 10 ppm sulfur and onshore diesel limited to 15 ppm sulfur;
- electric generators in compliance with NSPS Subpart IIII; and
- rock crusher equipped with wet dust suppression controls.

AGDC has identified the following equipment associated with construction of the Liquefaction Facilities that would require air permits:

- one rock crusher (permit application to be submitted to ADEC in the 4th quarter of 2020); and

- one waste incinerator at the construction camp (permit application to be submitted to ADEC in the 3rd quarter of 2020).

AGDC would obtain air permits from ADEC for this equipment prior to installation. The waste incinerator at the construction camp would also require a Title V operating permit, which AGDC would obtain based on the timing specified within the construction permit to be issued by ADEC.

Based on the above discussion and table, and in consideration of observations of the participants in the traditional knowledge workshops, construction of the Liquefaction Facilities would have a moderate impact on air quality in the Project area during Years 1 to 6. To ensure that construction emissions, when combined with operational emissions, do not have a significant effect on ambient air quality in construction Years 7 and 8, AGDC developed and would implement an Ambient Air Quality Monitoring Plan. See section 4.15.5.3 for additional details.

4.15.5 Operational Emissions Impacts and Mitigation

Project operation, including maintenance, would result in air emissions from stationary equipment (e.g., the GTP, compressor stations, heater station, meter stations, and Liquefaction Facilities). Fugitive air emissions would also be generated due to operation of the PTTL, PBTL, and Mainline Facilities. Additional air emissions would be generated by employees traveling to and from Project facilities and from maintenance activities for the Project. Operational emissions would be generated from a variety of sources and equipment, and would be long term and permanent. These various sources and associated criteria pollutant, GHG, VOC, and HAP emission rates are addressed in the following sections. Potential GHG emissions from permafrost thaw associated with facility operation are included in section 4.2.5.

4.15.5.1 Gas Treatment Facilities

GTP

Operating Air Emissions

The GTP would consist of three natural gas processing trains that would receive natural gas from the PTU and PBU and clean the natural gas by removing CO_2, H_2S, and water before shipping the natural gas via the Mainline Pipeline. The GTP would include the following emission sources that would operate continuously:

- six natural gas compressor turbines;
- six CO_2 compressor turbines;
- six power generation turbines;
- two building heaters;
- two operations camp heaters; and
- fugitive emissions from tanks, pipe flanges, valves, and valve stems.

The GTP also would include the following emission sources, which would operate on an intermittent or as-needed basis:

- three emergency generators;
- three diesel firewater pumps;
- four CO_2 flares;
- four hydrocarbon flares;
- two buyback gas bath heaters; and
- miscellaneous mobile sources, including vehicle emissions, cranes, backhoes, mobile generators, and air compressors.

Annual emissions by source for the GTP and a summary of total annual emissions are provided in table 4.15.5-1.[127] Emission estimates include control technologies proposed for the GTP based on the completion of the required BACT assessment for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and GHGs. The GTP would be a PSD major source for CO, NO_X, VOCs, PM_{10}, $PM_{2.5}$, SO_2, and GHGs; and a Title V major source for CO, NO_X, VOCs, PM_{10}, and $PM_{2.5}$. The facility would also be a major source of HAP emissions.

TABLE 4.15.5-1

Estimated Annual Emissions Associated with GTP Operation

	Estimated Emissions (tpy)							
Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs [a]	CO_2e [b]
Stationary Sources (without Maximum Flare)								
Natural Gas Compressor Turbines (6)	837.0	732.0	226.8	95.4	95.4	97.2	15.0	1,605,306
CO_2 Compressor Turbines (6)	717.6	723.6	171.0	72.0	72.0	72.6	11.4	1,208,166
Power Generation Turbines (6)	439.2	334.2	152.4	70.8	70.8	22.8	10.2	1,077,600
Emergency Generators (3)	8.4	8.3	<0.1	0.1	0.1	0.4	0.1	1,194
Firewater Pumps (3)	1.5	1.5	<0.1	0.1	0.1	0.1	<0.1	195
CO_2 Flares (4)	5.8	26.5	1.3	2.4	2.4	48.9	0.3	9,114
Hydrocarbon Flares (4)	5.6	25.2	1.2	2.3	2.3	46.4	0.2	8,641
Building Heaters (2)	192.6	198.2	36.2	18.0	18.0	14.4	4.4	255,670
Buyback Gas Bath Heater (2)	1.1	1.1	0.2	0.1	0.1	<0.1	<0.1	1,372
Operations Camp Heaters (2)	22.4	22.4	4.2	2.0	2.0	1.6	0.6	29,658
Tank Emissions	N/A	N/A	N/A	N/A	N/A	<0.1	N/A	N/A
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	47.3	N/A	2,781
Subtotal	**2,231.2**	**2,073.0**	**593.3**	**263.2**	**263.2**	**351.7**	**42.4**	**4,199,697**
Maximum Flare Events								
CO_2 Flares Maximum Flaring (4) [c]	217.3	990.8	156.8	90.2	90.2	1,821.8	9.2	339,523
Hydrocarbon Flares Maximum Flaring(4) [c]	1,322.7	6,029.8	326.2	548.9	548.9	11,087.1	56.4	2,066,270
Subtotal	**1,540.0**	**7,020.6**	**483.0**	**639.1**	**639.1**	**12,908.9**	**65.6**	**2,405,793**
Mobile Sources								
Mobile Equipment	3.3	3.3	<0.1	0.2	0.2	0.3	<0.1	2,165
Non-Road/Portable Equipment	7.6	3.2	N/A	0.7	0.7	2.4	N/A	N/A
Subtotal	**10.9**	**6.5**	**<0.1**	**0.9**	**0.9**	**2.7**	**<0.1**	**2,165**
Total (without Maximum Flare)	**2,242.1**	**2,079.5**	**593.3**	**264.1**	**264.0**	**354.4**	**42.4**	**4,201,862**
Total (with Maximum Flare)	**3,782.1**	**9,100.1**	**1,076.3**	**903.2**	**903.2**	**13,263.3**	**108.0**	**6,607,655**

N/A = Not applicable

[a] The three largest HAP emissions would be formaldehyde (51.8 tpy), ethylbenzene (33.4 tpy), and toluene (6.0 tpy).

[b] CO_2e is listed in metric tons.

[c] CO_2 and hydrocarbon flares would operate at maximum capacity only during emergency events, maintenance, and startup and shutdown events, assumed to be 500 hours per year for emission calculation purposes.

[127] Further details regarding individual HAP emissions are available in appendix F to AGDC's Resource Report 9 (Accession No. 20170417-5345), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 in the "Numbers: Accession Number" field.

The GTP would include four flare systems: high- and low-pressure hydrocarbon flare systems and high- and low-pressure CO_2 flare systems. Each of the flare systems are designed to receive various process streams during commissioning, startup, shutdown, maintenance, and upset conditions. AGDC states that maximum GTP flaring would occur rarely as an unplanned event and would last about 30 minutes per event. However, during these flaring events, pollutants would be released at a much increased rate.

Based on the emission estimates summarized in table 4.15.5-1, the GTP would be a PSD major source of GHG emissions. AGDC has incorporated the potential effects of climate change on the GTP into the Project design. AGDC has listed BACT-level control for GHG emissions at the GTP as operational efficiency measures such as the use of waste heat recovery units to increase efficiency on combustion turbines, and the use of pipeline quality natural gas for gas turbine operation over more GHG intensive fuels, such as distillate oil. While we concur that natural gas for gas turbine operation would generate lower GHG emissions than distillate oil, the latter is not commonly used to drive compressors at natural gas facilities; therefore, we do not agree that using natural gas to drive compressors would constitute a GHG control technology.

Air Quality Impacts

AGDC performed an air quality modeling analysis for the GTP that included a NAAQS/AAAQS analysis, PSD increment analysis, and a Class I and Class II nationally designated protected area analysis for stationary sources at the GTP.[128] Pollutants modeled included CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2. The analysis considered emissions associated with the GTP, regional emission sources in the vicinity of the GTP, and ambient background concentrations to determine if the emissions associated with the GTP would have a significant impact on air quality in the region. The full PSD impact analysis would be completed as part of the PSD permitting process and is currently under review by ADEC. The regional emissions sources in the vicinity of the GTP included the following nearby off-site sources:

- BP Exploration (Alaska), Inc. Central Compression Plant; and
- BP Exploration (Alaska), Inc. Central Gas Facility.

Table 4.15.5-2 presents the NAAQS/AAAQS analysis, which was completed using EPA's AERMOD air dispersion model (American Meteorological Society/Environmental Protection Agency Regulatory Model). As shown in this table, the total predicted concentration for each pollutant and averaging period, which includes the GTP impacts, nearby source impacts, and background concentration, is less than the corresponding NAAQS/AAAQS. Therefore, the GTP would not cause or contribute to an exceedance of the NAAQS or AAAQS.

PSD sources, such as the GTP, are required to demonstrate that the increased pollutant levels resulting from the proposed source would not exceed PSD increment thresholds for certain criteria pollutants. Table 4.15.5-3 presents the results of AGDC's PSD increment analysis for the GTP, which was completed using EPA's AERMOD air dispersion model. As shown in this table, the GTP would not exceed PSD increment thresholds.

[128] Further details regarding the air quality modeling analysis, including the modeling methodology and meteorological data set used in the analysis, were included in appendix F to AGDC's Resource Report 9 (Accession No. 20170417-5345), accessible on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 in the "Numbers: Accession Number" field.

There are no Class I areas within 186.4 miles (300 km) of the GTP, but the FLMs have identified the following Class II nationally designated protected areas within 186.4 miles of the GTP for analysis:

- ANWR, about 58 miles southeast of the GTP; and
- Gates of the Arctic NPP, about 133 miles southwest of the GTP.

To comply with the environmental analysis requirements of NEPA and to assess the potential impacts of the GTP on these Class II nationally designated protected areas, AGDC completed air quality modeling using EPA's CALPUFF air dispersion model. The model included the GTP, existing off-site sources, Reasonably Foreseeable Development (RFD) sources,[129] and ambient background concentrations. Table 4.15.5-4 presents a summary of the NAAQS analysis results. Based on this analysis, the GTP would not cause an exceedance of the NAAQS or AAAQS in any Class II nationally designated protected areas.

TABLE 4.15.5-2

NAAQS/AAAQS Modeling Results for the GTP

		Concentrations						
Pollutant	Averaging Period	Model Predicted (GTP only)	Model Predicted (GTP + Nearby Sources) (µg/m^3)	Background (µg/m^3)	Total (GTP + Nearby Sources + Background) (µg/m^3)	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/AAAQS Exceedance? (Yes/No)
CO	1-hour [a]	366.0	423.0	1,150.0	1,573.0	40,000	40,000	No
	8-hour [a]	139.0	302.0	1,150.0	1,452.0	10,000	10,000	No
NO_2	1-hour [b]	65.0	158.0	N/A [h]	158.0	188	188	No
	Annual [c]	2.6	14.0	6.0	20.0	100	100	No
PM_{10}	24-hour [d]	3.8	18.4	50.0	68.4	150	150	No
$PM_{2.5}$	24-hour [e]	3.3	14.5	15.0	29.5	35	35	No
	Annual [f]	0.2	3.3	3.7	7.0	12	12	No
SO_2	1-hour [g]	11.2	39.2	9.4	48.6	196	196	No
	3-hour [a]	37.7	57.0	21.0	78.0	1,300	1,300	No
	24-hour [a]	11.2	30.1	8.1	38.2	N/A	365	No
	Annual [c]	0.5	2.8	1.8	4.6	N/A	80	No

N/A = Not applicable

[a] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.

[b] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[c] Value reported is the maximum annual average concentration for the 5-year period.

[d] Value reported is the highest-sixth-high concentration over the 5-year period.

[e] Value reported is the highest 98th percentile averaged over the 5-year period.

[f] Value reported is the annual mean concentration, averaged over the 5-year period.

[g] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[h] The modeled predicted 1-hour NO_2 modeling was conducted to include the background NO_2 concentration.

[129] RFD sources are new projects within Alaska that are currently engaged in the permitting process or in construction and may become operational over the next several years.

TABLE 4.15.5-3

Prevention of Significant Deterioration Increment Modeling Results for the GTP

Pollutant	Averaging Period	Total Increment Consumed by PSD Sources (Facility Only) (µg/m^3)	Total Increment Consumed by PSD Sources (Facility + Nearby Sources) (µg/m^3)	Class II PSD Increment (µg/m^3)	PSD Increment Exceedance? (Yes/No)
NO_2	Annual [a]	2.6	6.6	25	No
PM_{10}	24-hour [b]	4.8	12.8	30	No
	Annual [a]	0.3	1.2	17	No
$PM_{2.5}$	24-hour [b]	4.8	4.8	9	No
	Annual [a]	0.3	0.3	4	No
SO_2	3-hour [a]	37.7	52.9	512	No
	24-hour [a]	11.2	27.0	91	No
	Annual [b]	0.5	2.0	20	No

[a] Value reported is the maximum annual average concentration for the 5-year period.
[b] Value reported is the maximum of the highest-second-high values from each of the 5 modeled years.

AGDC also modeled applicable PSD increment pollutant and averaging periods for each of the Class II areas using EPA's CALPUFF air dispersion model. PSD increment is the amount of pollution an area is allowed to increase. PSD increments prevent the air quality in clean areas from deteriorating to the levels set by the NAAQS (EPA, 2018c). A summary of the results are presented in table 4.15.5-5. The PSD increment analysis demonstrates that the GTP would not cause or contribute to an exceedance of Class II PSD increments in these Class II nationally designated protected areas.

In addition to potential impacts on air quality, AGDC completed an analysis of air-quality-related values, which are resources that can be affected by air pollution, including vegetation, wildlife, soils, water, and visibility. The analysis considered whether pollutant deposition or potential changes to visibility from emissions associated with the GTP could have an adverse impact on both Class I and Class II nationally designated protected areas. AGDC assessed impacts on Class II nationally designated protected areas (in addition to Class I areas) to fully disclose potential Project impacts. The AQRV analysis included all proposed equipment under normal operations, as well as maximum flare events.

AGDC completed a regional haze analysis. Haze is caused when light encounters tiny pollution particles in the air. Some particles are naturally occurring, such as non-anthropogenic windblown dust and soot from wildfires, but the majority of the particles come from manmade sources, such as motor vehicles and pollution from industrial development. Haze can reduce the clarity and color of what can be seen, which in turn impacts the visual experience of scenic areas (EPA, 2018a). Scenery is an important resource in many nationally designated protected areas in Alaska, including units of the National Park System. Maintaining high quality visibility is essential to the management and protection of these areas. The regional haze analysis assessed the potential impacts of air emissions associated with the GTP on the visibility in these protected environments. The cumulative assessment included regional off-site sources previously identified. Visibility is measured in terms of light extinction (scattering plus absorption)—the more pollution in the air, the greater the extinction.

The visibility thresholds used in the analysis are based on human perceptibility of visibility changes as compared to natural background conditions. In the regional haze Best Available Retrofit Technology guidelines, the EPA concluded that if a source's emissions result in a modeled 98th percentile visibility change that is greater than 0.5 deciview (about a 5-percent change in light extinction), then the source is considered to *contribute* to regional haze visibility impairment. Similarly, a visibility change that exceeds

1.0 deciview (about a 10-percent change in light extinction) *causes* visibility impairment. A summary of the facility-only and cumulative regional haze modeling results are presented in table 4.15.5-6.

TABLE 4.15.5-4

NAAQS/AAAQS Modeling Results for Class II Nationally Designated Protected Areas near the GTP

Pollutant	Averaging Period	Concentrations						NAAQS/ AAAQS Exceedance? (Yes/No)
		Model Predicted (GTP Only) ($\mu g/m^3$)	Model Predicted (GTP + Existing Sources + RFD) ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$) [a]	NAAQS ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	
ANWR								
CO	1-hour [b]	17.2	53.0	1,150.0	1,203.0	40,000	40,000	No
	8-hour [b]	2.0	16.2	1,150.0	1,166.2	10,000	10,000	No
NO_2	1-hour [c]	0.9	16.8	61.7	78.5	188	188	No
	Annual [d]	<0.1	0.4	6.0	6.4	100	100	No
PM_{10}	24-hour [e]	0.3	4.6	50.0	54.6	150	150	No
$PM_{2.5}$	24-hour [f, i]	0.2	2.1	15.0	17.1	35	35	No
	Annual [g, i]	<0.1	0.3	3.7	4.0	12	12	No
SO_2	1-hour [h]	<0.1	4.3	9.4	13.7	196	196	No
	3-hour [b]	<0.1	4.1	21.0	25.1	1,300	1,300	No
	24-hour [b]	<0.1	1.2	8.1	9.3	N/A	365	No
	Annual [d]	<0.1	<0.1	1.8	1.8	N/A	80	No
Gates of the Arctic NPP								
CO	1-hour [b]	5.4	18.1	1,150.0	1,168.1	40,000	40,000	No
	8-hour [b]	1.4	6.6	1,150.0	1,156.6	10,000	10,000	No
NO_2	1-Hour [c]	0.3	2.9	61.7	64.6	188	188	No
	Annual [d]	<0.1	<0.1	6.0	6.0	100	100	No
PM_{10}	24-hour [e]	0.2	1.7	50.0	51.7	150	150	No
$PM_{2.5}$	24-hour [f]	<0.1	<0.1	15.0	15.1	35	35	No
	Annual [g]	0.1	0.7	3.7	4.4	12	12	No
SO_2	1-hour [h]	<0.1	0.2	9.4	9.6	196	196	No
	3-hour [b]	<0.1	0.2	21.0	21.2	1,300	1,300	No
	24-hour [b]	<0.1	0.1	8.1	8.2	N/A	365	No
	Annual [d]	<0.1	<0.1	1.8	1.8	N/A	80	No

N/A = Not applicable

[a] Total is the sum of the facility impacts, existing sources, RFD, and background concentration.

[b] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[d] Value reported is the maximum annual average concentration for the 5-year period.

[e] Value reported is the highest-sixth-high concentration over the 5-year period.

[f] Value reported is the highest 98th percentile averaged over the 5-year period.

[g] Value reported is the annual mean concentration, averaged over the 5-year period.

[h] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

TABLE 4.15.5-5

Prevention of Significant Deterioration Class II Increment Modeling Results for Class II Nationally Designated Protected Areas near the GTP

Pollutant	Averaging Period	Model Predicted (GTP Only) ($\mu g/m^3$)	Model Predicted (GTP + Existing Sources + RFD) ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)	PSD Increment Exceedance? (Yes/No)
ANWR					
NO_2	Annual [a]	<0.1	0.4	25	No
PM_{10}	24-hour [b]	0.3	4.3	30	No
	Annual [a]	<0.1	0.3	17	No
$PM_{2.5}$	24-hour [b]	0.3	4.5	9	No
	Annual [a]	<0.1	0.3	4	No
SO_2	3-hour [a]	<0.1	4.1	512	No
	24-hour [a]	<0.1	1.2	91	No
	Annual [a]	<0.1	<0.1	20	No
Gates of the Arctic NPP					
NO_2	Annual [a]	<0.1	<0.1	25	No
PM_{10}	24-hour [b]	0.2	1.6	30	No
	Annual [a]	<0.1	0.1	17	No
$PM_{2.5}$	24-hour [b]	0.2	1.6	9	No
	Annual [a]	<0.1	<0.1	4	No
SO_2	3-hour [a]	<0.1	0.2	512	No
	24-hour [a]	<0.1	0.1	91	No
	Annual [a]	<0.1	<0.1	20	No

[a] Value reported is the maximum annual average concentration for the 5-year period.

[b] Value reported is the maximum of the highest-second-high values from each of the 5 modeled years.

TABLE 4.15.5-6

Regional Haze Modeling Results for the GTP

Model Year	GTP Results: 8th Highest Change in Extinction (%) [a]	GTP Results: Visibility Extinction Threshold for a Project (Contribute/ Cause) (%)	Cumulative Results: 8th Highest Change in Extinction (%)	Cause or Contribute to Exceedance of Visibility Extinction Threshold? (Yes/No)
ANWR				
1	3.0	5.0 / 10.0	38.7	No
2	5.5	5.0 / 10.0	71.3	Yes (Contribute)
3	4.5	5.0 / 10.0	49.3	No
Gates of the Arctic NPP				
1	1.6	5.0 / 10.0	23.0	No
2	2.8	5.0 / 10.0	35.9	No
3	2.8	5.0 / 10.0	32.5	No

[a] 8th highest result corresponds to the 98th percentile of modeled results.

As presented in table 4.15.5-6, visibility impacts associated with air emissions from the GTP could exceed the 0.5 deciview visibility change threshold at the ANWR for one of the three modeled years, suggesting that the GTP could contribute to visibility impairment. Additionally, air emissions from the GTP could also contribute to cumulative visibility impacts at the ANWR and the Gates of the Arctic NPP for all three of the modeled years for each location. This modeling analysis does not include other sources (i.e., compressor stations and the heater station) proposed by AGDC beyond the 186-mile (300-km) radius used for evaluating far-field off-site sources. These sources may also have a minor cumulative effect on visibility impacts at the ANWR and Gates of the Arctic NPP.

AGDC completed a deposition analysis to assess potential impacts of air emissions associated with the GTP on nearby Class II nationally designated protected areas. Acid deposition results when SO_2 and/or NO_x emissions react with water, oxygen, and other chemicals to form sulfuric and/or nitric acids. These acids then mix with water before falling to the ground. In addition, in natural environments, nitrogen deposition can result in harmful nitrogen fertilization. Excess nitrogen can disrupt nutrient cycling in the ecosystem and create competitive advantages for some species at the expense of others. This can lead to shifts in species composition and declines in biodiversity, particularly for lichen species, which are important for wildlife forage and habitat in Alaska. Changes related to nitrogen deposition can also stress vegetation, leading to increases in disease and insect outbreaks.

AGDC's analysis included the GTP emissions, regional off-site sources previously identified, and existing background. Based on the FLM's Air Quality Related Values Work Group 2010 guidance, if the facility results are less than the 0.005 kilogram per hectare per year (kg/ha/yr) deposition analysis thresholds, then the facility impacts are considered negligible and do not require additional consideration (NPS, 2010). For any areas above the 0.005 kg/ha/yr deposition analysis threshold for the facility, additional information, including cumulative modeling, background deposition levels, and ecosystem sensitivity in the affected area, is considered to determine whether adverse deposition effects would occur. A summary of the facility-only and cumulative deposition analysis results are provided in table 4.15.5-7.

Based on comments received from cooperating agencies, we requested that AGDC complete cumulative modeling to assess NAAQS/AAAQS compliance, regional haze, and acid deposition impacts associated with the combined operational emissions of the GTP, compressor stations, heater station, and Liquefaction Facilities. The results of this cumulative analysis are provided in section 4.19.4.15.

As presented in table 4.15.5-7, the sulfur and nitrogen deposition impacts associated with the air emissions from the GTP would be less than sulfur and nitrogen deposition thresholds at the nearby Gates of the Arctic NPP. Sulfur deposition impacts would be below deposition thresholds for ANWR, but nitrogen deposition impacts would exceed deposition thresholds.

While preparing the draft EIS, we issued information requests on July 28, 2017 and February 15, 2018 to AGDC requesting that they work with the FLMs to establish a mitigation strategy to ensure that air emissions from the proposed facilities would not negatively affect nearby Class I and Class II nationally designated protected areas. To date, AGDC has not provided a mitigation strategy or determined acceptable thresholds agreed upon by the FLMs. The GTP is currently under review by ADEC as part of the PSD permitting process, which involves a review of AQRVs, potential impacts on Class I and Class II nationally designated protected areas, and input from the FLMs. Without mitigation, the potential exists for exceedance of regional haze and acid deposition thresholds in some Class I and Class II nationally

designated areas. Additional mitigation measures may be implemented during the air permitting phase that could further reduce impacts on these resources.

Regional Ozone

The GTP would be in the North Slope Borough, which is currently designated as attainment for the 8-hour O_3 NAAQS and would not be near any area designated as nonattainment for the 8-hour O_3 NAAQS. As noted in section 4.15.2.3, existing O_3 background design concentrations near the GTP are about 56 parts per billion by volume (ppbv) (0.056 ppmv), which is below the 8-hour O_3 NAAQS of 70 ppbv. The highest background concentrations also typically occur in the winter.

Recent EPA research focused on the assessment of O_3 formation from industrial source emissions in the Lower 48 suggests that single sources of NO_X emissions in the range of 1,000 to 3,000 tpy could result in ozone impacts between 0.2 to 12 ppbv, with an average of 4 parts per billion by volume (ppbv) (Baker et al., 2016; EPA, 2019). Facility emissions on the North Slope of Alaska would likely not result in concentrations on the higher end of the distribution indicated in this study due to the limited solar radiation in the area. Also, ozone formation from facility emissions would be maximized in the summer due to peak temperatures and solar radiation, whereas the highest background concentrations tend to occur in the winter. Based on this information, the facility impacts are unlikely to result in exceedances of the 8-hour O_3 levels at or near the NAAQS of 70 ppbv.

TABLE 4.15.5-7

Deposition Analysis Thresholds for the GTP

	GTP Results			Cumulative Results	
Pollutant	Predicted Deposition Impact (GTP only) (kg/ha/yr) / Class II Nationally Designated Protected Area	NPS Deposition Analysis Thresholds (kg/ha/yr)	Deposition Analysis Thresholds (%)	Predicted Deposition Impact (GTP+ Off-Site Sources + Background) (kg/ha/yr)	Exceeds Deposition Analysis Thresholds? (Yes/No)
Sulfur Deposition					
ANWR	0.001	0.005	18	Below threshold [a]	No
Gates of the Arctic NPP	0.0003	0.005	6	Below threshold [a]	No
Nitrogen Deposition					
ANWR	0.007	0.005	272	0.107	Yes
Gates of the Arctic NPP	0.002	0.005	43	0.031	No

[a] GTP sulfur deposition was below the deposition analysis thresholds and did not require cumulative modeling.

Regional Secondary Formation of $PM_{2.5}$

The North Slope Borough is currently designated as attainment for $PM_{2.5}$ NAAQS and is not in proximity to any area designated as nonattainment for the $PM_{2.5}$ NAAQS. As noted in section 4.15.2.3, existing $PM_{2.5}$ background design concentrations in the vicinity of the GTP are about 15 $\mu g/m^3$ for the 24-hour standard and 3.7 $\mu g/m^3$ for the Annual standard. Based on predicted modeled results, $PM_{2.5}$ concentrations would be about 29.5 $\mu g/m^3$ for the 24-hour standard and 7.0 $\mu g/m^3$ for the Annual standard during GTP operation, which are below the current 24-hour $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$ and the current Annual $PM_{2.5}$ NAAQS of 12.0 $\mu g/m^3$.

Recent EPA research focused on the assessment of secondary $PM_{2.5}$ formation from emissions of NO_X and SO_2 from industrial sources in the Lower 48 suggests that single sources of NO_X emissions in the range of 1,000 to 3,000 tpy could result in secondary 24-hour $PM_{2.5}$ impacts between 0.1 to 1.7 µg/m^3, with an average of about 0.2 µg/m^3 and secondary Annual $PM_{2.5}$ impacts between 0.004 to 0.127 µg/m^3, with an average of about 0.01 µg/m^3. The research further shows that SO_2 sources in the range of 500 to 1,000 tpy have peak secondary 24-hour $PM_{2.5}$ impacts between 0.1 to 5 µg/m^3, with an average of about 0.5 µg/m^3, and secondary Annual $PM_{2.5}$ impacts between 0.01 to 0.23 µg/m^3 (Baker et al., 2016; EPA, 2019). It is unlikely that impacts from facility emissions on the North Slope could result in impacts on the higher end of the distribution indicated in this study due to limited solar radiation. Also, maximum secondary $PM_{2.5}$ tends to occur some distance downwind of the facility, while maximum modeled primary $PM_{2.5}$ concentrations occur near the fence line. Based on this information, it is unlikely the combination of primary, secondary, and background $PM_{2.5}$ would result in an exceedance of the 24-hour or Annual $PM_{2.5}$ NAAQS.

Maximum Flare Modeling Analysis

AGDC completed an air quality modeling analysis to assess potential impacts associated with maximum flare events on criteria pollutants and toxic air pollutants, which includes operation of all four flares for 30 minutes. AGDC has estimated that maximum flare events could last 0.5 hour to 36 hours. The results of this analysis are presented in tables 4.15.5-8 and 4.15.5-9. We compared the modeling results to the NAAQS/AAAQS for criteria pollutants. Toxic air pollutant emissions were compared to 1-hour reference exposure levels (RELs) established by the EPA. Based on the results of these analyses, the emissions associated with maximum flare events at the GTP would not result in exceedances of the NAAQS/AAAQS, nor would the toxic air pollutants generated during maximum flare events result in exceedances of the EPA's REL.

TABLE 4.15.5-8

Short-Term Criteria Pollutant Impacts from GTP Maximum Flare Events

Criteria Pollutant	Averaging Period	Ambient Background Concentration (µg/m^3)	Maximum Modeled Concentration (µg/m^3)	Total Concentration (µg/m^3)	NAAQS/AAAQS (µg/m^3)	Exceeds NAAQS/AAQS (Yes/No)
NO_2	1-hour	61.7	33.6	95.3	188	No
CO	1-hour	1,150	1,333.8	2,483.8	40,000	No
	8-hour	1,150	167.9	1,317.9	10,000	No
PM_{10}	24-hour	50.0	5.2	55.2	150	No
$PM_{2.5}$	24-hour	15.0	5.2	20.2	35	No
SO_2	1-hour	9.4	10.5	19.9	196	No
	3-hour	21.0	30.7	51.7	1,300	No
	24-hour	8.1	30.7	38.8	365	No

TABLE 4.15.5-9

Air Toxics Exposure Assessment from GTP Maximum Flare Events

Hazardous Air Pollutants	Maximum Modeled 1-Hour Concentration (µg/m^3)	Reference Exposure Levels (1-hour) (µg/m^3)	Exceeds Reference Exposure Level (Yes/No)
Benzene	0.7	1,300	No
Toluene	0.2	37,000	No
Ethylbenzene	6.1	350,000	No
Xylene	0.1	22,000	No
n-Hexane	0.1	390,000	No
Formaldehyde	4.9	55	No

GTP Conclusions

GTP operation would have a permanent effect on air quality in the vicinity of the facility. The effects on air quality in the Project area would be minor to moderate during normal facility operation, but certain short-term activities such as flaring have the potential to result in significant effects on regional haze and deposition. Additionally, modeling showed that GTP emissions would exceed the screening-level visibility change threshold at ANWR for one of the years. Given the modeled exceedance, as well as current and projected warming in the area that exacerbates regional haze formation, we conclude that GTP operation could have a long-term significant impact on regional haze at ANWR for years when conditions are similar to the modeled exceedance. We conclude that there would be moderate visibility impacts on the Gates of the Arctic NPP. Modeling also showed the GTP emissions would exceed the nitrogen deposition threshold at ANWR, which could have a long-term significant impact.

PTTL and PBTL

The operational emission sources associated with the PTTL and PBTL would be fugitive emissions of GHGs (primary CH_4) emitted from piping components and connectors along the pipeline. Table 4.15.5-10 presents the estimated annual emissions from PTTL and PBTL operation. The emissions associated with PTTL and PBTL operation would not require an air permit.

TABLE 4.15.5-10

Estimated Annual Emissions Associated with PTTL and PBTL Operation

Facility	CO_2e (tpy) [a,b]
PTTL	46
PBTL	29

[a] CO_2e is listed in metric tons.
[b] Source: Interstate Natural Gas Association of America 2005, table 4-3.

PTTL and PBTL operation would have a permanent effect on air quality in the vicinity of the facilities, but the effects on air quality in the Project area would be minor and limited to the area near the pipeline systems.

4.15.5.2 Mainline Facilities

Operating Air Emissions

The Mainline Facilities would include eight compressor stations, one of which includes heaters, and one stand-alone heater station. The emission sources associated with the compressor stations are divided into three categories: multi-unit with cooling, single-unit with cooling, and single-unit without cooling.

The Sagwon Compressor Station would be a multi-unit compressor station with cooling and would include the following emission sources:

- three compressor turbines with a total horsepower capacity of 68,000;
- four natural gas-fired power generators;
- two auxiliary utility glycol heaters;
- one waste incinerator; and
- fugitive valves, flanges, compressor seals, and blowdowns.

While the Sagwon Compressor Station would have three compressor turbines, AGDC would only operate two simultaneously. The emission calculations include two compressor turbines operating on an annual basis. Table 4.15.5-11 summarizes the operational annual emissions associated with the Sagwon Compressor Station.

The Galbraith Lake, Coldfoot, Ray River, Minto, and Healy Compressor Stations would be single-unit cooling compressor stations and would include the following emission sources:

- one 42,000-hp compressor turbine;
- three natural gas-fired power generators;
- two auxiliary utility glycol heaters;
- one waste incinerator; and
- fugitive valves, flanges, compressor seals, and blowdowns.

TABLE 4.15.5-11

Emissions Source and Total Annual Estimated Emissions Associated with Operation of the Sagwon Compressor Station

	Estimated Emissions (tpy)							
Emission Source and Number of Units	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs [a]	CO_2e [b]
Natural Gas Compressor Turbines (2) [c]	150.7	183.3	4.0	24.5	24.5	10.4	4.3	191,416
Power Generators (4)	27.0	54.0	0.5	3.8	3.8	7.5	6.3	22,613
Auxiliary Utility Glycol Heaters (2)	6.9	10.5	0.3	0.8	0.8	0.6	0.1	13,335
Waste Incinerator	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	5
Compressor Seal and Blowdown	N/A	N/A	N/A	N/A	N/A	14.6	<0.1	6,328
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	0.3	<0.1	88
Total	**184.6**	**247.8**	**4.8**	**29.1**	**29.1**	**33.4**	**10.7**	**233,785**

N/A = Not applicable

[a] The three largest HAP emissions would be formaldehyde (7.9 tpy), acetylaldehyde (0.7 tpy), and methanol (0.6 tpy).

[b] CO_2e is listed in metric tons.

[c] Only two of the three compressor turbines would operate simultaneously.

Table 4.15.5-12 summarizes the annual emissions associated with operation of the Galbraith Lake, Coldfoot, Ray River, Minto, and Healy Compressor Stations.

The Honolulu Creek and Rabideux Creek Compressor Stations would be single-unit without cooling compressor stations and would include the following emission sources:

- one 33,000-hp compressor turbine;
- three power generators;
- two auxiliary utility glycol heaters;
- one waste incinerator;
- five indirect-fired gas heaters (Rabideux Creek only); and
- fugitive valves, flanges, compressor seals, and blowdowns.

Table 4.15.5-13 summarizes the annual emissions associated with operation of the Honolulu Creek and Rabideux Creek Compressor Stations.

The Theodore River Heater Station would be a stand-alone heater station and would include the following emission sources:

- two natural gas-fired power generators;
- nine indirect-fired natural gas heaters;
- one waste incinerator; and
- fugitive valves, flanges, compressor seals, and blowdowns.

TABLE 4.15.5-12

Emissions by Source and Total Annual Emissions Associated with Operation of the Galbraith Lake, Coldfoot, Ray River, Minto, and Healy Compressor Stations

	Estimated Emissions (tpy)							
Emission Sources	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs [a]	CO_2e [b]
Facility Emissions for Each Compressor Station								
Natural Gas Compressor Turbine	139.5	203.6	3.7	10.0	10.0	5.8	4.0	177,207
Power Generators (3)	16.2	32.4	0.3	2.5	2.5	4.5	4.2	15,075
Auxiliary Utility Glycol Heaters (2)	5.3	8.1	0.2	0.6	0.6	0.4	0.1	10,258
Waste Incinerator	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	5
Compressor Seal and Blowdown	N/A	N/A	N/A	N/A	N/A	10.0	<0.1	3,772
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	0.2	<0.1	64
Total	**161.0**	**244.1**	**4.3**	**13.1**	**13.1**	**21.0**	**8.3**	**206,381**

N/A = Not applicable

[a] The three largest HAP emissions would be formaldehyde (6.3 tpy), acetylaldehyde (0.6 tpy), and methanol (0.4 tpy).

[b] CO_2e is listed in metric tons.

TABLE 4.15.5-13

Emissions by Source and Total Annual Emissions Associated with Operation of the Honolulu Creek and Rabideux Creek Compressor Stations

Compressor Station, Emission Sources	Estimated Emissions (tpy)							
	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs [a]	CO_2e [b]
Honolulu Creek Compressor Station								
Natural Gas Compressor Turbine	111.5	162.8	3.0	8.0	8.0	4.6	3.2	141,684
Power Generator (3)	14.8	29.6	0.3	2.0	2.0	4.1	3.3	12,044
Auxiliary Utility Glycol Heater (2)	5.3	8.1	0.2	0.6	0.6	0.4	0.1	10,258
Waste Incinerator	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	5
Compressor Seal and Blowdown	N/A	N/A	N/A	N/A	N/A	4.5	<0.1	1,995
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	<0.1	<0.1	27
Total	**131.6**	**200.5**	**3.5**	**10.6**	**10.6**	**13.7**	**6.6**	**166,013**
Rabideux Creek Compressor Station								
Natural Gas Compressor Turbine	111.5	162.8	3.0	8.0	8.0	4.6	3.2	141,684
Power Generator (2)	14.8	29.6	0.3	2.0	2.0	4.1	3.3	12,044
Auxiliary Utility Glycol Heater (2)	5.3	8.1	0.2	0.6	0.6	0.4	0.1	10,258
Indirect-fired Heaters (5)	13.2	20.2	0.5	1.5	1.5	1.0	0.2	25,645
Waste Incinerator	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	5
Compressor Seal and Blowdown	N/A	N/A	N/A	N/A	N/A	4.5	<0.1	1,995
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	<0.1	<0.1	27
Total	**144.8**	**220.7**	**4.0**	**12.1**	**12.1**	**14.7**	**6.8**	**191,658**

N/A = Not applicable

[a] The three largest HAP emissions would be formaldehyde (5.0 tpy), acetylaldehyde (0.4 tpy), and methanol (0.3 tpy).

[b] CO_2e is listed in metric tons.

Table 4.15.5-14 summarizes the annual emissions associated with Theodore River Heater Station operation.

The annual emissions for each of the eight compressor stations and heater station as presented in tables 4.15.5-11 to 4.15.5-14 would be below PSD major source thresholds (see section 4.15.3.1). Each of the compressor stations and the heater station would require a minor source permit under ADEC's Minor NSR permit program. In addition, each station would be a Title V major source and would require a Title V operating permit. AGDC has not yet submitted Minor NSR permit applications for the eight compressor stations and the heater station, and has stated that these applications are currently under development. AGDC would apply for a Title V operating permit within 180 days of commencing operation at each station.

Mainline Pipeline operation would also result in fugitive emissions of GHGs (primarily CH_4). The pollutants would be emitted from piping components and connectors along the Mainline Pipeline. The estimated fugitive emissions from the Mainline Pipeline are presented in table 4.15.5-15. The annual fugitive emissions associated with Mainline Pipeline operation do not require additional analysis. For comparison purposes, the PSD major source threshold for GHG emissions is 100,000 tpy of CO_{2e}.

TABLE 4.15.5-14

Emissions by Source and Total Annual Emissions Associated with Operation of the Theodore River Heater Station

Emission Source	Estimated Emissions (tpy)							
	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs [a]	CO_2e [b]
Power Generator (2)	14.8	29.6	0.3	2.0	2.0	4.1	3.3	12,044
Indirect-fired Natural Gas Heater (9)	34.5	73.8	2.3	6.7	6.7	4.9	0.9	110,784
Waste Incinerator	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	5
Compressor Seal and Blowdown	N/A	N/A	N/A	N/A	N/A	7.1	<0.1	2,318
Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	0.2	<0.1	50
Total	**49.3**	**103.4**	**2.6**	**8.7**	**8.7**	**16.3**	**4.2**	**125,201**

N/A = Not applicable

[a] The three largest HAP emissions would be formaldehyde (2.1 tpy), propylene oxide (0.6 tpy), and methanol (0.3 tpy).

[b] CO_2e is listed in metric tons.

TABLE 4.15.5-15

Estimated Annual Fugitive Emissions Associated with Mainline Pipeline Operation

Facility	CO_2e [a] (tpy)
Mainline Pipeline	272

Source: Interstate Natural Gas Association of America (2005), Table 4-3.

[a] CO_{2e} is listed in metric tons.

Ambient Impacts

AGDC conducted an air quality modeling analysis for stationary sources associated with the Mainline Pipeline, including the eight compressor stations and heater station.[130] Pollutants modeled included CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2. The impact analysis considered emissions associated with the Mainline Facilities and ambient background concentrations to determine if there would be a significant impact on the surrounding areas. The modeled ground-level concentrations were compared to the corresponding NAAQS/AAAQS to determine if facility operation would exceed the applicable NAAQS/AAAQS. The compressor stations and heater station would be minor sources of HAPs. Due to the low level of HAPs emitted from these facilities, an air quality impact analysis for HAPs was not completed.

No nearby stationary emission sources were identified in proximity to the compressor stations or heater station. Air quality impacts associated with any potential sources of air emissions within the regions in which the compressor stations or heater station would be located are reflected in the background ambient air quality data. Additionally, each of the compressor stations and the heater station was modeled separately because they are greater than 31.1 miles (50 km) from one another and their plumes would not be anticipated to overlap. Table 4.15.5-16 presents a summary of the air quality modeling analysis results for compressor stations and the heater station, which was completed using EPA's AERMOD air dispersion model.

[130] Further details regarding the air quality modeling analysis, including the modeling methodology and meteorological data set used in the analysis, were included in appendix E to AGDC's Resource Report No. 9 (Accession No. 20170417-5345) and in an October 12, 2017 response to a FERC information request dated July 28, 2017 (Accession No. 20171012-5306), both of which are available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 or 20171012-5306 in the "Numbers: Accession Number" field.

TABLE 4.15.5-16

Air Quality Modeling Results for Compressor Stations and Heater Station

Pollutant	Averaging Period	Concentrations: Model Predicted (Facility) (µg/m³)	Background (µg/m³)	Total (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)	NAAQS/AAAQS Exceedance? (Yes/No)
Sagwon Compressor Station							
CO	1-hour [a, j]	370.7	573.0	943.7	40,000	40,000	No
	8-hour [b, j]	295.9	458.0	753.9	10,000	10,000	No
NO_2	1-hour [c, j]	71.4	61.2	132.6	188	188	No
	Annual [d, j]	5.4	2.5	7.9	100	100	No
PM_{10}	24-hour [e, j]	12.4	35.6	48.0	150	150	No
$PM_{2.5}$	24-hour [f, j]	12.4	7.1	19.5	35	35	No
	Annual [g, j]	0.9	2.3	3.2	12	12	No
SO_2	1-hour [h, j]	14.2	5.2	19.4	196	196	No
	3-hour [l, j]	14.2	6.2	20.4	1,300	1,300	No
	24-hour [j]	14.2	5.4	19.6	N/A	365	No
	Annual [j]	0.5	0.5	1.0	N/A	80	No
Galbraith Lake Compressor Station							
CO	1-hour [a]	544.2	573.0	1,117.2	40,000	40,000	No
	8-hour [b]	251.6	458.0	709.6	10,000	10,000	No
NO_2	1-hour [c]	90.8	61.2	152.0	188	188	No
	Annual [d]	8.2	2.5	10.7	100	100	No
PM_{10}	24-hour [e]	8.6	35.6	44.2	150	150	No
$PM_{2.5}$	24-hour [f]	8.6	7.1	15.7	35	35	No
	Annual [g]	1.9	2.3	4.2	12	12	No
SO_2	1-hour [h]	30.1	5.2	35.3	196	196	No
	3-hour [i]	30.1	6.2	36.3	1,300	1,300	No
	24-hour	30.1	5.4	35.5	N/A	365	No
	Annual	2.1	0.5	2.6	N/A	80	No
Coldfoot Compressor Station							
CO	1-hour [a]	410.8	573.0	983.8	40,000	40,000	No
	8-hour [b]	399.1	458.0	857.1	10,000	10,000	No
NO_2	1-hour [c]	55.6	61.2	116.8	188	188	No
	Annual [d]	6.7	2.5	9.2	100	100	No
PM_{10}	24-hour [e]	10.9	38.3	49.2	150	150	No
$PM_{2.5}$	24-hour [f]	10.9	11.8	22.7	35	35	No
	Annual [g]	2.5	2.8	5.3	12	12	No
SO_2	1-hour [h]	15.8	5.2	21.0	196	196	No
	3-hour [i]	15.8	6.2	22.0	1,300	1,300	No
	24-hour	15.8	5.4	21.2	N/A	365	No
	Annual	3.1	0.5	3.6	N/A	80	No

TABLE 4.15.5-16 (cont'd)

Air Quality Modeling Results for Compressor Stations and Heater Station

Pollutant	Averaging Period	Concentrations: Model Predicted (Facility) (µg/m³)	Background (µg/m³)	Total (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)	NAAQS/AAAQS Exceedance? (Yes/No)
Ray River Compressor Station							
CO	1-hour [a]	376.7	573.0	949.7	40,000	40,000	No
	8-hour [b]	276.6	458.0	734.6	10,000	10,000	No
NO_2	1-hour [c]	81.0	61.2	142.2	188	188	No
	Annual [d]	8.7	2.5	11.2	100	100	No
PM_{10}	24-hour [e]	13.8	38.3	52.1	150	150	No
$PM_{2.5}$	24-hour [f]	13.8	11.8	25.6	35	35	No
	Annual [g]	1.7	2.8	4.5	12	12	No
SO_2	1-hour [h]	14.4	5.2	19.6	196	196	No
	3-hour [i]	14.4	6.2	20.6	1,300	1,300	No
	24-hour	14.4	5.4	19.8	N/A	365	No
	Annual	1.7	0.5	2.2	N/A	80	No
Minto Compressor Station							
CO	1-hour [a]	360.8	573.0	933.8	40,000	40,000	No
	8-hour [b]	304.0	458.0	762.0	10,000	10,000	No
NO_2	1-hour [c]	73.1	61.2	134.3	188	188	No
	Annual [d]	7.8	2.5	10.3	100	100	No
PM_{10}	24-hour [e]	11.0	38.3	49.3	150	150	No
$PM_{2.5}$	24-hour [f]	11.0	10.2	21.2	35	35	No
	Annual [g]	2.7	2.4	5.1	12	12	No
SO_2	1-hour [h]	13.6	5.2	18.8	196	196	No
	3-hour [i]	13.6	6.2	19.8	1,300	1,300	No
	24-hour	13.6	5.4	19.0	N/A	365	No
	Annual	3.1	0.5	3.6	N/A	80	No
Healy Compressor Station							
CO	1-hour [a]	624.9	7,962.0	8,586.9	40,000	40,000	No
	8-hour [b]	295.0	5,041.0	5,336.0	10,000	10,000	No
NO_2	1-hour [c]	89.2	15.5	104.7	188	188	No
	Annual [d]	12.9	1.9	14.8	100	100	No
PM_{10}	24-hour [e]	12.5	18.8	31.3	150	150	No
$PM_{2.5}$	24-hour [f]	12.5	6.7	19.2	35	35	No
	Annual [g]	2.3	1.5	3.8	12	12	No
SO_2	1-hour [h]	24.0	5.2	29.2	196	196	No
	3-hour [i]	24.0	6.2	30.2	1,300	1,300	No
	24-hour	24.0	5.4	29.4	N/A	365	No
	Annual	1.3	0.5	1.8	N/A	80	No

TABLE 4.15.5-16 (cont'd)

Air Quality Modeling Results for Compressor Stations and Heater Station

Pollutant	Averaging Period	Concentrations: Model Predicted (Facility) ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	NAAQS/AAAQS Exceedance? (Yes/No)
Honolulu Creek Compressor Station							
CO	1-hour [a]	380.5	7,962.0	8,342.5	40,000	40,000	No
	8-hour [b]	260.8	5,041.0	5,301.8	10,000	10,000	No
NO_2	1-hour [c]	88.5	15.5	104.0	188	188	No
	Annual [d]	17.7	1.9	19.6	100	100	No
PM_{10}	24-hour [e]	12.3	18.8	31.1	150	150	No
$PM_{2.5}$	24-hour [f]	12.3	6.7	19.0	35	35	No
	Annual [g]	2.8	1.5	4.3	12	12	No
SO_2	1-hour [h]	14.6	5.2	19.8	196	196	No
	3-hour [i]	14.6	6.2	20.8	1,300	1,300	No
	24-hour	14.6	5.4	20.0	N/A	365	No
	Annual	1.9	0.5	2.4	N/A	80	No
Rabideux Creek Compressor Station							
CO	1-hour [a]	313.8	7,962.0	8,275.8	40,000	40,000	No
	8-hour [b]	205.2	5,041.0	5,246.2	10,000	10,000	No
NO_2	1-hour [c]	71.6	15.5	87.1	188	188	No
	Annual [d]	4.0	1.9	5.9	100	100	No
PM_{10}	24-hour [e]	21.1	33.4	54.5	150	150	No
$PM_{2.5}$	24-hour [f]	21.1	5.6	26.7	35	35	No
	Annual [g]	1.0	1.7	2.7	12	12	No
SO_2	1-hour [h]	12.0	5.2	17.2	196	196	No
	3-hour [i]	12.0	6.2	18.2	1,300	1,300	No
	24-hour	12.0	5.4	17.4	N/A	365	No
	Annual	1.0	0.5	1.5	N/A	80	No
Theodore River Heater Station							
CO	1-hour [a]	360.8	7,962.0	8,322.8	40,000	40,000	No
	8-hour [b]	298.2	5,041.0	5,339.2	10,000	10,000	No
NO_2	1-hour [c]	114.4	15.5	129.9	188	188	No
	Annual [d]	11.3	1.9	13.2	100	100	No
PM_{10}	24-hour [e]	21.1	33.4	54.4	150	150	No
$PM_{2.5}$	24-hour [f]	21.1	5.6	26.7	35	35	No
	Annual [g]	2.4	1.7	4.1	12	12	No
SO_2	1-hour [h]	10.8	5.2	16.0	196	196	No
	3-hour [i]	10.8	6.2	17.0	1,300	1,300	No
	24-hour	10.8	5.4	16.2	N/A	365	No
	Annual	0.8	0.5	1.3	N/A	80	No

TABLE 4.15.5-16 (cont'd)

Air Quality Modeling Results for Compressor Stations and Heater Station

Pollutant	Averaging Period	Concentrations: Model Predicted (Facility) (µg/m^3)	Background (µg/m^3)	Total (µg/m^3)	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/AAAQS Exceedance? (Yes/No)

N/A = Not applicable

[a] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.

[b] Maximum 8-hour average CO concentration assumed equal to maximum 1-hour CO average concentration.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[d] Value reported is the maximum annual average concentration for the 5-year period.

[e] 24-hour PM_{10} concentration assumed equal to $PM_{2.5}$.

[f] Value reported is the highest 98th percentile averaged over the 5-year period.

[g] Value reported is the annual mean concentration, averaged over the 5-year period.

[h] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[i] Maximum 3-hour and 24-hour average SO_2 concentration assumed equal to maximum 1-hour average SO_2 concentration.

[j] Values reported represent the worst-case operating scenario of three scenarios modeled.

As shown in table 4.15.5-16, the total predicted concentration for each pollutant and averaging period at each of the compressor stations and the heater station is less than the associated NAAQS/AAAQS. Therefore, operation of the aboveground facilities associated with the Mainline Pipeline would not cause or contribute to a violation of the NAAQS/AAAQS.

In addition to potential impacts on air quality, AGDC completed an analysis of air-quality-related values for the compressor stations and the heater station. As indicated previously, air-quality-related values are resources that could be adversely affected by a change in air quality, which in turn could have an adverse impact on Class I or Class II nationally designated protected areas. Air-quality-related values include visibility impacts and pollutant-deposition-related impacts (e.g., acid rain). Table 4.15.5-17 details the Class I and Class II nationally designated protected areas within 31.1 miles of the compressor stations and the heater station.

TABLE 4.15.5-17

Class I and Class II Nationally Designated Protected Areas Within 31.1 Miles of the Mainline Aboveground Facilities

Mainline Facilities	Class I Area (Distance and Direction)	Class II Nationally Designated Protected Area (Distance and Direction)
Sagwon Compressor Station	None	ANWR (18 miles southeast)
Galbraith Lake Compressor Station	None	ANWR (2 miles east) Gates of the Arctic NPP (7 miles southwest)
Coldfoot Compressor Station	None	Gates of the Arctic NPP (5 miles northwest) Yukon Flats NWR (27 miles southeast)
Ray River Compressor Station	None	Yukon Flats NWR (11 miles northeast Kanuti NWR (22 miles west)
Minto Compressor Station	None	None
Healy Compressor Station	DNPP (3 miles west)	None
Honolulu Creek Compressor Station	DNPP (9 miles northwest)	None
Rabideux Creek Compressor Station	None	None
Theodore River Heater Station	None	Kenai NWR (29 miles southeast)

EPA's VISCREEN[131] model was used to analyze near-field visibility impacts, the results of which are presented in table 4.15.5-18. If the perceptibility is less than 2 and the contrast is not greater than ±0.05 then the impacts are considered negligible and would not cause or contribute to an exceedance of visibility extinction thresholds. Visibility was analyzed for 'forward scatter', which analyzes visibility effects when the sun is in front of the observer, and 'backward scatter', which analyzes visibility effects when the sun is behind the observer.

As presented in table 4.15.5-18, the visibility plume perceptibility thresholds could be exceeded by the Galbraith Lake Compressor Station at ANWR and by the Healy and Honolulu Creek Compressor Stations at the DNPP. Emissions from other facilities would be below visibility plume perceptibility thresholds at the Class I and Class II nationally designated protected areas within 31.1 miles of the Project facilities.

As presented in table 4.15.5-19, sulfur deposition thresholds could be exceeded by air emissions from the Galbraith Lake Compressor Station at the ANWR. Nitrogen deposition thresholds could be exceeded by air emissions from the compressor stations and the heater station at the Class I and Class II nationally designated protected areas within 31.1 miles of the facilities. The facilities contribute to minor permanent cumulative deposition impacts at Class I areas, but AGDC did not analyze cumulative deposition impacts at Class II nationally designated protected areas. Therefore, the Mainline Facilities could also contribute to cumulative deposition impacts at Class II nationally designated protected areas.

Based on comments received from cooperating agencies, AGDC also completed cumulative modeling to assess NAAQS/AAAQS compliance, regional haze, and acid deposition impacts associated with the combined operational emissions of the GTP, compressor stations, heater station, and Liquefaction Facilities. The results of this cumulative analysis are provided in section 4.19.4.15.

Mainline Facilities Conclusion

Mainline Facilities Operation would have a permanent effect on air quality in the vicinity of the facility. The effects on air quality associated with compressor station operation would be minor, but operation of the Galbraith Lake Compressor Station could have a significant plume impact at ANWR, and compressor station and heater station operation could have significant impacts on ecosystems from nitrogen deposition in Class I and Class II nationally designated protected areas. The effects on air quality in the vicinity of the Mainline Pipeline would be minor and limited to the immediate vicinity of the pipeline systems.

[131] Visual Impact Screening and Analysis Model.

TABLE 4.15.5-18

Visibility Screening Analysis for the Compressor Stations and Heater Station

Facility	Class I / Class II Nationally Designated Protected Area - Observer Location	Background	Scattering Angle (degrees)	Perceptibility (ΔE)		Contrast (Cp)		Exceeds Visibility Extinction Criteria? (Yes/No)
				Criteria	Modeled VISCREEN	Criteria	Modeled VISCREEN	
Forward Scatter								
Sagwon Compressor Station	ANWR	Sky	10	±0.05	0.02	2.00	1.46	No
		Terrain	10	±0.05	0.01	2.00	1.66	No
Galbraith Lake Compressor Station	ANWR	Sky	10	±0.05	0.01	2.00	1.83	No
		Terrain	10	±0.05	0.03	2.00	2.56	Yes
	Gates of the Arctic NPP	Sky	10	±0.05	0.01	2.00	0.87	No
		Terrain	10	±0.05	0.01	2.00	1.29	No
Coldfoot Compressor Station	Gates of the Arctic NPP	Sky	10	±0.05	0.01	2.00	0.87	No
		Terrain	10	±0.05	0.01	2.00	1.31	No
	Yukon Flats NWR	Sky	10	±0.05	0.01	2.00	1.87	No
		Terrain	10	±0.05	0.00	2.00	0.19	No
Ray River Compressor Station	Kanuti NWR	Sky	10	±0.05	0.00	2.00	0.17	No
		Terrain	10	±0.05	0.00	2.00	0.29	No
	Yukon Flats NWR	Sky	10	±0.05	0.01	2.00	1.87	No
		Terrain	10	±0.05	0.02	2.00	2.65	No
Healy Compressor Station	Inside DNPP	Sky	10	±0.05	0.01	2.00	1.36	No
		Terrain	10	±0.05	0.02	2.00	1.91	No
	Outside DNPP	Sky	10	±0.05	-0.03	2.00	3.19	Yes
		Terrain	10	±0.05	0.05	2.00	4.94	Yes
Honolulu Creek Compressor Station	Inside DNPP	Sky	10	±0.05	0.00	2.00	0.30	No
		Terrain	10	±0.05	0.00	2.00	0.50	No
	Outside DNPP	Sky	10	±0.05	0.01	2.00	2.05	Yes
		Terrain	10	±0.05	0.03	2.00	2.80	Yes
Theodore River Heater Station	Kenai NWR	Sky	10	±0.05	0.01	2.00	0.63	No
		Terrain	10	±0.05	0.00	2.00	0.23	No
Back Scatter								
Sagwon Compressor Station	ANWR	Sky	140	±0.05	-0.01	2.00	0.76	No
		Terrain	140	±0.05	0.00	2.00	0.12	No
Galbraith Lake Compressor Station	ANWR	Sky	140	±0.05	-0.02	2.00	1.21	No
		Terrain	140	±0.05	0.01	2.00	0.90	No
	Gates of the Arctic NPP	Sky	140	±0.05	-0.01	2.00	0.61	No
		Terrain	140	±0.05	0.00	2.00	0.34	No
Coldfoot Compressor Station	Gates of the Arctic NPP	Sky	140	±0.05	-0.01	2.00	0.63	No
		Terrain	140	±0.05	0.00	2.00	0.38	No

TABLE 4.15.5-18 (cont'd)

Visibility Screening Analysis for the Compressor Stations and Heater Station

Facility	Class I / Class II Nationally Designated Protected Area - Observer Location	Background	Scattering Angle (degrees)	Perceptibility (ΔE)		Contrast (Cp)		Exceeds Visibility Extinction Criteria? (Yes/No)
				Criteria	Modeled VISCREEN	Criteria	Modeled VISCREEN	
	Yukon Flats NWR	Sky	140	±0.05	-0.02	2.00	1.27	No
		Terrain	140	±0.05	0.00	2.00	0.02	No
Ray River Compressor Station	Kanuti NWR	Sky	140	±0.05	-0.02	2.00	1.26	No
		Terrain	140	±0.05	0.00	2.00	0.13	No
	Yukon Flats NWR	Sky	140	±0.05	0.00	2.00	0.11	No
		Terrain	140	±0.05	0.00	2.00	0.05	No
Healy Compressor Station	Inside Denali NPP	Sky	140	±0.05	-0.01	2.00	0.92	No
		Terrain	140	±0.05	0.01	2.00	0.65	No
	Outside Denali NPP	Sky	140	±0.05	-0.03	2.00	1.86	No
		Terrain	140	±0.05	0.01	2.00	1.52	No
Honolulu Creek Compressor Station	Inside Denali NPP	Sky	140	±0.05	-0.00	2.00	0.23	No
		Terrain	140	±0.05	0.00	2.00	0.11	No
	Outside Denali NPP	Sky	140	±0.05	-0.02	2.00	1.31	No
		Terrain	140	±0.05	0.01	2.00	1.06	No
Theodore River Heater Station	Kenai NWR	Sky	140	±0.05	-0.01	2.00	0.33	No
		Terrain	140	±0.05	0.00	2.00	0.06	No

ΔE = Total color contrast; Cp = Plume contrast

TABLE 4.15.5-19

Deposition Analysis Thresholds for the Compressor Stations and Heater Station [a]

Facility	Class I / Class II Nationally Designated Protected Areas	Maximum Modeled Deposition (Facility Only) (kg/ha/yr)	National Park Service Deposition Analysis Threshold (kg/ha/yr)	Predicted Deposition Impact (Facility + Off-Site Sources + Background) (kg/ha/yr)	National Park Service Class I Critical Loading Value (kg/ha/yr)	Exceeds Deposition Analysis Thresholds? (Yes/No)
Sulfur Deposition						
Sagwon Compressor Station	ANWR	<0.005	0.005	NP	NP	No
Galbraith Lake Compressor Station	ANWR	0.030	0.005	NP	NP	Yes
	Gates of the Arctic Preserve	<0.005	0.005	NP	NP	No
	Gates of the Arctic NPP	<0.005	0.005	NP	NP	No
Coldfoot Compressor Station	Gates of the Arctic NPP	<0.005	0.005	NP	NP	No
	Yukon Flats NWR	<0.005	0.005	NP	NP	No
Ray River Compressor Station	Kanuti NWR	<0.005	0.005	NP	NP	No
	Yukon Flats NWR	<0.005	0.005	NP	NP	No
Healy Compressor Station	Denali NPP	<0.005	0.005	0.008	2-4	No
Honolulu Creek Compressor Station	Denali NPP	<0.005	0.005	0.008	2-4	No
Theodore River Heater Station	Kenai NWR	<0.005	0.005	NP	NP	No
Nitrogen Deposition						
Sagwon Compressor Station	ANWR	**0.062**	0.005	NP	NP	Yes
Galbraith Lake Compressor Station	ANWR	**1.937**	0.005	NP	NP	Yes
	Gates of the Arctic Preserve	**0.147**	0.005	NP	NP	Yes
	Gates of the Arctic NPP	**0.047**	0.005	NP	NP	Yes
Coldfoot Compressor Station	Gates of the Arctic NPP	**0.395**	0.005	NP	NP	Yes
	Yukon Flats NWR	**0.011**	0.005	NP	NP	Yes
Ray River Compressor Station	Kanuti NWR	**0.102**	0.005	NP	NP	Yes
	Yukon Flats NWR	**0.115**	0.005	NP	NP	Yes
Healy Compressor Station	Denali NPP	**0.273**	0.005	0.009	3	Yes

TABLE 4.15.5-19 (cont'd)

Deposition Analysis Thresholds for the Compressor Stations and Heater Station [a]

Facility	Class I / Class II Nationally Designated Protected Areas	Maximum Modeled Deposition (Facility Only) (kg/ha/yr)	National Park Service Deposition Analysis Threshold (kg/ha/yr)	Predicted Deposition Impact (Facility + Off-Site Sources + Background) (kg/ha/yr)	National Park Service Class I Critical Loading Value (kg/ha/yr)	Exceeds Deposition Analysis Thresholds? (Yes/No)
Honolulu Creek Compressor Station	Denali NPP	**0.084**	0.005	0.009	3	Yes
Theodore River Heater Station	Kenai NWR	**0.030**	0.005	0.009	NP	Yes

NP = Not provided by AGDC

4.15.5.3 Liquefaction Facilities

Operating Air Emissions

The Liquefaction Facilities would consist of three liquefaction trains for processing and liquefaction of the natural gas, LNG storage tanks, and a Marine Terminal to load LNG onto LNG carriers. The three liquefaction trains would be expected to operate continuously. The Liquefaction Facilities would include the following emission sources:

- six compression turbines;
- four combined-cycle combustion turbines for power generation;
- one thermal oxidizer; and
- fugitive emissions from pipe flanges, valves, and valve stems.

The Liquefaction Facilities would contain the following emission sources, which would operate on an intermittent or as-needed basis:

- one backup auxiliary air compressor;
- one emergency firewater pump;
- one dry gas flare for treating vapor gases;
- one wet gas flare for treating hydrocarbon streams;
- one low-pressure (LP) flare for treating warm inert gas from the LNG carriers;
- 204 to 360 LNG carriers per year, and their attendant tugs; and
- miscellaneous mobile sources.

Annual emissions by source for the Liquefaction Facilities and a summary of total annual emissions are presented in table 4.15.5-20. Emission estimates include the control technologies proposed for the Liquefaction Facilities, which were determined based on the BACT assessment for CO, NO_X, VOCs, PM_{10}, $PM_{2.5}$, SO_2, and GHGs. The Liquefaction Facilities would be a PSD major source for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and GHGs, and a Title V major source for CO, NO_X, VOCs, PM_{10}, and $PM_{2.5}$. The facilities would also be considered a major source of HAP emissions.

The Liquefaction Facilities would include a wet/dry flare system associated with the LNG Plant, and a low pressure flare system associated with the Marine Terminal. The wet/dry flare system would be

used during LNG Plant commissioning, startup, shutdown, maintenance, and upset conditions. Maximum LNG Plant flaring would occur during upset conditions or planned startup/shutdown and maintenance. AGDC has estimated that flaring would typically last about 30 minutes per event, but AGDC has indicated it may last up to 36 hours. As with the GTP, pollutant emissions during flaring would be released at a much higher rate, as compared to normal facility operation.

The Marine Terminal flare system would be used in the event that the boil-off gas compression unit, which would be used to capture gas streams from storage and loading operations, is inoperable. The Marine Terminal flare would also be used to flare vapors displaced from LNG carriers during loading operations. The maximum duration of Marine Terminal flare operation would be 17 hours, which is the time to load the largest LNG carrier volume considered for the Project, but would only operate in the event the boil-off gas compression unit is inoperable.

Ambient Air Quality

AGDC conducted an air quality modeling analysis for the Liquefaction Facilities that included a NAAQS/AAAQS analysis, PSD increment analysis, and a Class I and Class II nationally designated protected areas analysis for stationary sources at the facilities.[132] Pollutants modeled included CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2. The impact analysis considered emissions associated with the Liquefaction Facilities, regional emission sources within the area of the Liquefaction Facilities, and ambient background concentrations to determine if there would be a significant impact on air quality in the region. The full PSD impact analysis would be completed as part of the PSD permitting process and is currently under review by ADEC.

In addition to the ambient background concentration, the NAAQS analyses included the following nearby off-site sources:

- Andeavor Refinery;
- ConocoPhillips Company Kenai LNG Facility (including ships);
- Tesoro Kenai Pipe Line Marin Loading Terminal (including ships);
- Homer Electric Association Bernice Lake Power Plant;
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships); and
- Homer Electric Association Nikiski Generation Plant.

Table 4.15.5-21 presents the NAAQS/AAAQS analysis, which was completed using EPA's AERMOD air dispersion model. As shown in table 4.15.5-21, the total predicted concentration for each pollutant and averaging period, which includes the Liquefaction Facilities impacts, nearby source impacts, and background concentration is less than the corresponding NAAQS/AAAQS. Therefore, the Liquefaction Facilities would not cause or contribute to an exceedance of the NAAQS or AAAQS.

[132] Further details regarding the air quality modeling analysis, including the modeling methodology and meteorological data set used in the analysis were included in appendix D to AGDC's Resource Report 9 (Accession No. 20170417-5345), available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 in the "Numbers: Accession Number" field.

TABLE 4.15.5-20

Emissions by Source and Total Annual Emissions Associated with Liquefaction Facilities Operation

Emission Source	Estimated Emissions (tpy)							
	NOx	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs	CO_2e [g]
Stationary Sources (without maximum flaring) [a]								
Compression Turbines (6)	940.4	1,590.3	72.9	205.7	205.7	65.6	30.1	3,107,178
Combined Cycle Combustion Turbines (4)	211.6	71.6	16.8	47.3	47.3	15.0	6.9	714,679
Auxiliary Air Compressor	<0.1	0.5	<0.1	<0.1	<0.1	<0.1	<0.1	78
Emergency Firewater Pump	1.1	1.0	<0.1	<0.1	<0.1	<0.1	<0.1	149
Dry Gas Flares (3) [a]	4.3	19.4	0.2	1.7	1.7	35.7	0.2	6,654
Wet Gas Flare (3) [a]	1.3	6.1	<0.1	0.6	0.6	11.2	<0.1	2,094
LP Gas Flare	3.1	14.3	0.2	1.3	1.3	26.2	0.1	4,886
Thermal Oxidizer	2.6	2.2	<0.1	0.2	0.2	0.1	<0.1	2,796
Fugitive Emissions	NA	NA	NA	NA	NA	18.0	NA	2,424
Subtotal	**1,164.4**	**1,705.4**	**90.2**	**256.8**	**256.8**	**171.8**	**37.3**	**3,840,938**
Maximum Flare Events								
Dry Gas Flares Maximum Flaring (3) [b, c]	2,039.7	9,298.8	74.8	846.5	846.5	17,097.7	86.9	3,186,463
Wet Gas Flares Maximum Flaring (3) [b, c]	476.7	2,173.1	17.5	197.8	197.8	3,995.7	20.3	744,670
LP Gas Flares Maximum Flaring [b, c]	5.1	22.4	0.2	2.0	2.0	40.9	0.2	7,629
Subtotal	**2,521.5**	**11,494.3**	**92.5**	**1,046.3**	**1,046.3**	**21,134.3**	**107.4**	**3,938,762**
Mobile Sources								
LNG carriers (minimum) and tugs [d]	379.6	630.4	1.2	14.0	13.0	116.6	0.3	81,248
LNG carriers (average) and tugs [e]	560.5	930.7	1.8	20.6	19.2	172.0	0.5	120,011
LNG carriers (maximum) and tugs [f]	963.5	1,600.2	3.1	35.4	32.8	295.9	0.9	206,231
Mobile Equipment	3.3	3.3	<0.1	0.2	0.2	0.3	<0.1	2,165
Non-Road/Portable Equipment	7.6	3.2	NA	0.7	0.7	2.4	NA	NA
Subtotal (based on average number of LNG carriers)	**571.4**	**937.2**	**1.8**	**21.5**	**20.1**	**174.7**	**0.5**	**122,176**
Total (without maximum flaring)	**1,735.8**	**2,642.6**	**92.0**	**278.3**	**276.9**	**346.5**	**37.8**	**3,963,114**
Total (with maximum flaring)	**4,257.3**	**14,136.9**	**184.5**	**1,324.6**	**1,323.2**	**21,480.8**	**145.2**	**7,901,876**

[a] Operation without maximum flare would include some routine operations that would require flare usage, including ship loading and operation of flares in standby status.

[b] Only two of the three flares would be operated at one time.

[c] CO_2 and hydrocarbon flares would operate at maximum capacity only during emergency, maintenance, startup, and shutdown events, assumed to be 500 hours per year for emission calculation purposes.

[d] Includes the minimum of 204 LNG carriers per year, each with an estimated 34.5-hour call, of which 18 hours would be spent hoteling/loading; and tug operations for each LNG carrier based on seasonal support demands.

[e] Includes the average of 252 LNG carriers per year, each with an estimated 34.5-hour call, of which 18 hours would be spent hoteling/loading; and tug operations for each LNG carrier based on seasonal support demands.

[f] Includes the maximum of 360 LNG carriers per year, each with an estimated 34.5-hour call, of which 18 hours would be spent hoteling/loading; and tug operations for each LNG carrier based on seasonal support demands.

[g] CO_2e is listed in metric tons.

TABLE 4.15.5-21

NAAQS/AAAQS Modeling Results for the Liquefaction Facilities

Pollutant	Averaging Period	Concentrations: Model Predicted (Liquefaction Facilities Only) ($\mu g/m^3$) [a]	Concentrations: Model Predicted (Liquefaction Facilities + Nearby Sources) ($\mu g/m^3$) [b]	Concentrations: Background ($\mu g/m^3$)	Concentrations: Total (Liquefaction Facilities + Nearby Sources + Background) ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	NAAQS/ AAAQS Exceedance? (Yes/No)
CO	1-hour [c]	2,721.0	2,799.3	1,145.0	3,944.3	40,000	40,000	No
	8-hour [c]	1,071.0	1,149.3	1,145.0	2,294.3	10,000	10,000	No
NO_2	1-hour [d]	140.1	149.5	32.3	181.8	188	188	No
	Annual [e]	8.6	54.7	2.6	57.3	100	100	No
PM_{10}	24-hour [f]	5.1	28.9	40.0	68.9	150	150	No
$PM_{2.5}$	24-hour [g]	3.6	11.4	12.0	23.4	35	35	No
	Annual [h]	0.4	7.8	3.7	11.4	12	12	No
SO_2	1-hour [i]	57.5	69.1	5.0	74.1	196	196	No
	3-hour [c]	39.6	56.3	5.0	61.3	1,300	1,300	No
	24-hour [c]	17.1	37.7	2.4	40.1	NA	365	No
	Annual [e]	0.1	6.3	<0.1	6.3	NA	80	No

[a] Liquefaction Facilities emissions include emissions from LNG carriers.
[b] Value includes Liquefaction Facilities, nearby sources, and coastline air effects.
[c] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.
[d] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.
[e] Value reported is the maximum annual average concentration for the 5-year period.
[f] Value reported is the highest-sixth-high concentration over the 5-year period.
[g] Value reported is the highest 98th percentile averaged over the 5-year period.
[h] Value reported is the maximum annual concentration, averaged over the 5-year period.
[i] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

Although a detailed construction and operation schedule has not been provided by AGDC, the potential exists for portions of the Liquefaction Facilities to be brought on-line sequentially. Therefore, simultaneous construction, startup, and operational activities could occur in Years 7 and 8 of construction, which would result in overlapping emissions in excess of the modeled operational emissions for PM_{10} and $PM_{2.5}$ presented in table 4.15.5-21. AGDC developed and would implement a Project Ambient Air Quality Monitoring Plan to monitor compliance with the NAAQS/AAAQS for PM_{10} and $PM_{2.5}$ during this period. The plan describes the site selection process for installing air quality monitors, includes procedures for data management and reporting, and identifies protocols for managing any exceedances of the NAAQS/AAAQS observed during monitoring.

PSD sources, such as the Liquefaction Facilities, are required to demonstrate that the increased pollutant levels resulting from the proposed source would not exceed PSD increment thresholds for certain criteria pollutants. Table 4.15.5-22 presents the results of the Project's PSD increment modeling analysis for the Liquefaction Facilities, which was completed using EPA's AERMOD air dispersion model. As shown in table 4.15.5-22, the Liquefaction Facilities would not exceed PSD increment thresholds.

The FLMs have identified the following Class I and Class II nationally designated protected areas within 186.4 miles of the Liquefaction Facilities for analysis:

- Tuxedni NWR (Class I), about 53 miles southwest of the Liquefaction Facilities;
- DNPP (Class I), about 114 miles north of the Liquefaction Facilities;
- Kenai NWR (Class II nationally designated protected area), about 6 miles east of the Liquefaction Facilities (note: see tables 4.15.5-21 and 4.15.5-22 for near-field NAAQS/AAQS and Incremental Analyses, which includes the Kenai NWR);
- Lake Clark NPP (Class II nationally designated protected area), about 31 miles west of the Liquefaction Facilities;
- Chugach National Forest (Class II nationally designated protected area), about 46 miles east of the Liquefaction Facilities;
- Kenai Fjords National Park (Class II nationally designated protected area), about 57 miles southeast of the Liquefaction Facilities; and
- Kodiak NWR (Class II nationally designated protected area), about 159 miles south-southwest of the Liquefaction Facilities.

AGDC completed air quality modeling to assess the potential impacts of the Liquefaction Facilities on these Class I and Class II nationally designated protected areas, which was completed using EPA's CALPUFF air dispersion model. The model included the Liquefaction Facilities, existing off-site sources, RFD sources, and ambient background concentrations. Table 4.15.5-23 presents a summary of the Class I Area analysis results and table 4.15.5-24 presents a summary of the Class II nationally designated protected area analysis results. Based on this analysis, the Liquefaction Facilities would not cause an exceedance of any of the NAAQS or AAAQS in any of the Class I or Class II nationally designated protected areas near the Liquefaction Facilities.

AGDC also modeled applicable PSD increment pollutants and averaging periods for each of the Class I and Class II nationally designated protected areas using EPA's CALPUFF air dispersion model. Summaries of the modeling results are presented in tables 4.15.5-25 and 4.15.5-26. The PSD Class I increment modeling demonstrates that the Liquefaction Facilities would not cause or contribute to an exceedance of Class I or Class II PSD increments.

AGDC completed a regional haze analysis. This analysis assessed the potential impacts of air emissions associated with the Liquefaction Facilities and other off-site sources on nearby Class I and Class II nationally designated protected areas. Due to the proximity of the Kenai NWR to the Liquefaction Facilities, the EPA's VISCREEN model was used to analyze near-field visibility impacts, the results of which are presented in table 4.15.5-27. If the perceptibility is less than 2 and the contrast is not greater than ±0.05, then the impacts are considered negligible and would not cause or contribute to an exceedance of visibility plume perceptibility thresholds.

TABLE 4.15.5-22

Prevention of Significant Deterioration Increment Modeling Results for the Liquefaction Facilities

Pollutant	Averaging Period	Total Increment Consumed by PSD Sources (Liquefaction Facilities Only) ($\mu g/m^3$) [c]	Total Increment Consumed by PSD Sources (Liquefaction Facilities + Nearby Sources) ($\mu g/m^3$) [d]	Class II PSD Increment ($\mu g/m^3$)	PSD Increment Exceedance? (Yes/No)
NO_2	Annual [a]	8.6	12.7	25	No
PM_{10}	24-hour [b]	5.4	29.7	30	No
	Annual [a]	0.4	7.7	17	No
$PM_{2.5}$	24-hour [b]	4.8	8.7	9	No
	Annual [a]	0.4	1.3	4	No
SO_2	3-hour [a]	39.6	45.4	512	No
	24-hour [a]	17.1	23.3	91	No
	Annual [b]	0.1	4.9	20	No

[a] Value reported is the maximum annual average concentration for the 5-year period.
[b] Value reported is the maximum of the highest-second-high values from each of the 5 modeled years.
[c] Liquefaction Facilities emissions include emissions from LNG carriers.
[d] Value includes Liquefaction Facilities, nearby sources, and coastline air effects.

The far-field regional haze analysis included the emissions from the Liquefaction Facilities and off-site sources. Visibility is measured in terms of light extinction (scattering plus absorption)—the more pollution in the air, the greater the extinction. The visibility thresholds used in the analysis are based on human perceptibility of visibility changes as compared to natural background conditions. In the regional haze Best Available Retrofit Technology guidelines, EPA concluded that if a source's emissions result in a modeled 98th percentile visibility change that is greater than 0.5 deciview (about a 5-percent change in light extinction), then the source is considered to *contribute* to regional haze visibility impairment. Similarly, a visibility change that exceeds 1.0 deciview (about a 10-percent change in light extinction) *causes* visibility impairment. A summary of the modeling results for the facilities and cumulative regional haze impacts is presented in table 4.15.5-28.

As presented in table 4.15.5-28, visibility impacts associated with air emissions from the Liquefaction Facilities would exceed the threshold for contributing to visibility impairment in Tuxedni NWR, Kenai Fjords National Park, and Lake Clark NPP; and would exceed the threshold for causing visibility impairment in the DNPP.

AGDC also completed an acid deposition analysis to assess potential impacts of air emissions associated with the Liquefaction Facilities on nearby Class I and Class II nationally designated protected areas. The analysis included the emissions from the Liquefaction Facilities, off-site sources, and existing background. If the Liquefaction Facilities-only results are less than the 0.005 kg/ha/yr deposition analysis thresholds, then the facilities' impacts are considered insignificant. For any areas above the 0.005 kg/ha/yr deposition analysis threshold for the facility, additional information, including cumulative modeling, background deposition levels, and ecosystem sensitivity in the affected area, is considered to determine whether adverse deposition effects would occur. A summary of the facility-only and cumulative deposition analysis results is presented in table 4.15.5-29.

TABLE 4.15.5-23

NAAQS/AAAQS Modeling Results for Class I Areas near the Liquefaction Facilities

Class I Area / Pollutant	Averaging Period	Concentrations: Model Predicted (Liquefaction Facilities Only) (µg/m³) [a]	Concentrations: Model Predicted (Liquefaction Facilities + Existing Sources + RFD) (µg/m³)	Concentrations: Background (µg/m³)	Concentrations: Total (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)	NAAQS/AAAQS Exceedance? (Yes/No)
Tuxedni NWR								
CO	1-hour [b]	5.7	14.7	1,145.0	1,159.7	40,000	40,000	No
	8-hour [b]	3.0	7.8	1,145.0	1,152.8	10,000	10,000	No
NO_2	1-hour [c]	0.8	4.8	32.3	37.1	188	188	No
	Annual [d]	<0.0	0.2	2.6	2.8	100	100	No
PM_{10}	24-hour [e]	0.3	2.2	40.0	42.2	150	150	No
$PM_{2.5}$	24-hour [f]	0.1	0.9	12.0	12.9	35	35	No
	Annual [g]	<0.1	0.1	3.7	3.8	12	12	No
SO_2	1-hour [h]	0.1	0.7	5.0	5.7	196	196	No
	3-hour [b]	0.1	0.7	5.0	5.7	1,300	1,300	No
	24-hour [b]	<0.1	0.3	2.3	2.6	N/A	365	No
	Annual [d]	<0.1	<0.1	<0.1	<0.1	N/A	80	No
DNPP								
CO	1-hour [b]	4.9	46.6	1,145.0	1,191.6	40,000	40,000	No
	8-hour [b]	2.6	17.3	1,145.0	1,162.3	10,000	10,000	No
NO_2	1-hour [c]	0.6	9.6	32.3	41.9	188	188	No
	Annual [d]	<0.1	0.2	2.6	2.8	100	100	No
PM_{10}	24-hour [e]	0.3	2.2	40.0	42.2	150	150	No
$PM_{2.5}$	24-hour [f]	0.1	0.8	12.0	12.8	35	35	No
	Annual [g]	<0.1	0.1	3.7	3.8	12	12	No
SO_2	1-hour [h]	0.1	22.2	5.0	27.2	196	196	No
	3-hour [b]	0.1	15.4	5.0	20.4	1,300	1,300	No
	24-hour [b]	<0.1	4.0	2.3	6.3	N/A	365	No
	Annual [d]	<0.1	0.3	<0.1	0.3	N/A	80	No

N/A = Not applicable

[a] Liquefaction Facilities emissions include emissions from LNG carriers.

[b] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[d] Value reported is the maximum annual average concentration for the 5-year period.

[e] Value reported is the highest-sixth-high concentration over the 5-year period.

[f] Value reported is the highest 98th percentile averaged over the 5-year period.

[g] Value reported is the annual mean concentration, averaged over the 5-year period.

[h] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

TABLE 4.15.5-24

NAAQS/AAAQS Modeling Results for Class II Nationally Designated Protected Areas near the Liquefaction Facilities

Class II Nationally Designated Protected Area [a] / Pollutant	Averaging Period	Concentrations						
		Model Predicted (Liquefaction Facilities Only) (µg/m^3) [b]	Model Predicted (Liquefaction Facilities + Existing Sources + RFD) (µg/m^3)	Background (µg/m^3)	Total (µg/m^3)	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/ AAAQS Exceedance? (Yes/No)
Lake Clark NPP								
CO	1-hour [c]	6.8	47.0	1,145.0	1,192.0	40,000	40,000	No
	8-hour [c]	3.4	23.3	1,145.0	1,168.3	10,000	10,000	No
NO_2	1-hour [d]	0.8	12.0	32.3	44.3	188	188	No
	Annual [e]	<0.1	0.5	2.6	3.1	100	100	No
PM_{10}	24-hour [f]	0.4	2.5	40.0	42.5	150	150	No
$PM_{2.5}$	24-hour [g]	0.1	1.4	12.0	13.4	35	35	No
	Annual [h]	<0.1	0.2	3.7	3.9	12	12	No
SO_2	1-hour [i]	0.1	1.3	5.0	6.3	196	196	No
	3-hour [c]	0.1	1.1	5.0	6.1	1,300	1,300	No
	24-hour [c]	<0.1	0.4	2.3	2.7	N/A	365	No
	Annual [e]	<0.1	<0.1	<0.1	<0.1	N/A	80	No
Chugach National Forest								
CO	1-hour [c]	4.6	73.1	1,145.0	1,218.1	40,000	40,000	No
	8-hour [c]	2.1	32.5	1,145.0	1,177.5	10,000	10,000	No
NO_2	1-hour [d]	0.4	17.4	32.3	49.7	188	188	No
	Annual [e]	<0.1	0.7	2.6	3.3	100	100	No
PM_{10}	24-hour [f]	<0.1	1.4	40.0	41.4	150	150	No
$PM_{2.5}$	24-hour [g]	<0.1	1.4	12.0	13.4	35	35	No
	Annual [h]	<0.1	0.2	3.7	3.9	12	12	No
SO_2	1-hour [i]	<0.1	2.0	5.0	7.0	196	196	No
	3-hour [c]	<0.1	1.7	5.0	6.7	1,300	1,300	No
	24-hour [c]	<0.1	0.6	2.3	2.9	N/A	365	No
	Annual [e]	<0.1	<0.1	<0.1	<0.1	N/A	80	No
Kenai Fjords National Park								
CO	1-hour [c]	4.6	5.3	1,145.0	1,150.3	40,000	40,000	No
	8-hour [c]	1.9	2.6	1,145.0	1,147.6	10,000	10,000	No
NO_2	1-hour [d]	0.4	0.8	32.3	33.1	188	188	No
	Annual [e]	<0.1	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [f]	<0.1	0.5	40.0	40.5	150	150	No
$PM_{2.5}$	24-hour [g]	<0.1	0.2	12.0	12.2	35	35	No
	Annual [h]	<0.1	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [i]	<0.1	0.1	5.0	5.1	196	196	No
	3-hour [c]	<0.1	0.1	5.0	5.1	1,300	1,300	No
	24-hour [c]	<0.1	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	<0.1	<0.1	<0.1	NA	80	No

TABLE 4.15.5-24 (cont'd)

NAAQS/AAAQS Modeling Results for Class II Nationally Designated Protected Areas near the Liquefaction Facilities

Class II Area [i] / Pollutant	Averaging Period	Concentrations: Model Predicted (Liquefaction Facilities Only) (µg/m^3) [a]	Model Predicted (Liquefaction Facilities + Existing Sources + RFD) (µg/m^3)	Background (µg/m^3)	Total (µg/m^3)	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/ AAAQS Exceedance? (Yes/No)
Kodiak NWR								
CO	1-hour [c]	1.1	1.1	1,145.0	1,146.1	40,000	40,000	No
	8-hour [c]	0.6	0.6	1,145.0	1,145.6	10,000	10,000	No
NO_2	1-hour [d]	<0.1	<0.1	32.3	32.3	188	188	No
	Annual [e]	<0.1	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [f]	<0.1	<0.1	40.0	40.0	150	150	No
$PM_{2.5}$	24-hour [g]	<0.1	<0.1	12.0	12.0	35	35	No
	Annual [h]	<0.1	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [i]	5.0	5.0	5.0	10.0	196	196	No
	3-hour [c]	5.0	5.0	5.0	10.0	1,300	1,300	No
	24-hour [c]	2.4	2.4	2.3	4.7	N/A	365	No
	Annual [e]	<0.1	<0.1	<0.1	<0.1	N/A	80	No

N/A = Not applicable

[a] Because the Kenai NWR (Class II nationally designated protected area) would be within 31.1 miles of the Liquefaction Facilities, potential impacts on this area are included in the NAAQS/AAAQS analysis presented in table 4.15.5-17.

[b] Liquefaction Facilities emissions include emissions from LNG carriers.

[c] Value reported is the highest-second-high concentration of the values determined for each of the 5 modeled years.

[d] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

[e] Value reported is the maximum annual average concentration for the 5-year period.

[f] Value reported is the highest-sixth-high concentration over the 5-year period.

[g] Value reported is the highest 98th percentile averaged over the 5-year period.

[h] Value reported is the annual mean concentration, averaged over the 5-year period.

[i] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

TABLE 4.15.5-25

Prevention of Significant Deterioration Class I Increment Modeling Results for Class I Areas near the Liquefaction Facilities

Class I Area/ Pollutant	Averaging Period	Model Predicted (Liquefaction Facilities Only) (µg/m^3) [a]	Model Predicted (Liquefaction Facilities + Existing Sources + RFD) (µg/m^3)	Class I PSD Increment (µg/m^3)	PSD Increment Exceedance? (Yes/No)
Tuxedni NWR					
NO_2	Annual [b]	<0.1	0.2	2.5	No
PM_{10}	24-hour [c]	0.3	1.7	8	No
	Annual [b]	<0.1	0.1	4	No
$PM_{2.5}$	24-hour [c]	0.4	1.8	2	No
	Annual [b]	<0.1	0.1	1	No
SO_2	3-hour [b]	0.1	0.6	25	No
	24-hour [b]	<0.1	0.3	5	No
	Annual [b]	<0.1	<0.1	2	No
DNPP					
NO_2	Annual [b]	<0.1	0.1	2.5	No
PM_{10}	24-hour [c]	0.3	1.7	8	No
	Annual [b]	<0.1	<0.1	4	No
$PM_{2.5}$	24-hour [c]	0.3	1.8	2	No
	Annual [b]	<0.1	<0.1	1	No
SO_2	3-hour [b]	0.1	15.4	25	No
	24-hour [b]	<0.1	4.0	5	No
	Annual [b]	<0.1	0.3	2	No

[a] Liquefaction Facilities emissions include emissions from LNG carriers.
[b] Value reported is the maximum annual average concentration for the 5-year period.
[c] Value reported is the maximum of the highest-second-high values from each of the 5 modeled years.

TABLE 4.15.5-26

Prevention of Significant Deterioration Class II Increment Modeling Results for Class II Nationally Designated Protected Areas near the Liquefaction Facilities

Class II Nationally Designated Protected Area [a] / Pollutant	Averaging Period	Model Predicted (Facility Only) (µg/m^3) [b]	Model Predicted (Facility + Existing Sources + RFD) (µg/m^3)	Class I PSD Increment (µg/m^3)	PSD Increment Exceedance? (Yes/No)
Lake Clark NPP					
NO_2	Annual [c]	<0.1	0.5	25	No
PM_{10}	24-hour [d]	0.4	2.2	30	No
	Annual [c]	<0.1	0.2	17	No
$PM_{2.5}$	24-hour [d]	0.4	2.4	9	No
	Annual [c]	<0.1	0.2	4	No
SO_2	3-hour [c]	0.1	1.1	512	No
	24-hour [c]	<0.1	0.4	91	No
	Annual [c]	<0.1	<0.1	20	No
Chugach National Forest					
NO_2	Annual [c]	<0.1	0.7	25	No
PM_{10}	24-hour [d]	0.1	2.4	30	No
	Annual [c]	<0.1	0.2	17	No
$PM_{2.5}$	24-hour [d]	0.2	2.5	9	No
	Annual [c]	<0.1	0.2	4	No
SO_2	3-hour [c]	<0.1	1.7	512	No
	24-hour [c]	<0.1	0.6	91	No
	Annual [c]	<0.1	<0.1	20	No
Kenai Fjords National Park					
NO_2	Annual [c]	<0.1	<0.1	25	No
PM_{10}	24-hour [d]	<0.1	0.4	30	No
	Annual [c]	<0.1	<0.1	17	No
$PM_{2.5}$	24-hour [d]	0.1	0.4	9	No
	Annual [c]	<0.1	<0.1	4	No
SO_2	3-hour [c]	<0.1	0.1	512	No
	24-hour [c]	<0.1	<0.1	91	No
	Annual [c]	<0.1	<0.1	20	No
Kodiak NWR					
NO_2	Annual [c]	<0.1	<0.1	25	No
PM_{10}	24-hour [d]	<0.1	0.4	30	No
	Annual [c]	<0.1	<0.1	17	No
$PM_{2.5}$	24-hour [d]	<0.1	0.5	9	No
	Annual [c]	<0.1	<0.1	4	No
SO_2	3-hour [c]	<0.1	2.6	512	No
	24-hour [c]	<0.1	0.6	91	No
	Annual [c]	<0.1	<0.1	20	No

[a] Because the Kenai NWR (Class II nationally designated protected area) would be within 31.1 miles (50.0 km) of the Liquefaction Facilities, potential impacts on this area are included in the NAAQS/AAAQS analysis presented in table 4.15.5-17.

[b] Liquefaction Facilities emissions include emissions from LNG carriers.

[c] Value reported is the maximum annual average concentration for the 5-year period.

[d] Value reported is the maximum of the highest-second-high values from each of the 5 modeled years.

TABLE 4.15.5-27

Modeled Visibility Impacts Inside Kenai National Wildlife Refuge from the Liquefaction Facilities

Source Plume	Observer Location	Scattering Angle (degrees)	Perceptibility (ΔE)		Contrast (Cp)		Exceeds Visibility Extinction Criteria? (Yes/No)
			Criteria	Modeled	Criteria	Modeled	
Forward Scatter							
Compressor Turbine	Closest Park Boundary	10	2.00	5.63	±0.05	0.02	Yes
	Skilak Lake	10	2.00	2.15	±0.05	0.03	Yes
Power Generators	Closest Park Boundary	10	2.00	1.61	±0.05	0.01	No
	Skilak Lake	10	2.00	0.60	±0.05	0.01	No
LP Flare + Thermal Oxidizer	Closest Park Boundary	10	2.00	0.04	±0.05	0.00	No
	Skilak Lake	10	2.00	0.01	±0.05	0.00	No
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.07	±0.05	0.00	No
	Skilak Lake	10	2.00	0.03	±0.05	0.00	No
Marine	Closest Park Boundary	10	2.00	0.68	±0.05	0.00	No
	Skilak Lake	10	2.00	0.46	±0.05	0.01	No
Backward Scatter							
Compressor Turbine	Closest Park Boundary	10	2.00	0.46	±0.05	0.00	No
	Skilak Lake	10	2.00	0.75	±0.05	0.02	No
Power Generators	Closest Park Boundary	10	2.00	0.12	±0.05	0.00	No
	Skilak Lake	10	2.00	0.21	±0.05	0.01	No
LP Flare + Thermal Oxidizer	Closest Park Boundary	10	2.00	0.00	±0.05	0.00	No
	Skilak Lake	10	2.00	0.00	±0.05	0.00	No
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.01	±0.05	0.00	No
	Skilak Lake	10	2.00	0.01	±0.05	0.00	No
Marine	Closest Park Boundary	10	2.00	0.11	±0.05	0.00	No
	Skilak Lake	10	2.00	0.20	±0.05	0.01	No

ΔE = Total color contrast; Cp = Plume contrast

TABLE 4.15.5-28

Regional Haze Modeling Results for the Liquefaction Facilities

Class I / Class II Nationally Designated Protected Area / Model Year	Liquefaction Facilities Results		Cumulative Results	
	8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (Contribute / Cause) (%) [a]	8th Highest Change in Extinction (%)	Cause or Contribute to Exceedance of Visibility Extinction Threshold? (Yes/No)
Tuxedni National Wildlife Refuge (Class I Area)				
1	6.1	5.0 / 10.0	27.7	Yes (Contribute)
2	4.9	5.0 / 10.0	29.9	No
3	5.8	5.0 / 10.0	26.6	Yes (Contribute)
Denali National Park (Class I Area)				
1	14.5	5.0 / 10.0	58.4	Yes (Causes)
2	17.1	5.0 / 10.0	67.3	Yes (Causes)
3	14.9	5.0 / 10.0	59.0	Yes (Causes)
Kenai Fjords National Park (Class II Area)				
1	5.0	5.0 / 10.0	14.7	Yes (Contribute)
2	4.7	5.0 / 10.0	12.9	No
3	5.0	5.0 / 10.0	11.0	Yes (Contribute)
Chugach National Forest (Class II Area)				
1	4.2	5.0 / 10.0	36.1	No
2	4.1	5.0 / 10.0	39.5	No
3	4.1	5.0 / 10.0	45.1	No
Lake Clark National Park (Class II Area)				
1	9.1	5.0 / 10.0	44.4	Yes (Contribute)
2	6.2	5.0 / 10.0	41.5	Yes (Contribute)
3	7.6	5.0 / 10.0	53.1	Yes (Contribute)
Kodiak National Wildlife Refuge (Class II Area)				
1	2.3	5.0 / 10.0	13.0	No
2	3.5	5.0 / 10.0	13.4	No
3	2.3	5.0 / 10.0	15.1	No

[a] Liquefaction Facilities emissions include emissions from LNG carriers.

TABLE 4.15.5-29

Three-Year Maximum Deposition Results for the Liquefaction Facilities

Pollutant	Liquefaction Facilities Results [a]			Cumulative Results	
	Predicted Deposition Impact (Facility Only) (kg/ha/yr) / Class I or Class II Nationally Designated Protected Area	NPS Deposition Analysis Threshold (kg/ha/yr)	Percent of Depositional Analysis Threshold	Predicted Deposition Impact (Facility + Off-site Sources + Background) (kg/ha/yr)	Exceeds Depositional Analysis Threshold? (Yes/No)
Sulfur Deposition					
Tuxedni NWR	0.0052	0.0050	104	0.0542	Yes
DNPP	0.0037	0.0050	74	0.0795	No
Kenai NWR	**0.0058**	0.0050	116	NP	Yes
Kenai Fjords National Park	0.0029	0.0050	60	0.0024	No
Chugach National Forest	0.0010	0.0050	19	0.0300	No
Lake Clark NPP	**0.0059**	0.0050	119	0.0528	Yes
Kodiak NWR	0.0002	0.0050	4	0.0270	No
Nitrogen Deposition					
Tuxedni NWR	**0.0136**	0.0050	272	0.1190	Yes
DNPP	**0.0143**	0.0050	287	0.0934	Yes
Kenai NWR	**0.0314**	0.0050	627	NP	Yes
Kenai Fjords National Park	0.0020	0.0050	39	0.0137	No
Chugach National Forest	0.0048	0.0050	95	0.0731	No
Lake Clark NPP	**0.0197**	0.0050	393	0.1220	Yes
Kodiak NWR	0.0021	0.0050	42	0.0182	No

NP = Not provided by AGDC

As presented in table 4.15.5-29, sulfur deposition thresholds could be exceeded by air emissions from the Liquefaction Facilities at the Tuxedni NWR, Kenai NWR, and Lake Clark National Park. Nitrogen deposition thresholds could be exceeded by air emissions from the Liquefaction Facilities at the Tuxedni NWR, DNRR, Kenai NWR, and Lake Clark NPP. Because AGDC did not analyze cumulative deposition impacts at the Kenai NWR, we have assumed that the Project could contribute to cumulative deposition impacts on this area.

As previously stated, AGDC completed cumulative modeling to assess NAAQS/AAAQS compliance, regional haze, and acid deposition impacts associated with the combined operational emissions of the GTP, compressor stations, heater station, and Liquefaction Facilities (see section 4.19.4.15).

While preparing the draft EIS, we issued information requests on July 28, 2017 and February 15, 2018 to AGDC requesting that they work with the FLMs to establish a mitigation strategy to ensure that air emissions from the proposed facilities would not negatively affect nearby Class I and Class II nationally designated protected areas. To date, AGDC has not provided a mitigation strategy or determined acceptable thresholds agreed upon by the FLMs. The Liquefaction Facilities are currently under review by ADEC as part of the PSD permitting process, which involves a review of AQRVs, potential impacts on

Class I and Class II nationally designated protected areas, and input from the FLMs. Without mitigation, the potential exists for exceedance of regional haze and acid deposition thresholds in some Class I and Class II nationally designated areas. Additional mitigation measures may be implemented during the air permitting phase that could further reduce impacts on these resources.

Regional Ozone

The Liquefaction Facilities would be in the Kenai Peninsula Borough, which is currently designated as attainment for the 8-hour O_3 NAAQS, and would not be near any area designated nonattainment for 8-hour O_3 NAAQS. As noted in section 4.15.2.3, existing O_3 concentrations in the vicinity of the Liquefaction Facilities are about 47 ppbv (0.047 ppmv), which is below the current 8-hour O_3 NAAQS of 70 ppbv.

Recent EPA research focused on the assessment of ozone formation from industrial source emissions in the Lower 48 suggests that single sources of NO_X emissions in the range of 1,000 to 3,000 tpy could result in ozone impacts between 0.2 to 12.3 ppbv, with an average of 4 ppbv (Baker et al., 2016; EPA, 2019). Based on this information, the facility impacts are unlikely to result in 8-hour O_3 levels at or near the NAAQS of 70 ppbv.

Regional Secondary Formation of $PM_{2.5}$

The Kenai Peninsula Borough is currently designated as attainment for $PM_{2.5}$ NAAQS and the Liquefaction Facilities would not be near any area designated as nonattainment for the $PM_{2.5}$ NAAQS. As noted in section 4.15.2.3, existing 24-hour $PM_{2.5}$ concentrations in the vicinity of the Liquefaction Facilities are about 12 $\mu g/m^3$, and based on predicted modeled results, $PM_{2.5}$ concentrations would be about 23.4 $\mu g/m^3$ for the 24-hour standard and 11.4 $\mu g/m^3$ for the Annual standard during operation of the Liquefaction Facilities, which are below the current 24-hour $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$ and the current Annual $PM_{2.5}$ NAAQS of 12.0 $\mu g/m^3$.

Recent EPA research focused on the assessment of secondary $PM_{2.5}$ formation from the emissions of NO_X and SO_2 from industrial facilities in the Lower 48 suggests that single sources of NO_X emissions in the range of 1,000 to 3,000 tpy could result in secondary 24-hour $PM_{2.5}$ impacts between 0.01 to 1.7 $\mu g/m^3$, with an average of about 0.2 $\mu g/m^3$, and secondary Annual $PM_{2.5}$ impacts between 0.004 to 0.127 $\mu g/m^3$, with an average of about 0.01 $\mu g/m^3$. The research further shows that SO_2 sources in the range of 500 to 1,000 tpy have peak secondary 24-hour $PM_{2.5}$ impacts between 0.03 to 4.8 $\mu g/m^3$ and secondary Annual $PM_{2.5}$ impacts between 0.01 to 0.23 $\mu g/m^3$ (Baker et al., 2016; EPA, 2019). It is unlikely impacts from facility emissions could result in secondary $PM_{2.5}$ concentrations on the higher end of the distribution indicated in this study because meteorological conditions are not as favorable (less sunlight, lower temperatures, etc.) as those in some areas of the Lower 48. Also, maximum secondary $PM_{2.5}$ concentrations tend to occur some distance downwind of the facility, while maximum primary $PM_{2.5}$ concentrations tend to occur near the fence line. Based on this information, it is unlikely the combination of primary, secondary, and background $PM_{2.5}$ would result in an exceedance of the 24-hour or Annual $PM_{2.5}$ NAAQS.

Maximum Flare Modeling Analysis

AGDC completed an air quality modeling analysis to assess potential impacts associated with maximum flare events on criteria pollutants and toxic air pollutants. Maximum flare emissions were also included in the AQRV analysis above. AGDC has indicated that maximum flaring events could occur between 0.5 hour and 36 hours. The results of this analysis are presented in tables 4.15.5-30 and 4.15.5-31. We compared the modeling results to the NAAQS/AAAQS for criteria pollutants. Toxic air pollutant emissions were compared to 1-hour RELs established by the EPA.

Based on the results of these analyses, the emissions associated with maximum flare events at the Liquefaction Facilities would not result in exceedances of the NAAQS/AAAQS, nor would the toxic air pollutants generated during maximum flare events result in exceedances of the EPA's 1-hour REL.

TABLE 4.15.5-30

Short-Term Criteria Pollutant Impacts from Liquefaction Facilities Maximum Flare Events

Criteria Pollutant	Averaging Period	Ambient Background Concentration ($\mu g/m^3$)	Maximum Modeled Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS/AAAQS ($\mu g/m^3$)
NO_2	1-hour	32.3	3.5	35.8	188
CO	1-hour	1,145	148.6	1,293.6	40,000
	8-hour	1,145	31.0	1,176.0	10,000
PM_{10}	24-hour	40	1.8	41.8	150
$PM_{2.5}$	24-hour	12	1.8	13.8	35
SO_2	1-hour	5	0.1	5.1	196
	3-hour	5	0.5	5.5	1,300
	24-hour	2.4	0.5	2.9	365

TABLE 4.15.5-31

Air Toxics Exposure Assessment from Liquefaction Facilities Maximum Flare Events

Hazardous Air Pollutants	Maximum Modeled 1-Hour Concentration ($\mu g/m^3$)	Reference Exposure Levels (1-hour) ($\mu g/m^3$)
Benzene	<0.1	1,300
Toluene	<0.1	37,000
Ethylbenzene	0.7	350,000
Xylene	<0.1	22,000
n-Hexane	<0.1	390,000
Formaldehyde	0.6	55

Liquefaction Facilities Conclusion

Liquefaction Facilities operation would have a permanent effect on air quality in the vicinity of the Facilities. The effects on air quality in the Project area would be minor to moderate during normal facility operation, but certain short-term activities such as flaring have the potential to result in short-term significant effects on regional haze. Additionally, without additional control measures, emissions from the Liquefaction Facilities could have a significant impact on regional haze at the Kenai NWR, Tuxendi NWR, Kenai Fjords National Park, DNPP, and Lake Clark; and could have a long-term significant impact on acid deposition at the Tuxedni NWR, DNPP, Kenai NWR, and Lake Clark NPP.

4.15.6 Conclusion

Impacts on air quality resulting from Project construction would be temporary, although impacts from the construction of the GTP and Liquefaction Facilities would occur over the course of 8 years for each of the facilities. Construction emissions would have a minor to moderate effect on air quality in the Project area and would be mitigated by the use of multiple plans to control emissions associated with construction equipment, fugitive dust, and open burning activities.

During the years that simultaneous construction, startup, and operational activities would occur at the Liquefaction Facilities, which would likely be Years 7 and 8 of construction, emission levels could result in exceedances of the NAAQS/AAAQS. AGDC developed and would implement an Ambient Air Quality Monitoring Plan to ensure the emissions associated with simultaneous construction, startup, and operational activities would not result in exceedances of PM_{10} and $PM_{2.5}$ ambient air quality standards.

Project operation would have a permanent effect on air quality in the vicinity of the aboveground facilities associated with the Project. The direct effects on air quality in the Project area would be minor to moderate during normal facility operation, but emissions from the aboveground facilities, including the GTP, compressor stations, heater station, and Liquefaction Facilities, could cause exceedances of visibility extinction thresholds and sulfur or nitrogen deposition thresholds at some Class I and Class II nationally designated protected areas. Both the GTP and Liquefaction Facilities are currently under review by ADEC as part of the PSD permitting process, which involves a review of AQRVs, potential impacts on Class I and Class II nationally designated protected areas, and input from the FLMs. Without mitigation, emissions from the GTP and Liquefaction Facilities could have a significant impact on regional haze and acid deposition in some Class I and Class II nationally designated areas. Mitigation measures may be implemented during the air permitting phase that could further reduce impacts on these resources.

4.16 NOISE

This section describes ambient noise levels near Project components that would be directly or indirectly affected by construction and operation of the Project. It also summarizes federal, state, and local noise regulations applicable to the Project, and identifies and analyzes estimated noise impacts associated with the Project.

Noise issues were raised by participants in the Traditional Knowledge Workshops. In the vicinity of the GTP Facilities, participants commented on the effects of noise, especially related to air traffic and industrial noise associated with development in the Prudhoe Bay area. Participants commented that noise from existing facilities in the Prudhoe Bay area can be heard up to 3 miles away, especially during flaring activities. Participants noted that caribou, wolves, and marine mammals are susceptible to noise disturbance. Along the Mainline Facilities, noise from oil and gas and industrial development was observed to have a negative effect on hunting due to animal reactions to the noise. Participants commented that sound can travel long distances in areas along the Mainline Pipeline corridor, such as Minto Flats, and over water in Cook Inlet, especially during cold weather. Participants in the Traditional Knowledge Workshops near the Liquefaction Facilities commented that noise from intermittent sounds like barge and vehicle traffic has a negative effect on hunting and fishing due to animal reactions to the noise.

4.16.1 Principles of Noise

Sound is a sequence of pressure waves that propagate through compressible media such as air or water. When sound becomes excessive, annoying, or unwanted, it is referred to as noise. Construction and operation of the Project would affect overall noise levels near the various Project components. The ambient sound level of a region is defined by the total noise generated within the specific environment and usually comprises natural and anthropogenic sounds. At any location, both the magnitude and frequency of environmental noise could vary considerably over the course of a day and throughout the week. This variation is caused in part by changing weather conditions and the effect of seasonal vegetation cover.

Two measurements used by some federal agencies to relate the time-varying quality of noise to its known effects on people are the equivalent sound level (L_{eq}) and the day-night average sound level (L_{dn}). The preferred single value figure to describe sound levels that vary over time is L_{eq}, which is defined as the sound pressure level (SPL) of a noise fluctuating over a period of time, expressed as the amount of average

energy. L_{dn} is defined as the 24-hour average of the equivalent average of the sound levels during the daytime (from 7:00 a.m. to 10:00 p.m.) and the equivalent average of the sound levels during the nighttime (from 10:00 p.m. to 7:00 a.m.). Specifically, in the calculation of the L_{dn}, late night and early morning (10:00 p.m. to 7:00 a.m.) noise exposures are increased by 10 dB to account for people's greater sensitivity to sound during nighttime hours. In general, if the sound energy does not vary over the given time period, the L_{dn} level would be equal to the L_{eq} level plus 6.4 dB. The 6.4-dB difference between the L_{dn} and the L_{eq} is a result of the 10-dB nighttime addition for the L_{dn} calculation.

Decibels are the units of measurement used to quantify the intensity of noise. To account for the human ear's sensitivity to low level noises, the decibel values are corrected to weighted values known as decibels on the A-weighted scale (dBA). The A-weighted scale is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies.

Table 4.16.1-1 demonstrates the relative dBA noise levels of common sounds measured in the environment and industry. A 3-dB change of sound level is barely perceivable by the human ear, a 6-dB change of sound level is noticeable, and a 10-dB increase is as if the sound intensity is doubled.

TABLE 4.16.1-1

Typical Sound Levels of Various Activities [a]

Noise Source or Activity	Sound Level (dBA)
Threshold of pain	140
Jet taking off (200-foot distance)	130
Operating heavy equipment	120
Night club with music	110
Construction site	100
Boiler room	90
Freight train (100-foot distance)	80
Classroom chatter	70
Conversation (3-foot distance)	60
Urban residence	50
Soft whisper (5-foot distance)	40
North rim of Grand Canyon	30
Silent study room	20
Threshold of hearing (1,000 hertz)	0

Source: Occupational Safety and Health Administration (OSHA), 2013

Additional noise measurements are used to characterize noise associated with specific Project activities including the maximum A-weighted sound level over a particular time interval (L_{max}) (EPA, 1974) and peak sound level (L_{peak}), which is the highest pressure above or below ambient that is associated with a sound wave. The L_{max} and L_{peak} are measurements used to characterize maximum sound pressure generated by an activity and are often associated with intermittent activities such as pile driving. Decibels re 1 µPa are used to report underwater sound levels, which accounts for the difference between sound under water and sound in air (Caltrans, 2015).

4.16.2 Regulatory Noise Requirements

4.16.2.1 Federal Regulations

In 1974, the EPA published *Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin on Safety*, which evaluated the effects of environmental noise with respect to health and safety. As set forth in this publication, the EPA determined that noise levels should not exceed an L_{dn} of 55 dBA, which is the level that protects the public from activity interference and annoyance with indoor and outdoor activities. We have adopted this criterion (18 CFR 157.206(b)(5)) for new compression facilities, LNG facilities, and associated pipeline facilities, and it is used here to evaluate the potential noise effects from operation of the Gas Treatment Facilities, compressor stations and the heater station associated with the Mainline Pipeline, and Liquefaction Facilities. An L_{dn} of 55 dBA is equivalent to a continuous noise level of 48.6 dBA for facilities that operate at a constant level of noise. A 55 dBA L_{dn} noise level equates to a L_{eq} of 48.6 dBA (i.e., a facility that does not exceed a continuous noise impact of 48.6 dBA would not exceed 55 dBA L_{dn}).

The NPS manages lands that would be near and crossed by the Project, and the USFWS manages lands near the Project. These public lands have the potential to be affected by construction and operation of the Project Facilities (see figure 4.16.2-1).

While the NPS does not have a numeric noise criterion for human exposure applicable to the Project, it has a Soundscape Management Policy that states: "Using appropriate management planning, superintendents would identify what levels and types of unnatural sound constitute acceptable impacts on park natural soundscape. Adjacent to parks, the NPS would monitor human activities that generate noise that adversely affects park soundscapes, including noise caused by mechanical or electronic devices." As stated in the NPS management policies: "The NPS will strive to preserve or restore the natural quiet and natural sounds associated with … parks. The natural ambient sound level—that is, the environment of sound that exists in the absence of human-caused noise—is the baseline condition, and the standard against which current conditions in a soundscape will be measured and evaluated" (NPS, 2006c). As shown on figure 4.16.2-1, the Mainline Facilities would be near the Gates of the Arctic NPP and directly affect the DNPP. Because both of these parks are managed by the NPS, the Project would be subject to the Soundscape Management Policy.

The NPS has developed the *Denali Backcountry Management Plan*, which further describes noise conditions within the DNPP and maximum sound levels and percent time of allowable audible noise from unnatural sounds (NPS, 2006a).

The USFWS does not have a numeric noise criterion for human exposure applicable to the Project. The USFWS does preserve "natural soundscapes" as an "aspect of wilderness character" to "prevent or minimize unnatural sounds that adversely affect wilderness resources or values or visitors' enjoyment of them" (USFWS, 2008b). As shown on figure 4.16.2-1, four NWRs managed by the USFWS would be near the Mainline Facilities: ANWR, Yukon Flats NWR, Kanuti NWR, and Kenai NWR.

4.16.2.2 State and Local Regulations

The State of Alaska has no regulations that would limit noise generated from Project construction and operation. There are no other identified numeric regulatory requirements at the local or borough level specific to construction or operational noise for any of the Project components.

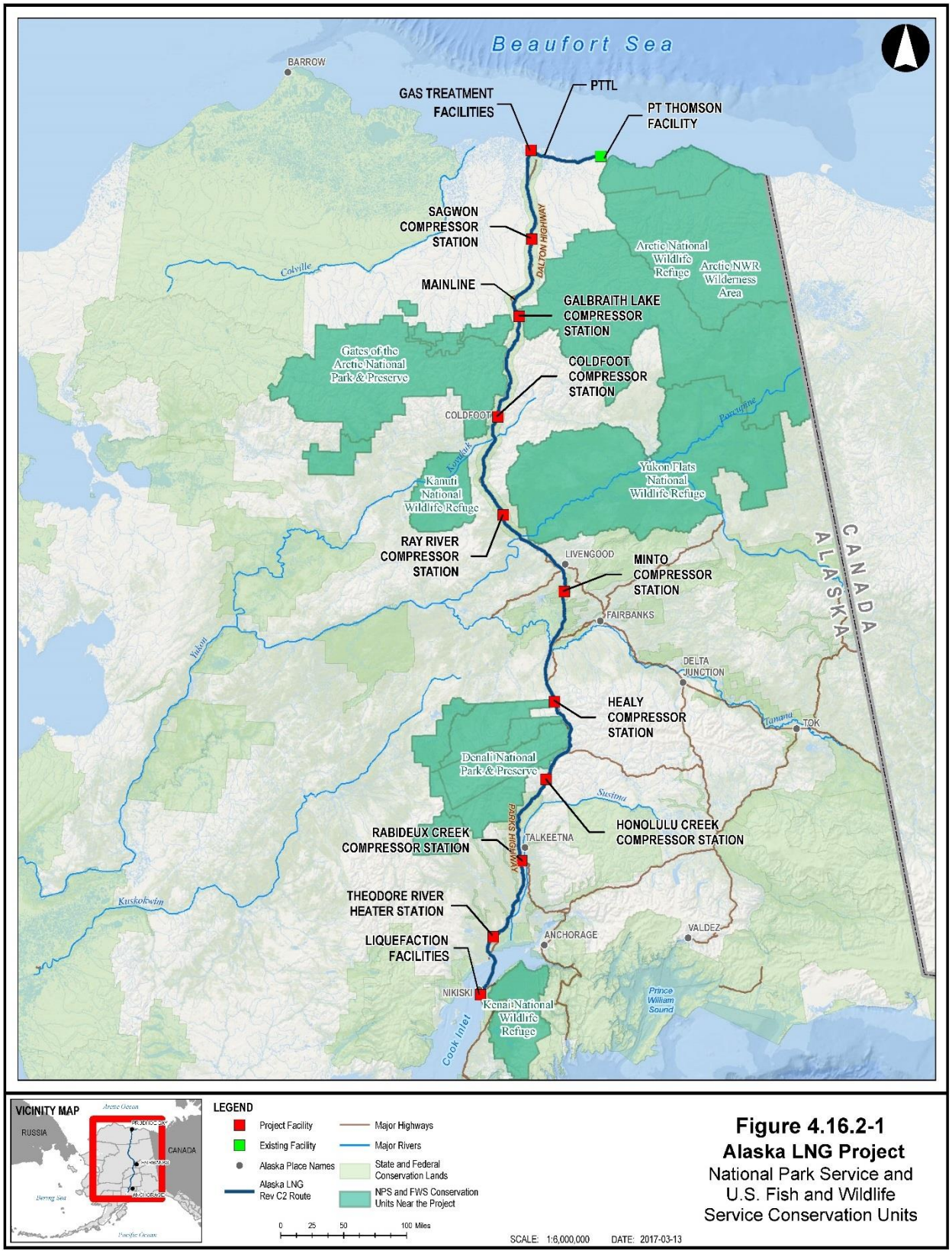


Figure 4.16.2-1
Alaska LNG Project
National Park Service and U.S. Fish and Wildlife Service Conservation Units

4.16.3 Construction Noise Impacts and Mitigation

Construction of the Project would generate noise near construction activities. Noise associated with pipeline construction would be spread over the length of the pipeline route and would not be concentrated at any one location for an extended period of time, except at the DMT sites. Construction noise associated with the aboveground facilities (i.e., GTP, compressor stations, heater station, meter stations, and LNG Plant) would be concentrated near each site and would extend for the duration of the construction activity, but would vary depending on the specific activities that are taking place at any given time. The following sections describe the noise that would be generated due to construction of each Project component and AGDC's proposed mitigation measures.

4.16.3.1 Gas Treatment Facilities

GTP

Construction of the GTP would produce variable noise levels, depending on the work taking place at that time. Major noise-generating sources during construction would involve clearing and grading associated with site preparation, materials and equipment delivery, installation of the facility foundations (e.g., pile driving), installation and operation of the gravel mine, installation of the water reservoir, installation and operation of the construction camps, and construction of compression equipment and buildings. Construction crews would typically work 6 days per week during daylight hours, which could be between 7:00 a.m. and 10:00 p.m., depending on the season. AGDC has estimated that the GTP would require 90 months (7 years and 6 months) to construct.

No Noise Sensitive Areas (NSA) were identified within 1 mile of the GTP. The closest known residential area is the Nuiqsut community, about 50 miles from the GTP. Noise from construction of the GTP has the potential to affect the surrounding environment, however, including wildlife and subsistence practices. Background sound levels at the GTP were assessed for the Alaska Pipeline Project and found to be about 66 dBA L_{dn} near the GTP site and at levels ranging from 52 to 57 dBA L_{dn} within 2 to 4 miles from the GTP site (TransCanada, 2017). Figure 4.16.3-1 provides the estimated radial noise impact associated with construction of the GTP on the surrounding area. Sound levels would be at or near existing background sound levels within about 2 miles of the GTP. Potential impacts of the noise generated from GTP construction on wildlife and subsistence uses are addressed in sections 4.6 and 4.14, respectively.

West Dock Causeway

West Dock Causeway construction, particularly pile driving, would result in the generation and propagation of aboveground and underwater noise energy. Due to the remote location of the West Dock Causeway, the potential resource impacts associated with the construction activities would be related to underwater noise. AGDC estimated pile driving activities based on the facilities to be installed. West Dock Causeway construction would occur during the summer season of Years 1 and 8. Activities that would generate underwater noise include installation of sheet piling and construction of the barge bridge and Dock Head 4 mooring dolphins.

Because pile driving would be an intermittent activity, the noise impact would not be continuous. Project activities would require the use of both impact and vibratory hammers, which generate different underwater noise levels that have been estimated separately. Further details regarding the estimated noise levels, potential noise impacts, and proposed mitigation measures for marine mammals and fish are included in sections 4.6.3 and 4.7.1, respectively, and appendix L-1.

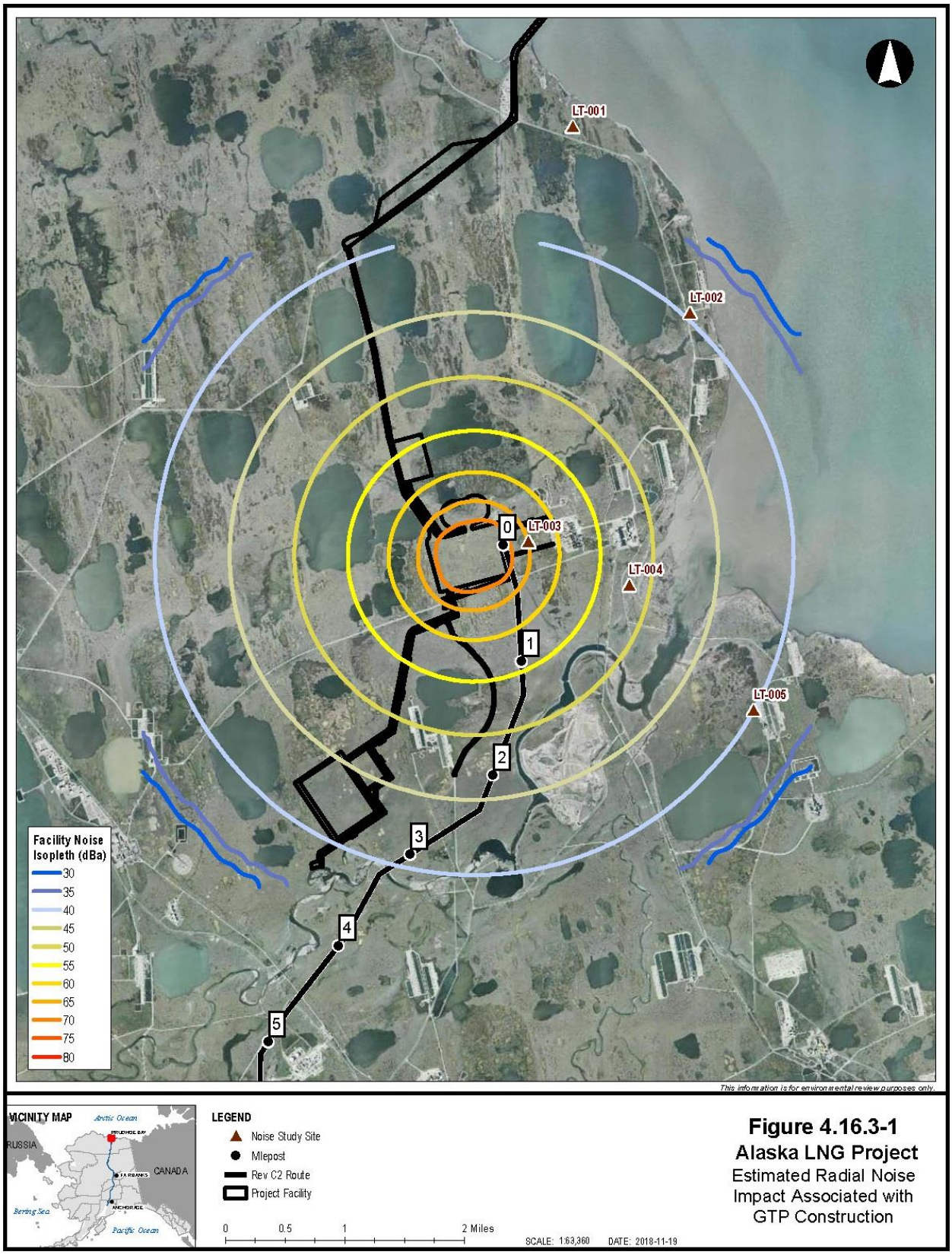


Figure 4.16.3-1
Alaska LNG Project
Estimated Radial Noise Impact Associated with GTP Construction

Gravel Mine and Water Reservoir

Construction of the gravel mine and water reservoir would require blasting. Blasting would generate temporary noise near the blasting sites. AGDC has indicated that blasting would occur only during daytime hours (i.e., 7:00 a.m. to 10:00 p.m.). No NSAs have been identified within 1 mile of the gravel mine or water reservoir, but blasting could affect wildlife and subsistence practices near these facilities. Potential impacts of the noise generated from blasting activities on wildlife are addressed in section 4.6.

Once construction of the gravel mine is complete, it would be operated during construction of the Gas Treatment Facilities. The gravel mine would be approximately 700 feet from the existing Put-23 Mine. The noise generated by the new gravel mine associated with the Project would be similar in nature to the existing noise associated with the operation of the Put-23 Mine. Noise levels near the gravel mine would increase during the operation of the mine. The water reservoir would be used during construction as well as during operation. It would be anticipated that minimal noise would be generated from the operation of the water reservoir.

PTTL and PBTL

The PTTL would include a meter station to be installed at the PTU concurrently with construction of the pipeline. The PBTL would not involve aboveground facilities (other than the pipeline, which would be aboveground). Noise associated with construction of the PTTL and PBTL pipelines would be short term and temporary at any given location because of the transient nature of pipeline installation. The pipelines would be installed over the course of one winter construction season and would be hydrostatically tested during the next construction season. While the noise levels attributable to construction equipment could noticeably increase ambient noise levels near the workspace, this noise would be temporary and localized. The existing ambient noise at the PTTL and PBTL includes operational noise from current PTU and PBU operation, which include natural gas liquids extraction and transport. No NSAs were identified within 1 mile of the meter station associated with the PTTL. Construction activities for the PTTL and PBTL would result in temporary increases to ambient sound levels near the area, which could temporarily effect wildlife and subsistence practices. AGDC has estimated that noise generated by construction would be approximately 72.5 dBA at 100 feet from the noise generating activities.

4.16.3.2 Mainline Facilities

Mainline Pipeline

Construction noise associated with the Mainline Pipeline would be temporary and spread over the length of the pipeline route. It would not be concentrated at any one location for an extended period of time, with the exception of DMT installation locations and air transportation to Project sites. Noise associated with these activities is discussed below. The Mainline Pipeline would be trenched, buried, and/or directly laid on the seafloor across Cook Inlet. Additionally, an MOF would be constructed on the eastern shore of Cook Inlet. Construction of these facilities would generate both aboveground and underwater noise. Aboveground noise impacts would be similar to general pipeline construction impacts. Underwater noise impacts associated with these activities are further discussed in section 4.16.3.3. Construction crews would typically work 6 days per week during daylight hours, which could be between 7:00 a.m. and 10:00 p.m., depending on the season. AGDC has estimated that the Mainline Facilities would require approximately 4 years to construct.

Directional Micro-tunneling

Five DMT river crossings are planned. Noise impact assessments were completed for the Yukon River, Tanana River, and Chulitna River DMT sites, each of which has NSAs within 1 mile of the drilling

locations. Because no NSAs were identified within 1 mile of the Middle Fork Koyukuk River and Deshka River crossings, background noise surveys were not completed for these crossings.

Total equipment sound power levels (SPL) at exit sites were used to calculate the SPL at nearby NSAs, assuming simultaneous operation of the entry and exit sites. The assessment assumes a worst-case condition that all of the equipment would be operated continuously, including during the nighttime hours of 10:00 p.m. to 7:00 a.m. Predicted sound levels for the crossing locations are shown in table 4.16.3-1, as provided in AGDC's *Baseline Noise Level Report* for the Mainline Pipeline.[133]

TABLE 4.16.3-1

Predicted Sound Levels at Noise Sensitive Areas from Construction – Potential Directional Micro-tunneling Locations

DMT Crossing / Milepost	Noise Sensitive Area	Distance (feet) / Direction from Station	Existing Ambient L_{dn} (dBA)	Predicted DMT Sound Contribution L_{dn} (dBA)	Ambient + Construction L_{dn} (dBA) [a]	Predicted Increase in Ambient Noise Level (dB)
Yukon River (exit) / MP 356.2	1	150 / west	46	53.9	54.6	8.6
Tanana River (entry) / MP 472.7	1	1,400 / northwest	55	44.6	55.4	0.4
Tanana River (exit) / MP 473.3	1	3,390 / east	58	34.2	58.0	0
Chulitna River (exit) / MP 641.4	1	5,200 / southeast	61	33.4	61.0	0

[a] Noise levels are summed logarithmically; therefore, the predicted ambient noise level at the NSAs during crossing activities would not be the sum of the two noise levels.

Based on the estimates presented in table 4.16.3-1, noise generated by DMT activities would be less than 55 dBA L_{dn} at NSAs within 1 mile of the DMT drill entry and exit locations. Noise generated by DMT activities at the Yukon River DMT exit location would likely be perceptible at the nearest NSA. Noise generated by DMT activities at the Tanana River DMT entry and exit locations and the Chulitna River DMT exit location could be perceptible at the nearby NSAs, but would not noticeably increase the existing noise levels.

While the Middle Fork Koyukuk and Deshka River DMTs would not be near NSAs, the noise generated by these DMTs would increase the existing background sound levels near the crossing locations. Due to the Middle Fork Koyukuk River DMT crossing near the Dalton Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Due to the remote location of the Deshka River DMT crossing, AGDC estimated that ambient sound levels would be less than 40 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Based on noise modeling completed by AGDC, sound levels associated with the Middle Fork Koyukuk River crossing would be at or near existing background noise levels within about 0.25 mile of the DMT entrance and exit sites, and sound levels associated with the Deshka River crossing would be at or near existing background noise levels within about 0.3 mile of the DMT entrance and exit sites.

[133] AGDC's *Baseline Noise Level Report* for the Mainline Pipeline was included as appendix O (Accession No. 20170417-5345) to Resource Report 9, available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5345 in the "Numbers: Accession Number" field.

Several KOPs are near the DMT locations. Noise associated with DMT activities has the potential to affect sound levels at the nearby KOPs, which could affect the user experience at these locations. Additional information on KOPs is provided in section 4.10.1 and table 4.10.1-4.

KOPs 12 (Yukon River Camp) and 13 (Yukon River) are near the Yukon River DMT site. KOPs 12 and 13 are farther from the Yukon River DMT exit site than NSA 1, by about 3,900 and 4,100 feet, respectively. AGDC did not collect ambient sound levels at KOPs 12 and 13. Based on their proximity to the Dalton Highway, ambient sound levels at the KOPs would be anticipated to be at or higher than the ambient levels measured at NSA 1 (see table 4.16.3-1). Because these KOPs would be greater than 0.5 mile from the DMT sites, noise levels associated with drilling activities would be anticipated to be at or near ambient sound levels, which could be perceptible, but would not noticeably increase the existing noise levels at the KOPs.

KOPs 19 (Tanana River – North) and 20 (Tanana River – South) are near the Tanana River DMT entrance site. KOPs 19 and 20 are closer to the Tanana River DMT entrance site than NSA 1 by about 170 and 900 feet, respectively. AGDC did not collect ambient sound levels at KOPs 19 and 20. Based on their proximity to the George Parks Highway, ambient sound levels at the KOPs would be anticipated to be at or higher than the ambient levels measured at NSA 1 (see table 4.16.3-1). Because these KOPs would be closer to the Tanana River DMT entrance site than NSA 1, noise levels associated with drilling activities would be anticipated to be higher than the estimated noise as NSA 1. Due to the elevated ambient sound levels in this area, noise associated with drilling activities is anticipated to be at or near ambient sound levels at KOPs 19 and 20; the noise could be perceptible, but would not noticeably increase the existing noise levels at the KOPs.

KOPs 21 and 22 (Nenana City School [northwest and southwest views]) are near the Tanana River DMT exit site. KOPs 21 and 22 are farther from the Tanana River DMT exit location than NSA 1 by about 4,500 feet. AGDC did not collect ambient sound levels at KOPs 21 and 22. Based on their proximity to the George Parks Highway, ambient sound levels at the KOPs would be anticipated to be similar to the levels recorded at NSA 1 (see table 4.16.3-1). Because KOPs 21 and 22 would be greater than 1 mile from the DMT site, noise levels associated with drilling activities could be perceptible at the KOPs, but would not noticeably increase the existing noise levels at these sites.

KOPs O (Upper Troublesome Creek Trailhead) and P (Lower Troublesome Creek Trailhead) are near the Chulitna River DMT exit site. KOPs O and P are closer to the Chulitna River DMT exit location than NSA 1 by about 3,200 and 4,900 feet, respectively. AGDC did not collect ambient sound levels at KOPs O and P. Based on their proximity to the George Parks Highway, ambient sound levels at the KOPs would be anticipated to be at or higher than the ambient levels measured at NSA 1 (see table 4.16.3-1). Because KOPs O and P would be near the DMT exit site, noise levels associated with drilling activities would likely be clearly perceptible, and could increase the existing noise levels at the KOPs.

Based on our assessment, DMT activities could have a temporary impact on KOPs due to the temporary increased noise levels, but the noise levels would return to pre-construction levels once the DMT is complete.

As discussed in section 4.3.3.3, AGDC would incorporate the use of the DMT continuation methodology for the proposed shoreline crossings at Beluga Landing and Suneva Lake if feasible.[134]

[134] A preliminary feasibility assessment of the DMT continuation method concluded that the Beluga Landing approach has a 90-percent probability of success, while the Suneva Lake approach has a 75-percent probability of success.

Because AGDC has not identified NSAs or provided an analysis of noise impacts on NSAs in the vicinity of the shoreline crossings, **we recommend that:**

- **If the DMT continuation methodology is used for the proposed shoreline crossings at Beluga Landing and Suneva Lake, then prior to construction of the Mainline Facilities, AGDC should file with the Secretary noise impact calculations for any NSAs within 1 mile of these sites to reflect use of the DMT continuation methodology. If the noise impact estimates would result in noise attributable to DMT continuation activities greater than 55 dBA L_{dn} at any of the NSAs, AGDC should include proposed mitigation measures, for the review and written approval by the Director of the OEP, to ensure the estimated noise attributable to the DMT continuation activities is below 55 dBA L_{dn}.**

Blasting

Construction of the pipeline would require blasting in areas of shallow bedrock or frozen soil to excavate the pipeline trench. Blasting would generate temporary noise near the blasting sites. AGDC has indicated that blasting would occur only during daytime hours (i.e., 7:00 a.m. to 10:00 p.m.). Where blasting would occur near NSAs, the potential exists for blasting to be audible at the NSAs. Due to the temporary nature and short duration of blasting, as well as the fact that blasting would occur during daytime hours, the noise associated with blasting activities would have a minor impact on NSAs within 0.5 mile of the blast area.

Blasting would be required at the material extraction sites. Where the Project would use existing material sites, no new NSAs would be affected by blasting activities because blasting currently occurs at these locations. Where the Project would install new material sites, blasting could result in noise impacts on nearby NSAs. Due to the temporary nature and duration of blasting, as well as the fact that blasting would occur during daytime hours, the noise associated with blasting activities would have a minor impact on NSAs within 0.5 mile of the blast area.

The potential for blasting to affect subsistence practices was evaluated. AGDC identified 11 subsistence use areas within 0.5 mile of blasting sites for the Mainline Pipeline. Of those subsistence use areas, blasting has the greatest potential to affect the Wiseman and Cantwell subsistence use areas due to the amount of blasting due to the shallow bedrock required in these areas and the multiple overlapping subsistence use resources potentially affected by temporary noise increases. Potential impacts of the noise generated from blasting activities on wildlife are addressed in section 4.6.

AGDC has proposed several mitigation measures to minimize the impacts of blasting on the Wiseman and Cantwell subsistence use areas, including restricting blasting activities during sensitive life stages of wildlife (e.g., nesting or denning), restricting blasting during subsistence hunting periods, using blasting mats or pads for containing noise, and monitoring nests and denning locations during blasting operations. To minimize impacts on subsistence uses, AGDC would also employ local subsistence representatives from communities along the Project route during construction to facilitate communication between local residents and AGDC. With the implementation of these mitigation measures, the potential impacts of blasting noise on subsistence uses would be temporary and minor.

Air Traffic

Construction of the Mainline Facilities would require air traffic to deliver employees and equipment to remote locations. While AGDC has indicated that no new temporary or permanent air strips would be added in support of the Project, a total of 48 helipads would be installed and used along the Mainline

Pipeline; 28 helipads would be maintained for operational use following construction. AGDC has estimated that Project construction would generate an average of one helicopter flight per day for each of the Project's construction camps, with a peak of six helicopter flights per day to any single construction camp. There would be no regular helicopter trips to MLVs or compressor or heater stations during construction.

Because the Project would increase the volume of air traffic to the existing air strips planned to support the Project, the potential exists for increased noise at these existing air strips. In addition, temporary noise would be generated by helicopter traffic at the new helipads. Noise impacts from use of the air strips and helipads could affect wildlife and subsistence uses. These impacts are addressed in sections 4.6 and 4.14, respectively. We additionally note that the BLM's Resource Management Plan has altitude restrictions for air traffic associated with BLM-permitted activities.

Underwater Noise Impacts from Construction

About 27.3 miles of the Mainline Pipeline would be installed on the Cook Inlet seabed. These activities would require anchor handling to install the pipeline. Underwater noise would be generated during installation. Further details regarding the estimated noise impacts and proposed mitigation measures for marine mammals and fish are provided in sections 4.6.3 and 4.7.1, respectively, and appendix L-1.

Aboveground Facilities

Construction noise associated with installation of the compressor stations and heater station would be concentrated near each site and would extend for the duration of the construction activity, but would vary depending on the specific activities taking place at any given time. Construction of the eight compressor stations, heater station, and two meter stations would occur over about a 3-year construction period. The meter station sites would be collocated with the GTP and LNG Plant and are discussed relative to those facilities. Each meter station would be constructed in about 12 months. Additional noise would be generated at MLV sites, which would each require about 3 months to complete, and from air and ground vehicle traffic associated with equipment delivery and workers traveling to the Mainline Facilities. Construction crews would typically work 6 days per week during daylight hours, which would be between 7:00 a.m. and 10:00 p.m. depending on the season.

Each of the compressor station and heater station sites was assessed for proximity to NSAs. The Coldfoot and Healy Compressor Stations are the only aboveground facilities along the Mainline Pipeline with NSAs identified within 1 mile of the facilities. AGDC completed background noise surveys for these facilities and estimated noise levels at the nearby NSAs for construction and operation. Although traditional NSAs, as described in section 4.16, would not be near other aboveground facilities along the Mainline Pipeline route, construction of these facilities would generate noise above background noise levels and would have an impact on the surrounding environment. The proximity of each compressor station and heater station to sensitive federally managed lands, such as national parks, is presented on figure 4.15.3-1. Potential impacts of facility construction on nearby NSAs and the surrounding environment are summarized below.

Compressor Stations/Heater Station

Construction of the compressor stations and heater station would produce variable noise levels, depending on the work taking place at any given time. Major noise-generating sources during construction would include clearing and grading associated with site preparation; materials and equipment delivery; installation of the facility foundations (e.g., pile driving); and construction of compression/heating equipment and buildings. Table 4.16.3-2 summarizes the estimated background sound levels at each compressor/heater station, the proximity of NSAs to each compressor/heater station site, and the estimated distance from the compressor/heater station site where construction noise would be at or near background sound levels.

Potential impacts of the noise generated from construction of the compressor stations and heater station on wildlife and subsistence uses are addressed in sections 4.6 and 4.14, respectively. As presented in table 4.16.3-2, the noise associated with construction of the compressor stations and heater station could increase sound levels at distances up to 1 mile from the construction location, which could affect wildlife and subsistence uses. Construction noise could be audible at distances greater than 1 mile, but at that distance, the noise attributable to construction activities would be at or near the existing background levels.

AGDC completed site-specific noise analyses for the Coldfoot and Healy Compressor Stations to analyze construction noise impacts on NSAs identified within 1 mile of the facilities. The results of these analyses are summarized below.

Coldfoot Compressor Station

Construction of the Coldfoot Compressor Station would produce variable noise levels, depending on the work taking place at that time. AGDC performed modeling to calculate noise levels that would be generated by construction of the Coldfoot Compressor Station. The noise model included construction equipment that AGDC anticipates would be needed during the construction process, including cranes, dump trucks, skip loaders, bull dozers, excavators, backhoes, forklifts, ATV, compressors, welding machines, generators, pile drivers, and other ancillary equipment.

TABLE 4.16.3-2

Compressor Station / Heater Station Construction Noise Analysis

Compressor Station	Estimated Background Sound Level (dBA L_{dn})	Noise Sensitive Area Within 1 Mile?	Estimated Distance Where Construction Noise is at Background Levels (miles)
Sagwon Compressor Station	41–64 [a]	No	0.5
Galbraith Lake Compressor Station	41–64 [a]	No	0.5
Coldfoot Compressor Station	47 [b]	Yes	NA
Ray River Compressor Station	41–64 [a]	No	0.5
Minto Compressor Station	<40 [c]	No	0.6–1.0
Healy Compressor Station	52	Yes	NA
Honolulu Creek Compressor Station	41–64 [d]	No	0.5
Rabideux Creek Compressor Station	41–64	No	0.5
Theodore River Heater Station	40 [c]	No	0.6–1.0

NA = Not available. A site-specific noise analysis was completed for NSAs near the Coldfoot and Healy Compressor Stations.

[a] Background sound levels estimated based on proximity to the Dalton Highway.

[b] Background sound levels based on noise survey.

[c] Background sound levels estimated based on ambient sound levels collected at other representative locations in the Project area.

[d] Background sound levels estimated based on proximity to the Parks Highway.

Table 4.16.3-3 presents the results of the noise modeling, along with a comparison to the existing ambient noise levels, the expected future noise level after adding the construction noise to the ambient noise levels, and the increase in ambient level as a result of the construction noise. One NSA (a residence) is within about a 1-mile radius of the facility site. The NSA near Coldfoot Compressor Station is presented on figure 4.16.3-2.

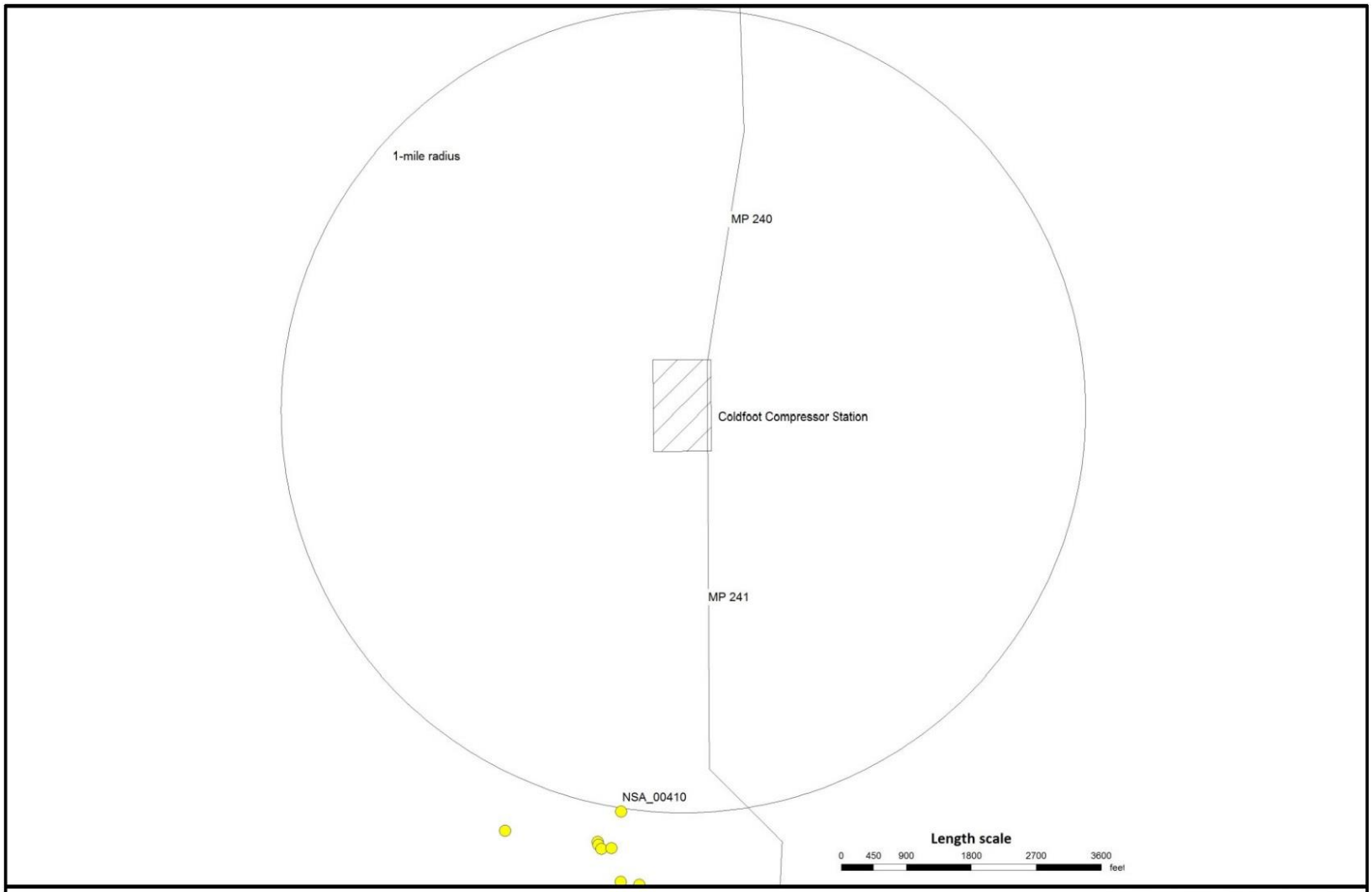


Figure 4.16.3-2
Alaska LNG Project
Coldfoot Compressor Station
Noise Sensitive Areas

APRIL 14, 2017

TABLE 4.16.3-3

Coldfoot Compressor Station Construction – Noise Levels at Nearby Noise Sensitive Area

Noise Sensitive Area	Distance / Direction from Station (feet)	Existing Ambient L_{dn} (dBA)	Predicted Construction Contribution L_{dn} (dBA)	Ambient + Construction L_{dn} (dBA) [a]	Predicted Increase in Ambient Noise Level (dB)
1	5,525 / south–southwest	47.0	50.3	52.0	5.0

[a] SPLs are summed logarithmically; therefore, the predicted ambient noise level at the NSAs during construction of the Coldfoot Compressor Station would not be the sum of the two noise levels.

Based on the estimates presented in table 4.16.3-3, noise generated by construction of the Coldfoot Compressor Station would likely be perceptible at the nearby NSA. There are additional residences beyond NSA 1, but noise attributable to the station at these NSAs would be less than the predicted noise levels at NSA 1. Therefore, the noise attributable to construction activities could be perceptible at these NSAs, but would not noticeably increase the existing noise levels at the nearby NSAs.

The results of the noise impact analysis indicate that the noise attributable to operation of the Coldfoot Compressor Station would be in compliance with FERC's sound level guidance of 55 dBA L_{dn} at the nearest NSA (see section 4.16.4). In addition to impacts on NSAs, construction noise at the Coldfoot Compressor Station would affect the surrounding environment. Potential impacts of the noise generated from Coldfoot Compressor Station construction on wildlife and subsistence practices are addressed in sections 4.6 and 4.14, respectively.

Healy Compressor Station

AGDC performed noise modeling to calculate noise levels that would be generated by construction of the Healy Compressor Station. Table 4.16.3-4 presents the results of the noise modeling, along with a comparison with the existing ambient noise levels, the expected future noise level after adding the construction noise to the ambient noise levels, and the increase in ambient level as a result of the construction noise. One NSA (a residence) is within about a 1-mile radius of the compressor station. The NSA is presented on figure 4.16.3-3.

Based on the estimates presented in table 4.16.3-4, noise generated by construction of the Healy Compressor Station would likely be perceptible at the nearby NSA. The results of the analysis indicate that the noise attributable to the Healy Compressor Station construction would exceed 55 dBA L_{dn} at the nearby NSA. Based on comments received from the NPS, we updated table 4.16.3-4 to include the equivalent sound level exceeded 50 percent of the time (L_{50}), which is used by the NPS for development management policies. The noise impacts would be moderate to high during construction.

TABLE 4.16.3-4

Healy Compressor Station Construction – Noise Levels at Nearby Noise Sensitive Areas

Noise Sensitive Area	Distance / Direction from Station (feet)	Existing Ambient L_{50} (dBA)	Existing Ambient L_{dn} (dBA)	Predicted Construction Contribution L_d (dBA)	Predicted Construction Contribution L_n (dBA)	Predicted Construction Contribution L_{dn} (dBA)	Predicted Increase in L_{50} Noise Level (dB) – Daytime	Predicted Increase in L_{50} Noise Level (dB) – Nighttime	Predicted Increase in L_{dn} Noise Level (dB)
1	2,885 / northwest	41.0	52.0	57.5	54.5	61.5	16.6	13.7	10.0

L_d = daytime sound level; L_n = nighttime sound level

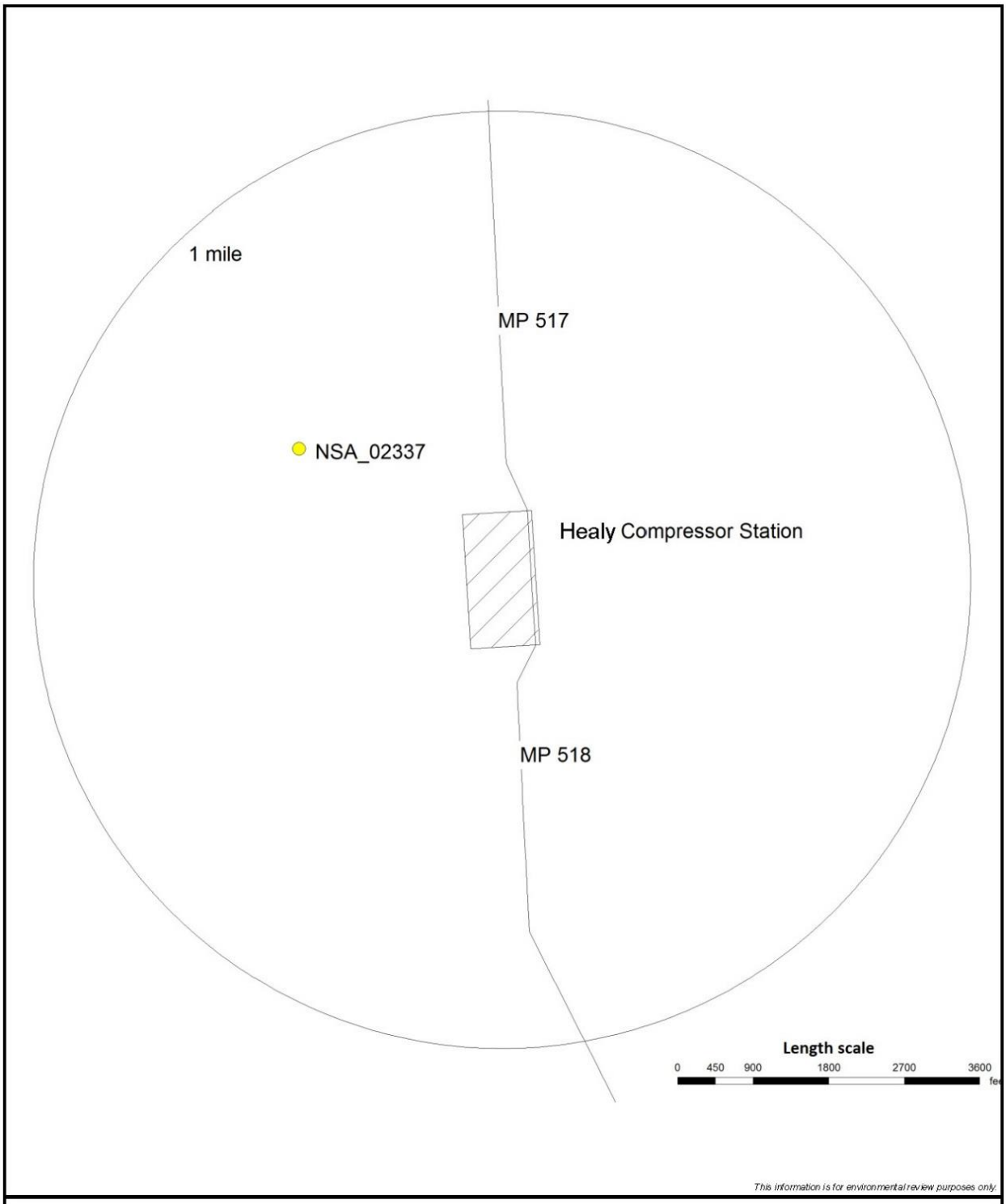


Figure 4.16.3-3
Alaska LNG Project
Healy Compressor Station
Noise Sensitive Areas

APRIL 14, 2017

In addition to impacts on NSAs, noise generated by the Healy Compressor Station construction would affect the surrounding environment. Potential impacts of the noise generated from construction of the Healy Compressor Station on wildlife and subsistence uses are addressed in sections 4.6 and 4.14, respectively.

4.16.3.3 Liquefaction Facilities

Construction activities at the Liquefaction Facilities would generate increases in sound levels over a total of 81 months (6 years and 9 months). Construction activities would occur during the day between 7:00 a.m. and 7:00 p.m., Monday through Saturday, with the exception of dredging, which could occur up to 24 hours per day, 6 days per week.

To assess noise impacts associated with construction of the Liquefaction Facilities, AGDC modeled construction noise during the site grading phase, foundation preparation phase, equipment installation phase, and the finishing phase. The most prevalent sound-generating equipment and activity during construction of the Liquefaction Facilities is anticipated to be pile driving, although internal combustion engines associated with general construction equipment and dredging would also produce sound levels that would be perceptible near the site. The Nikiski Meter Station would be collocated with the LNG Plant, but noise associated with construction of the meter station would be insignificant compared to the larger LNG Plant. The estimated worst-case noise levels associated with the Liquefaction Facilities construction on nearby NSAs are shown in table 4.16.3-5. The locations of the NSAs relative to the Liquefaction Facilities are depicted on figure 4.16.3-4.

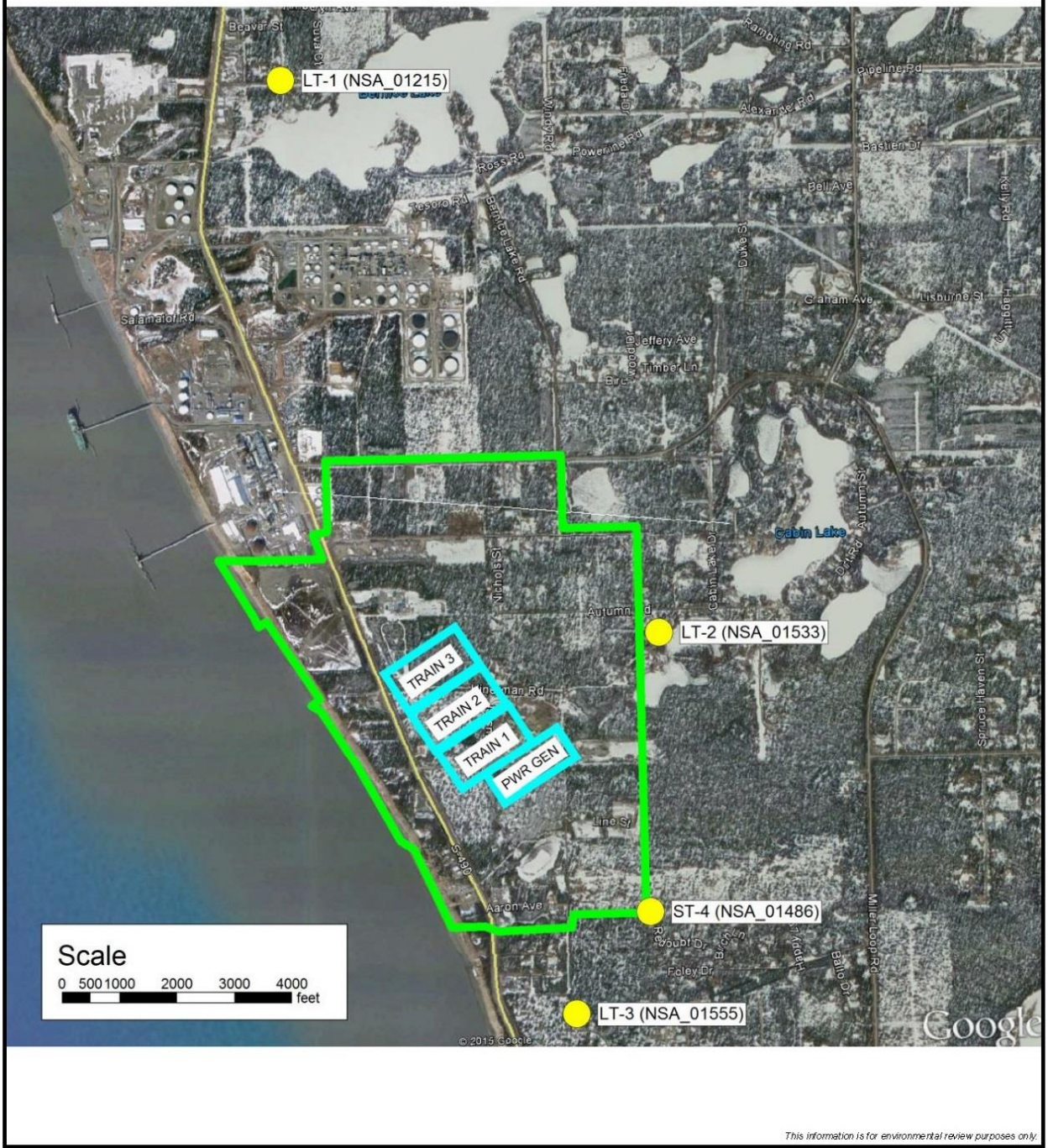
TABLE 4.16.3-5

Construction Noise Impacts on Noise Sensitive Areas Surrounding the Liquefaction Facilities

Noise Sensitive Area	Distance to Noise Sensitive Area (feet)	Direction to Noise Sensitive Area	Existing Ambient L_{dn} (dBA)	Predicted Sound Levels Associated with LNG Plant Construction L_{dn} (dBA)	Construction L_{dn} + Ambient L_{dn} (dBA)	Potential Increase Above Baseline Ambient (dB)
1	3,700	E	43	67.1	67.1	24.1
2	5,700	SE	39	65.5	65.5	26.5
3	6,600	S	48	63.6	63.7	15.7
4	10,500	NW	51	53.5	55.4	1.4

The results of the noise impact analysis indicate that the noise attributable to construction of the Liquefaction Facilities would exceed FERC's sound level guidance of 55 dBA L_{dn} at the nearest NSAs. The estimated noise associated with Liquefaction Facilities construction would range from 55.4 to 67.1 dBA L_{dn} at the nearby NSAs, which would correspond to noise increases at the NSAs ranging from 1.4 to 26.5 dB. The construction noise would likely be inaudible at NSA 4, but audible at NSAs 1, 2, and 3.

KOP 54 (Mt. Redoubt Church) is about 4,900 feet from the Liquefaction Facilities. AGDC did not collect ambient sound levels at KOP 54, but ambient sound levels would be anticipated to be similar to those measured at NSAs 1 and 2 (see table 4.16.3-5). During construction, AGDC estimated that noise levels at KOP 54 would increase between 24.1 and 26.5 dBA, which would be clearly perceptible.



This information is for environmental review purposes only.

Figure 4.16.3-4
Alaska LNG Project
Liquefaction Facilities Noise Sensitive Areas

APRIL 14, 2017

AGDC has identified several potential noise mitigation measures to lower the noise associated with construction of the Liquefaction Facilities between 10 and 15 dB, but AGDC has not yet committed to implementing these measures. To ensure construction noise is mitigated to the extent possible, prior to construction of the Liquefaction Facilities, AGDC would file with the Secretary, for the review and written approval of the Director of the OEP, a detailed construction Noise Mitigation Plan for the Liquefaction Facilities that includes the noise mitigation measures that AGDC would implement at the construction site. The Noise Mitigation Plan would include the predicted noise attributable to construction activities at the nearby NSA after implementing the additional mitigation showing at least a 10-dB reduction in noise levels at the NSA, a noise monitoring plan during construction, and a procedure for resolving noise complaints.

The Marine Terminal and Mainline MOF construction, particularly pile driving and dredging, would result in the generation and propagation of underwater noise energy. AGDC estimated Project facility pile driving and dredging activities based on the facilities to be installed. Construction of the Marine Terminal, including a temporary MOF, would occur during Years 1 and 2 during the ice-free season. Construction crews would work 12 hours per day, 6 days per week for normal construction activities. Mainline MOF construction would occur during Year 2.

Because pile driving would be an intermittent activity, occurring about 25 percent of the time, the noise impact would not be continuous. Project activities would require the use of both impact and vibratory hammers, which generate different underwater noise levels that have been estimated separately. Further details regarding the estimated quantity of piles to be installed at the Marine Terminal, which includes both standard piles and sheet piles, along with the sound levels for the two types of pile driving, are presented in appendix L-1. The Marine Terminal MOF and Mainline MOF would require pile driving in Years 1 and 2, and the Marine Terminal PLF would require pile driving in Years 3, 4, and 5.

Dredging activities associated with Marine Terminal MOF and Mainline MOF construction would occur during Years 1 and 2. The Marine Terminal PLF would not require dredging. Maintenance dredging for the Marine Terminal MOF would occur during Years 3 and 4. Dredging would occur throughout the construction season, and could occur 24 hours per day. Sound levels for various activities associated with dredging are presented in appendix L-1.

Further details regarding the estimated noise impacts and proposed mitigation measures for marine mammals and fish are provided in sections 4.6.3 and 4.7.1, respectively, and appendix L-1.

4.16.4 Operational Noise Impacts and Mitigation

4.16.4.1 Gas Treatment Facilities

Operation of the GTP would produce noise on a continual basis. While no NSAs were identified within 1 mile of the site, the Gas Treatment Facilities' operation would contribute to noise levels in the vicinity, which could affect wildlife. Background sound levels for the GTP were assessed for the Alaska Pipeline Project and found to be about 66 dBA L_{dn} near the GTP, and at levels ranging from 52 to 57 dBA L_{dn} within 2 to 4 miles from the GTP (TransCanada, 2017). AGDC estimated that GTP operation would result in sound levels at or near background conditions at the facility site. The PTU Meter Station would be collocated with the GTP, but noise associated with operation of the meter station would be insignificant compared to the larger components of the GTP. There would be minimal noise associated with operation of the PTTL and PBTL. No NSAs were identified within 1 mile of the meter station along the PTTL.

Figure 4.16.4-1 provides the estimated radial noise impact associated with GTP operation on the surrounding area. Sound levels from GTP operation would be at or near existing background sound levels within about 0.5 mile of the GTP.

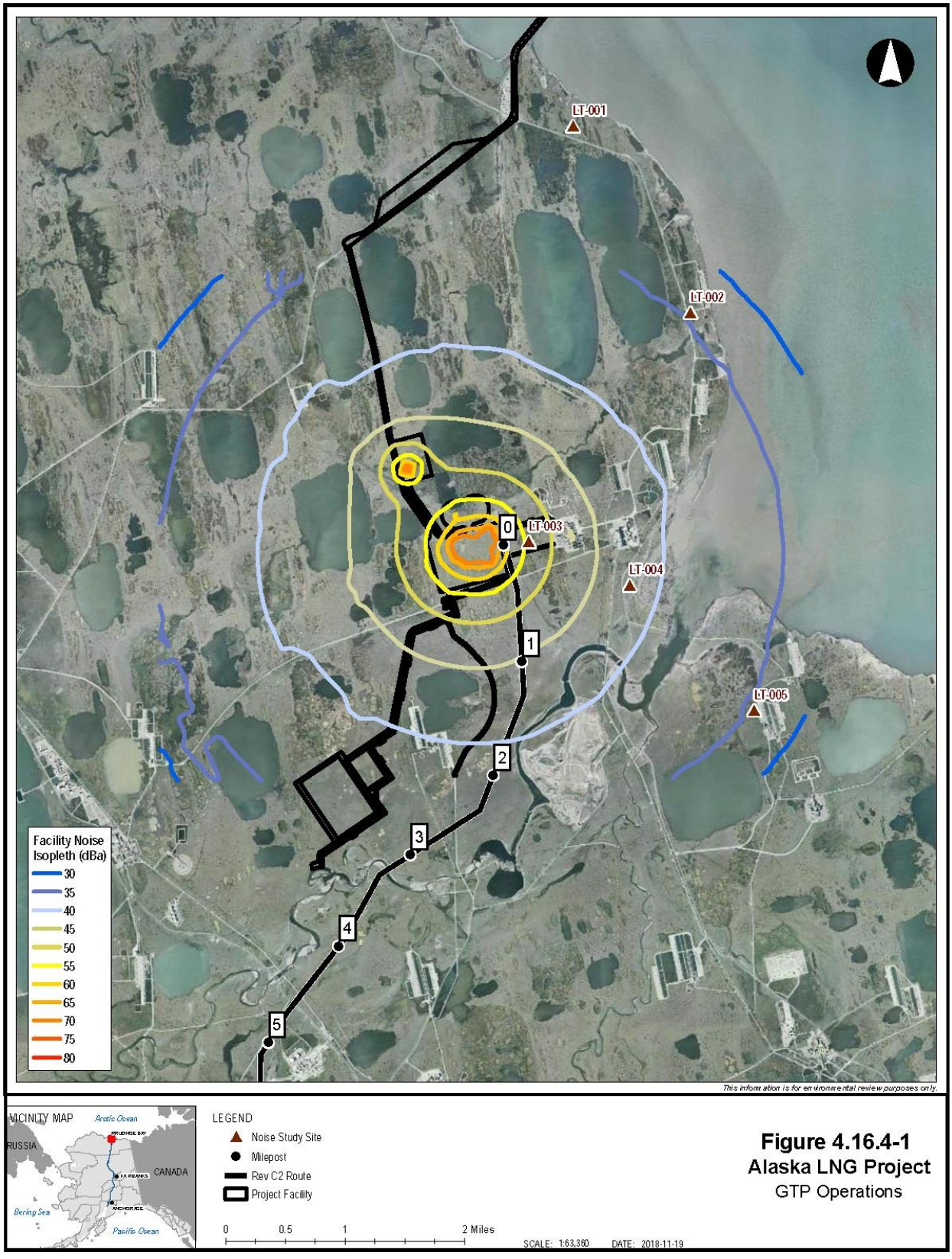


Figure 4.16.4-1
Alaska LNG Project
GTP Operations

4.16.4.2 Mainline Facilities

The primary source of operational noise associated with Mainline Facilities operation would be from the aboveground facilities (i.e., compressor stations, heater station, meter stations, and MLVs). Additional noise would be generated on an intermittent basis due to periodic blowdowns, as well as air and ground vehicle traffic associated with the delivery of equipment and workers to the pipeline facilities for maintenance or repairs. As previously noted, permanent helipads would be installed at the compressor station sites, the heater station site, and the MLV sites along the Mainline Pipeline.

Aboveground Facilities

AGDC evaluated each of the compressor and heater station sites for proximity to NSAs. Because the meter stations would be collocated with the GTP and Liquefaction Facilities, noise impacts on NSAs from operation of these facilities are included in section 4.16.4. The Coldfoot and Healy Compressor stations are the major aboveground facilities along the Mainline Pipeline with NSAs identified within 1 mile of the facility. Background noise surveys were completed for these facilities, and noise levels at the nearby NSAs due to operation of the compressor stations were estimated. Although traditional NSAs, as described in section 4.16, would not be near the other aboveground facilities along the Mainline Pipeline route, operation of these facilities would generate noise on a continuous basis and would have an impact on the surrounding environment. The potential effects of operation of these facilities on the surrounding environment are summarized below. Potential impacts of the noise generated from operation of the compressor stations and heater station on wildlife and subsistence practices are addressed in sections 4.6 and 4.14, respectively.

Sagwon Compressor Station

The Sagwon Compressor Station would include the following major noise-generating equipment:

- three gas turbine-driven centrifugal natural gas compressor units with a total capacity of 68,000 hp;
- four power generators;
- two auxiliary utility glycol heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor units.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Sagwon Compressor Station were not measured. Due to the facility location adjacent to the Dalton Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-2 provides the estimated radial noise impact associated with the Sagwon Compressor Station operation on the surrounding area. Sound levels would be at or near existing background sound levels within about 0.5 mile.

Galbraith Lake Compressor Station

The Galbraith Compressor Station would include the following major noise-generating equipment:

- one 42,000-hp gas turbine-driven centrifugal natural gas compressor unit;
- three power generators;
- two auxiliary utility glycol heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Galbraith Lake Compressor Station were not measured. Due to the facility location adjacent to the

Dalton Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-3 provides the estimated radial noise impact from operation of the Galbraith Lake Compressor Station operation on the surrounding area. Sound levels would be at or near existing background sound levels within about 0.5 mile.

Coldfoot Compressor Station

AGDC performed modeling to calculate noise levels that would be generated by the Coldfoot Compressor Station operation. The following noise-generating equipment was included in the noise model, which incorporates noise mitigation and design measures that would decrease noise levels:

- 42,000-hp gas turbine-driven centrifugal natural gas compressor unit installed within a pre-engineered metal building;
- natural gas-fired turbine air intake and exhaust system, with in-line silencer on the exhaust;
- one lube oil cooler for the natural gas compressor unit;
- aboveground intake and exhaust piping servicing the natural gas compressor unit;
- four air-cooled heat exchanger banks, each with 12 individual axial fan/drive systems; and
- three electrical generators each driven by a reciprocating engine (1,680 hp).

One NSA (a residence) is within about a 1-mile radius of the facility site. The NSA near the facility is presented on figure 4.16.3-2. Table 4.16.4-1 presents the noise modeling results along with a comparison with the existing ambient level, the expected future noise level after adding the facility noise to the ambient sound level, and the increase in the ambient sound level as a result of adding the facility.

TABLE 4.16.4-1

Coldfoot Compressor Station Operation – Noise Levels at Nearby Noise Sensitive Area

Noise Sensitive Area	Distance / Direction from Station (feet)	Existing Ambient L_{dn} (dBA)	Predicted Compressor Station Contribution L_{dn} (dBA)	Ambient + Compressor Station L_{dn} (dBA) [a]	Predicted Increase in Ambient Noise Level (dB)
1	5,770 / south–southwest	47	40.7	47.9	0.9

[a] SPLs were measured on a logarithmic scale; therefore, the predicted increase in ambient noise level at the NSAs during the Coldfoot Compressor Station operation would not be the sum of the two noise levels.

Based on the estimates presented in table 4.16.4-1, noise generated by the Coldfoot Compressor Station operation would likely be perceptible, but would not noticeably increase the existing noise levels at the nearby NSA. Figure 4.16.4-4 provides the estimated radial noise impact associated with operation of the Coldfoot Compressor Station on the surrounding area. Sound levels would be at or near existing background levels within about 0.5 mile.

Operation of the Coldfoot Compressor Station has the potential to affect noise levels at the nearby Arctic Interagency Visitor Center. AGDC estimated that noise attributable to operation of the compressor station would be about 50 dBA L_{dn}, which is about 2 dB higher than estimated ambient sound levels at the Visitor Center. Based on this assessment, noise associated with operation of the Coldfoot Compressor Station would have a minor impact on sound levels at the Visitor Center.

AGDC also evaluated the potential for the Coldfoot Compressor Station operation to result in perceptible vibration at the nearby NSA. Based on AGDC's analysis, vibration associated with operation of the compressor station would be controlled to a level that would ensure the vibration would not be perceptible at the nearby NSA. We have reviewed AGDC's analysis and agree with this conclusion.

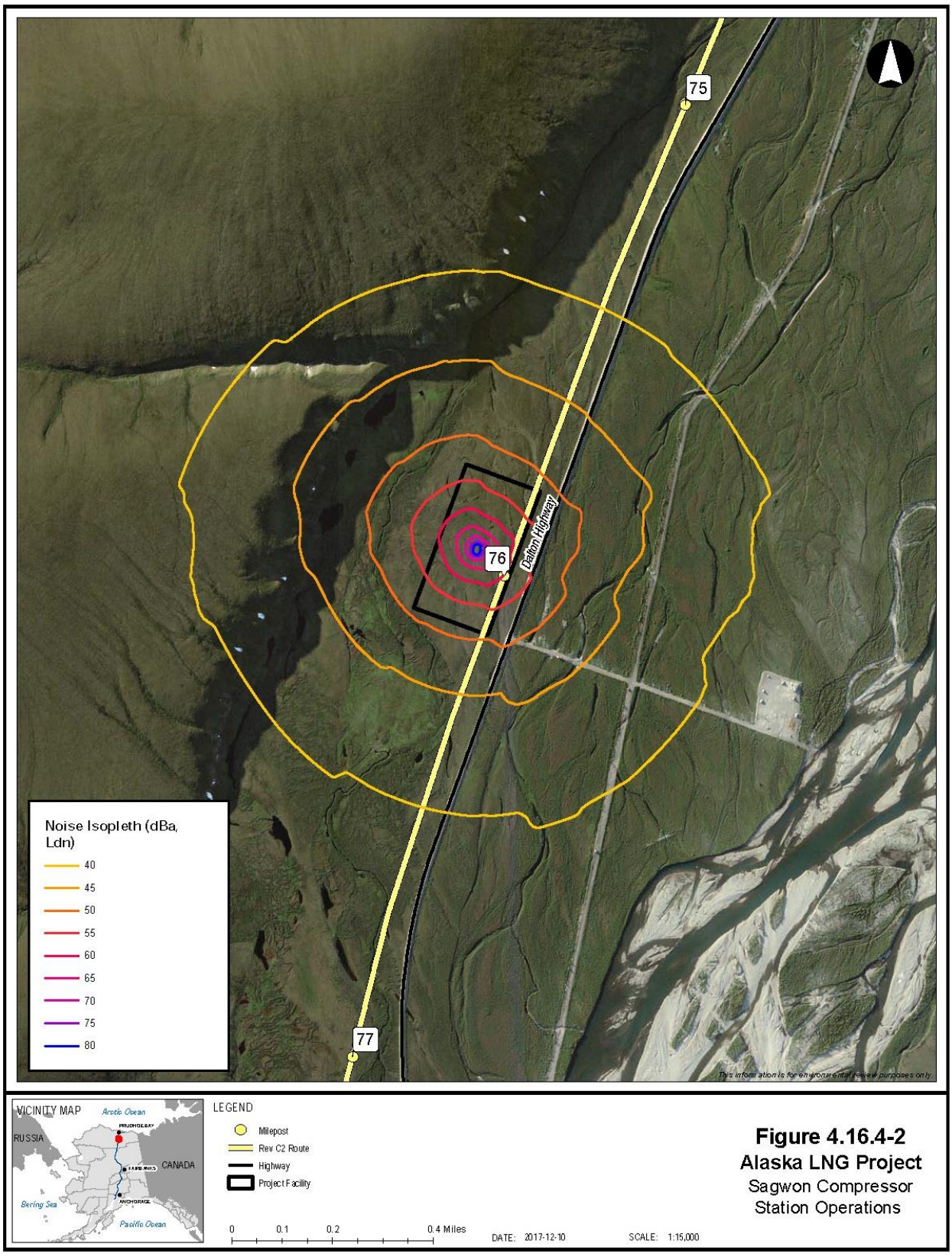


Figure 4.16.4-2
Alaska LNG Project
Sagwon Compressor Station Operations

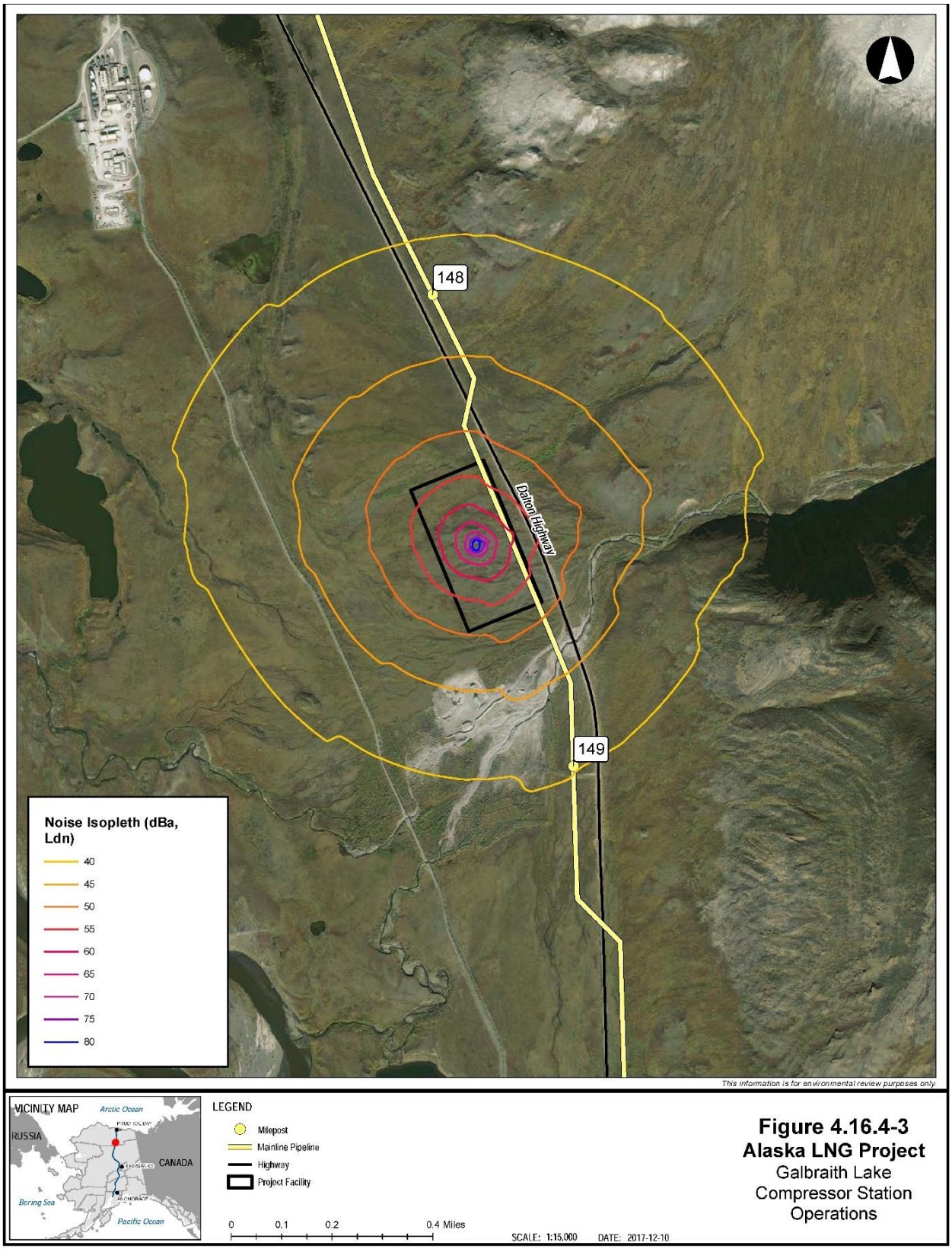


Figure 4.16.4-3
Alaska LNG Project
Galbraith Lake
Compressor Station
Operations

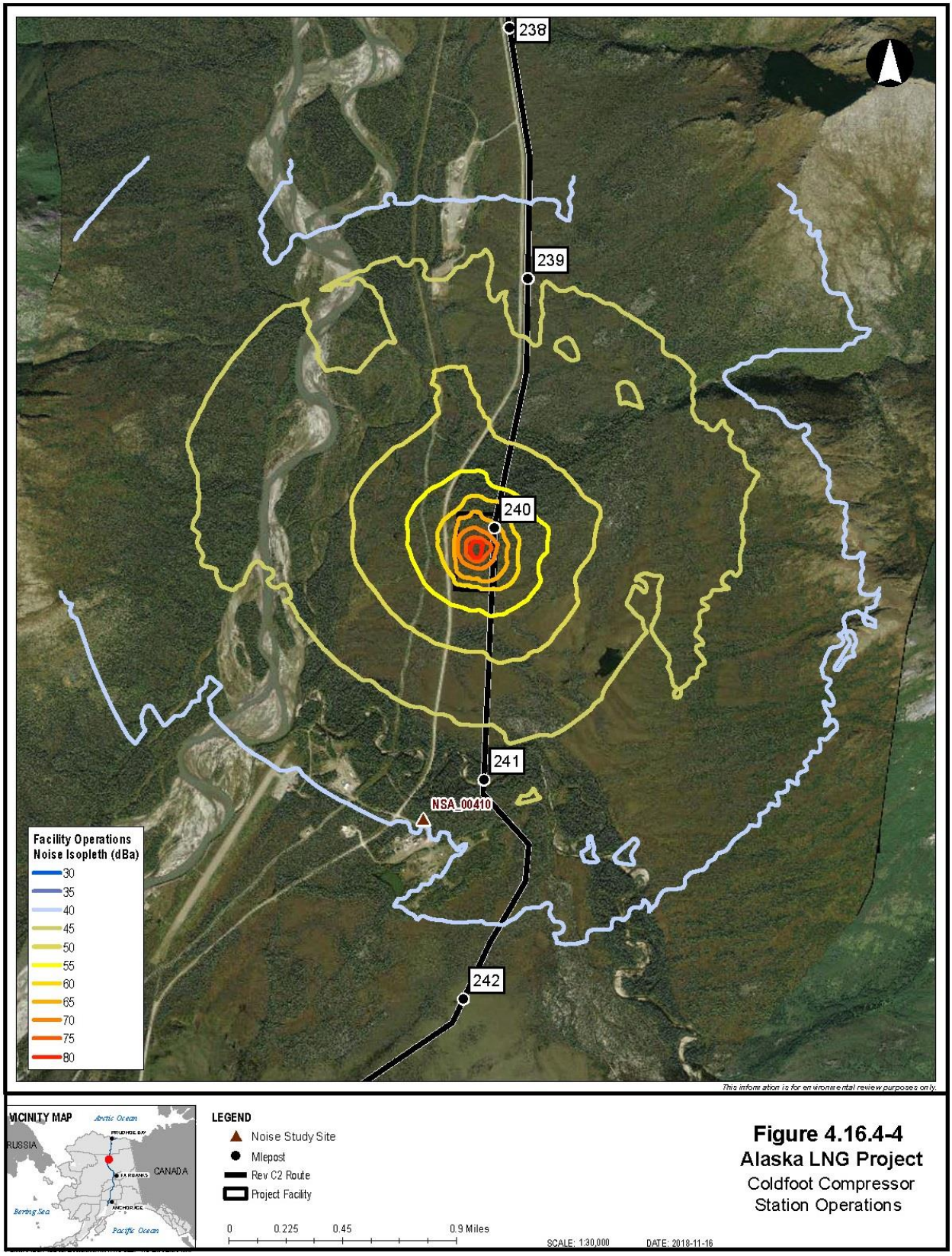


Figure 4.16.4-4
Alaska LNG Project
Coldfoot Compressor Station Operations

The results of the noise impact analysis indicate that the noise attributable to operation of the Coldfoot Compressor Station would be in compliance with FERC's sound level requirement of 55 dBA L_{dn} at the nearest NSA. We recognize that actual results could be different from those obtained from modeling. To ensure operation of this facility would comply with FERC's sound level requirement, AGDC would file with the Secretary a noise survey no later than 60 days after placing the Coldfoot Compressor Station in service. If a full load condition noise survey is not possible, AGDC would file an interim survey at the maximum possible horsepower load within 60 days of placing the station into service and file the full load survey within 6 months. If the noise attributable to operation of all equipment at the Coldfoot Compressor Station under interim or full horsepower load conditions exceeds an L_{dn} of 55 dBA at any nearby NSAs, AGDC would file a report on what changes are needed and install the additional noise controls to meet the level within 1 year of the in-service date. AGDC would confirm compliance with the above requirement by filing an additional noise survey with the Secretary no later than 60 days after the additional noise controls are installed.

Ray River Compressor Station

The Ray River Compressor Station would include the following major noise-generating equipment:

- one 42,000-hp gas turbine-driven centrifugal natural gas compressor unit;
- three power generators;
- two auxiliary utility glycol heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Ray River Compressor Station were not measured. Due to the facility location adjacent to Dalton Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-5 provides the estimated radial noise impact from operation of the Ray River Compressor Station on the surrounding area. Sound levels generated would be at or near existing background sound levels within 0.5 mile.

Minto Compressor Station

The Minto Compressor Station would include the following major noise-generating equipment:

- one 42,000-hp gas turbine-driven centrifugal natural gas compressor unit;
- three power generators;
- two auxiliary utility glycol heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Minto Compressor Station were not measured. Due to the facility's remote location, AGDC estimated that ambient sound levels would be less than 40 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-6 provides the estimated radial noise impact from operation of the Minto Compressor Station on the surrounding area. Sound levels generated would be at or near background sound levels within 0.6 to 1.0 mile.

Healy Compressor Station

Operation of the Healy Compressor Station would produce noise on a continual basis. AGDC performed modeling to calculate noise levels that would be generated by operation of this compressor

station. The following noise generating equipment was included in the noise model, which incorporates proposed noise mitigation and design measures that would decrease the noise levels:

- one 42,000-hp gas turbine-driven centrifugal natural gas compressor unit, with in-line silencer on the exhaust;
- three electrical generators;
- four air-cooled heat exchanger banks; and
- one lube oil cooler for the natural gas compressor unit, with aboveground intake and exhaust piping servicing the unit.

One NSA (a residence) is within about a 1-mile radius of the facility site. The NSA near the facility is presented on figure 4.16.3-3. Table 4.16.4-2 presents the results of the noise modeling and compares the existing ambient level, the expected future noise level after adding the facility noise to the ambient sound level, and the increase in ambient sound level as a result of adding the facility. Based on comments received from the NPS, we updated table 4.16.3-4 to include the L_{50}.

TABLE 4.16.4-2

Healy Compressor Station Operation – Noise Levels at Nearby Noise Sensitive Areas

Noise Sensitive Area	Distance / Direction from Station (feet)	Existing Ambient L_{50} (dBA)	Existing Ambient L_{dn} (dBA)	Predicted Compressor Station Contribution L_{eq} (dBA)	Predicted Compressor Station Contribution L_{dn} (dBA)	Ambient + Compressor Station L_{dn} (dBA) [a]	Predicted Increase in L_{50} Noise Level (dB)	Predicted Increase in L_{dn} Noise Level (dB)
1	2,885 / northwest	41.0	52.0	45.6	53.0	55.5	5.8	3.5

[a] SPLs are summed logarithmically; therefore, the predicted increase in ambient noise level at the NSAs during the Healy Compressor Station operation would not be the sum of the two noise levels.

Based on the estimates presented in table 4.16.4-2, noise generated by Healy Compressor Station operation would likely be perceptible at the nearby NSA. Figure 4.16.4-7 provides the estimated radial noise impact associated with operation of the Healy Compressor Station on the surrounding area. Sound levels would be at or near existing background sound levels within about 1.1 miles.

AGDC also evaluated the potential for Healy Compressor Station operation to result in perceptible vibration at the nearby NSA. Based on AGDC's analysis, any potential vibration associated with operation of the compressor station with installed controls would not be perceptible at the nearby NSA. We have reviewed AGDC's analysis and agree with this conclusion.

The results of the noise impact analysis indicate that the noise attributable to operation of the Healy Compressor Station would be in compliance with FERC's sound level requirement of 55 dBA L_{dn} at the nearest NSA. We recognize that actual results could be different from those obtained from modeling. To ensure that operation of this facility would comply with FERC's sound level requirement, AGDC would file with the Secretary a noise survey no later than 60 days after placing the Healy Compressor Station in service. If a full load condition noise survey is not possible, AGDC would file an interim survey at the maximum possible horsepower load within 60 days of placing the station into service and file the full load survey within 6 months. If the noise attributable to the operation of all of the equipment at the Healy Compressor Station under interim or full horsepower load conditions exceeds an L_{dn} of 55 dBA at any nearby NSAs, AGDC would file a report on what changes are needed and install the additional noise controls to meet the level within 1 year of the in-service date. AGDC would confirm compliance with the above requirement by filing an additional noise survey with the Secretary no later than 60 days after the additional noise controls are installed.

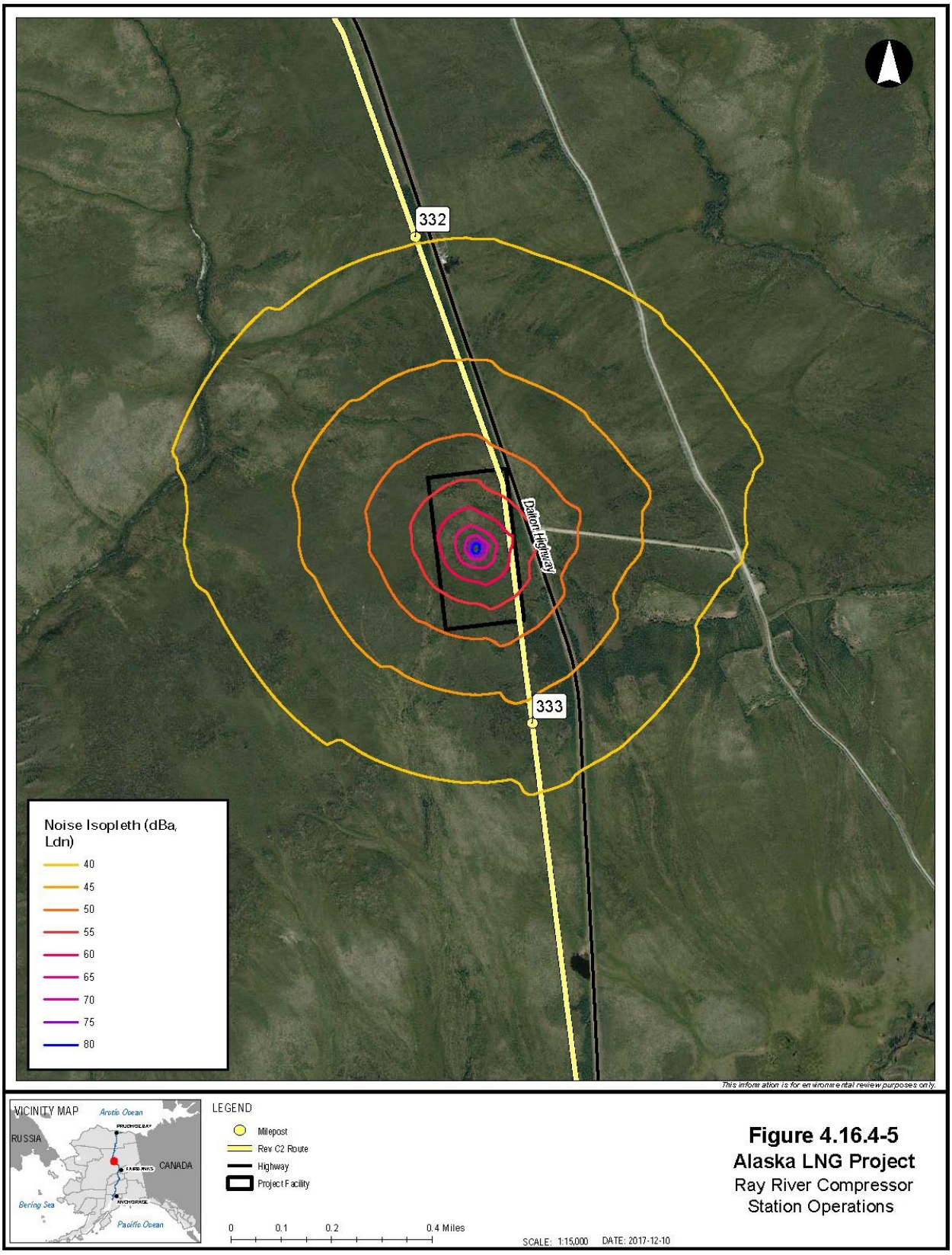


Figure 4.16.4-5
Alaska LNG Project
Ray River Compressor Station Operations

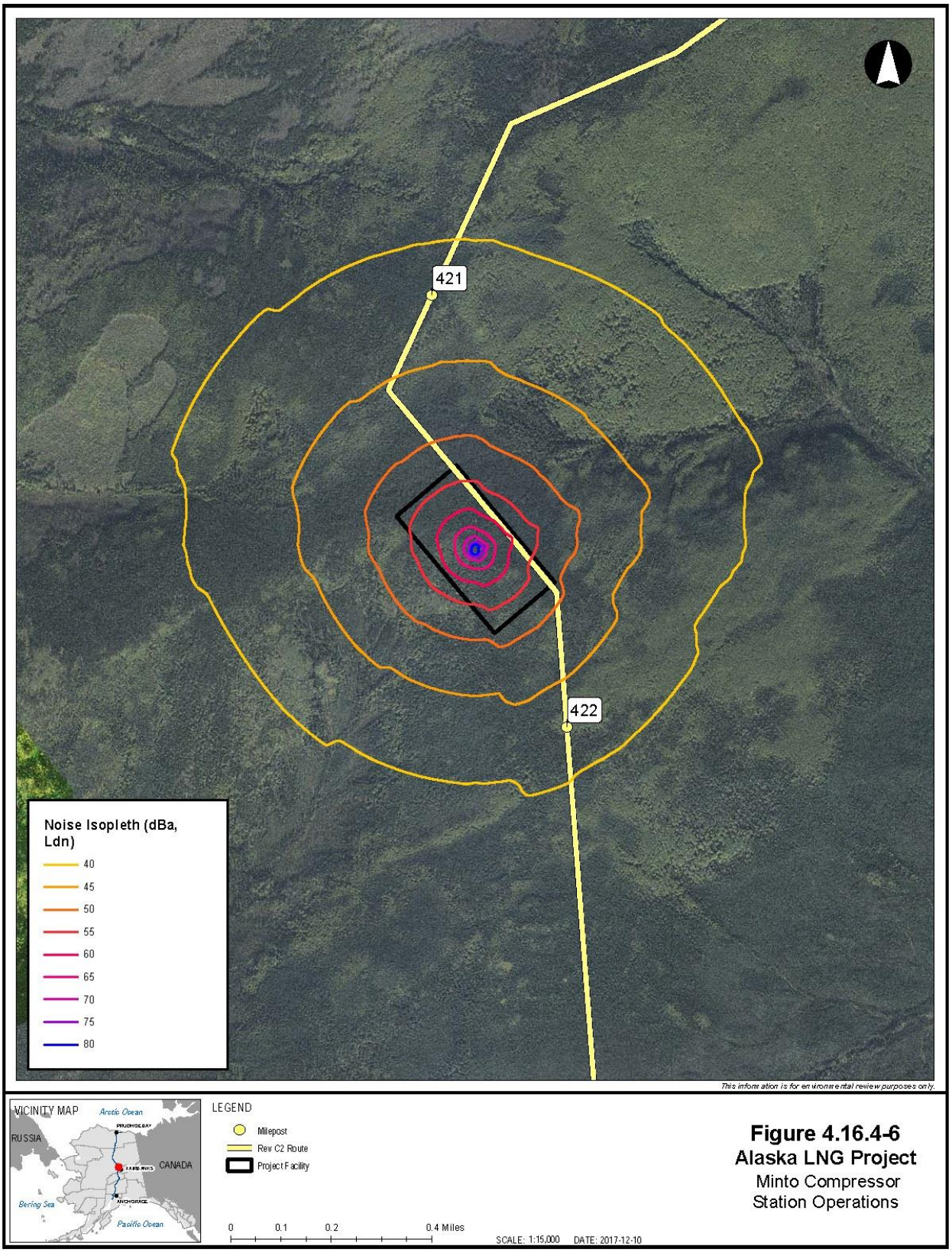


Figure 4.16.4-6
Alaska LNG Project
Minto Compressor Station Operations

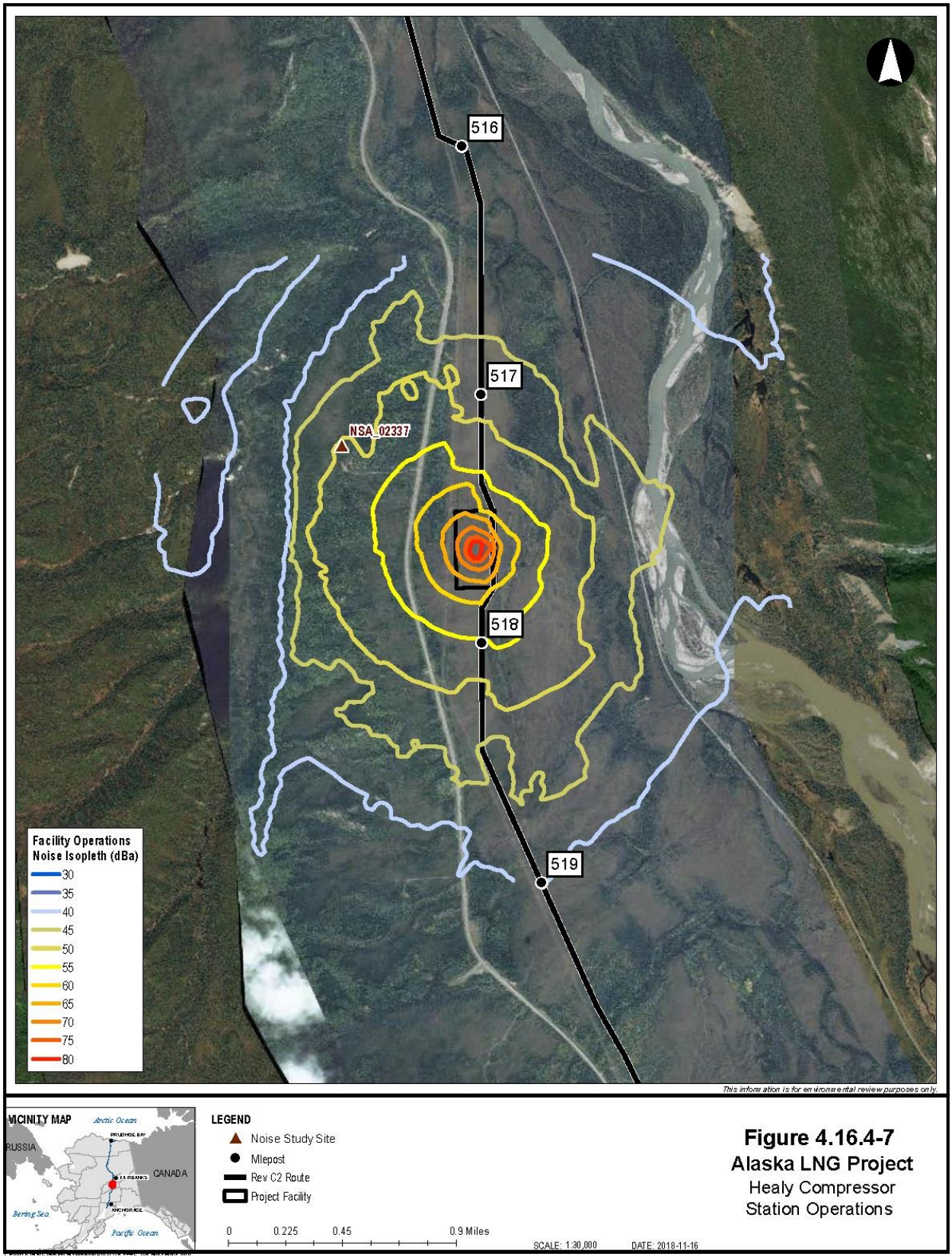


Figure 4.16.4-7
Alaska LNG Project
Healy Compressor
Station Operations

In comments on the draft EIS, the NPS stated that operational noise from the Healy Compressor Station would need to comply with a standard of 40 dBA L_{eq} at the border of the DNPP according to the conditions in the *Denali Backcountry Management Plan* (NPS, 2006a), and that median background sound levels of 20 dBA L_{50} occur within the DNPP in proximity to the Healy Compressor Station. Figure 4.16.4-8 provides the estimated operational sound levels associated with the Healy Compressor Station at the DNPP boundary. As shown on figure 4.16.4-8, operational sound levels associated with the Healy Compressor Station would be less than 40 dBA L_{eq} at the border of the DNPP and less than the median background sound levels in the DNPP. Because the compressor station is a continuous noise source, the L_{eq} is equivalent to the L_{50}. Based on this analysis, the operational noise from the Healy Compressor Station would have a negligible impact on the DNPP.

Honolulu Creek Compressor Station

The Honolulu Creek Compressor Station would include the following major noise-generating equipment:

- one 33,000-hp gas turbine-driven centrifugal natural gas compressor unit;
- three power generators;
- two auxiliary utility glycol heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Honolulu Creek Compressor Station were not measured. Due to the facility location near the Parks Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-9 provides the estimated radial noise impact from operation of the Honolulu Creek Compressor Station on the surrounding area. Sound levels generated would be at or near background sound levels within 0.5 mile.

Rabideux Creek Compressor Station

The Rabideux Creek Compressor Station would include the following major noise-generating equipment:

- one 33,000-hp gas turbine-driven centrifugal natural gas compressor unit;
- three power generators;
- two auxiliary utility glycol heaters;
- five indirect-fired heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the compressor station site. Background sound levels for the Rabideux Creek Compressor Station were not measured. Due to the facility location near the Parks Highway, AGDC estimated that ambient sound levels would range from 41 to 64 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-10 provides the estimated radial noise impact from operation of the Rabideux Creek Compressor Station on the surrounding area. Sound levels generated would be at or near background sound levels within 0.5 mile.

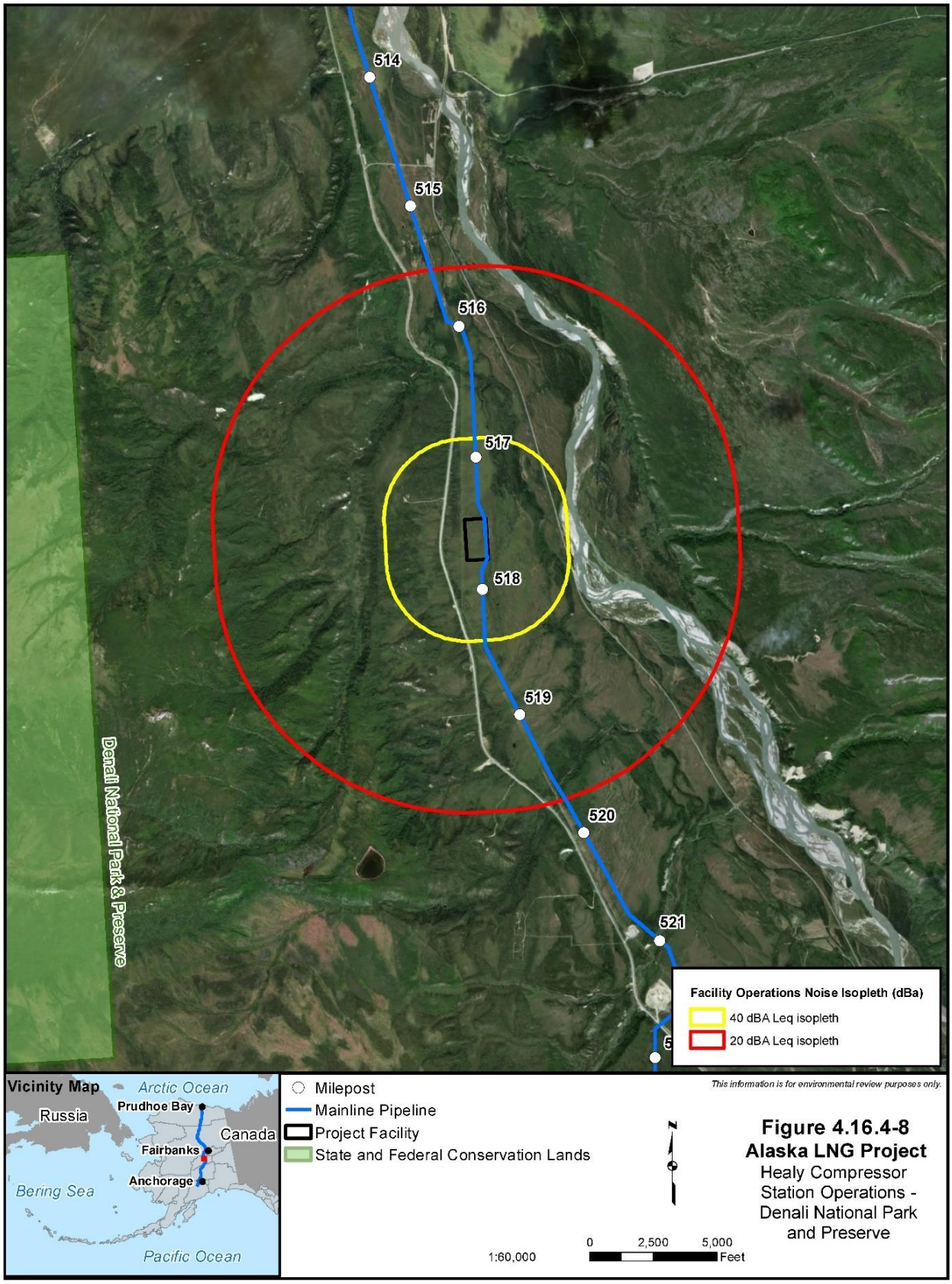


Figure 4.16.4-8
Alaska LNG Project
Healy Compressor Station Operations - Denali National Park and Preserve

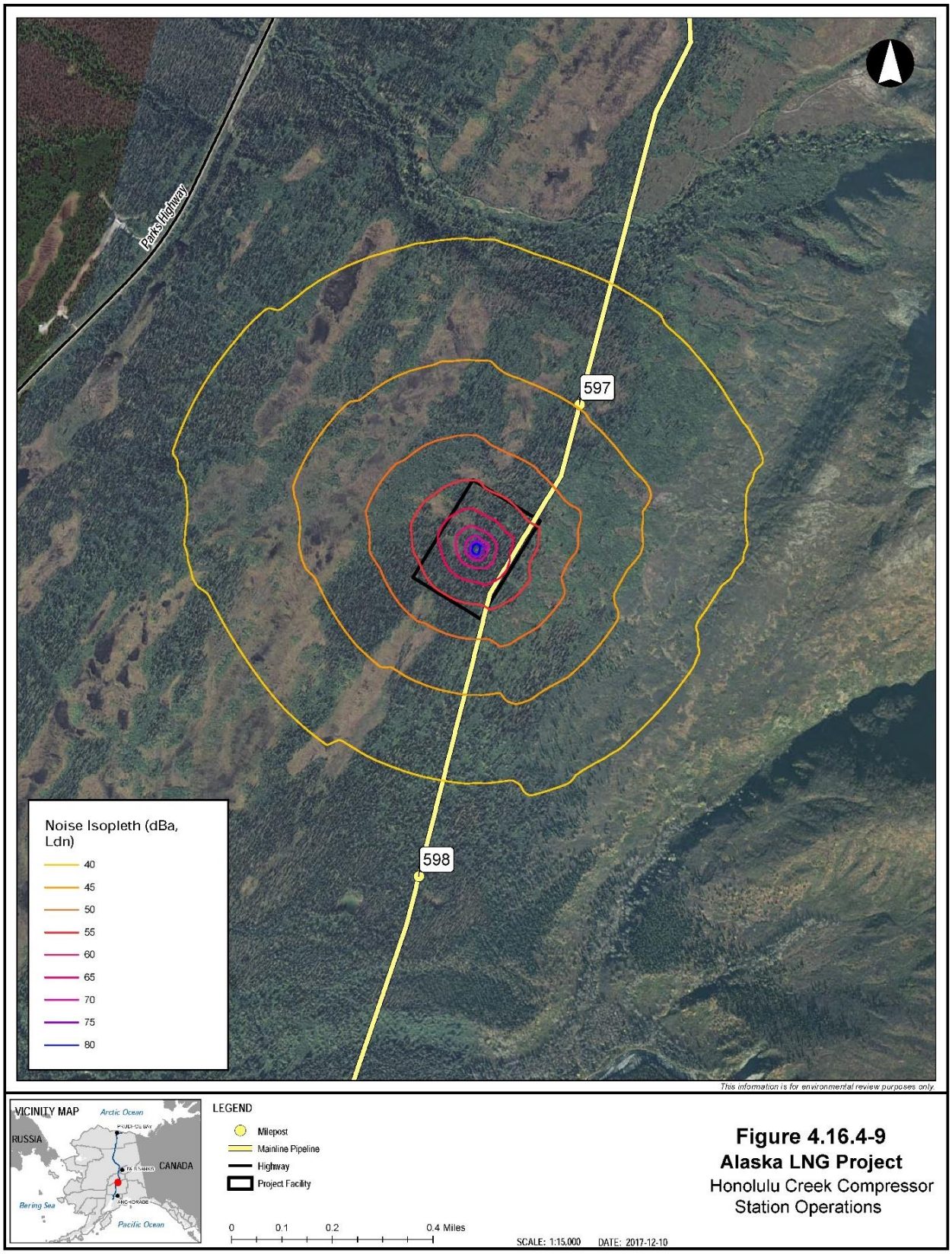


Figure 4.16.4-9
Alaska LNG Project
Honolulu Creek Compressor Station Operations

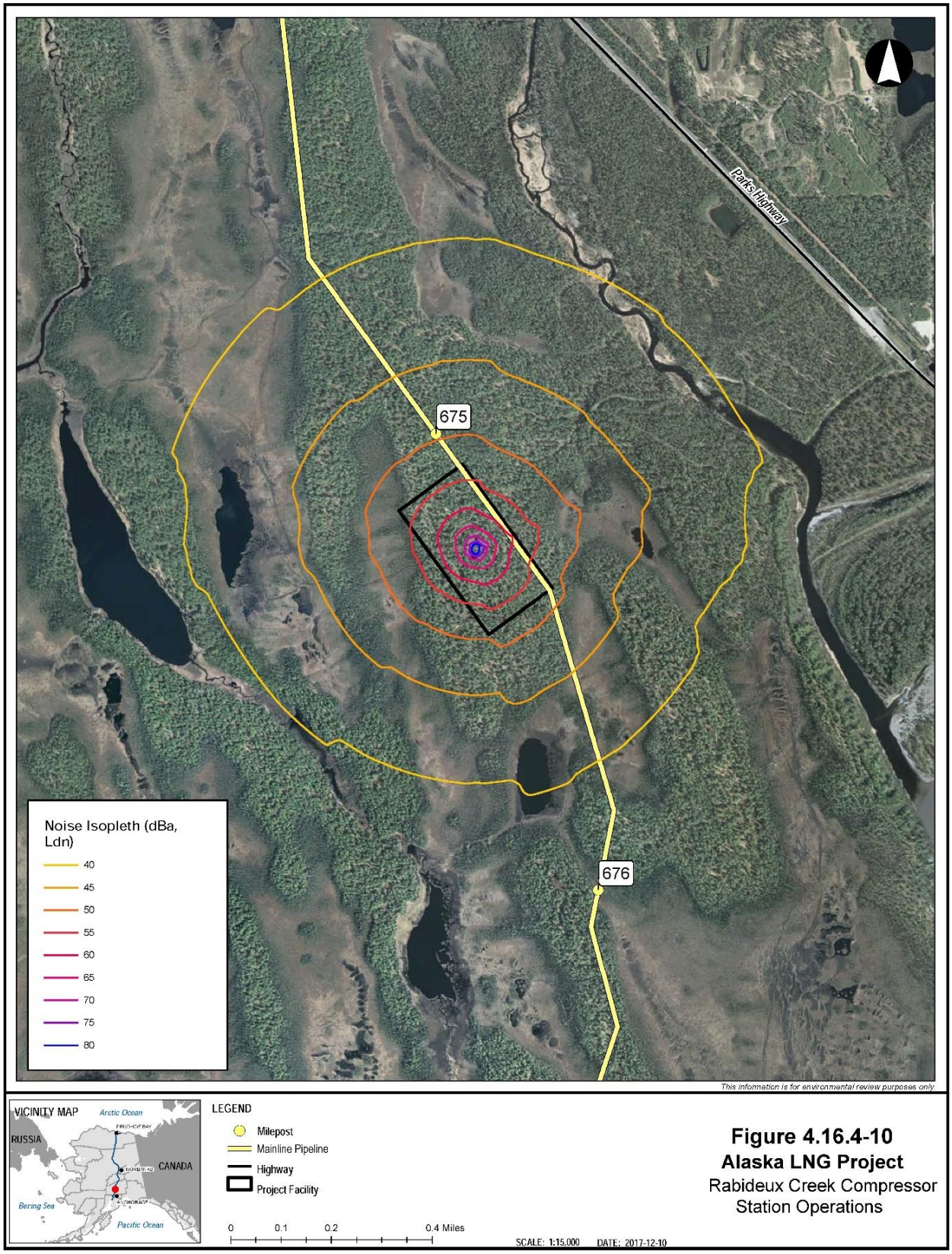


Figure 4.16.4-10
Alaska LNG Project
Rabideux Creek Compressor Station Operations

Theodore River Heater Station

The Theodore River Heater Station would include the following major noise-generating equipment:

- two power generators;
- nine indirect-fired natural gas heaters; and
- aboveground intake and exhaust piping servicing the natural gas compressor unit.

No NSAs were identified within 1 mile of the heater station site. Background sound levels for the Theodore River Heater Station were not measured. Due to the facility's remote location, AGDC estimated that ambient sound levels would be less than 40 dBA L_{dn} based on ambient sound levels collected at other representative locations in the Project area. Figure 4.16.4-11 provides the estimated radial noise impact from operation of the Theodore River Heater Station on the surrounding area. Sound levels generated would be at or near background sound levels within 0.6 to 1.0 mile.

Blowdown Noise

Blowdowns would occur at compressor stations and MLVs as part of normal pipeline safety operations. Compressor unit blowdowns would occur to allow for routine maintenance activities or during a facility upset, which would require high-pressure gas to be rapidly vented. AGDC would affix silencers on the blow down equipment at each compressor station site, which would ensure that noise associated with blowdown events would be less than 55 dBA L_{dn} at nearby NSAs.

Routine blowdown events associated with MLV sites would be scheduled from 7:00 a.m. to 10:00 p.m., and the maximum duration of the blowdown event would be 3 hours. MLVs with NSAs greater than 1 mile from the site would be outfitted with a standard vent muffler, which would provide sufficient sound muffling to ensure that noise attributable to blowdown events at NSAs 1 mile or greater from the MLV would be 64 dBA L_{eq} or less. In the event that an emergency blowdown is required during the night, nearby NSAs could experience perceptible noise levels during the blowdown event, but these would be infrequent and would not represent normal operating conditions.

Three MLV sites, MLVs 27, 28, and 29, have NSAs within a 0.5 mile radius of the sites. AGDC would install increased performance vent silencers to limit the noise levels at these NSAs.

Operational Traffic Noise

Operation of the Mainline Facilities would require air traffic to deliver employees and equipment to remote locations. Because the Project would increase the volume of air traffic to the existing air strips planned to support the Project, the potential exists for increased noise at these air strips. AGDC additionally would increase air traffic in the region due to performing its maintenance and monitoring of the compressor stations and MLVs. Many of these sites would use helicopters for access, which would be accommodated using helipads installed at these facilities. AGDC estimates that Project operation would generate an average of one helicopter trip per month to these facilities. Periodic helicopter traffic would temporarily increase noise associated with operation of the compressor stations and MLVs.

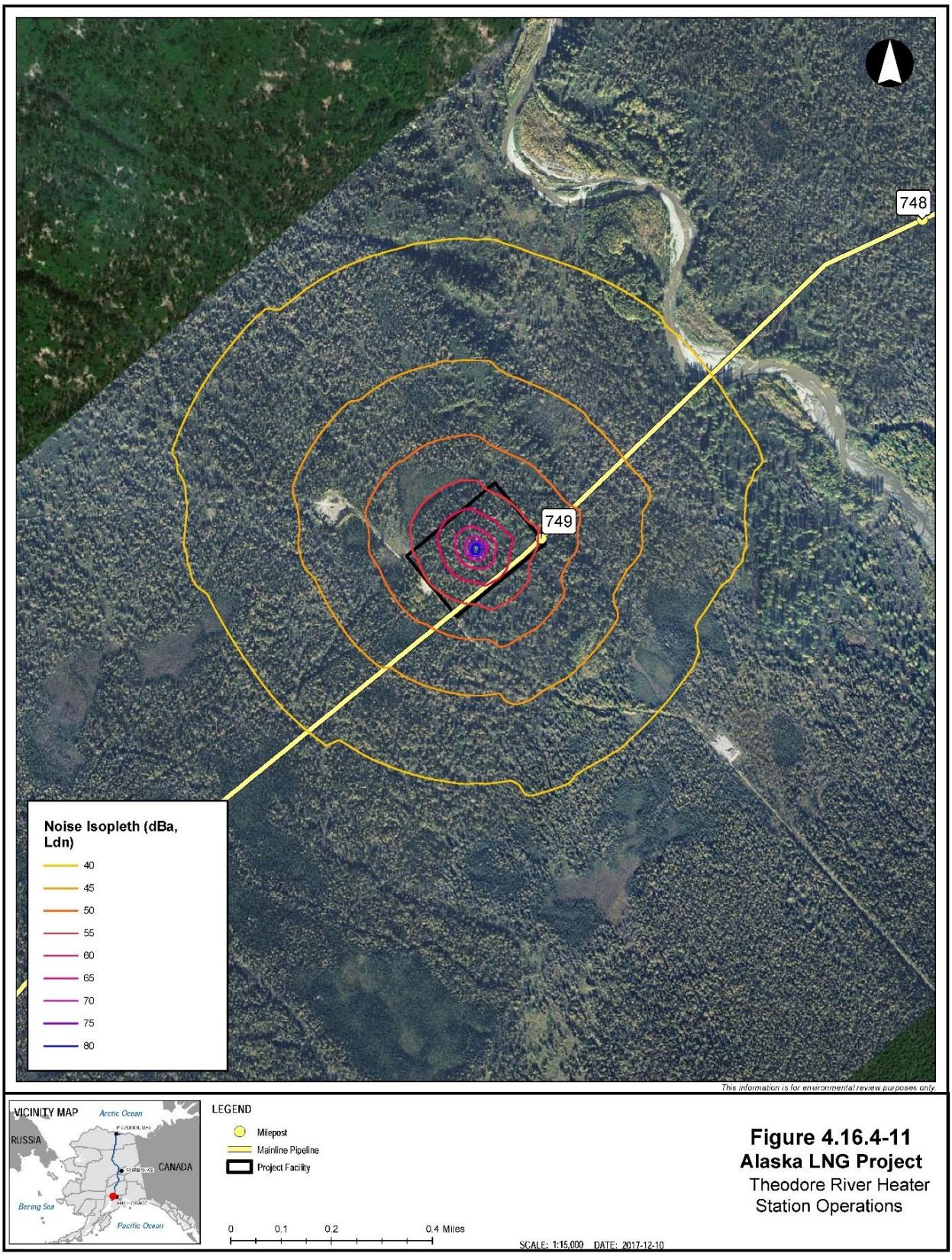


Figure 4.16.4-11
Alaska LNG Project
Theodore River Heater Station Operations

4.16.4.3 Liquefaction Facilities

Major noise-producing equipment at the Liquefaction Facilities includes turbine compressors, process compressors, connected piping, fans, motors, and pumps. Other sound sources include power generation, heat recovery steam generators, and steam turbine and utility equipment such as air compressors and air dryers. The Nikiski Meter Station would be collocated with the Liquefaction Facilities, but noise associated with operation of the meter station would be insignificant compared to the larger components of the Liquefaction Facilities.

As previously noted, there are several NSAs near the Liquefaction Facilities. Background noise levels at the NSAs were determined by a noise survey. AGDC performed modeling to assess the impacts of operational noise generated by the Liquefaction Facilities on the nearby NSAs. Sound level data for the equipment were obtained either from vendors or from measurements at other LNG facilities.

AGDC has proposed the following noise mitigation measures which would be incorporated into the design of the Liquefaction Facilities and are included in the operational noise modeling:

- duct insulation on combustion turbine inlets, process compressor piping, and power generator turbine inlet;
- silencers on combustion turbine exhaust systems, process compressor lines, and air dryer;
- metal acoustic walls/enclosures surrounding combustion turbines, process compressors, and air compressor; and
- acoustically designed walls/enclosures for the power generator turbine, boil-off-gas, and boil-off-gas recycle compressors.

Table 4.16.4-3 shows results of the noise modeling, along with a comparison with the existing ambient noise level at nearby NSAs; the anticipated future noise level during operation of the Liquefaction Facilities, including existing ambient noise levels; and the resulting increase in ambient noise level due to operation of the Liquefaction Facilities. Four NSAs (residences) are near the Liquefaction Facilities' site. The NSAs near the facility are depicted on figure 4.16.3-4.

TABLE 4.16.4-3

Liquefaction Facilities Operation – Composite Noise Levels at Nearby Noise Sensitive Areas

Noise Sensitive Area	Distance / Direction from Liquefaction Facilities (feet)	Existing Ambient L_{dn} (dBA)	Predicted Liquefaction Facilities Contribution L_{dn} (dBA)	Ambient + Liquefaction Facilities L_{dn} (dBA) [a]	Predicted Increase in Ambient Noise Level (dB)
1	3,700 / east	43	54.8	55.1	12.1
2	5,700 / southeast	39	53.5	53.7	14.7
3	6,600 / south	48	47.6	50.8	2.8
4	10,500 / northwest	51	39.0	51.3	0.3

[a] SPLs are measured on a logarithmic scale; therefore, the predicted increase in ambient noise level at the NSAs during LNG Plant operation would not be the sum of the two noise levels.

Based on the estimates in table 4.16.4-3, noise generated by operation of the Liquefaction Facilities would comply with our 55 dBA L_{dn} noise criterion at the nearby NSAs. Noise associated with the Liquefaction Facilities would likely be perceptible at all nearby NSAs; however, the sound intensities at

NSAs 1 and 2 would likely double due to facility operation. Sound intensities at NSAs 3 and 4 would likely be unchanged.

Due to the increase in sound levels at NSAs 1 and 2, we requested that AGDC analyze the practicability of installing additional noise mitigation measures to further reduce predicted noise increases at these NSAs. AGDC determined that lowering the ambient noise level increases at NSAs 1 and 2 would require the placement of 30 to 60 foot high noise barriers between the NSAs and the facility for distances ranging from 800 to 1,600 feet. While technically feasible, this mitigation measure would create other potential effects, including visual impacts from these large structures. We have reviewed the mitigation measures proposed by AGDC in the Liquefaction Facilities operational noise analysis and determined that they would sufficiently minimize noise impacts at nearby NSAs to the extent practicable.

The noise analysis presented in table 4.16.4-3 includes noise associated with one docked LNG carrier. The facility would have the ability to have two LNG carriers docked at one time, although only one carrier could be loaded at a time. The estimated duration that two LNG carriers could be docked at one time would range from 4 to 13 hours, during which time the noise associated with LNG carriers could increase by about 0.4 dB at the nearest NSA.

KOP 54 (Mt. Redoubt Church) is about 4,900 feet from the Liquefaction Facilities. AGDC did not collect ambient sound levels at KOP 54, but ambient sound levels would be anticipated to be similar to the ambient sound levels measured at NSAs 3 and 4 (see table 4.16.4-3). Operation of the Liquefaction Facilities has the potential to affect noise levels at KOP 54. AGDC estimated that noise attributable to operation of the Liquefaction Facilities would be between 47 and 53 dBA L_{dn}, which is similar to the estimated ambient sound levels at KOP 54. Based on this assessment, noise associated with operation of the Liquefaction Facilities would have a minor impact on sound levels at KOP 54.

AGDC evaluated the potential for operation of the Liquefaction Facilities to result in perceptible vibration at the nearby NSAs. Based on AGDC's analysis, noise levels associated with operation of the Liquefaction Facilities would not be perceptible at the nearby NSAs. We have reviewed AGDC's analysis and agree with this conclusion.

While the results of the noise impact analysis indicate that the noise attributable to operation of the Liquefaction Facilities would be lower than FERC's sound level requirement of 55 dBA L_{dn} at the nearest NSA, we recognize that actual results could be different from those obtained from modeling. To ensure that operation of this facility would comply with FERC's sound level requirement, AGDC would file with the Secretary a full power load noise survey for the Liquefaction Facilities no later than 60 days after each liquefaction train is placed into service. If the noise attributable to operation of the equipment at the Liquefaction Facilities exceeds an L_{dn} of 55 dBA at the nearest NSA, within 60 days, AGDC would modify operation of the Liquefaction Facilities or install additional noise controls until a noise level below an L_{dn} of 55 dBA at the NSA is achieved. AGDC would confirm compliance with the above requirement by filing a second noise survey with the Secretary no later than 60 days after it installs the additional noise controls.

In addition, AGDC would file with the Secretary a noise survey no later than 60 days after placing the entire Liquefaction Facilities into service. If a full load condition noise survey is not possible, AGDC would file an interim survey at the maximum possible horsepower load within 60 days of placing the Liquefaction Facilities into service and file the full load survey within 6 months. If the noise attributable to operation of the equipment at the Liquefaction Facilities exceeds an L_{dn} of 55 dBA at the nearest NSA under interim or full horsepower load conditions, AGDC would file a report on what changes are needed and install the additional noise controls to meet the level within 1 year of the in-service date. AGDC would confirm compliance with the above requirement by filing an additional noise survey with the Secretary no later than 60 days after it installs the additional noise controls.

Operation of the ground-level and elevated low-pressure flares at the Liquefaction Facilities would generate noise. Flaring would occur during certain non-routine facility events, such as start-up, depressurization of equipment units, or other equipment malfunctions. Estimated duration of flare events range from 0.5 hour to 36 hours. AGDC estimated that flare events would occur at most once per month. Noise attributable to flaring activities is estimated at between 45 and 78 dBA L_{dn} at nearby NSAs depending on the nature of the event. AGDC has stated that it would be possible to schedule most flare events outside potentially sensitive timeframes, and would work to schedule the flare events in contact with the local community. Because of the intensity and potential duration of these flare events and the associated noise levels, and to ensure these mitigation measures would be implemented, AGDC would develop a Flare Noise Mitigation Plan, to be filed with the Secretary for the review and written approval of the Director of the OEP, prior to commencing operation of the flares associated with the Liquefaction Facilities. The plan would detail AGDC's plans to mitigate noise impacts associated with flare events to the extent practicable, including measures that AGDC would implement to minimize the frequency of flare events and the procedure for contacting and scheduling flare events with local community representatives.

Vessel traffic associated with operation of the Marine Facilities would generate underwater sounds. Cargo vessels, which are in the same category as LNG carriers, are known to emit high levels of low frequency sound (6.8 to 7.7 hertz at 181 to 190 dB [re 1 µPa]) capable of traveling long distances (Richardson et al., 1995). Noise generated by LNG carriers is generally omni-directional, emitting from all sides of the vessel (Whale and Dolphin Conservation Society, 2004). Noise levels are greatest on the sides of the ship and weakest on the front and rear of the ship. Above-water noise associated with the LNG carriers would be similar to other large vessel traffic along the waterway and would result in temporary and minor noise impacts along the vessel transit route.

Based on the noise evaluation completed for the Liquefaction Facilities, operation of the facility, including the mitigation measures proposed by AGDC, would have a moderate, long-term effect on NSAs in the Project area. The operation of flares during non-routine facility events have the potential to result in significant, short-term noise effects, but with implementation of the Project Flare Noise Mitigation Plan, we find that noise effects associated with these events would be appropriately mitigated.

4.16.5 Conclusion

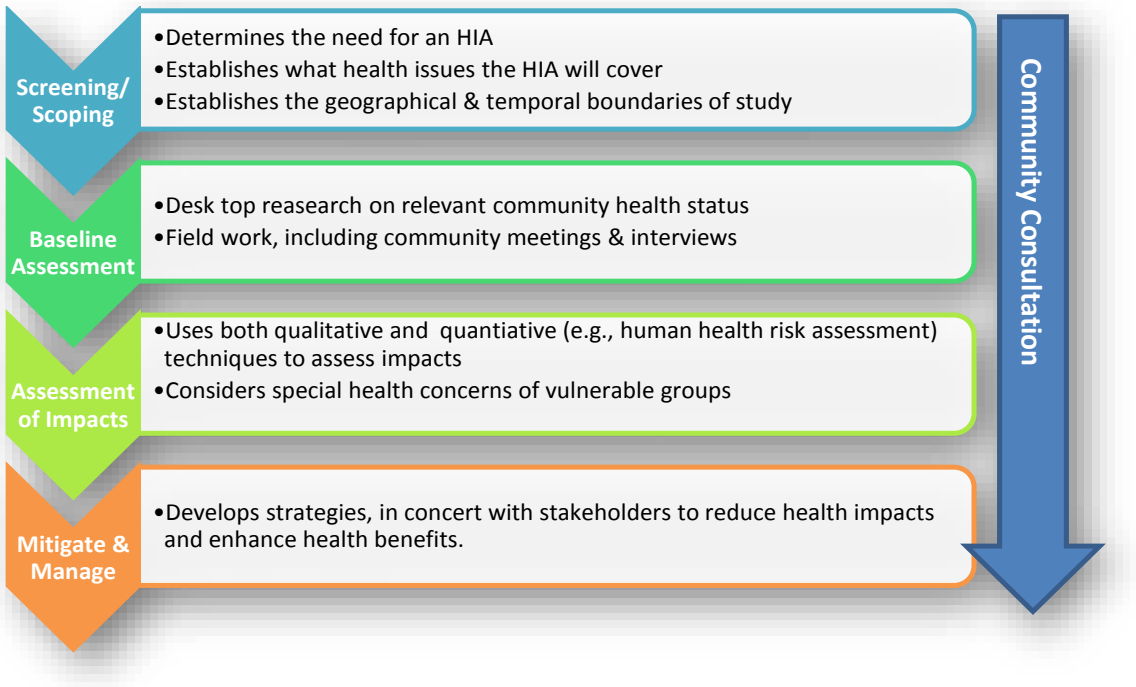
Noise impacts resulting from Project construction would be short term and temporary, with the exception of noise from construction of the GTP, aboveground facilities and DMT crossings associated with the Mainline Facilities, and the Liquefaction Facilities. Construction noise would have a minor to moderate temporary effect on NSAs near the DMT crossings and Coldfoot Compressor Station, a moderate to high temporary effect on NSAs near the Healy Compressor Station, and a significant temporary effect on NSAs near the Liquefaction Facilities. Other intermittent construction activities—such as pile driving, dredging, and blasting—could affect wildlife and subsistence practices. These impacts are further described in sections 4.6 and 4.14, respectively. We note that AGDC has agreed to implement one of our recommendations from section 4.16 of the draft EIS regarding construction noise (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

Project operation would have a permanent effect on noise near the aboveground facilities associated with the Project, including the GTP, compressor stations and heater station, and Liquefaction Facilities. The direct effects on noise levels in the Project area would be minor to moderate during normal facility operation, with the exception of operational noise associated with the Liquefaction Facilities at the two nearest NSAs. The sound intensities at NSAs 1 and 2 would likely double due to facility operation. In addition, certain intermittent events such as blowdowns and flaring events could generate sound levels above FERC's noise criteria of 55 dBA L_{dn}, which have the potential to result in short-term significant effects. We note that AGDC has agreed to implement four of our recommendations from section 4.16 of the draft EIS regarding operation noise (see section 5.1 for additional discussion regarding AGDC's commitments to staff recommendations from the draft EIS).

4.17 PUBLIC HEALTH AND SAFETY

The following section describes the public health and safety conditions present in the Project area, and the potential direct and indirect impacts on public health due to the Project. AGDC, as part of its FERC application, provided an HIA for the Project, which is included as appendix V. The ADHSS has developed guidance for the performance of HIAs in Alaska (ADHSS, 2015b). Although there is no federal regulatory requirement to conduct an HIA, AGDC prepared its HIA at the request of stakeholders in potentially affected Project communities and in accordance with ADHSS guidance.

An HIA is "a structured planning and decision-making process that analyzes the potential positive and negative impacts of programs, projects, and policies on the public's health" (ADHSS, 2015b). The four steps outlined in ADHSS's guidance are shown on figure 4.17-1. The HIA in appendix V focuses on a baseline assessment, an assessment of impacts, and mitigation and management of impacts. AGDC completed HIA screening/scoping during the Project's scoping phase.



Source: Environmental Resources Management

Figure 4.17-1 Steps of a Health Impact Assessment

ADHSS's HIA guidance establishes eight health effects categories (HECs) that a project should consider as part of the assessment (ADHSS, 2015b). Table 4.17-1 lists the HECs and provides the ADHSS definition of each category. Note that there is some overlap between categories (e.g., respiratory diseases may be related to hazardous materials as well as chronic diseases). Because impacts relevant to human health are often related to social and environmental factors, certain health impacts are addressed in other EIS sections (e.g., health impacts from air emissions). Table 4.17-1 provides a cross-reference to other EIS sections that contain information relevant to each HEC.

TABLE 4.17-1

Alaska's Department of Health and Social Services Health Effects Categories

Health Effects Category	Alaska's Department of Health and Social Services Definition [a]	Analysis Relevant to the HIA in other EIS Sections
Social Determinants of Health	The social determinants of health are the conditions in which people are born, grow, live, work, and age. These circumstances are shaped by the distribution of money, power, access, and resources at global, national, state, regional, and local levels. The social determinants of health are mostly responsible for health inequities, the unfair and avoidable differences in health status seen within the state. This category reviews outcomes and determinants related to maternal health, maternal and child health, substance use, social exclusion, psychosocial distress, historical trauma, family dynamics, economic status, educational status, social support systems, and employment status.	Socioeconomics, section 4.11.8 (provides demographic information on the local population, specifically race, ethnicity, and income status, all of which can be surrogates for health status of vulnerable populations)
Accidents and Injuries	The key outcomes considered are increases and decreases in intentional and unintentional injuries with fatal and nonfatal results. The key determinants in this category include items such as the presence of law enforcement, traffic patterns, alcohol consumption, distance to emergency services, and the presence of prevention programs.	Socioeconomics, section 4.11.6 (provides information on law enforcement); Transportation, section 4.12 (provides information on traffic increases and flow); Reliability and Safety, section 4.18 (addresses unplanned events [e.g., spills, leaks, explosions, and terrorist acts])
Exposure to Potentially Hazardous Materials	The key health outcomes considered are increases and decreases in documented illnesses or exacerbation of illnesses commonly associated with pollutants of potential concern. These by be mediated through inhalation, ingestion, or physical contact**.**	Landfills, Mines, and Hazardous Waste Sites, section 4.9.6 (provides information on prevention of hazardous waste exposures from existing contamination); Reliability and Safety, section 4.18 (addresses accidents due to unplanned events [spills, leaks, explosions, terrorist acts]); Air Quality, section 4.15 (describes baseline conditions and the anticipated levels of air emissions from the Project)
Food, Nutrition, and Subsistence Activity	The key health outcomes considered are nutrient levels, malnutrition or improvements in intake, and the subsequent increases or decreases in related diseases. The key determinants include diet composition, food security, and the consumption of subsistence foods.	Subsistence, section 4.14 (describes subsistence resources and activities in the study area)
Infectious Disease	The key health outcomes include rates of increase or decrease for a range of infectious diseases, such as sexually transmitted infections, respiratory illnesses, or skin infections. Important health determinants may include immunization rates and the presence of infectious disease prevention efforts.	Only addressed in this section.
Water and Sanitation	Key determinants reviewed include distance to clean water, water fluoridation, indoor plumbing, water treatment facilities, adequate volume of water resources, and the existence of community facilities, such as community showers.	Water Use, section 4.3.4 (addresses water uses, drinking water supply, and water quality)
Non-communicable and Chronic Diseases	Important outcomes include increases or decreases in mortality and morbidity, rates of cancer, cardiovascular and cerebrovascular diseases, diabetes, respiratory diseases, and mental health disorders. Key determinants for chronic diseases may include smoking rates, rates of alcohol and drug abuse, physical activity levels, presence of recreational centers, as well as cancer screening rates.	Air Quality and Noise, sections 4.15 and 4.16, respectively (describes baseline conditions and the anticipated levels of air emissions and noise levels from the Project)
Health Services Infrastructure and Capacity	Important outcomes include the increase or decrease in the number of medical evacuations, clinics or hospital visit trends, health expenditures, and medication usage. Health determinants may include distance to health facilities, medevac facilities/aircraft, the presence of community health aides, and the frequency of physician visits to the area.	Only addressed in this section

[a] Source: Definitions are direct excerpts from ADHSS, 2015b.

4.17.1 Health Study Area

A PAC is defined as an area, community, or village where Project-related health impacts may reasonably be expected to occur. The affected area for public health and safety is generally the same as that described in section 4.11, with some slight differences. It includes boroughs, census areas, and villages where there are Project facilities and major Project transportation routes. Table 4.17.1-1 lists the PACs identified in the Project's health study area grouped by census area, the key Project and Project-related components and activities occurring in those areas, and the areas that would be expected to experience population and economic growth. Impacts on subsistence are discussed in section 4.14.

4.17.2 Baseline Health Conditions

Several health measures, such as the leading causes of death, mortality rates, and disease prevalence, can provide a high-level picture of the general health status of a population. These key indicators, while described in detail in subsequent sections where they are used as measures of the HECs, are worth highlighting here as they describe the degree to which a population is burdened by poor health outcomes (illness and mortality).

Figure 4.17.2-1 shows the leading causes of death for all Alaskans between 2010 and 2015. During that time period, cancer was the leading cause of death for Alaskans, followed by cardiovascular disease. While cancer saw a slight decrease in mortality rate during this time, the rate for cardiovascular diseases fluctuated but did not indicate an upward or downward trend. Table 4.17.2-1 includes a summary of other key health indicators reported by census area within the health study area. In general, the study area populations have a similar health status to state averages. It should be noted, however, that health information is typically only available as aggregated data at the census group level, and not for each individual PAC, due to how data is reported and tracked. For example, health data for the North Slope Borough census area includes data for the five PACs listed under the North Slope Borough in table 4.17.1-1, as well as all the other communities in the North Slope Borough that would not be directly affected by the Project. This is an area of uncertainty as aggregated data can mask differences at the individual community level.

The following baseline sections provide a high-level summary of the health status of the population in the health study area by HEC category. The information is derived from the HIA prepared by AGDC (see appendix V). Health data at the community level is limited; therefore, information for the boroughs and key census areas are presented, where applicable, to provide context for understanding the community health and public safety conditions. State-level information is presented for comparison.

Additionally, in the field of public health, it is recognized that some groups suffer higher rates of diseases or have poorer health outcomes than the general populace. A multitude of complex and often inter-related demographic, social, economic, and environmental conditions can increase or decrease the risk for illness. For example, individuals with fewer economic resources may be less likely to seek preventative medical care and, as a result, are at a higher risk of serious illness or premature death. Often, members of racial or ethnic minority groups, those with lower education status or income levels, and those living in rural communities suffer a greater burden of health problems than the general population (Hadley, 2003; Hadley and Cunningham, 2005; Gresenz and Escarce, 2011; Phelan et al., 2010). These populations may be sensitive to changes as a result of the Project and are therefore given special consideration when assessing potential health impacts. Therefore, where information is available, data on vulnerable populations (groups that appear to have greater levels of poverty or are ethnic minorities) is presented alongside data on the general population.

TABLE 4.17.1-1

Potentially Affected Communities Identified in the Project's Health Study Area

Census Area/Potentially Affected Community	Project Facility in the Area	Transportation Corridor [a]	Logistical and Supply Center [b]	Growth-Related Effects [c]
North Slope Borough	Mainline/GTP/PTTL/PBTL	–	–	X
Prudhoe Bay/Deadhorse [d]	Mainline/GTP/PTTL/PBTL	Dalton Highway (Hwy) / primary port / airport	X	–
Barrow (Utqiagvik) [d,e]	–	–	–	–
Nuiqsut [d,e]	–	–	–	–
Kaktovik [d,e]	–	–	–	–
Anaktuvuk Pass [d,e]	–	–	–	–
Yukon-Koyukuk Census Area	Mainline	–	–	–
Bettles [d,e]	–	Dalton Hwy	–	–
Coldfoot [d,e]	–	Dalton Hwy / airport	–	–
Evansville/Evansville [d,e] ANVSA	–	Dalton Hwy	–	–
Livengood [d]	–	Dalton Hwy / airport	–	–
Manley Hot Springs [d,e]	–	Dalton Hwy	–	–
Minto [d,e]	–	Dalton Hwy	–	–
Nenana [d,e]	Mainline	Dalton Hwy/airport	–	–
Wiseman [d,e]	Mainline	Dalton Hwy	–	–
Alatna [d,e]	–	–	–	–
Allakaket [d,e]	–	–	–	–
Stevens Village [d,e]	–	–	–	–
Beaver [d]	–	–	–	–
Rampart [d,e]	–	–	–	–
Tanana [d,e]	–	–	–	–
Four Mile Road [d,e]	–	–	–	–
Fairbanks North Star Borough	Mainline	–		X
Fairbanks	–	Richardson Hwy / Parks Hwy / Steese Hwy / airport / railway	X	–
Denali Borough	Mainline		–	–
Anderson [d,e]	–	Parks Hwy	–	–
Cantwell [d,e]	–	Parks Hwy / airport	–	–
Healy [d,e]	Mainline	Parks Hwy / airport	–	–
McKinley Park (DNPP) [d,e]	Mainline	Parks Hwy	–	–
Ferry [d,e]	–	–	–	–
Matanuska-Susitna Borough	Mainline	–		X
Big Lake	Mainline	Parks Hwy	–	–
Houston [d]	Mainline	Parks Hwy	–	–
Knik-Fairview [d]	–	Knik–Goose Bay Rd	–	–
Palmer	–	Parks Hwy	–	–
Point Mackenzie	Mainline	Knik–Goose Bay Road / secondary port / railway	–	–

TABLE 4.17.1-1 (cont'd)

Potentially Affected Communities Identified in the Project's Health Study Area

Census Area/Potentially Affected Community	Project Facility in the Area	Transportation Corridor [a]	Logistical and Supply Center [b]	Growth-Related Effects [c]
Skwentna [e]	Mainline	–	–	–
Talkeetna [d,e]	Mainline	Parks Hwy / airport	–	–
Trapper Creek [e]	Mainline	Parks Hwy	–	–
Wasilla [d]	Mainline	Parks Hwy	–	–
Willow [d]	Mainline	Parks Hwy / airport	–	–
Chase [d,e]	–	–	–	–
Petersville [d]	–	–	–	–
Susitna North [d]	–	–	–	–
Lakes [d]	–	–	–	–
Meadow Lakes [d]	–	–	–	–
Point MacKenzie [d]	–	–	–	–
Tanaina [d]	–	–	–	–
Buffalo Soapstone [d]	–	–	–	–
Butte [d]	–	–	–	–
Farm Loop [d]	–	–	–	–
Knik River [d]	–	–	–	–
Lazy Mountain [d]	–	–	–	–
Palmer [d]	–	–	–	–
Sutton Alpine [d]	–	–	–	–
Chickaloon [d]	–	–	–	–
Glacier View [d]	–	–	–	–
Skwentna [d,e]	–	–	–	–
Alexander Creek [d,e]	–	–	–	–
Kenai Peninsula Borough	Mainline	–	–	X
Anchor Point [d]	–	Sterling Hwy	–	–
Beluga [d,e]	–	Road to Tyonek / airport / primary barge landing	–	–
Clam Gulch	–	Sterling Hwy	–	–
Cohoe	Liquefaction Facility	Sterling Hwy	–	–
Cooper Landing [d]	–	Sterling Hwy	–	–
Happy Valley	–	Sterling Hwy	–	–
Homer [d]	–	Sterling Hwy / secondary port	–	–
Kalifornsky	Liquefaction Facility	Sterling Hwy	–	–
Kasilof	Liquefaction Facility	Sterling Hwy	–	–
Kenai [d]	Liquefaction Facility	Airport	–	–
Moose Pass	–	Seward Hwy	–	–

TABLE 4.17.1-1 (cont'd)

Potentially Affected Communities Identified in the Project's Health Study Area

Census Area/Potentially Affected Community	Project Facility in the Area	Transportation Corridor [a]	Logistical and Supply Center [b]	Growth-Related Effects [c]
Nikiski [d,e]	Liquefaction Facility	Primary port	X	
Ninilchik/Ninilchik ANVSA [d]	–	Sterling Hwy	–	–
Salamatof [d]	Liquefaction Facility	–	–	–
Seward	–	Seward Hwy / primary port / railway / airport	–	–
Soldotna [d]	Liquefaction Facility	Sterling Hwy	–	–
Sterling	Liquefaction Facility	Sterling Hwy	–	–
Tyonek [d,e]	Mainline	–	–	–
Hope [d]	–	–	–	–
Sunrise [d]	–	–	–	–
Nikolaevsk [d]	–	–	–	–
Fritz Creek [d]	–	–	–	–
Seldovia [d,e]	–	–	–	–
Port Graham [d,e]	–	–	–	–
Nanwalek [e]	–	–	–	–
Municipality of Anchorage	–	–		X
Anchorage [d]	–	Glenn Hwy / Seward Hwy / primary port / airport / railway	X	–
Eklutna ANVSA	–	Glenn Hwy	–	–
Southeast Fairbanks Census Area		–		
Big Delta	–	Richardson Hwy	–	–
Delta Junction	–	Richardson Hwy	–	–
Dot Lake/Dot Lake ANVSA	–	Alaska Hwy	–	–
Dry Creek	–	Alaska Hwy	–	–
Tanacross	–	Alaska Hwy	–	–
Tok	–	Alaska Hwy	–	–
Tetlin	–	Alaska Hwy	–	–
Northway Junction	–	Alaska Hwy	–	–
Northway	–	Alaska Hwy	–	–
Alcan Border	–	Alaska Hwy	–	–
Municipality of Skagway Borough	–	Klondike Hwy / Alaska Hwy / secondary port	–	–
Valdez-Cordova Census Area	–	–	–	–
Chistochina	–	Tok Cutoff	–	–
Copper Center/Copper Center ANVSA	–	Richardson Hwy	–	–
Gakona	–	Richardson Hwy	–	–
Gakona ANVSA	–	Richardson Hwy	–	–

TABLE 4.17.1-1 (cont'd)

Potentially Affected Communities Identified in the Project's Health Study Area

Census Area/Potentially Affected Community	Project Facility in the Area	Transportation Corridor [a]	Logistical and Supply Center [b]	Growth-Related Effects [c]
Glennallen [d]	–	Richardson Hwy	–	–
Gulkana	–	Richardson Hwy	–	–
Gulkana ANVSA	–	Richardson Hwy	–	–
Mentasta Lake/Mentasta Lake ANVSA	–	Tok Cutoff	–	–
Paxson	–	Richardson Hwy	–	–
Slana	–	Tok Cutoff	–	–
Tazlina/Tazlina ANVSA	–	Richardson Hwy	–	–
Tonsina	–	Richardson Hwy	–	–
Valdez [d]	–	Richardson Hwy / secondary port / airport	–	–
Whittier [d]	–	Primary port / railway	–	–
Copper Center [d]	–	–	–	–
Kenny Lake [d]	–	–	–	–
Other	–	–	–	–
Adak	–	Secondary port	–	–
Nome/Nome ANVSA	–	Secondary port	–	–
Unalaska	–	Primary port / airport	–	–

Source: See appendix V

ANVSA = Alaska Native Village Statistical Area; X = Effects apply to these communities; "–" = Not applicable

Note: A city/CDP and the corresponding ANVSA are listed separately only if the populations of the two geographical units differ.

[a] The anticipated Project transportation routes, including public roads, airports, and port infrastructure.

[b] The Project logistical and supply centers in Prudhoe Bay/Deadhorse, Fairbanks, Nikiski, and Anchorage.

[c] Inferred from AGDC's HIA to refer to population and economic growth.

[d] Inferred from AGDC's HIA as the villages that could be affected from potential changes in subsistence resources. The HIA defines these PACs as within the "Subsistence and Traditional Knowledge (TLK) Study Area" for the HIA.

[e] Subsistence impacts are assessed in section 4.14.

4.17.2.1 Health Effect Category 1: Social Determinants of Health

Social determinants of health are defined as "the circumstances in which people are born, grow up, live, work, and age, and the systems put in place to deal with illness" and "are mostly responsible for health inequities—the unfair and avoidable differences in health status seen within and between countries" (World Health Organization, 2008). Social determinants of health are real and important; and their influence on health outcomes can be complex and often indirect. For outcomes (or endpoints), the HIA reports life expectancy, maternal and child health, suicide rates, and substance abuse rates as general indicators of physical and social well-being. To provide context, the general demographics, family structure, economic status, and educational attainment are included.

TABLE 4.17.2-1

Key Health Indicators Presented in AGDC's Health Impact Assessment

Census Area	Infant Mortality Rate per 1,000 live births [a] (data year)	Mortality Rates (per 100,000 people) from Key Infectious Diseases, Age-Adjusted (2011–2013) [b]		Mortality Rate per 100,000 people from Major Cardiovascular Disease Age-adjusted (2011–2013) [c]
		Infectious and Parasitic Diseases	Influenza and Pneumonia	
State of Alaska	5.5 (2012)	14.8	12.1	189.9
North Slope Borough	6.8 * (2008–2012)	**	0.0	165.8
Yukon-Koyukuk Census Area	** (2008–2012)	**	46.4*	261.9
Fairbanks North Star Borough	3.8 * (2010–2012)	9.8	12.1	191.5
Denali Borough	** (2008–2012)	**	**	**
Matanuska-Susitna Borough	4.0 * (2010–2012)	9.9	9.6*	182.2
Kenai Peninsula Borough	3.2 * (2010–2012)	12	11.8*	183.7
Municipality of Anchorage	5.0 (2012)	17.6	10.9	119.1
Southeast Fairbanks Census Area	** (2008–2012)	**	**	206.0
Skagway-Hoonah-Angoon Census Area	0.0 (2008–2012)	**	**	208.0*
Valdez-Cordova Census Area	** (2008–2012)	**	**	233.8

Source: Alaska Bureau of Vital Statistics; Center for Diseases Control Behavioral Risk Factor Surveillance System, Feeding America, as cited in appendix V.

* = Rates based on fewer than 20 occurrences are statistically unreliable and should be used with caution.

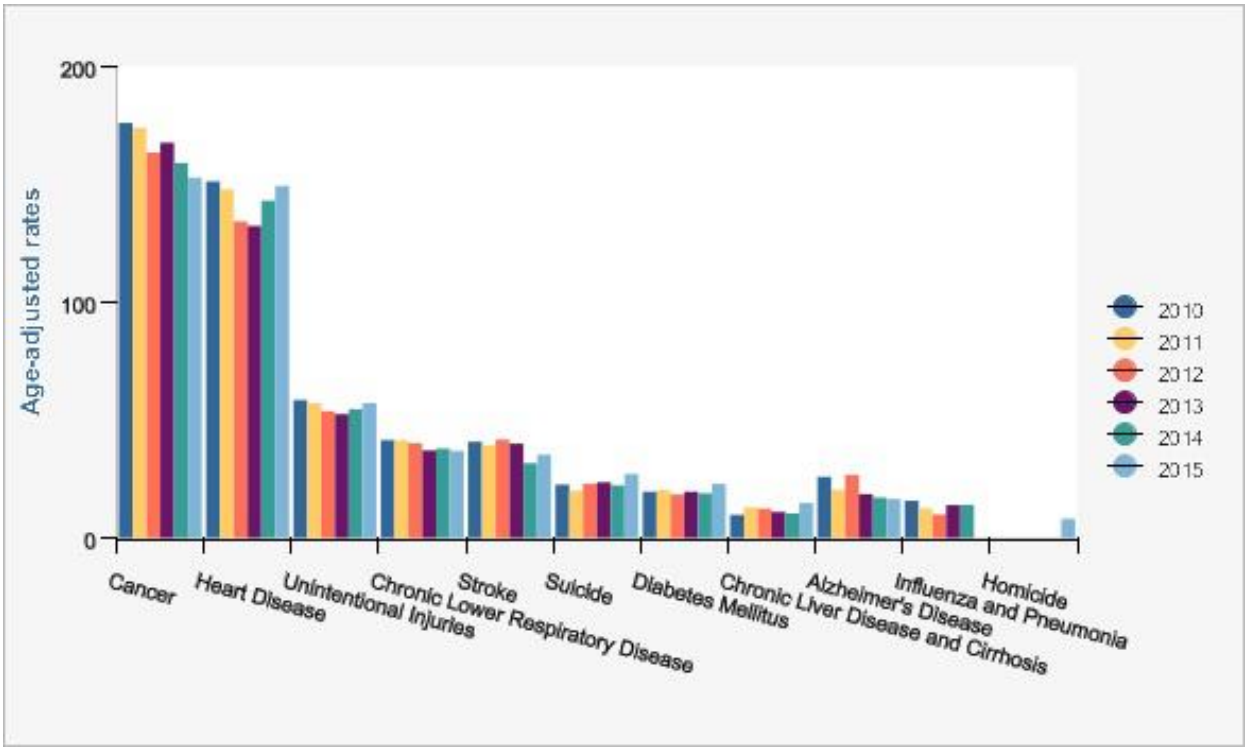
** = Rates based on fewer than six occurrences are not reported.

NA = Not available: data not included in the HIA (appendix V).

[a] Infant Mortality Rate refers to the number of deaths of infants less than 1 year of age, per 1,000 live births.

[b] Infectious and parasitic diseases refers to hygiene-related diseases, such as tuberculosis and septicemia, sexually transmitted diseases (e.g., HIV), and parasitic diseases (e.g., giardia); influenza and pneumonia are infections that commonly impact the respiratory system.

[c] Includes heart disease and cerebrovascular disease.



Source: ADHSS, 2015a

Figure 4.17.2-1 Leading Causes of Death for all Alaskans 2010–2015

Concerning maternal and infant care, a key marker for a healthy pregnancy is the adequacy of prenatal care. The Adequate Prenatal Care Utilization Index is a measure that combines the initiation of prenatal care and the number of prenatal visits. In the health study area, 2012 data indicates that the Southeast Fairbanks Census Area and Denali Borough had the highest percentage of births (over 30 percent) where the mother was documented as having inadequate prenatal care. In the Yukon-Koyukuk Census Area and North Slope Borough, 29.5 and 22.5 percent of mothers, respectively, were reported to have had inadequate prenatal care, which is above the state average of 17.2 percent. Of pregnant Alaska Native women, the percentage considered to have received inadequate prenatal care is higher than the state-wide average (24.2 percent) (based on Alaska Bureau of Vital Statistics [ABVS] 2016 data, as cited in appendix V, section 3.1.1.4.2).

Two other measures of maternal and infant health are low birth weight, which refers to newborns weighing less than 5.5 pounds (2,500 grams) at the time of birth, and infant mortality. Low birth weight is generally an indicator of poor delivery of nutrients and oxygen to the fetus, which is related to the mother's health. In the health study area, 2012 data indicates that the percentage of low birth weight births to mothers under the age of 20 years ranged from 0 percent in the Southwest Fairbanks and Skagway-Hoonah-Angoon census areas, up to 8.8 percent in the Kenai Peninsula Borough, and 10.1 percent in the Matanuska-Susitna Borough. The other PACs had low birth weight rates within 1 to 2 percentage points of Alaska's average of 5.6 percent. Infant mortality rates are presented in table 4.17.2-1. All PACs had infant mortality rates below the state average of 5.5 per 1,000 births, with the exception of the North Slope Borough at 6.8 per 1,000 births (based on ABVS 2016 data, as cited in appendix V, sections 3.1.1.4.5 and 3.1.1.4.8).

Concerning mental health, suicide mortality rates are an important health outcome that can function as an indicator for the mental health wellness in a population. Alaska's suicide rates are highest among males, young adults, and American Indian/Alaska Native people. Within the health study area, the Yukon-

Koyukuk Census Area has the highest age-adjusted suicide rate at 72.3 per 100,000 people (due to a small sample size, this figure is not statistically robust but is included to indicate there may be a special concern for this population) (based on ABVS and Alaska Indicator-Based Information System [AK-IBIS] 2016 data, as cited in appendix V, section 3.1.1.5.2). Kenai Peninsula Borough has the highest statistically reliable suicide rate at 27.3 per 100,000 people. Alaska's suicide rate is 22.2 per 100,000 people, compared to about 12 per 100,000 in the rest of the United States).

Substance abuse, which refers to the "overindulgence in or dependence on an addictive substance, especially alcohol or drugs," is a key risk factor for health problems and strongly influences health outcomes, such as accidents and injuries (see appendix V). Within the health study area, all key census areas had levels of binge drinking among adults higher than the state average of 12.5 percent. The Yukon-Koyukuk Census Area reported the highest level of binge drinking at over 30 percent. Binge drinking was similar among Alaska Native people as for the general population with the exception of the Yukon-Koyukuk Census Area where Alaska Native people were estimated at over 37 percent. In addition to alcohol use, heroin and opioid overdose rates in Alaska are twice the rate of the rest of the United States (10.5 versus 5.1 per 100,000 people for opioids and 3.0 versus 1.9 per 100,000 for heroin) (based on ADHSS [2016] and Alaska Indicator-Based Information System 2016 data, as cited in appendix V, section 3.1.1.5.8.1).

Poverty, which takes into account household income and size, is an important determinant of human health status. In general, the poverty rate is higher in Alaska rural areas than in Alaska urbanized areas. Within the health study area, the poverty rates for the Yukon-Koyukuk Census Area, North Slope Borough, and Southeast Fairbanks Census Area in 2013 were higher than that of the state as a whole. Poverty rates are higher among Alaska Native populations than for the general population (appendix V).

Cultural factors, including cultural continuity and cultural engagement, are important determinants of health in that people who are involved with their cultural community tend to be healthier than people who are not (Chandler, 1998; Chandler, 2004). Among Alaska Natives, speaking a native language and participating in subsistence activities are recognized as important signifiers of community health and cultural continuity. Within the health study area, the predominant group in the North Slope Borough is Inupiat, and in the Yukon-Koyukuk and Southeast Fairbanks Census Areas it is Athabascan. In the study area, the North Slope Borough has the highest percentage of households speaking a language other than English at home (31.9 percent) (based on U.S. Census Bureau estimates, as cited in appendix V, section 3.1.1.6.7).

In addition to the social determinants information provided in the HIA, section 4.11 of this EIS provides additional baseline demographic information on the study area, including information on race, ethnicity, and income status (see sections 4.11.1 and 4.11.8).

4.17.2.2 Health Effect Category 2: Accidents and Injuries

In Alaska, accidents and injuries are an important cause of mortality and morbidity. Unintentional injury (injury or death other than suicide and homicide) is the third leading cause of death in the state, while assault (homicide) is the tenth leading cause. Poisoning is the primary cause of unintentional injury-related death. In terms of traffic accidents, the number of fatalities remained fairly constant (between 60 to 64 fatalities) between 2009 and 2015. Among Alaska Natives, unintentional injury was the third leading cause of death, and it is the leading cause of death for Alaska Native people aged 25 to 44 years. While mortality rates over the past 30 years have improved, data from 2008 to 2011 indicate that Alaska Natives have an unintentional injury mortality rate 2.2 times that of Alaska non-Natives and 2.6 times that of U.S.

whites. Among the potentially affected Tribal Health Regions,[135] the Interior Public Health Region had the highest unintentional injury death rate. Poisoning, followed by drowning, were the leading causes of unintentional death among Alaska Natives (based on information from the ADOT&PF and AN Epicenter [2017], as cited in appendix V, section 3.2.1.5).

In addition to the accidents and injuries information provided in the HIA, section 4.11.6 of this EIS provides information on law enforcement, section 4.12 provides information on baseline traffic and safety, and section 4.18.10 reviews baseline information pertaining to accidents related to spills or fires from existing pipeline accident data.

4.17.2.3 Health Effect Category 3: Exposure to Potentially Hazardous Materials

Human exposure to potentially hazardous materials can cause or exacerbate certain health conditions and sometimes increase the risk of chronic illnesses, such as cancer. Rural communities in Alaska have several possible contamination exposure sources, including fuel and biomass combustion, local waste processes, and abandoned contaminated sites. Exposure to mercury through the consumption of fish and marine mammals is a public health concern, in particular for Native Alaskans. Nikiski, in the Kenai Peninsula Borough, is a contaminated industrial area where there may be higher risk for pre-existing environmental hazards, such as chlorinated contaminates and hydrocarbons, which have been found in groundwater monitoring wells around the area. In terms of air quality, there is an elevated potential for exposures to particulate matter in rural Alaska. Important outdoor air pollution sources are open burning/smoke, road dust, and vehicle exhaust. Significant indoor air quality sources are mold, lack of ventilation or fresh air, and dust. In terms of drinking water quality, in 2013, all key census areas in the health study area had at least one drinking water violation related to contaminate levels with the exception of North Slope Borough. There was no data on drinking water reported for Denali Borough (based on County Health Rankings [2016b] and Ware et al [2013], as cited in appendix V, section 3.3.5).

In addition to the description on potentially hazardous materials presented in the HIA, section 4.9.6 of this EIS provides information on potential existing sources of hazardous waste in the Project area; section 4.3.4 provides baseline information on water uses, water supply, and quality; and section 4.15.2 describes baseline air quality conditions.

4.17.2.4 Health Effect Category 4: Food, Nutrition, and Subsistence Activity

In Alaska, subsistence fishing and hunting are important sources of income and nutrition in almost all rural communities, in particular for residents where food prices are high. Subsistence fishing and hunting are used to supplement diets throughout the year; subsistence fish and animals are considered nutritious as they are dense in protein, iron, vitamin B12, polyunsaturated fats, monounsaturated fats, and omega-3 fatty acids (appendix V). A detailed discussion of subsistence practices is described in section 4.14.

Food security refers to having enough food to meet basic needs at all times. Food insecurity is the percentage of the population that did not have access to a reliable food source during the past year (Gundersen et al., 2015). The 2013 data reported in the HIA indicates that the Yukon-Koyukuk Census Area has the highest percentage of residents who live with food insecurity at 21 percent, which is 50-percent

[135] The Alaska Native Tribal Health Consortium, a non-profit Tribal health organization that serves the Alaska Native and American Indian people of Alaska, is administratively divided up into 12 Tribal Health Regions spread across the state. The boundaries of the Tribal Health Regions do not always follow those of boroughs and census areas.

higher than the state average.[136] The rest of the study area had levels of food insecurity within 4 percentage points of the state average.

Various factors may contribute to food insecurity, including cost of living, access, and income. Due to the remoteness of some areas of the state, the cost of living in Alaska is 8-percent higher than the cost of living in the rest of the United States (Gundersen et al., 2015; Economic Policy Institute, 2016; County Health Rankings, 2016a). In the health study area in 2010, the percentage of the population with "limited access to healthy foods" (referring to the percentage of the population who are low income and do not live close to a grocery store) ranged from 4 percent in the North Slope Borough and Skagway-Hoonah-Angoon to 50 percent in the Yukon-Koyukuk census area (Gundersen et al., 2015).

These findings are not always straight-forward, however, as more recent information collected by the ADF&G (as described in section 4.14) indicates that the Yukon-Koyukuk Census Area may not have a higher food insecurity rate than the state average; localized subsistence studies completed for the Project of four communities in the Yukon-Koyukuk Census Area—including Nenana, Stevens Village, Rampart, and Tanana—reported food security greater than 90 percent (Brown and Kostick, 2017; Brown et al., 2016).

4.17.2.5 Health Effect Category 5: Infectious Diseases

Infectious, or communicable diseases, are caused by a diverse range of pathogens and can affect populations differently depending on environmental and other contextual factors. Communicable diseases disproportionally affect poor individuals and are exacerbated by unsanitary conditions, such as unsafe water and inadequate personal hygiene. Infectious diseases of public health concern in Alaska include sexually transmitted chlamydial infection, which has a statewide incidence rate of 766 cases per 100,000 people, the highest in the nation during the reporting period of 2010 to 2014. HIV/AIDS incidence in Alaska, however, remains fairly low compared to national levels. Cases of giardiasis, a well-known water-borne pathogen in Alaska, had outbreaks in 2012 and 2014. From 2011 to 2013, reportable communicable diseases[137] were not among the leading causes of death for populations in the health study area.

Septicemia followed by viral hepatitis were the most common causes of death due to infectious and parasitic disease in all areas. Anchorage had the highest rate of infectious and parasitic disease-related death (17.6 per 100,000 people) in the study area. Mortality rates due to influenza and pneumonia were generally higher than the rates for infectious and parasitic diseases across all census areas, with pneumonia being the most common cause of death. The Yukon-Koyukuk Census Area had the highest rate of pneumonia-related deaths in the study area, and a rate close to four times the state average (46.4 versus 12.1 per 100,000 people) (ADHSS, 2016).

4.17.2.6 Health Effect Category 6: Non-communicable and Chronic Diseases

Chronic, or non-communicable diseases are defined broadly as conditions that last more than 1 year and require ongoing medical attention and/or limit activities of daily living. These most commonly include cardiovascular diseases, chronic respiratory diseases, cancer, mental disorders, and diabetes. In Alaska, cancer is the leading cause of death, followed by heart disease. Alaska Native cancer incidence was similar to that of U.S. whites nationally in 2012 to 2013, but the cancer mortality rate is higher among Alaska Natives (272.5 per 100,000 people) than for all Alaskans (167.9 per 100,000 people). Alaska Natives also

[136] The HIA based its assessment of food insecurity on the USDA's Core Food Insecurity Model and 2013 data collected from the Community Population Survey, Bureau of Labor Statistics, and American Community Survey.

[137] Disease considered to be of great public health importance that government agencies (e.g., county and state health departments or the U.S. Centers for Disease Control and Prevention) require be reported when they are diagnosed.

have a much higher incidence rate of colorectal cancer than any other ethnic group in Alaska. Overall, more Alaskans died from cancer of the trachea, bronchus, and lung than any other type of cancer.

Within the health study area in the reporting period of 2011 to 2013, the North Slope Borough had the highest mortality rate due to cancer (238.7 per 100,000 people), followed by the Yukon-Koyukuk Census Area (229.4 per 100,000 people). While heart disease is the second leading cause of death, there was a general decline in mortality related to cardiovascular diseases between 2000 and 2013 statewide. In 2011 to 2013, the rate of cardiovascular disease-related deaths was higher than the state in 5 of the 10 primary census areas, with the Yukon-Koyukuk Census Area reporting the highest rate (261.9 per 100,000 people). Chronic lower respiratory disease, or chronic obstructive pulmonary disease, is the fourth leading cause of death in Alaska. Between 2006 and 2015, the age-adjusted mortality rate due to chronic lower respiratory disease has decreased by several percentage points (based on ABVS and AK IBIS 2016 data, as cited in appendix V, section 3.6.3).

Key behavioral risk factors for chronic illnesses include smoking, a poor diet, and lack of physical activity. In 2013, 55 percent of all Alaskans reported getting the recommended amount of physical activity, while 46.8 percent of Alaska Natives reported the same. The percentage of all adults nationally who reported getting the recommended amount of physical activity during the same year was 50.5 percent. In the study area, the North Slope Borough reported the lowest levels of physical activity, and also had the highest prevalence of obesity at 39.9 percent (based on Behavioral Risk Factor Surveillance System 2016 data, as cited in appendix V, section 3.6.8).

4.17.2.7 Health Effect Category 7: Water and Sanitation

Many Alaska villages lack adequate sources of water that are safe to drink and facilities that can safely dispose of wastewater. In 2008, regions in Alaska with a lower proportion of home water service had significantly higher hospitalization rates for certain infectious diseases, including pneumonia and influenza (rate ratio = 2.5), skin or soft tissue infection (rate ratio = 1.9), and respiratory syncytial virus (rate ratio = 3.4 among children under 5 years of age) than did higher-service regions. Despite major improvements in recent decades, Alaska remains behind other states in terms of having basic sanitation services. In 2014, 85 percent of rural community housing units statewide had water and sewer services. Additionally, fluoridation of water, a Center for Diseases Control-recognized mechanism for safely delivering fluoride to populations, was included in 45.7 percent of the drinking water systems in Alaska in 2013, below the 2012 national rate of 74.6 percent (based on Hennessy et al. [2008], AK-IBIS [2016], and ADEC [2016b], as cited in appendix V, section 3.7). In addition to water and sanitation information provided in the HIA, baseline drinking water supply information for the study area is included in section 4.3.4 of this EIS.

4.17.2.8 Health Effect Category 8: Health Services Infrastructure and Capacity

Much of Alaska's healthcare system is made up of native health care organizations, which operate the area health care facilities. In Alaska, access to quality healthcare is influenced by a number of factors, including access to care, affordability, and having health insurance. Preventable hospitalizations are those that could be avoided if patients had early access to quality outpatient healthcare services. This measure can be used to assess the effectiveness and accessibility of primary health care. Alaska Native adults, with a preventable hospitalization rate of 18.2 per 1,000 adults, had more than twice the statewide preventable hospitalization rate of all Alaskans (7.3 per 1,000 adults) in 2012. In 2014, 13.6 percent of Alaskans statewide reported cost as a barrier to accessing healthcare within the past year, while a slightly lower percentage of Alaska Natives reported cost as a barrier to care (11.8 percent) (based on AK-IBIS 2016 data, as cited in appendix V, section 2.8.2).

4.17.3 Impacts and Mitigation

The methodology used to rate health impacts, which follows the ADHSS guidelines (2015b), is described in appendix V. Impacts were evaluated based on the potential severity of the impact and the likelihood that an impact would occur. For severity, a numeric score of 0 to 4 was selected based on the nature of the health outcome and the duration, extent, frequency, and magnitude of the potential impact. Impact severities were rated as low, medium, high, or very high depending on the numeric score. Once the impact severity was selected, the likelihood of the impact was determined according to ADHSS' likelihood scale (ADHSS, 2015b). Final impact ratings were assigned as low, medium, high, or very high, depending on their severity and likelihood of occurring. Positive impacts as well as adverse impacts were assessed using this methodology.

Tables 4.17.3-1 and 4.17.3-2 present summaries, organized according to HECs, of the health impacts that AGDC's HIA determined could result from Project construction and operation, respectively. All ratings presented in tables 4.17.3-1 and 4.17.3-2 are from AGDC's HIA. Also included in the tables are the recommendations that the HIA provided to mitigate or prevent adverse impacts. Because the HIA impacts were not evaluated separately for the Gas Treatment, Mainline, and Liquefaction Facilities, it is assumed that the impacts would be similar for all three Project components unless a specific area is noted (e.g., improvements in air quality in Fairbanks).

As summarized in table 4.17.3-1, the potential for increases in infectious diseases due to construction worker influx during construction (HEC 5) would be considered high adverse, while depression and anxiety due to the influx of construction workers and activity (HEC 1), changes in food and nutrition due to disruptions to subsistence use areas (HEC 4), and accidents and injuries due to increased truck, rail, and marine traffic (HEC 2) would be considered medium adverse. All other HECs were rated low.

Operational impacts for adverse effects were also rated low for all HECs except three that were rated as medium adverse (see table 4.17.3-2): increased stress over concerns about possible gas leaks, fires, or explosions (HEC 1); accidents and injuries due to the potential for fatal and non-fatal injuries from leaks, fires, or explosions (HEC 2); and the potential for increases in infectious disease transmission due to worker influx, although the operational workforce would be less than that for construction (HEC 5).

The HIA concluded the Project would result in one high potential positive impact during construction: increases in employment and household income (HEC 1). During operation, three medium potential positive impacts were identified, including increases in employment and household income (HEC 1), and air quality improvements in the Fairbanks area due to decreases in harmful emissions based on the conversion of other fuel sources to natural gas, resulting in potential positive ratings for both HECs 3 and 6.

TABLE 4.17.3-1

Construction Impacts and Mitigation Summary

Impact Description [a]	Impact Rating [b]	Mitigation Measures [c]
HEC 1: Social Determinants of Health		
Increase in depression and anxiety due to influx of construction workers and construction activity. Potential impacts on subsistence and subsistence lifestyle arising in selected PACs, including Minto, Nenana, Four Mile Road, Alexander Creek, Tyonek, and Beluga.	Medium Adverse	Potential adverse impacts during construction would be reduced by keeping worker camps closed to reduce the presence of the outside workforce in communities; keeping local communities and their leaders informed of the Project schedule; and providing community-based participatory monitoring and community engagement to stay aware of and respond to community concerns.
Change in employment and median household income.	High Positive	Employment opportunities during construction could alleviate family stress by improving family income and the local economy during construction.
HEC 2: Accidents and Injuries		
Potential for fatal and nonfatal injuries from construction activity; and increased rail, truck, and sea transport activity.	Medium Adverse [d]	Potential adverse impacts during construction would be reduced by providing training for drivers and requiring transportation equipment to meet legal requirements and be in working order. In addition, the chance of an accident would be lowered by following systematic approaches to transportation safety. AGDC would follow the Health, Safety, Security, and Environment Plan, which outlines requirements for training, safety meetings, accident investigation, and contractor requirements; and would follow a Traffic Mitigation Plan for road traffic and a Journey Management Plan for marine traffic (see section 4.12). Finally, developing and implementing emergency response plans and drills for accidents, injuries, or hazardous material release events would reduce the risk of accidents (see section 4.18).
HEC 3: Exposure to Potentially Hazardous Materials		
The potential for human exposure to hazardous materials would occur primarily due to air emissions (e.g., fugitive dust, criteria pollutants, VOCs) from increased vehicle traffic on unpaved roads, general construction activities, use of diesel-powered mobile equipment, and truck and rail traffic in PACs along the rail line and highways.	Low Adverse	Potential adverse impacts during construction would be reduced by implementing BMPs that would reduce fugitive dust in accordance with regulatory requirements; meeting regulatory requirements that reduce PM emissions; and, implementing BMPs that manage the use of hazardous substances, including tracking and reporting. AGDC would follow the Project Fugitive Dust Control Plan, SPCC Plan, Waste Management Plan, and the Unanticipated Contamination Discovery Plan.
HEC 4: Food, Nutrition, and Subsistence Activity		
Construction activities (e.g., construction noise, traffic, human presence, barging, and water use requirements) causing removal or disruption of subsistence use areas; temporary decrease in resource availability; temporary reduction in harvester access; and contamination (real or perceived).	Medium Adverse [e]	Potential adverse impacts during construction would be reduced by developing a subsistence plan of cooperation to minimize work during times when subsistence activities would occur to the extent practicable; keeping local communities and their leaders informed of the Project schedule; and providing community-based participatory monitoring and community engagement to stay aware of and respond to community concerns. Project plans that address this impact include the Wildlife Avoidance and Interaction Plan; the Marine Mammal Monitoring and Mitigation Plan for Construction of the Alaska LNG Project in Cook Inlet; the Marine Mammal Monitoring and Mitigation Plan for Construction of the Alaska LNG Project in Prudhoe Bay; the Revegetation Plan; the Invasives Plan; and the ISPMP.

TABLE 4.17.3-1 (cont'd)

Construction Impacts and Mitigation Summary

Impact Description [a]	Impact Rating [b]	Mitigation Measures [c]
HEC 5: Infectious Disease		
Due to influx of new workers there is a potential for increases in the transmission of pediatric or adult respiratory disease rates, increases in sexually transmitted infection rates, gastro intestinal outbreaks, and antibiotic-resistant staph skin infections.	High Adverse	Potential adverse impacts during construction would be reduced by reducing opportunity for interaction with other persons outside the camps; and providing health education and outreach programs. Construction contractors would be required to have health and safety programs that provide adequate health and medical equipment and staff to respond to and prevent medical emergencies.
HEC 6: Non-Communicable Chronic Diseases		
Potential increased rates of asthma, chronic obstructive pulmonary disease, and cardiovascular disease from Project emissions of criteria pollutants, particularly $PM_{2.5}$. Potential increased rates of diabetes from change in diet from loss of access to or opportunity to harvest subsistence resources.	Low Adverse	Any adverse impacts during construction would be reduced by the implementation of regulatory requirements regarding the mitigation of fugitive dust, including implementation of the Project Fugitive Dust Control Plan and Open Burning Plan, and the reduction of particulate matter emissions. See the mitigation measures for subsistence resources provided for HEC 4.
HEC 7: Water and Sanitation		
Increases in diseases if there is insufficient water for cleaning and/or drinking if Project activities cause a change in potable water access, water quantity or quality, or demand on water and sanitation infrastructure due to the influx of non-resident workers.	Low Adverse	Any adverse impacts during construction would be reduced by the implementation of regulatory requirements and BMPs. AGDC would obtain (and comply with provisions of) the necessary permits prior to water withdrawal, thereby minimizing any potential adverse effects on existing water rights and supplies. An increased demand on water and sanitation infrastructure due to camps would be managed and mitigated accordingly through permits obtained from ADEC and contracts with local service providers. Applicable plans are the Project Water Use Plan and Water Well Monitoring Plan.
HEC 8: Health Service Infrastructure and Capacity		
Potential increased use of health infrastructure resources/clinic burden due to resident or worker influx injuries or illness. During many days, EMS services in Nikiski, Kenai, and Soldotna are understaffed relative to the number of calls received. Any increase in call volume would exacerbate these understaffing problems. In addition, should the workload of EMS service providers increase as a result of population increases related to Project construction, they may be compelled to hire full-time paid professionals, rather than continuing to rely on volunteers.	Low Adverse	Any adverse impacts during construction would be reduced by the implementation of regulatory requirements and the health care plans developed by AGDC. The temporary construction camps built by the Project would provide onsite healthcare to respond to minor medical needs for the construction workforce. Most construction camps would have trained medical staff and dedicated transportation (i.e., ambulances or helicopters) to handle routine and emergency response situations. An exception would be the GTP construction camp, which would have first aid capabilities only and would rely on the Fairweather Deadhorse Medical Clinic and Prudhoe Bay Operations Center in the Prudhoe Bay CDP for emergency medical response. The Project would implement "fit-for-duty" screenings of incoming construction workers to decrease the number of Project non-related injuries/illnesses requiring medical treatment at worksite facilities or community medical facilities. The Liquefaction Facilities worksite would be largely self-sufficient with respect to emergency response services, including medical facilities and small-scale fire response.

[a] Describes the health effect (i.e., the impact of specific Project activities).

[b] Presents the results of the analysis of the potential severity of the impact and the likelihood that an impact would occur, according to ADHSS guidelines (2015b).

[c] Based on the impact ratings, AGDC proposed actions in its HIA to reduce or prevent the level of adverse impact.

TABLE 4.17.3-2

Operational Impacts and Mitigation Summary

Impact Description [a]	Impact Rating [b]	Mitigation Measures [c]
HEC 1: Social Determinants of Health		
Perceptions that the Project threatens a way of life due to concerns over possible gas leaks, fires, or explosions.	Medium Adverse	Potential adverse impacts during operation would be reduced by maintaining community engagement to keep operators aware of and respond to community concerns.
Changes in long-term employment and median household income.	Medium Positive	AGDC's HIA does not provide recommendations for measures to enhance positive impacts.
HEC 2: Accidents and Injuries		
Potential for fatal and nonfatal injuries due to leaks, fires, or explosions.	Medium Adverse [d]	Potential adverse impacts during operation would be reduced by implementing a systematic contractor oversight program that addresses equipment and maintenance standards. AGDC would follow the Project Health, Safety, Security, and Environment Plan, which outlines requirements for training, safety meetings, accident investigation, and contractors. Maintenance requires ongoing equipment inspections. AGDC would promptly notify applicable regulatory agencies of fires on, or that could threaten, any portion of the Project and facilities. AGDC would take measures necessary for the prevention and suppression of fires in accordance with applicable law.
HEC 3: Exposure to Potentially Hazardous Materials		
Potential fugitive emissions from pipeline connections; operation of the GTP LNG Plant would emit combustion related pollutants, such as NO_x, CO, PM, VOCs, and SO_2.	Low Adverse	Potential adverse impacts during operation would be reduced by implementing the BACT as defined under the ADEC air permitting process.
Potential for other toxic / hazardous substances to be emitted – components of natural gas and NGLs (e.g., isobutene, pentanes, hexanes, hydrogen sulfide, butane, and ethane) as well as paints, solvents, petroleum products, and fertilizers.		
Potential decrease in harmful emissions from sources other than those from natural gas when natural gas is used in Fairbanks, Anchorage, or other communities.	Medium Positive	AGDC's HIA does not provide recommendations for measures to enhance positive impacts.
HEC 4: Food, Nutrition, and Subsistence Activity		
Potential decrease in consumption of subsistence resources and decrease in food security due to competition from increased access; and increase in traffic and noise that could displace or reduce availability of subsistence resources.	Low Adverse	Potential adverse impacts during operation would be reduced by maintaining community engagement in order to keep operators aware of and respond to community concerns.
HEC 5: Infectious Disease		
Worker influx lower than during construction, but still potential for increases in the transmission of pediatric or adult respiratory disease rates, increases in sexually transmitted infection rates, gastro intestinal outbreaks, and antibiotic-resistant staph skin infections.	Medium Adverse	Potential adverse impacts during operation would be reduced by continuing health education and outreach programs. The number of workers would be significantly less during operation (as compared to construction) as would the potential impacts.
HEC 6: Non-Communicable Chronic Diseases		
Potential increased rates of asthma, chronic obstructive pulmonary disease, and cardiovascular disease from Project emissions of criteria pollutants, particularly $PM_{2.5}$.	Low Adverse	Potential adverse impacts during operation would be reduced by the implementation of the BACT for combustion equipment to mitigate emissions of NO_x and CO.

TABLE 4.17.3-2 (cont'd)

Operational Impacts and Mitigation Summary

Impact Description [a]	Impact Rating [b]	Mitigation Measures [c]
Changes in air quality in Fairbanks and other places of expansion of the gas distribution network.	Medium Positive	AGDC's HIA does not provide recommendations for measures to enhance positive impacts.
HEC 7: Water and Sanitation		
Increases in disease due to operation of the Project changing water quantity or quality or demand on water and sanitation infrastructure due to the influx of non-resident workers.	Low Adverse	Any impacts would be very unlikely.
HEC 8: Health Service Infrastructure and Capacity		
Potential increased use of health infrastructure resources/clinic burden due to resident or worker injuries or illness. During many days, EMS services in Nikiski, Kenai, and Soldotna are understaffed relative to the number of calls received. Any increase in call volume would exacerbate these understaffing problems. In addition, should the workload of EMS service providers increase as a result of population increases related to Project operation, they may be compelled to hire full-time paid professionals, rather than continuing to rely on volunteers.	Low Adverse	Any impacts are considered to be extremely unlikely. The Project could consider capacity mitigation measures by payments in lieu of property tax as described in section 4.11.6.2. For example, potential payments could be used for hiring additional fire fighters and emergency medical service personnel during the period of Project operation.

[a] Describes the health effect (i.e., the impact of specific Project activities).

[b] Presents the results of the analysis of the potential severity of the impact and the likelihood that an impact would occur, according to ADHSS guidelines (2015b).

[c] Based on the impact ratings, AGDC proposed actions in its HIA that would reduce or prevent the level of adverse impact.

4.18 RELIABILITY AND SAFETY

4.18.1 LNG Facility Regulatory Oversight

LNG facilities handle flammable and sometimes toxic materials that can pose a risk to the public if not properly managed. These risks are managed by the companies owning the facilities, through selecting the site location and plant layout as well as through suitable design, engineering, construction, and operation of the LNG facilities. Multiple federal agencies share regulatory authority over the LNG facilities and the operator's approach to risk management. The safety, security, and reliability of the Project would be regulated by PHMSA, the Coast Guard, and FERC. The Department of Homeland Security (DHS), Occupational Safety and Health Administration (OSHA), and the EPA would also have jurisdiction of certain parts of the GTP about 800 miles away on a separate property upstream of the Liquefaction Facilities.

In February 2004, PHMSA, the Coast Guard, and FERC entered into an Interagency Agreement to ensure greater coordination among these three agencies in addressing the full range of safety and security issues at LNG terminals and LNG marine vessel operations, and maximizing the exchange of information related to the safety and security aspects of the LNG facilities and related marine operations. Under the Interagency Agreement, FERC is the lead federal agency responsible for the preparation of the analysis required under NEPA for impacts associated with terminal construction and operation. PHMSA and Coast Guard participate as cooperating agencies but remain responsible for enforcing their regulations covering LNG facilities siting, design, construction, operation, maintenance, and security. All three agencies have some oversight and responsibility for the inspection and compliance during the LNG facilities' operation.

PHMSA establishes and has the authority to enforce the federal safety standards for the location, design, installation, construction, inspection, testing, operation, and maintenance of onshore LNG facilities under the Federal Pipeline Safety Laws (49 USC 60101, *et seq.*). PHMSA's LNG safety regulations are codified in 49 CFR 193, which prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that are subject to federal pipeline safety laws (49 USC 60101 *et seq.*) and 49 CFR 192. On August 31, 2018, PHMSA and FERC signed an MOU regarding methods to improve coordination throughout the LNG permit application process for FERC jurisdictional LNG facilities. In the MOU, PHMSA agreed to issue an LOD stating whether LNG facilities would be capable of complying with location criteria and design standards contained in Subpart B of Part 193. The Commission committed to rely upon the LOD in conducting its review of whether the facilities would be consistent with the public interest. The issuance of the LOD does not abrogate PHMSA's continuing authority and responsibility over a proposed project's compliance with Part 193 during facility construction and future operation. PHMSA's conclusion on the siting and hazard analysis required by Part 193 would be based on preliminary design information, which may be revised as the engineering design progresses to final design. PHMSA regulations also contain requirements for the design, construction, equipment, operation, maintenance, qualifications and training of personnel, fire protection, and security for LNG facilities, as defined in 49 CFR 193, and which would be completed during later stages of the Project. If the Project is authorized, constructed, and operated, the LNG facilities, as defined in 49 CFR 193, would be subject to PHMSA's inspection and enforcement programs to ensure compliance with the requirements of 49 CFR 193.

PHMSA has indicated that the GTP would not be subject to PHMSA's 49 CFR 193, LNG Facilities: Federal Safety Standards because it would meet the exemption under 49 CFR 193.2001(b)(2) in not storing any LNG. PHMSA also indicates the GTP would be not be regulated under 49 CFR 192, Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards, with the exception of the outlet piping leaving the processing plant, including the last pressure control device before the gas enters the regulated pipeline, which would have Part 192 regulatory oversight. In addition, the GTP would have three 16-inch distribution pipelines that would transport liquid byproduct (i.e., CO_2 and H_2S) at 4,000 pounds per square inch (psi) from the GTP to well pads, drill sites, and an injection pad that are located approximately 8 to 25 miles away in the North Slope area (see the discussion of the PBY MGS Project in section 4.19.2.2). PHMSA has indicated that these three 16-inch pipelines would be regulated under 49 CFR 195, Transportation of Hazardous Liquids by Pipeline, from the GTP outlet piping to the production facilities, as described in 49 CFR 195.1(b)(10).

OSHA's Process Safety Management regulations under 29 CFR 1910.119 would apply to certain portions of the GTP, and the EPA's Risk Management Plan regulations under 40 CFR 68 may apply to certain portions of the GTP, including the process piping, process vessels and tanks, and associated auxiliary equipment at the GTP. If the GTP is constructed and becomes operational, the facilities would be subject to the OSHA and EPA inspection programs to enforce compliance with the requirements of 29 CFR 1910.119 and 40 CFR 68, respectively.

The Coast Guard has authority over the safety of an LNG terminal's marine transfer area and LNG marine vessel traffic, as well as over security plans for the waterfront facilities handling LNG terminal and LNG marine vessel traffic. The Coast Guard regulations for waterfront facilities handling LNG are codified in 33 CFR 105 and 33 CFR 127. As a cooperating agency, the Coast Guard assists FERC staff in evaluating whether an applicant's proposed waterway would be suitable for LNG marine traffic and whether the waterfront facilities handling LNG would be operated in accordance with 33 CFR 105 and 33 CFR 127. If the facilities are constructed and become operational, the facilities would be subject to the Coast Guard inspection program to ensure compliance with the requirements of 33 CFR 105 and 33 CFR 127.

The DHS has authority over the security of the GTP. The DHS regulations are codified in 6 CFR 27 Chemical Facility Anti-Terrorism Standards (CFATS). If the GTP is constructed and becomes operational,

the facilities would be subject to the DHS inspection program to ensure compliance with the requirements of 6 CFR 27.

FERC authorizes the siting and construction of LNG terminals under the NGA and delegated authority from the DOE. FERC requires standard information to be submitted to perform safety and reliability engineering reviews. FERC's filing regulations are codified in 18 CFR 380.12 (m) and (o), and require each applicant to identify how its proposed design would comply with PHMSA's siting requirements of 49 CFR 193, Subpart B. The level of detail necessary for this submittal requires the applicant to perform substantial front-end engineering of the complete project. The design information is required to be site-specific and developed to the extent that further detailed design would not result in significant changes to the siting considerations, basis of design, operating conditions, major equipment selections, equipment design conditions, or safety system designs. As part of the review required for a FERC order, we use this information from the applicant to assess whether the proposed facilities would have a public safety impact and recommend mitigation measures for the Commission to incorporate as conditions in the order. If the facilities are approved, FERC staff would review material filed to satisfy the conditions of the order and conduct periodic inspections throughout construction and operation.

In addition, the Energy Policy Act of 2005 requires FERC to coordinate and consult with the DOD on the siting, construction, expansion, and operation of LNG terminals that would affect the military. If it is determined that the proposed LNG terminal will adversely affect the test, training, or operational activities of an active military installation, the FERC and DOD are required to continue to work to avoid or mitigate those effects, and FERC is statutorily prohibited from authorizing a LNG terminal before getting a final letter of concurrence from the DOD. On November 21, 2007, FERC and the DOD (http://www.ferc.gov/legal/mou/mou-dod.pdf) entered into an MOU formalizing this process. In accordance with the MOU, FERC sent a letter to the DOD on November 16, 2016 requesting their comments on whether the Project could potentially have an impact on the test, training, or operational activities of any active military installation. On March 1, 2017, FERC received a response letter from the DOD Siting Clearinghouse stating that results of an informal review indicated that the Project may potentially affect military operations conducted in the Project area. Initial concerns were expressed on the proximity of an MLV and a helipad that could interfere with Clear AFS operations (see section 4.9.3). AGDC has committed to relocating the MLV 14 and its helipad. To ensure that these facilities would be relocated to an area that would avoid conflicts with Clear AFS, we have recommended that AGDC file a plan developed in coordination with Clear AFS for the relocation of MLV 14 and its helipad (see sections 4.9.3 and 4.18.10). Based on AGDC's commitments and our recommendation, the DOD provided a preliminary finding on February 23, 2020 that their concerns regarding potential impacts on Clear AFS are satisfactorily alleviated.

We consulted with the DOD regarding the potential for impacts on U.S. Air Force radar operations in the Anchorage, Alaska vicinity during Project operation due to tall structures at the Liquefaction Facilities. The DOD has indicated it had conducted a preliminary review based on a hypothetical structure height of 420 feet above ground level (513 feet above mean sea level) at its highest point. Based on that review, the DOD provided a preliminary finding on February 27, 2020 that the Project would not adversely affect DOD missions within the Anchorage, Alaska vicinity. FERC staff will continue to work with DOD staff to confirm that the Mainline and Liquefaction Facilities would not adversely affect DOD operations at the Clear AFS and in the Anchorage, Alaska vicinity.

4.18.2 PHMSA Siting Requirements and Part 193 Subpart B Determination

The siting of LNG facilities, as defined in 49 CFR 193, with regard to ensuring that the proposed site selection and location would not pose an unacceptable level or risk to public safety is required by PHMSA's regulations in 49 CFR 193, Subpart B. The Commission's regulations under 18 CFR 380.12 (o) (14) require AGDC to identify how the proposed design complies with the siting requirements of 49 CFR 193, Subpart B. The scope of PHMSA's siting authority under 49 CFR 193 applies to LNG facilities used in the transportation of gas by pipeline subject to the federal pipeline safety laws and 49 CFR 192.[138]

The regulations in 49 CFR 193, Subpart B, require the establishment of an exclusion zone surrounding an LNG facility in which an operator or government agency must exercise legal control over the activities where specified levels of thermal radiation and flammable vapors may occur in the event of a release for as long as the facility is in operation. Approved mathematical models must be used to calculate the dimensions of these exclusion zones. The siting requirements specified in NFPA 59A (2001), an industry consensus standard for LNG facilities, are incorporated into 49 CFR 193, Subpart B by reference, with regulatory preemption in the event of conflict. The sections of 49 CFR 193, Subpart B specifically address siting requirements are described below.

- Section 193.2051, Scope, states that each LNG facility designed, replaced, relocated, or significantly altered after March 31, 2000, must be provided with siting requirements in accordance with Subpart B and NFPA 59A (2001). In the event of a conflict with NFPA 59A (2001), the regulatory requirements in Part 193 prevail.

- Section 193.2057, Thermal radiation protection, requires that each LNG container and LNG transfer system have thermal exclusion zones in accordance with section 2.2.3.2 of NFPA 59A (2001).

- Section 193.2059, Flammable vapor-gas dispersion protection, requires that each LNG container and LNG transfer system have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA 59A (2001).

- Section 193.2067, Wind forces, requires that shop fabricated containers of LNG or other hazardous fluids less than 70,000 gallons must be designed to withstand wind forces based on the applicable wind load data in ASCE 7 (2005). All other LNG facilities must be designed for a sustained wind velocity of not less than 150 miles per hour (mph) unless the PHMSA Administrator finds a lower wind speed is justified or the most critical combination of wind velocity and duration for a 10,000-year-mean return interval.

As stated in 49 CFR 193.2051, under Subpart B, LNG facilities must meet the siting requirements of NFPA 59A (2001), Chapter 2, including but not limited to the requirements described below.

- NFPA 59A (2001) section 2.1.1 (c) requires consideration of protection against forces of nature.

[138] 49 CFR 193.2001 (b) (3), Scope of part, excludes any matter other than siting provisions pertaining to marine cargo transfer systems between the LNG marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

- NFPA 59A (2001) section 2.1.1 (d) requires that other factors applicable to the specific site that have a bearing on the safety of plant personnel and surrounding public be considered, including an evaluation of potential incidents and safety measures incorporated in the facility design or operation.

- NFPA 59A (2001) section 2.2.3.2 requires provisions to minimize the damaging effects of fire from reaching beyond a property line, and requires provisions to prevent a radiant heat flux level of 1,600 BTU per square foot per hour (Btu/ft^2-hr) from reaching beyond a property line that can be built upon. The distance to this flux level is to be calculated with LNGFIRE3 or with models that have been validated by experimental test data appropriate for the hazard to be evaluated and that have been approved by PHMSA.

- NFPA 59A (2001) section 2.2.3.4 requires provisions to minimize the possibility of any flammable mixture of vapors from a design spill from reaching a property line that can be built upon and that would result in a distinct hazard. Determination of the distance that the flammable vapors extend is to be determined with DEGADIS (Dense Gas Dispersion Model) or approved alternative models that take into account physical factors influencing LNG vapor dispersion.[139]

Taken together, 49 CFR 193, Subpart B, and NFPA 59A (2001) require that flammable LNG vapors from design spills do not extend beyond areas in which the operator or a government agency legally controls all activities. Furthermore, consideration of other hazards that may affect the public or plant personnel must be evaluated as prescribed in NFPA 59A (2001) section 2.1.1 (d).

Title 49 CFR 193, Subpart B, and NFPA 59A (2001) also specify three radiant heat flux levels which must be considered for LNG storage tank spills for as long as the facility is in operation:

- 1,600 Btu/ft^2-hr—this level can extend beyond the plant property line that can be built upon but cannot include areas that are used for outdoor assembly by groups of 50 or more persons;[140]

- 3,000 Btu/ft^2-hr—this level can extend beyond the plant property line that can be built upon but cannot include areas that contain assembly, educational, health care, detention, or residential buildings or structures;[141] and

- 10,000 Btu/ft^2-hr—this level cannot extend beyond the plant property line that can be built upon.[142]

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139 PHMSA has approved two additional models for the determination of vapor dispersion exclusion zones in accordance with 49 CFR 193.2059: FLACS 9.1 Release 2 (Oct. 7, 2011) and PHAST-UDM Version 6.6 and 6.7 (Oct. 7, 2011).

140 The 1,600 Btu/ft2-hr flux level is associated with producing pain in less than 15 seconds, first degree burns in 20 seconds, second degree burns in about 30 to 40 seconds, 1-percent mortality in approximately 120 seconds, and 100-percent mortality in about 400 seconds, assuming no shielding from the heat, and is typically the maximum allowable intensity for emergency operations with appropriate clothing based on average 10-minute exposure.

141 The 3,000 Btu/ft2-hr flux level is associated with producing pain in less than 5 seconds, first degree burns in 5 seconds, second degree burns in about 10 to 15 seconds, 1-percent mortality in approximately 50 seconds, and 100-percent mortality in about 180 seconds, assuming no shielding from the heat, and is typically the critical heat flux for piloted ignition of common building materials (e.g., wood, polyvinyl chloride [PVC], and fiberglass) with prolonged exposures.

142 The 10,000 Btu/ft2-hr flux level is associated with producing pain in less than 1 seconds, first degree burns in 1 seconds, second degree burns in about 3 seconds, 1-percent mortality in about 10 seconds, and 100-percent mortality in about 35 seconds, assuming no shielding from the heat, and is typically the critical heat flux for unpiloted ignition of common building materials (e.g., wood, PVC, and fiberglass) and degradation of unprotected process equipment after approximate 10-minute exposure and to reinforced concrete after prolonged exposure.

The requirements for design spills from process or transfer areas are more stringent. For LNG spills, the 1,600 Btu/ft^2-hr flux level cannot extend beyond the plant property line onto a property that can be built upon.

In addition, section 2.1.1 of NFPA 59A (2001) requires that factors applicable to the specific site with a bearing on the safety of plant personnel and the surrounding public must be considered, including an evaluation of potential incidents and safety measures incorporated into the design or operation of the facility. PHMSA has indicated that potential incidents, such as vapor cloud explosions and toxic releases, should be considered to comply with Part 193 Subpart B.[143]

In accordance with the August 31, 2018 MOU, PHMSA issued an LOD to the Commission on the 49 CFR 193 Subpart B regulatory requirements.[144] The LOD provides PHMSA's analysis and conclusions regarding 49 CFR 193 Subpart B regulatory requirements for the Commission to consider in its decision to authorize, with or without modification or conditions, or deny an application.

4.18.3 Coast Guard Safety Regulatory Requirements and Letter of Recommendation

4.18.3.1 LNG Marine Vessel Historical Record

Since 1959, marine vessels have transported LNG without a major release of cargo or a major accident involving an LNG marine vessel. There are more than 370 LNG marine vessels in operation routinely transporting LNG between more than 100 import/export terminals in operation worldwide. Since U.S. LNG terminals first began operating under FERC jurisdiction in the 1970s, there have been thousands of individual LNG marine vessel arrivals at terminals in the United States. For more than 40 years, LNG shipping operations have been safely conducted in U.S. ports and waterways.

A review of the history of LNG maritime transportation indicates that there has not been a serious accident at sea or in a port that resulted in a spill due to rupturing of the cargo tanks. However, insurance records, industry sources, and public websites identify a number of incidents involving LNG marine vessels, including minor collisions with other vessels of all sizes, groundings, minor LNG releases during cargo unloading operations, and mechanical/equipment failures typical of large vessels. Some of the more significant occurrences, representing the range of incidents experienced by the worldwide LNG marine vessel fleet, are described below.

- **El Paso Paul Kayser** grounded on a rock in June 1979 in the Straits of Gibraltar during a loaded voyage from Algeria to the United States. Extensive bottom damage to the ballast tanks resulted; however, no cargo was released because no damage was done to the cargo tanks. The entire cargo of LNG was subsequently transferred to another LNG marine vessel and delivered to its U.S. destination.

- **Tellier** was blown by severe winds from its docking berth at Skikda, Algeria in February 1989, causing damage to the loading arms and the LNG marine vessel and shore piping. The cargo loading had been secured just before the wind struck, but the loading arms had not been drained. Consequently, the LNG remaining in the loading arms spilled onto the deck, causing fracture of some plating.

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143 PHMSA's *LNG Plant Requirements: Frequently Asked Questions* item H1, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions, accessed August 2018.

144 February 4, 2020 letter "RE: Alaska LNG Project, Docket No. CP17-178-000, 49 CFR 193, Subpart B, Siting – Letter of Determination" from Massoud Tahamtani to Rich McGuire. Filed in Docket Number CP17-178-000 on February 4, 2020. FERC eLibrary Accession No. 20200204-3041.

- **Mostefa Ben Boulaid** had an electrical fire in the engine control room during unloading at Everett, Massachusetts on February 5, 1996. The LNG marine vessel crew extinguished the fire and the LNG marine vessel completed unloading.

- **Khannur** had a cargo tank overfill into the LNG marine vessel's vapor handling system on September 10, 2001, during unloading at Everett, Massachusetts. Approximately 100 gallons of LNG were vented and sprayed onto the protective decking over the cargo tank dome, resulting in several cracks. After inspection by the Coast Guard, the Khannur was allowed to discharge its LNG cargo.

- **Mostefa Ben Boulaid** had LNG spill onto its deck during loading operations in Algeria in 2002. The spill, which is believed to have been caused by overflow rather than a mechanical failure, caused significant brittle fracturing of the steelwork. The LNG marine vessel was required to discharge its cargo, after which it proceeded to dock for repair.

- **Norman Lady** was struck by the USS Oklahoma City nuclear submarine while the submarine was rising to periscope depth near the Strait of Gibraltar in November 2002. The 87,000-m^3 LNG marine vessel, which had just unloaded its cargo at Barcelona, Spain, sustained only minor damage to the outer layer of its double hull but no damage to its cargo tanks.

- **Tenaga Lima** grounded on rocks while proceeding to open sea east of Mopko, South Korea due to strong current in November 2004. The shell plating was torn open and fractured over an approximate area of 20 by 80 feet, and internal breaches allowed water to enter the insulation space between the primary and secondary membranes. The LNG marine vessel was refloated, repaired, and returned to service.

- **Golar Freeze** moved away from its docking berth during unloading on March 14, 2006, in Savannah, Georgia. The powered emergency release couplings on the unloading arms activated as designed, and transfer operations were shut down.

- **Catalunya Spirit** lost propulsion and became adrift 35 miles east of Chatham, Massachusetts on February 11, 2008. Four tugs towed the LNG marine vessel to a safe anchorage for repairs. The Catalunya Spirit was repaired and taken to port to discharge its cargo.

- **Al Gharrafa** collided with a container ship, Hanjin Italy, in the Malacca Strait off Singapore on December 19, 2013. The bow of the Al Gharrafa and the middle of the starboard side of the Hanjin were damaged. Both marine vessels were safely anchored after the incident. No loss of LNG was reported.

- **Al Oraiq** collided with a freight carrier, Flinterstar, near Zeebrugge, Belgium on October 6, 2015. The freight carrier sank, but the Al Oraiq was reported to have sustained only minor damage to its bow and no damage to the LNG cargo tanks. According to reports, the Al Oraiq took on a little water but was towed to the Zeebrugge LNG terminal where its cargo was unloaded using normal procedures. No loss of LNG was reported.

- **Al Khattiya** suffered damage after a collision with an oil carrier off the Port of Fujairah on February 23, 2017. Al Khattiya had discharged its cargo and was anchored at the time of the incident. A small amount of LNG was retained within the LNG marine vessel to

keep the cargo tanks cool. The collision damaged the hull and two ballast tanks on the Al Khattiya, but did not cause any injury or water pollution. No loss of LNG was reported.

- **Aseem** collided with a very large crude carrier (VLCC) Shinyo Ocean off the Port of Fujairah on March 26, 2019. The VLCC suffered severe portside hull height breach and Aseem had damage to its bow. Both marine vessels were unloaded at the time of the collision and subsequently no LNG or oil was released. Aseem was moved to port for anchorage and Shinyo Ocean was relocated to another point of anchorage.

4.18.3.2 LNG Marine Vessel Safety Regulatory Oversight

The Coast Guard exercises regulatory authority over LNG marine vessels under 46 CFR 154, which contains the U.S. safety standards for self-propelled LNG marine vessels transporting bulk liquefied gases. The LNG marine vessels visiting the proposed facility would also be constructed and operated in accordance with the IMO *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk* and the *International Convention for the Safety of Life at Sea*. All LNG marine vessels entering U.S. waters are required to possess a valid IMO Certificate of Fitness and either a Coast Guard Certificate of Inspection (for U.S. flag vessels) or a Coast Guard Certificate of Compliance (for foreign flag vessels). These documents certify that the LNG marine vessel is designed and operating in accordance with both international standards and the U.S. regulations for bulk LNG marine vessels under 46 CFR 154.

The LNG marine vessels that would deliver or receive LNG to or from the Project would also need to comply with various U.S. and international security requirements. The IMO adopted the *International Ship and Port Facility Security Code* in 2002. This code requires both ships and ports to conduct vulnerability assessments and to develop security plans. The purpose of the code is to prevent and suppress terrorism against ships, improve security aboard ships and ashore, and reduce the risk to passengers, crew, and port personnel on board ships and in port areas. All LNG marine vessels, as well as other cargo vessels (e.g., 500 gross tons and larger), and ports servicing those regulated vessels, must adhere to the IMO standards. Some of the IMO requirements for marine vessels are as follows:

- marine vessels must develop security plans and have a Vessel Security Officer;
- marine vessels must have a ship security alert system to transmit ship-to-shore security alerts identifying the marine vessel, its location, and an indication of whether the security of the marine vessel is under threat or has been compromised;
- marine vessels must have a comprehensive security plan for international port facilities, focusing on areas having direct contact with marine vessels; and
- marine vessels must have equipment onboard to help maintain or enhance the physical security of the marine vessel.

In 2002, the Maritime Transportation Security Act (MTSA) was enacted by the U.S. Congress and aligned domestic regulations with the maritime security standards of the *International Ship and Port Facility Security Code* and the *Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk* and the *International Convention for the Safety of Life at Sea*. The Coast Guard's regulations in 33 CFR 104 require marine vessels to conduct a vessel security assessment and develop a vessel security plan that addresses each vulnerability identified in the vessel security assessments. All LNG marine vessels servicing the facility would have to comply with the MTSA requirements and associated regulations while in U.S. waters.

The Coast Guard also exercises regulatory authority over LNG facilities that affect the safety and security of port areas and navigable waterways under Executive Order 10173; the Magnuson Act (50 USC 191); the Ports and Waterways Safety Act of 1972, as amended (33 USC 1221, *et seq.*); and the MTSA of 2002 (46 USC 701). The Coast Guard is responsible for matters related to navigation safety, LNG marine vessel engineering and safety standards, and all matters pertaining to the safety of facilities or equipment in or adjacent to navigable waters up to the last valve immediately before the receiving tanks. The Coast Guard also has authority for LNG facilities security plan review, approval, and compliance verification as provided in 33 CFR 105.

The Coast Guard regulations in 33 CFR 127 apply to the marine transfer area of waterfront facilities between the LNG marine vessel and the last manifold or valve immediately before the receiving tanks. Title 33 CFR 127 applies to the marine transfer area for LNG of each new waterfront facility handling LNG and to new construction in the marine transfer areas for LNG of each existing waterfront facility handling LNG. The scope of the regulations includes the design, construction, equipment, operation, inspections, maintenance, testing, personnel training, firefighting, and security of the marine transfer area of LNG waterfront facilities. The safety systems, including communications, emergency shutdown (ESD), gas detection, and fire protection, must comply with the regulations in 33 CFR 127. Under 33 CFR 127.019, AGDC would be required to submit two copies of its Operations and Emergency Manuals to the Coast Guard Captain of the Port (COTP) for examination.

Both the Coast Guard regulations under 33 CFR 127 and FERC regulations under 18 CFR 157.21, require an applicant who intends to build an LNG terminal to submit a Letter of Intent (LOI) to the Coast Guard no later than the date that the owner/operator initiates pre-filing with FERC, but, in all cases, at least 1 year prior to the start of construction. In addition, the applicant must submit a Preliminary WSA to the COTP with the LOI.

The Preliminary WSA provides an initial explanation of the port community and the proposed facility and transit routes. It provides an overview of the expected impacts LNG operations may have on the port and the waterway. Generally, the Preliminary WSA does not contain detailed studies or conclusions. This document is used by the COTP to begin his or her evaluation of the suitability of the waterway for LNG marine traffic. The Preliminary WSA must provide an initial explanation of the following:

- port characterization;
- characterization of the LNG facilities and the LNG marine vessel route;
- risk assessment for maritime safety and security;
- risk management strategies; and
- resource needs for maritime safety, security, and response.

A Follow-On WSA must be provided no later than the date the owner/operator files an application with FERC, but in all cases at least 180 days prior to transferring LNG. The Follow-On WSA must provide a detailed and accurate characterization of the waterfront facilities handling LNG, the LNG marine vessel route, and the port area. The Follow-On WSA provides a complete analysis of the topics outlined in the Preliminary WSA. It should identify credible security threats and navigational safety hazards for the LNG marine vessel traffic, along with appropriate risk management measures and the resources (i.e., federal, state, local, and private sector) needed to carry out those measures. Until a facility begins operation, applicants must also annually review their WSAs and submit a report to the COTP as to whether changes are required. This document is reviewed and validated by the Coast Guard and forms the basis for the agency's LOR to FERC.

In order to provide the Coast Guard COTPs / Federal Maritime Security Coordinators, members of the LNG industry, and port stakeholders with guidance on assessing the suitability of a waterway for LNG

marine traffic, the Coast Guard has published a Navigation and Vessel Inspection Circular (NVIC) – *Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic* (NVIC 01-11).

NVIC 01-11 directs the use of the three concentric Zones of Concern, based on LNG marine vessels with a cargo carrying capacity up to 265,000 m^3, used to assess the maritime safety and security risks of LNG marine traffic. The Zones of Concern are listed below.

- Zone 1: Impacts on structures and organisms are expected to be significant within 1,640 feet (500 meters). The outer perimeter of Zone 1 is about the distance to thermal hazards of 12,000 Btu/ft^2-hr (37.5 kW/square meter [m^2]) from a pool fire.

- Zone 2: Impacts would be significant but reduced, and damage from radiant heat levels are expected to transition from severe to minimal between 1,640 and 5,250 feet (500 and 1,600 meters). The outer perimeter of Zone 2 is approximately the distance to thermal hazards of 1,600 Btu/ft^2-hr (5 kW/m^2) from a pool fire.

- Zone 3: Impacts on people and property from a pool fire or an un-ignited LNG spill are expected to be minimal between 5,250 feet (1,600 meters) and a conservative maximum distance of 11,500 feet (3,500 meters) or 2.2 miles. The outer perimeter of Zone 3 should be considered the vapor cloud dispersion distance to the lower flammability limit (LFL) from a worst case un-ignited release. Impacts on people and property could be significant if the vapor cloud reaches an ignition source and burns back to the source.

Once the applicant submits a complete Follow-On WSA, the Coast Guard reviews the document to determine if it presents a realistic and credible analysis of the public safety and security implications from LNG marine traffic both in the waterway and when in port.

As required by its regulations (33 CFR 127.009), the Coast Guard is responsible for issuing an LOR to FERC regarding the suitability of the waterway for LNG marine traffic with respect to the following items:

- physical location and description of the facility;

- the LNG marine vessel's characteristics and the frequency of LNG shipments to or from the facility;

- waterway channels and commercial, industrial, environmentally sensitive, and residential areas in and adjacent to the waterway used by LNG marine vessels en route to the facility, within 15.5 miles (25 km) of the facility;

- density and character of marine traffic in the waterway;

- locks, bridges, or other manmade obstructions in the waterway;

- depth of water;

- tidal range;

- protection from high seas;

- natural hazards, including reefs, rocks, and sandbars;

- underwater pipes and cables; and

- distance of berthed LNG marine vessels from the channel and the channel width.

The Coast Guard may also prepare an LOR Analysis, which serves as a record of review of the LOR and contains detailed information along with the rationale used in assessing the suitability of the waterway for LNG marine traffic.

4.18.3.3 AGDC's Waterway Suitability Assessment

On May 15, 2014, AGDC submitted an LOI and a Preliminary WSA to the COTP, Sector Anchorage to notify the Coast Guard that it proposed to construct an LNG export terminal. AGDC submitted the Follow-On WSA to the Coast Guard on March 18, 2016.

4.18.3.4 LNG Marine Vessel Routes and Hazard Analysis

An LNG marine vessel's transit to and from the terminal would enter Cook Inlet from the Gulf of Alaska. The LNG marine vessel would then enter the U.S. Territorial Sea limit (State Waters) to arrive at Homer Pilot Station. At Homer Pilot Station, pilots would board the LNG marine vessel before entering Cook Inlet. Inland navigation from Cook Inlet to the Project site is approximately 140 miles. Pilotage is compulsory for foreign vessels and U.S. vessels under registry in foreign trade when in U.S. waters. All deep draft marine vessels currently entering the shared waterway would employ a U.S. pilot. The National Vessel Movement Center in the U.S. would require a 96-hour advance notice of arrival for deep draft marine vessels calling on U.S. ports. During transit, LNG marine vessels would be required to maintain voice contact with controllers and check in on designated frequencies at established way points.

NVIC 01-11 references the "Zones of Concern" for assisting in a risk assessment of the waterway. As LNG marine vessels proceed along the intended transit route, no hospitals, city centers, or military installations would be in any of the three Zones of Concern. Zone 1 would not extend over any public areas along the entire ship transit route as it enters from the Gulf of Alaska to the Liquefaction Facilities site. Zone 2 would encompass a larger area that would include a portion of the Liquefaction Facilities and adjacent areas such as multiple residential buildings, commercial buildings, industrial facilities, and a portion of the Kenai Spur Highway (KSH). Zone 3 would span larger portions of the Liquefaction Facilities and surrounding areas that include multiple residential buildings, commercial buildings, industrial facilities, churches, a fire department, a private airport, portions of the KSH, and a portion of the East Foreland Lighthouse Reserve. At the pilot station, Zone 3 would encompass multiple commercial buildings, residential buildings, campgrounds, and a boat harbor. Commercial, recreational, and fishing vessels may also fall within the Zones, depending on their course. Transit of such vessels through a Zone of Concern can be avoided by timing and course changes, if conditions permit.

The areas affected by the three different hazard zones are illustrated for accidental and intentional events on figures 4.18.3-1 and 4.18.3-2, respectively.

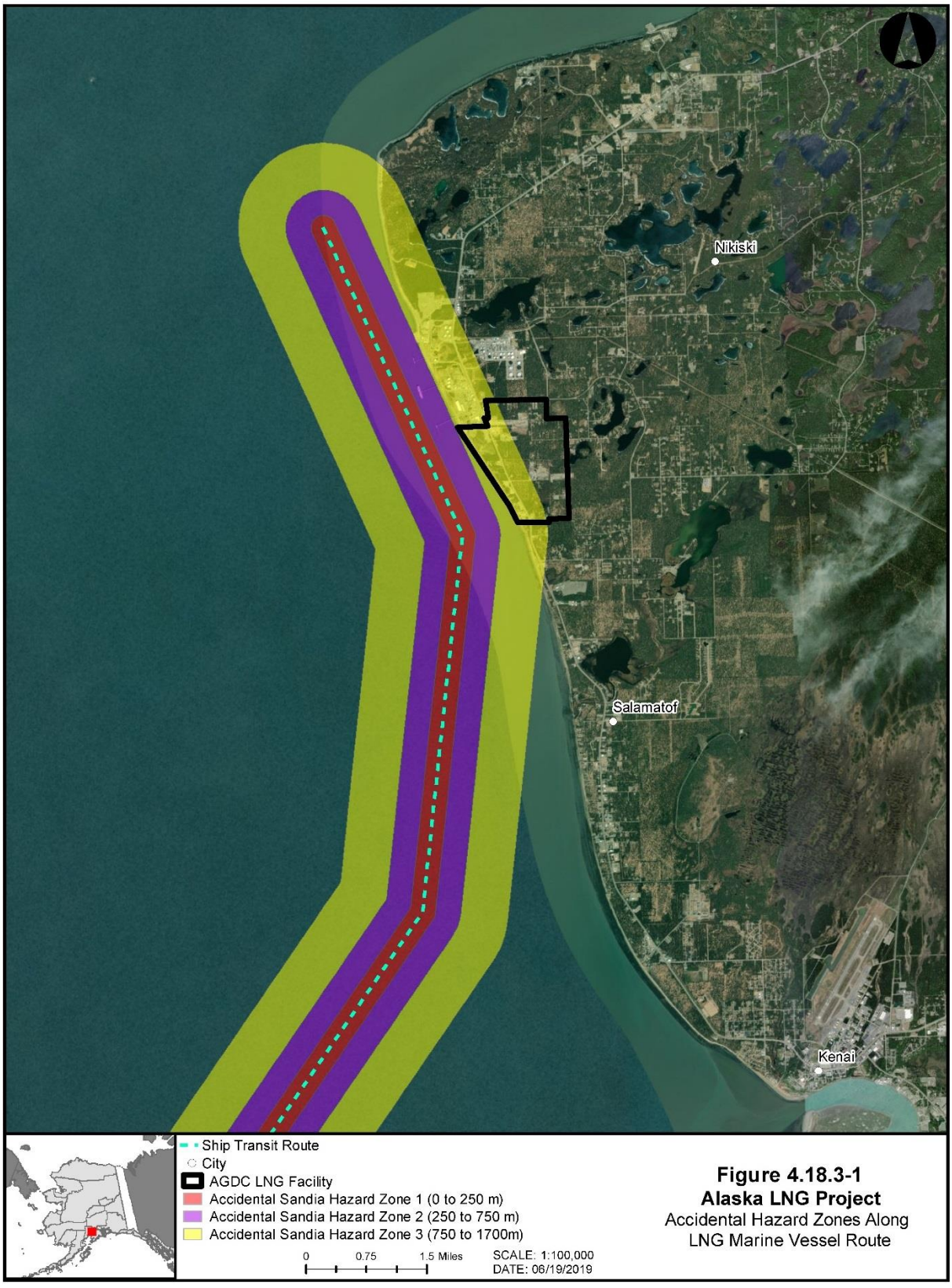


Figure 4.18.3-1
Alaska LNG Project
Accidental Hazard Zones Along
LNG Marine Vessel Route

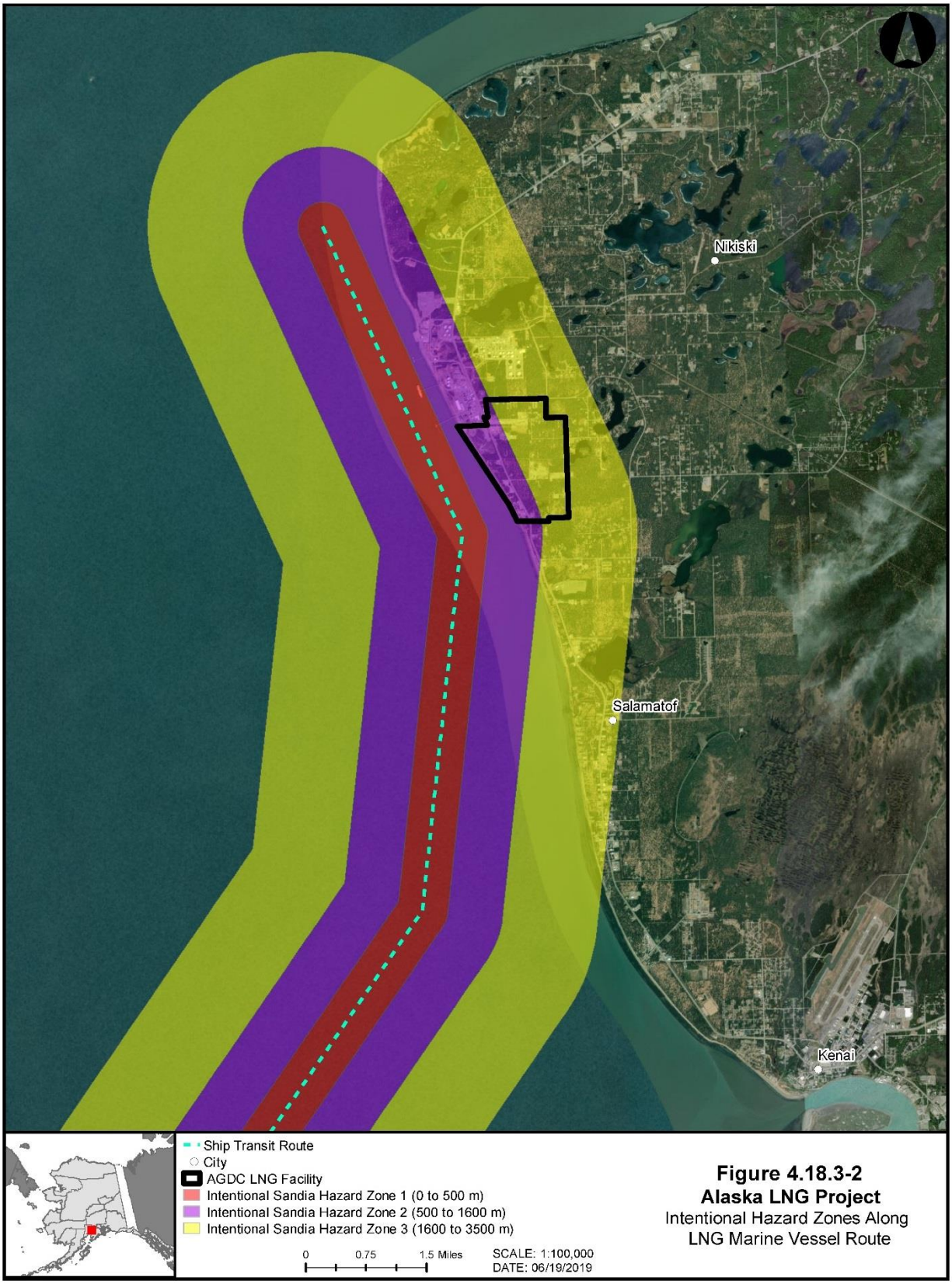


Figure 4.18.3-2
Alaska LNG Project
Intentional Hazard Zones Along
LNG Marine Vessel Route

4.18.3.5 Coast Guard Letter of Recommendation and Analysis

In a letter dated August 17, 2016, the Coast Guard issued an LOR and LOR Analysis to FERC stating that Cook Inlet would be considered suitable for accommodating the type and frequency of LNG marine traffic associated with the Project. As part of its assessment of the safety and security aspects of this Project, the COTP Sector Anchorage consulted a variety of stakeholders, including representatives from Area Maritime Security Committee, Cook Inlet Harbor Safety Committee, Cook Inlet Regional Citizens Advisory Council, and local emergency response groups. The LOR was based on full implementation of the strategies and risk management measures identified by the Coast Guard to AGDC in its WSA. In addition, the Coast Guard's Sector Anchorage Waterways Management Division handles day-to-day waterway issues and concerns, such as tidal ranges and sea ice conditions, that arise in the Western Alaska Captain of the Port Zone, which would include Cook Inlet. Specifically, the Coast Guard's Sector Anchorage Waterways Management Division has a navigation safety advisory on *Operating Guidelines for Ice Conditions in Cook Inlet.*[145] These guidelines include best practices and mitigation measures for vessels operating in Cook Inlet that address ice and current conditions, which were identified in the WSA and preliminary marine simulation studies. A more detailed discussion of these natural hazard conditions is provided in section 4.18.6.2.

Although AGDC has suggested mitigation measures for responsibly managing the maritime safety and security risks associated with LNG marine vessel marine traffic, the necessary vessel traffic and/or facility control measures may change depending on changes in conditions along the waterway. The Coast Guard regulations in 33 CFR 127 require that applicants annually review WSAs until a facility begins operation and submits a report to the Coast Guard identifying any changes in conditions—such as changes to the port environment, the proposed LNG project, or the LNG marine vessel route—that would affect the suitability of the waterway for LNG marine traffic.

The Coast Guard's LOR is a recommendation regarding the current status of the waterway to FERC, the lead agency responsible for siting the on-shore LNG facilities. Neither the Coast Guard nor FERC has authority to require waterway resources of anyone other than the applicant under any statutory authority or under the ERP or Cost Sharing Plan. As stated in the LOR, the Coast Guard would assess each transit on a case by case basis to identify what, if any, safety and security measures would be necessary to safeguard the public health and welfare, critical infrastructure and key resources, the port, the marine environment, and the LNG marine vessel.

Under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA, and the Security and Accountability For Every Port Act, the COTP has the authority to prohibit LNG transfer or LNG marine vessel movements within his or her area of responsibility if he or she determines that such action is necessary to protect the waterway, port, or marine environment. If this Project is approved and appropriate resources are not in place prior to LNG marine vessel movement along the waterway, then the COTP would consider at that time what, if any, vessel traffic and/or facility control measures would be appropriate to adequately address navigational safety and maritime security considerations.

4.18.4 LNG Facility Security Regulatory Requirements

The security requirements for the proposed Project are governed by 33 CFR 105, 33 CFR 127, and 49 CFR 193 Subpart J - Security, and 6 CFR 27. Title 33 CFR 105, as authorized by the MTSA, requires all terminal owners and operators to submit a Facility Security Assessment (FSA) and a Facility Security Plan (FSP) to the Coast Guard for review and approval before commencement of operation of the proposed project facilities. AGDC would also be required to control and restrict access, patrol and monitor the plant,

[145] USCG, *Operating Guidelines for Ice Conditions in Cook Inlet,* accessed at https://www.pacificarea.uscg.mil/Our-Organization/District-17/17th-District-Units/Sector-Anchorage/-Waterways-Management/.

detect unauthorized access, and respond to security threats or breaches under 33 CFR 105. Some of the responsibilities of the applicant include, but are not limited to:

- designating a Facility Security Officer with a general knowledge of current security threats and patterns, security assessment methodology, LNG marine vessel and facility operations, conditions, security measures, emergency preparedness, response, and contingency plans, who would be responsible for implementing the FSA and FSP and performing an annual audit for the life of the Project;

- conducting an FSA to identify site vulnerabilities, possible security threats and consequences of an attack, and facility protective measures; developing an FSP based on the FSA, with procedures for responding to transportation security incidents; notification and coordination with federal, state, and local authorities; prevention of unauthorized access; measures to prevent or deter entrance with dangerous substances or devices; training; and evacuation;

- defining the security organizational structure with facility personnel with knowledge or training in current security threats and patterns; recognition and detection of dangerous substances and devices, recognition of characteristics and behavioral patterns of persons who are likely to threaten security; techniques to circumvent security measures; emergency procedures and contingency plans; operation, testing, calibration, and maintenance of security equipment; and inspection, control, monitoring, and screening techniques;

- implementing scalable security measures to provide increasing levels of security at increasing maritime security levels for facility access control, restricted areas, cargo handling, LNG marine vessel stores and bunkers, and monitoring; and ensuring that the Transportation Worker Identification Credential (TWIC) program is properly implemented;

- ensuring coordination of shore leave for LNG marine vessel personnel or crew change out as well as access through the facility for visitors to the LNG marine vessel;

- conducting drills and exercises to test the proficiency of security and facility personnel on a quarterly and annual basis; and

- reporting all breaches of security and transportation security incidents to the National Response Center.

Title 33 CFR 127 has requirements for access controls, lighting, security systems, security personnel, protective enclosures, communications, and emergency power. In addition, LNG facilities regulated under 33 CFR 105 and 33 CFR 127 would be subject to the TWIC Reader Requirements Rule issued by the Coast Guard on August 23, 2016. This rule requires owners and operators of certain marine vessels and facilities regulated by the Coast Guard to conduct electronic inspections of TWICs (e.g., readers with biometric fingerprint authentication) as an access control measure. The final rule would also include recordkeeping requirements and security plan amendments that would incorporate these TWIC requirements. The implementation of the rule was first proposed to be in effect August 23, 2018. In a subsequent notice issued on June 22, 2018, Coast Guard indicated delaying the effective date for certain facilities by 3 years, until August 23, 2021. On August 2, 2018, the President of the United States signed into law the Transportation Worker Identification Credential Accountability Act of 2018 (H.R. 5729). This law prohibits the Coast Guard from implementing the rule requiring electronic inspections of TWICs until after the DHS has submitted a report to Congress. Although the implementation of this rule has been

postponed for certain facilities, the company may need to consider the rule when developing access control and security plan provisions for the facility.

Title 49 CFR 193 Subpart J also specifies security requirements for the onshore components of LNG facilities, as defined in 49 CFR 193, including requirements for conducting security inspections and patrols, liaison with local law enforcement officials, design and construction of protective enclosures, lighting, monitoring, alternative power sources, and warning signs. If the Project is authorized, constructed, and operated, compliance with the security requirements of 33 CFR 105, 33 CFR 127, and 49 CFR 193, Subpart J would be subject to the respective Coast Guard and PHMSA inspection and enforcement programs for the Liquefaction Facilities.

Title 6 CFR 27, as authorized under Section 550 of the Homeland Security Appropriations Act of 2007 and as extended under the CFATS Act of 2014, requires risk-based performance standards related to plant security that would apply to the GTP and would not be covered by the MTSA. The quantities of methane and other products that would be at the GTP could exceed the screening threshold quantities specified in Appendix A to 6 CFR 27. Under CFATS, DHS determines if a facility is considered a covered facility based on a report of chemical holdings. In accordance with 6 CFR 27.215, covered facilities must complete a security vulnerability assessment. Based on the chemical holdings and security vulnerability assessment, the DHS would assign the covered facilities to one of four risk based tiers, ranging from the highest risk in Tier 1 to the lowest risk in Tier 4, and ensure that a site security plan is developed based on the security vulnerability assessment and tier. Therefore, it is unclear whether the GTP's security system would meet all applicable requirements, including CFATS. Since the GTP would fall under CFATS, in accordance with 6 CFR 27.210(d), the GTP would be required to submit a revised Top Screen to the department within 60 calendar days of the modification, and the DHS would notify AGDC as to whether they must submit a revised security vulnerability assessment, site security plan, or both.

AGDC provided preliminary information as well as FERC information request responses on these security design features and indicated additional details would be completed in the final design for both the Liquefaction Facilities and GTP. AGDC indicates that the proposed security system design for the GTP would be based on current North Slope security practices and requirements of the PBU operator. We recommend in section 4.18.9 that AGDC provide final design details on these security features for review and approval, including lighting coverage drawings, camera coverage drawings, fencing drawings, and vehicle barrier and controlled access point drawings. AGDC has agreed to provide information in accordance with the timing of the recommendation. Furthermore, in accordance with the February 2004 Interagency Agreement among FERC, PHMSA, and the Coast Guard, FERC staff would collaborate with the Coast Guard and PHMSA on the Project's security features.

4.18.5 FERC Engineering and Technical Review of the Preliminary Engineering Designs

4.18.5.1 LNG Facility Historical Record

The operating history of the U.S. LNG industry has been free of safety-related incidents resulting in adverse effects on the public or the environment with the exception of the October 20, 1944 failure at an LNG plant in Cleveland, Ohio. The 1944 incident in Cleveland led to a fire that killed 128 people and injured 200 to 400 more people.[146] The failure of the LNG storage tank was due to the use of materials not suited for cryogenic temperatures. LNG migrated through streets and into underground sewers due to inadequate spill impoundments at the site. Current regulatory requirements ensure that proper materials suited for cryogenic temperatures are used in the design and that spill impoundments are designed and

[146] For a description of the incident and the findings of the investigation, see *U.S. Bureau of Mines, Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944*, dated February 1946.

constructed properly to contain a spill at the site. To ensure that this potential hazard would be addressed for proposed LNG facilities, we evaluate the preliminary and final specifications for suitable materials of construction and for the design of spill containment systems that would properly contain a spill at the site.

Another operational accident occurred in 1979 at the Cove Point LNG plant in Lusby, Maryland. A pump electrical seal on a submerged electrical motor LNG pump leaked, causing flammable gas vapors to enter an electrical conduit and settle in a confined space. When a worker switched off a circuit breaker, the flammable gas ignited, causing severe damage to the building and a worker fatality. With the participation of FERC, lessons learned from the 1979 Cove Point accident led to changes in the national fire codes to better ensure that the situation would not occur again. To ensure that this potential hazard would be addressed for proposed facilities that have electrical seal interfaces, we evaluated the preliminary design and recommend in section 4.18.9 that AGDC provide, for review and approval, the final design details of the electrical seal design at the interface between flammable fluids and the electrical conduit or wiring system, details of the electrical seal leak detection system, and the details of a downstream physical break (i.e., air gap) in the electrical conduit to prevent the migration of flammable vapors. AGDC has agreed to provide information in accordance with the timing of the recommendations.

On January 19, 2004, a blast occurred at Sonatrach's Skikda, Algeria, LNG liquefaction plant that killed 27 and injured 56 workers. No members of the public were injured. Findings of the accident investigation suggested that a cold hydrocarbon leak occurred at Liquefaction Train 40 and was introduced into a high-pressure steam boiler by the combustion air fan. An explosion developed inside the boiler firebox, which subsequently triggered a larger explosion of the hydrocarbon vapors in the immediate vicinity. The resulting fire damaged the adjacent liquefaction process and liquid petroleum gas separation equipment of Train 40 and spread to Trains 20 and 30. Although Trains 10, 20, and 30 had been modernized in 1998 and 1999, Train 40 had been operating with its original equipment since start-up in 1981. To ensure that this potential hazard would be addressed for proposed facilities, we evaluate the preliminary design for mitigation of flammable vapor dispersion and ignition in buildings and combustion equipment to ensure they would be adequately covered by hazard detection equipment that could isolate and deactivate any combustion equipment whose continued operation could add to or sustain an emergency. We also recommend in section 4.18.9 that AGDC provide, for review and approval, the final design details of hazard detection equipment, including location and elevation of all detection equipment, instrument tag numbers, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment. AGDC has agreed to provide information in accordance with the timing of the recommendations.

On March 31, 2014, a detonation occurred within a gas heater at Northwest Pipeline Corporation's LNG peak-shaving plant in Plymouth, Washington.[147] This internal detonation subsequently caused the failure of pressurized equipment, resulting in high velocity projectiles. The plant was immediately shut down, and emergency procedures were activated, which included notifying local authorities and evacuating all plant personnel. No members of the public were injured, but one worker was sent to the hospital for injuries. As a result of the incident, the liquefaction trains and a compressor station on site were rendered inoperable. Projectiles from the incident also damaged the control building that was near the pre-treatment facilities and penetrated the outer shell of one of the LNG storage tanks. All damaged facilities were ultimately taken out of service for repair. The accident investigation showed that an inadequate purge after maintenance activities resulted in a fuel-air mixture remaining in the system. The fuel-air mixture auto-ignited during startup after it passed through the gas heater at full operating pressure and temperature. To ensure that this potential hazard would be addressed for the proposed facilities, we recommend in section 4.18.9 that AGDC provide a plan for purging, for review and approval, that addresses the requirements of the American Gas Association's *Purging Principles and Practice*, and to provide

[147] For a description of the incident and the findings of the investigation, see Root Cause Failure Analysis, Plymouth LNG Plant Incident Investigation under CP14-515.

justification if not using an inert or non-flammable gas for purging. AGDC has agreed to provide information in accordance with the timing of the recommendation. In evaluating such plans, we would assess whether the purging could be done safely based on review of other plans and lessons learned from this and other past incidents. If a plan proposes the use of flammable mediums for cleaning, dry-out, or other activities, we would evaluate the plans against other recommended and generally accepted good engineering practices, such as NFPA 56, *Standard for Fire and Explosion Prevention during Cleaning and Purging of Flammable Gas Piping Systems.*

We also recommend in section 4.18.9 that AGDC provide, for review and approval, operating and maintenance plans, including safety procedures, prior to commissioning. In evaluating such plans, we would assess whether the plans cover all standard operations, including purging activities associated with startup and shutdown. Also, in order to prevent other sources of projectiles from affecting occupied buildings and storage tanks, we recommend in section 4.18.9 that AGDC incorporate mitigation into their final design with supportive information, for review and approval, that demonstrates it would mitigate the risk of a pressure vessel burst or boiling liquid expanding vapor explosion (BLEVE) from occurring. AGDC has agreed to provide information in accordance with the recommendations.

4.18.5.2 FERC Preliminary Engineering Review

FERC requires an applicant to provide safety, reliability, and engineering design information as part of its application, including hazard identification (HAZID) studies and engineering information for its proposed project, typically reflective of a front end-engineering design (FEED). AGDC has indicated they have completed a pre-FEED and that a FEED would occur during later stages. FERC staff evaluates the information submitted with a focus on potential hazards from within and nearby the site, including external events, that may have the potential to cause damage or failure to the Project facilities, and on the engineering design and safety and reliability concepts of the various protection layers to mitigate the risks of potential hazards.

The primary concerns are those events that could lead to a hazardous release of sufficient magnitude to create an off-site hazard or interruption of service. Furthermore, the potential hazards are dictated by the site location and engineering details. In general, FERC staff considers an acceptable design to include various layers of protection or safeguards to reduce the risk of a potentially hazardous scenario from developing into an event that could affect the off-site public. These layers of protection are generally independent of one another so that any one layer would perform its function regardless of the initiating event or failure of any other protection layer. Such design features and safeguards typically include:

- a facility design that prevents hazardous events, including the use of inherently safer designs; suitable materials of construction; adequate design margins from operating limits for process piping, process vessels, and storage tanks; and adequate design for wind, flood, seismic, and other outside hazards;

- control systems, including monitoring systems and process alarms; remotely-operated control and isolation valves; and operating procedures to ensure that the facility stays within the established operating and design limits;

- safety instrumented prevention systems, such as safety control valves and ESD systems, to prevent a release if operating and design limits are exceeded;

- physical protection systems, such as appropriate electrical area classification; proper equipment and building spacing; pressure relief valves; spill containment; and cryogenic, overpressure, and fire structural protection, to prevent escalation to a more severe event;

- site security measures for controlling access to the plant, including security inspections and patrols, response procedures to any breach of security, and liaison with local law enforcement officials; and

- on-site and off-site emergency response, including hazard detection and control equipment, firewater systems, and coordination with local first responders, to mitigate the consequences of a release and prevent it from escalating to an event that could affect the public.

The inclusion of such protection systems or safeguards in a plant design can minimize the potential for an initiating event to develop into an incident that could affect the safety of the off-site public. The review of the engineering designs for these layers of protection is initiated in the application process and will be carried through to the next phase of the Project in final design if authorization is granted by the Commission.

The reliability of these layers of protection is informed by occurrence and likelihood of root causes of past incidents and the potential severity of consequences based on past incidents and validated hazard modeling. As a result of a preliminary engineering review, we recommend mitigation measures and continuous oversight to the Commission for consideration to include as conditions in the order. If a facility is authorized and recommendations are adopted as requirements to the order, FERC staff would continue its engineering review through final design, construction, commissioning, and operation.

4.18.5.3 Process Design Review

AGDC proposes to receive the natural gas supply from two gas production fields on the North Slope of Alaska: 1) the PBU and 2) the PTU. The GTP would receive the natural gas from the new PBU and PTU gas transmission lines and would treat and process the natural gas for delivery into a proposed 42-inch-diameter natural gas pipeline (i.e., the Mainline Pipeline) approximately 807 miles long to the Liquefaction Facilities.

The GTP would be on the North Slope of Alaska where the inlet gas would be conditioned to remove solids and water droplets and for pressure regulation prior to entering feed gas pretreatment processes. Once the inlet gas is conditioned, the feed gas would then contact an amine-based solvent solution in an Acid Gas Removal Unit (AGRU) absorber to remove the H_2S and CO_2 (i.e., acid gas) present in the feed gas. Once the acid gas components accumulate in the amine solution, an AGRU Solvent Regenerator column would regenerate the amine solution by using heat to release the acid gas. The regenerated amine solution would be recycled back to the AGRU column. The removed acid gas, which would also contain some heavy hydrocarbons and water, would be compressed and treated to remove water prior to being sent as a byproduct off site. The feed gas exiting the AGRU absorber would enter the Treated Gas Dehydration Unit (TGDU) where water would be absorbed in a glycol-based solution in a TGDU contactor. The water removed in the contactor would be recycled for use in the TGDU regeneration process. The treated dry gas exiting the TGDU contactor would be compressed in stages and routed to a natural gas chilling unit in which propane would be used to as a refrigerant to cool the treated gas. Once the treated gas has been cooled, it would be sent to the new 42-inch-diameter Mainline Pipeline for delivery to the Liquefaction Facilities.

In order to liquefy natural gas, most liquefaction technologies require that the feed gas stream be pre-treated. The Liquefaction Facilities would be on the Kenai Peninsula and would receive treated natural gas from the GTP. After pressure regulation, the treated natural gas would be further treated to remove components that could freeze out and clog the liquefaction equipment or would otherwise be incompatible with the liquefaction process or equipment, including mercury, water, and heavy hydrocarbons. Normally

this would include acid gas components, water, heavier hydrocarbons, and mercury; however the acid gas components would be removed at the GTP, and while some water would also be removed at the GTP, additional dehydration would be needed for the liquefaction. Mercury is typically limited to concentrations less than 0.01 microgram per normal cubic meter because it can cause embrittlement and corrosion resulting in a catastrophic failure of aluminum, which is commonly used in heat exchangers for the liquefaction of natural gas. Hence, the Liquefaction Facilities would treat the inlet feed gas for mercury removal by entering a mercury removal vessel that uses an activated carbon bed. The mercury-free gas is then sent to a dehydration system for the removal of any moisture by using molecular sieve beds. After water is removed, the gas would be sent to a heavy hydrocarbon removal system where heavies such as ethane, propane, liquefied petroleum gas (LPG), and condensate would be extracted from the gas. The extracted ethane and propane would be sent to storage to be used as make-up refrigerant in the liquefaction process, extracted LPG would be reinjected in the liquefaction process, and extracted condensate would be sent to storage for disposal by truck.

In order to achieve the cryogenic temperatures needed to liquefy the resulting natural gas stream in the above process, the gas would be cooled by a thermal exchange process driven by a closed loop refrigeration system using mixed refrigerants comprised of a mixture of nitrogen, methane, ethane, and propane. Methane would be provided from the scrub column reflux drum in the liquefaction train. The other refrigerants required for the liquefaction process would be delivered by truck and stored on site for initial filling, and also would be produced on site as a result of the heavy hydrocarbon removal process for use, as needed, for refrigerant make-up. Truck loading/unloading facilities would be provided to unload refrigerants for initial fill and to load condensate for off-site disposal. FERC staff noted that the Liquefaction Facilities would have a single truck loading/unloading skid that would serve various components such as condensate, refrigerants, and diesel trucks. More commonly, LNG facilities under FERC jurisdiction have proposed separate truck areas for different products. While there are no chemical reactions expected, the inadvertent transferring of relatively warm diesel or condensate into refrigerants could result in rapid warming and vapor generation that could over-pressurize contents at rates beyond pressure relief valves are sized to handle. Additionally, in December 2017, the U.S. Chemical Safety and Hazard Investigation Board (CSB) issued a report, *Key Lessons for Preventing Inadvertent Mixing During Chemical Unloading Operations*, which included several safety recommendations and key lessons learned from an incident that occurred at a processing facility that had a multi-use single truck transfer area.[148] Therefore, FERC staff requested that AGDC explain the design features that would be incorporated in the design to safely carry out truck loading/unloading operations and prevent inadvertent mixing prior to transfer operations of condensate, refrigerants, and diesel. We also requested AGDC to discuss what consideration has been given to physically separating these transfer areas. AGDC responded that the proposed design already incorporates lessons learned from the referenced CSB report and indicated the following specific design features to be included: different connector mechanisms, proper signage, pipe marking with fluid service and flow direction, monitoring of process instrumentation for system isolation to stop transfers via remote access, hazard detection, and transfer procedures to incorporate best practices to be agreed upon the Project and truck operators. Based on these design features, AGDC indicated that there would be no need to physically separate the truck transfer areas. In addition, 49 CFR 193.2513 under Subpart F requires transfer of LNG or other hazardous fluid be in accordance with written procedures that, among other requirements, must verify that the materials being transferred are compatible and the operation is done by personnel in constant attendance. Title 49 CFR 193.2713 under Subpart H requires that all operating and appropriate supervisory personnel understand the LNG transfer procedures in 49 CFR 193.2513.

The CSB report included other lessons learned and recommendations that were not included or specified in AGDC's proposed design or required by regulation, such as training that ensures truck drivers

[148] https://www.csb.gov/mgpi-processing-inc-toxic-chemical-release-/

are fully aware of emergency shutoff mechanisms, including when to use them and the effectiveness of those devices to stop the flow during emergencies. Therefore, we recommend in section 4.18.9 that AGDC file information, for review and approval, on the final design that demonstrates truck drivers are trained and aware of emergency shutoff mechanisms and when to use them in order to safely carry out truck loading/unloading operations and prevent inadvertent mixing prior to transfer operations of the various components that would be loaded/unloaded at the trucking skid. The GTP also appears to show that it would have a single truck loading skid that would handle diesel, tri-ethylene glycol, and AGRU solvent; however, it is unclear by the documentation provided in the application. In addition, the GTP would not be subject to the 49 CFR 193 requirements. Therefore, we recommend in section 4.18.9 that AGDC file information on the truck loading skid at the GTP, including the design features, operating procedures, and training that would be incorporated to safely carry out truck loading/unloading operations as well as how these transfer areas would be marked, verified, and safeguarded from inadvertent mixing prior to transfer operations. In addition, we recommend in section 4.18.9 that AGDC discuss what consideration has been given to physically separating these transfer areas at the GTP. AGDC filed a response in accordance with the timing of the recommendation on September 18, 2019, which stated that the deliveries of various components can be safely managed at the GTP with the current trucking loading design that incorporates the CSB's key lessons referenced above. AGDC specifically noted that the design would include proper signage, pipe marking, proper sizing of nozzles and connections, monitoring of process instrumentation that would have the capability to stop transfers or isolate the system remotely, and procedures and training for truck transfer operations. Therefore, based on these design features, AGDC stated that there would be no need to physically separate the transfer areas for safe operation. We agree with AGDC's response and recommend in section 4.18.9 that AGDC include the specified design features in the final design of the GTP's truck loading/unloading facilities.

After cooling the natural gas into its liquid form, the LNG would be stored in two full-containment LNG storage tanks. However, FERC staff noted that the proposed LNG storage tank design does not include the capability to bottom fill the tank. Typically, new LNG storage tanks at import and export terminals have included both top and bottom fill capabilities for operational flexibility in preventing and managing tank stratification and rollover. Title 49 CFR 193.2503 under Subpart F requires operating procedures include provisions for recognizing abnormal operating conditions, and 49 CFR 193.2513 under Subpart F requires a means to prevent rollover due to stratification, if necessary, when making bulk transfer of LNG into a partially filled container. In addition, NFPA 59A (2001) section 4.1.2.4 requires all LNG containers be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification. NFPA 59A (2001) does not define the types of positive means that would be acceptable, but the NFPA 59A (2019) edition clarifies that there should be other *process* means provided to mitigate stratification. In addition, NFPA 59A (2019) provides guidance material in the annex on rollover phenomena and states that increased storage volume will increase the vaporization of the stratified layers and consequence of the event, and that flat bottom LNG storage tanks with less uniform heating and higher head (in contrast to smaller scale LNG pressure vessels) are often specified with level, temperature, and density gauges; top and bottom fill lines; and inter- and/or intra-tank transfers to monitor and mix the contents of the tank and prevent stratification. AGDC has indicated that rollover is primarily a concern with LNG import terminals where different compositions of LNG may be imported, and in LNG tanks that are left idle and where weathering of the LNG occurs, such as peakshavers that may not operate for extended periods of time.

AGDC indicates that they would have a recirculation line that recirculates LNG pumped from the bottom of the tank where the in-tank pumps are located to the top fill line after it is recirculated in the marine transfer line. AGDC also notes that they would have level, temperature, and density sensors and a BOG flowmeter that would give indication of stratification and potential rollover. With respect to AGDC's proposed tank recirculation method, it is unclear as to whether the recirculation line, which is also installed in nearly all import and export terminals to keep the marine transfer line(s) cool, would be sufficient to

prevent and manage tank stratification and rollover and whether additional process means would be provided. Specifically, although not included in AGDC's response, FERC staff noted that the proposed LNG tank piping and instrument diagrams (P&ID) appear to show inter- and intra-tank transfer capabilities, which FERC staff anticipates would provide a much higher flow rate and more fully mix the LNG contents to mitigate tank stratification. Therefore, we recommend in section in 4.18.9 that AGDC file information on additional process means that would be provided with higher flow rates than the recirculation line, as well as indicate whether inter- and intra-tank transfer capabilities would be included as part of the LNG tank design and procedures in order to mitigate LNG tank stratification and rollover. In addition, we recommend in section 4.18.9 that AGDC provide an evaluation on the inter- and intra-tank transfer capabilities to determine the effectiveness in preventing stratification and rollover while considering various scenarios such as changes in feed gas composition or extended outages. The evaluation should also demonstrate that the capacity of the LNG tank BOG system is sized to handle the additional vapor that would be generated during the process of mitigating LNG tank stratification and rollover. In a response filed on December 12, 2019, AGDC determined that in order to address certain scenarios that would cause potential changes in feed gas composition and to prevent tank stratification, AGDC would revise the final design of the LNG storage tanks to include bottom fill capabilities. FERC staff agrees that including bottom fill capabilities would provide sufficient mixing to effectively prevent tank stratification and rollover. In addition, FERC staff consulted with PHMSA and confirmed that including bottom fill capabilities in the LNG storage tank design would comply with NFPA 59A (2001) sections 4.1.2.4 and 11.3.7(b). We recommend in section 4.18.9 that AGDC provide updated LNG storage tank design information that incorporates top and bottom filling capabilities and provides stratification monitoring, prevention, and correction procedure to be included as part of the facility's operation and maintenance procedures. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 Subparts C, F, and H, and would be subject to PHMSA's inspection and enforcement programs.

During export operations, LNG stored within the LNG storage tanks would be sent out through multiple in-tank pumps (the pump discharge piping would penetrate through the roof and is an inherently safer design when compared to penetrating the side of an LNG storage tank) and would be routed through a marine transfer line and multiple liquid marine transfer arms connected to an LNG marine vessel. In order to keep the marine transfer line cold between LNG export cargoes and avoid cool down prior to every LNG marine vessel transfer operation, LNG would flow through a recirculation line and the marine transfer line back to the LNG storage tank(s). The LNG transferred to ships would displace vapors from the ships, which would be sent back through a vapor marine transfer arm, a vapor return line, and into the BOG system. Once loaded, the LNG marine vessel would be disconnected and leave for export. Low pressure BOG generated from stored LNG (LNG is continuously boiling) as well as vapors returned during LNG marine vessel filling operations, would be compressed and split and routed to the fuel gas system and to the liquefaction process. The closed BOG system would prevent the release of BOG to the atmosphere and would be in accordance with NFPA 59A; this system is an inherently safer design when compared to allowing the BOG to vent to the atmosphere.

In addition, the Project would include many utilities and associated auxiliary equipment. The main utilities required for GTP operation would include fuel gas, flares, instrument and utility air supply, water supply, nitrogen, and backup power. The fuel gas system would provide gas to the gas turbines, fired heaters, and purge/pilot gas for the flares. Four flare systems would be designed to handle and control the vent gases from the process areas. Two flares would vent high and low pressure hydrocarbons and two flares would vent high and low pressure H_2S and CO_2 to ensure adequate destruction of H_2S and disposal of CO_2. Electric power would be generated on site by six power generation gas turbines. Emergency loads normally powered from the normal power system would be automatically switched to power backed up by an emergency generator upon failure of the normal power system. A diesel fuel storage tank would be provided to supply a black start diesel generator that would support the start-up of the natural

gas generator, diesel firewater pumps, and diesel for service vehicles. In addition, smaller diesel storage would be provided to supply equipment and buildings at the operations camp and communication tower. There would be no liquid nitrogen storage on site; however, gaseous nitrogen would be generated on site for continuous usage throughout the plant including pre-commissioning, start-up, and maintenance.

The major auxiliary systems required for operation of the Liquefaction Facilities would include BOG, fuel gas, flares, thermal oxidizer, instrument and utility air supply, water supply, demineralized water, and nitrogen. Fuel gas would be supplied to the gas turbines, heat recovery steam generator, thermal oxidizer, and purge/pilot gas for the flares. Three flare systems would be designed to handle and control the vent gases from the process areas. The three flare systems would be the wet flare, dry flare, and LP flare. A thermal oxidizer would also be included in the design to handle operational reliefs from the condensate and off spec condensate storage tanks. Electric power would be generated on site by a combination of four gas turbines and two steam turbine generators. Emergency power for the black start generator and essential systems would be supplied by the local utility company (Homer Electric Association). A diesel tank would be provided to supply smaller diesel tanks that would be used for the firewater diesel pump, air compressor, and in plant vehicle use. Liquid nitrogen would be produced on site and stored in tanks. Vaporizers would supply gaseous nitrogen for various uses in the plant including pre-commissioning, start-up, maintenance, and refrigerant make-up.

The failure of this equipment could pose potential harm if not properly safeguarded through the use of appropriate engineering controls and operation. AGDC would install process control valves and instrumentation to safely operate and monitor the facilities. Alarms would have visual and audible notification in the control room to warn operators that process conditions may be approaching design limits. AGDC would design the control systems and human machine interfaces for both the GTP and Liquefaction Facilities to the International Society for Automation (ISA) Standards 5.3, 5.5, 60.1, 60.3, 60.4, and 60.6, and other standards and recommended practices. We recommend in section 4.18.9 that AGDC provide final specifications for these systems. In addition, we recommend in section 4.18.9 that AGDC develop and implement an alarm management program, for review and approval, to ensure the effectiveness of the alarms. FERC staff would evaluate the alarm management program against recommended and generally accepted good engineering practices, such as ISA Standard 18.2. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Operators would have the capability to take action from the control room to mitigate an upset. AGDC would develop facility operation procedures after completion of the final design; this timing is fully consistent with accepted industry practice. We also recommend in section 4.18.9 that AGDC provide more information on the operating and maintenance procedures, including, but not limited to, safety procedures, hot work procedures and permits, abnormal operating conditions procedures, and personnel training prior to commissioning. AGDC has agreed to provide information in accordance with the timing of the recommendation. We would evaluate these procedures to ensure that an operator can operate and maintain all systems safely based on benchmarking against other operating and maintenance plans and comparing against recommended and generally accepted good engineering practices, such as the American Institute of Chemical Engineers (AIChE) Center for Chemical Process Safety (CCPS) *Guidelines for Writing Effective Operating and Maintenance Procedures*, AIChE CCPS *Guidelines for Management of Change for Process Safety*, AIChE CCPS *Guidelines for Effective Pre-Startup Safety Reviews*, American Gas Association *Purging Principles and Practices*, and NFPA 51B *Standard for Fire Prevention During Welding, Cutting, and Other Hot Work*. In addition, we recommend in section 4.18.9 that AGDC tag and label instrumentation and valves, piping, and equipment and provide car-seals/locks to address human factor considerations, improve facility safety, and prevent incidents. AGDC has agreed to provide information in accordance with the timing of the recommendations.

In the event of a process deviation, ESD valves and instrumentation would be installed to monitor, alarm, shut down, and isolate equipment and piping during process upsets or emergency conditions. Both the GTP and Liquefaction Facilities would have an ESD system to initiate closure of valves and shutdown of the process during emergency situations, as well as the ability to shut down specific areas to address local emergency conditions. In addition, both the GTP and Liquefaction Facilities would have a plant-wide ESD and individual process unit shutdown capabilities. Safety-instrumented systems would comply with ISA Standard 84.00.01 and other recommended and generally accepted good engineering practices. We recommend in section 4.18.9 that AGDC file information, for review and approval, on the final design, installation, and commissioning of instrumentation and ESD equipment to ensure appropriate cause-and-effect alarm or shutdown logic and enhanced representation of the ESD system in the plant control room and throughout the plants. AGDC has agreed to provide information in accordance with the timing of the recommendations.

In developing the pre-FEED, AGDC conducted preliminary HAZID studies on the preliminary design of the GTP and Liquefaction Facilities based on the proposed piping and instrumentation diagrams. The preliminary HAZID study identifies potential hazards or environmental issues in the early stage of the Project's design that could produce undesirable consequences through the occurrence of an incident by evaluating the materials, systems, process, and plant design. A more detailed hazard and operability review (HAZOP) analysis would be performed by AGDC on both the GTP and Liquefaction Facilities during the FEED and final design to identify the major process hazards that may occur during the operation of the facilities. The HAZOP study would be intended to address hazards of the process, engineering, and administrative controls and would provide a qualitative evaluation of a range of possible safety, health, and environmental consequences that may result from the process hazard, and identify whether there are adequate safeguards (e.g., engineering and administrative controls) to prevent or mitigate the risk from such events. Where insufficient engineering or administrative controls were identified, recommendations to prevent or minimize these hazards would be generated from the results of the HAZOP review. We recommend in section 4.18.9 that AGDC file the HAZOP studies on the completed final design for review and approval. AGDC has agreed to provide information in accordance with the timing of the recommendation. We would evaluate the HAZOP to ensure all systems and process deviations are addressed appropriately based on likelihood, severity, and risk values with commensurate layers of protection in accordance with recommended and generally accepted good engineering practices, such as AIChE, *Guidelines for Hazard Evaluation Procedures*. We also recommend in section 4.18.9 that AGDC file the resolutions of the recommendations generated by the HAZOP reviews for review and approval by FERC staff. AGDC has also agreed to provide this information in accordance with the timing of the recommendation. Once the designs have been subjected to a HAZOP review, the design development team would track, manage, and keep records of changes in the facility design, construction, operation, documentation, and personnel. AGDC would evaluate these changes to ensure that the safety, health, and environmental risks arising from these changes are addressed and controlled based on its management of change procedures. If FERC staff recommendations are adopted into the Commission Order, resolutions of the recommendations generated by the HAZOP reviews would be monitored by FERC staff. We also recommend in section 4.18.9 that AGDC file all changes to their FEED for review and approval by FERC staff. AGDC has agreed to provide information in accordance with the timing of the recommendation. However, major modifications could require an amendment or new proceeding.

If the Project is authorized, constructed, and operated, AGDC would install equipment in accordance with its design. We recommend in section 4.18.9 that the Project facilities be subject to construction inspections and that AGDC provide, for review and approval, commissioning plans, procedures and commissioning demonstration tests that would verify the performance of equipment. AGDC has agreed to provide information in accordance with the timing of the recommendation. In addition, we recommend in section 4.18.9 that AGDC provide semi-annual reports that include abnormal operating conditions and facility modifications. Furthermore, we recommend in section 4.18.9 that the

Project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment is being properly maintained and that basis of design conditions, such as feed gas and sendout conditions, do not exceed the original basis of design. AGDC has agreed to provide information in accordance with the timing of the recommendations.

4.18.5.4 Mechanical Design

AGDC provided codes and standards for the design, fabrication, construction, and installation of piping and equipment and specifications for the GTP and Liquefaction Facilities. These were evaluated against recommended and generally accepted good engineering practices.

GTP

The design specifies materials of construction. The GTP design indicates a minimum design metal temperature (MDMT) of -50°F for outside equipment, piping, and supports, and -20°F for indoor equipment, piping, and supports. These MDMT ratings are typically suitable for the pressure and temperature conditions of the process design. However, the North Slope can reach temperatures below -50°F. AGDC indicates that if that were to occur, AGDC would depressurize its equipment outdoors. It is not clear if AGDC would also shut down and depressurize equipment indoors in the event the heating systems malfunctioned and there was an extended outage. Also, it is not clear if the depressurization would occur automatically through a Safety Instrumented System (SIS) or if would be written into procedures. Therefore, we recommend in section 4.18.9 that AGDC specify materials of construction with MDMTs that can withstand the minimum expected temperature at the North Slope or that AGDC demonstrate that the depressurization would occur with sufficient reliability through SIS or written procedures. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Piping within the GTP would be designed, fabricated, assembled, erected, inspected, examined, and tested in accordance with ASME Standards B31.3, B31.4, B31.5, B31.8, B36.10, and B36.19. Valves and fittings would be designed to standards and recommended practices such as API Standards 594, 598, 600, 602, 607, and 609; ASME Standards B16.5, B16.9, B16.10, B16.11, B16.20, B16.21, B16.25, B16.34, and B16.47; and ISA Standards 75.01.01, 75.08.01, and 75.08.05. We have included a recommendation, which applies to both the GTP and Liquefaction Facilities, in section 4.18.9 that AGDC demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Pressure vessels would be designed, fabricated, inspected, examined, and tested in accordance with ASME Boiler and Pressure Vessel Code (BPVC) Section VIII. Heat exchangers would also be designed to ASME BPVC Section VIII standards; API Standards 660, 661, and 662; and the Tubular Exchanger Manufacturers Association standards. Rotating equipment would be designed to standards and recommended practices, such as API Standards 610, 613, 614, 617, 618, 619, 670, 671, 675, 676, and 682; and ASME Standards B73.1 and B73.2. Fired heaters would be specified and designed to standards and recommended practices, such as API Standards 535, 556, and 560.

Pressure and vacuum safety relief valves and flares would be installed to protect the storage containers, pressure vessels, process equipment, and piping from an unexpected or uncontrolled pressure excursion. The safety relief valves would be designed to handle process upsets and thermal expansion within piping, per ASME Standard B31.3 and ASME BPVC Section VIII, and would be designed in accordance with API Standards 520, 521, 526, 527, 537, and 2000, and other recommended and generally accepted good engineering practices. In addition, we recommend in section 4.18.9 that AGDC provide, for

both the GTP and Liquefaction Facilities, final design information on pressure and vacuum relief devices and flares, for review and approval, to ensure that the final sizing, design, and installation of these components are adequate and in accordance with the standards referenced, along with other recommended and generally accepted good engineering practices. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Liquefaction Facilities

Piping within the Liquefaction Facilities would be designed, fabricated, assembled, erected, inspected, examined, and tested in accordance with the ASME Standards B31.3, B31.5, B36.10, and B36.19. Valves and fittings would be designed to standards and recommended practices such as API Standards 594, 600, 602, 607, 608, and 609; ASME Standards B16.5, B16.10, B16.20, B16.21, B16.25, and B16.34; and ISA Standard 75.01.01, 75.08.01, and 75.08.05. Portions of the facility regulated under 33 CFR 127 for the marine transfer system including piping, hoses, and loading arms should also be tested in accordance with 33 CFR 127.407. As stated above, we have included a recommendation in section 4.18.9 that AGDC demonstrate, for hazardous fluids, that piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Pressure vessels must be designed, fabricated, inspected, examined, and tested in accordance with ASME BPVC Section VIII per 49 CFR 193 Subparts C, D, and E and NFPA 59A (2001). Heat exchangers would be designed to ASME BPVC Section VIII standards; API Standards 660, 661, and 662; and the Tubular Exchanger Manufacturers Association standards. Rotating equipment would be designed to standards and recommended practices, such as API Standards 610, 613, 614, 617, 618, 619, 670, 671, 672, 675, 676, and 682; and ASME Standards B73.1, B73.2, and B73.3. Fired heaters would be specified and designed to standards and recommended practices, such as API Standards 556 and 560.

The LNG storage tanks must be designed, fabricated, tested, and inspected in accordance with 49 CFR 193 Subpart D, NFPA 59A (2001 and 2006), and API Standard 620. In addition, AGDC would design, fabricate, test, and inspect the LNG storage tanks in accordance with API Standard 625 and American Concrete Institute (ACI) Standard 376. Other low-pressure storage tanks, such as the condensate and off-spec condensate storage tanks, would be designed, inspected, and maintained in accordance with the API Standards 650 and 653.

Pressure and vacuum safety relief valves and flares would be installed to protect the storage containers, pressure vessels, process equipment, and piping from an unexpected or uncontrolled pressure excursion. The safety relief valves would be designed to handle process upsets and thermal expansion per NFPA 59A (2001), ASME Standard B31.3, and ASME BPVC Section VIII; and would be designed in accordance with API Standards 520, 521, 526, 527, 537, and 2000, along with other recommended and generally accepted good engineering practices. In addition, the operator should verify that the set pressure of the pressure relief valves meets the requirements in 33 CFR 127.407. As discussed above, we recommend in section 4.18.9 AGDC provide final design information on pressure and vacuum relief devices, for review and approval, to ensure that the final sizing, design, and installation of these components are adequate and in accordance with the standards reference and other recommended and generally accepted good engineering practices. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Although AGDC listed many of the codes and standards as those the Project would meet, AGDC did not make reference to these standards on many of the specifications and data sheets for process equipment (e.g., ASME B31.5, B16.10, B16.25, API 607, 608, 625, 653, and 662), did not include some

additional specifications that are recommended and generally accepted good engineering practices (e.g., API 603, 608), and included some codes and standards that did not seem applicable (e.g., ASME B31.4 and B31.8). Therefore, we recommend in section 4.18.9 that AGDC provide the final specifications for all equipment and a cross-referenced list of all codes and standards for review and approval. AGDC has agreed to provide this information; however, AGDC requested that this recommendation be revised to replace "all" codes and standards with "applicable" codes and standards. FERC staff notes that the intent of this recommendation is for the Project to include all codes and standards that are applicable to the Project; therefore, we have revised the recommendation in section 4.18.9 to state that AGDC should provide the final specifications for "all applicable" codes and standards to provide additional clarification. If the Project is authorized, constructed, and operated, AGDC would install equipment in accordance with its specifications and design, and FERC staff would verify equipment nameplates to ensure equipment is being installed based on the approved design. FERC staff would conduct construction inspections, including reviewing quality assurance and quality control plans, to ensure construction work is being performed according to proposed Project specifications, procedures, codes, and standards. We also recommend in section 4.18.9 that AGDC provide semi-annual reports that include equipment malfunctions and abnormal maintenance activities. In addition, we recommend in section 4.18.9 that the Project facilities be subject to inspections throughout the life of the facility to verify that the plant equipment is being properly maintained. AGDC has agreed to provide information in accordance with the timing of the recommendations.

4.18.5.5 Hazard Mitigation Design

If operational control of the facilities were lost and operational controls and ESD systems failed to maintain the Project within the design limits of the piping, containers, and safety relief valves, a release could potentially occur. FERC regulations under 18 CFR 380.12 (o) (1) through (4) require applicants to provide information on spill containment, spacing and plant layout, hazard detection, hazard control, and firewater systems. In addition, 18 CFR 380.12 (o) (7) require applicants to provide engineering studies on the design approach, and 18 CFR 380.12 (o) (14) requires applicants to demonstrate how they comply with 49 CFR 193 and NFPA 59A. As required by 49 CFR 193 Subpart I and by incorporation of section 9.1.2 of NFPA 59A (2001), fire protection must be provided for all PHMSA regulated LNG plant facilities based on an evaluation of sound fire protection engineering principles, analysis of local conditions, hazards within the facility, and exposure to or from other property. NFPA 59A (2001) also requires the evaluation on the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD and depressurizing systems, and emergency response equipment, training, and qualifications. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 Subpart I and would be subject to PHMSA's inspection and enforcement programs. However, NFPA 59A (2001) also indicates the wide range in size, design, and location of LNG facilities precludes the inclusion of detailed fire protection provisions that apply to all facilities comprehensively and includes subjective performance-based language on where ESD systems and hazard control are required. However, it does not provide any additional guidance on placement or selection of hazard detection equipment and provides minimal requirements on firewater. Also, the Marine Terminal, which would be at the Liquefaction Facilities, would be subject to 33 CFR 127, which incorporates sections of NFPA 59A (1994) that have similar performance-based guidance. The GTP would not be subject to PHMSA regulations under 49 CFR 193 or Coast Guard regulations under 33 CFR 127 or 33 CFR 105, but it would be subject to 40 CFR 68 and 29 CFR 1910.119, which require use of recognized and generally accepted good engineering practices (RAGAGEPs). While not prescriptive on which RAGAGEPs are required for process facilities, there are a number of standards that have requirements and recommendations for a fire hazard analysis or similar hazard analysis that form the basis for the design of hazard mitigation systems. In addition, 40 CFR 68 requires a Risk Management Plan be submitted with certain information, including mitigation systems identified in the most recent process hazard analysis (PHA). Title 29 CFR 1910.119 also requires RAGAGEPs and a PHA, such as a HAZOP, which often lists hazard mitigation measures. However, given the subjectivity in the regulations and PHAs, it is not clear if any hazard mitigation is

actually required or what the requirements would be for the design of hazard mitigation systems, as various RAGAGEPs can have different requirements or recommendations. Therefore, FERC staff evaluated the proposed spill containment and spacing, hazard detection, ESD and depressurization systems, hazard control, structural protection, firewater coverage, and on-site and off-site emergency response for both the GTP and Liquefaction Facilities, as described more fully below.

AGDC performed a preliminary fire protection evaluation on the Liquefaction Facilities to ensure that adequate mitigation would be in place, including spill containment and spacing, hazard detection, ESD and depressurization systems, hazard control, firewater coverage, structural protection, and on-site and off-site emergency response. After the draft EIS, AGDC submitted a preliminary fire protection evaluation for the GTP that provided a high-level summary of the hazardous materials present, potential release scenarios, general hazard mitigation layers of protection that would be in place, and recommendations to provide additional gas, flame, smoke detection, and shutdown systems for final design. However, it did not contain enough detail to substantially evaluate or inform the adequacy of the hazard mitigation design in accordance with RAGAGEPs, such as NFPA 10, API 2218, or other sound fire protection engineering practices. Therefore, we have reviewed the hazard mitigation design for the GTP, as described in each subsection below. We also recommend in section 4.18.9 that AGDC provide a final fire protection evaluation for review and approval prior to construction of the final design, on both the Liquefaction Facilities and the GTP, and to provide more information on the final design, installation, and commissioning of spill containment, hazard detection, hazard control, firewater systems, structural low temperature, and fire protection, as well as to provide finalized on-site and off-site emergency response procedures for review and approval prior to introduction of hazardous fluids. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Spill Containment

GTP

The impoundment system design for the GTP facilities would not be subject to the regulations in 49 CFR 193. However, it would be subject to 40 CFR 68 and 29 CFR 1910.119, which require use of RAGAGEPs that may include a number of standards with requirements for spill containment. In addition, 40 CFR 68 requires a Risk Management Plan be submitted with certain information, including mitigation systems in use identified in the most recent PHA. Title 29 CFR 1910.119 also requires a PHA, such as a HAZOP, which often lists spill containment as a mitigation measure. However, given the subjectivity in the regulations and PHAs, it is not clear if spill containment is actually required or what the requirements would be for the design of spill containment. Regardless, as general practice, FERC staff evaluated whether all hazardous liquids would be provided with spill containment based on the largest flow capacity from a single pipe for 10 minutes, accounting for de-inventory, or the liquid capacity of the largest vessel served, whichever is greater, and if this mitigation would prevent direct or cascading impacts on safety and security related equipment, occupied buildings, or offsite areas.

AGDC proposes to install elevated module platforms with buildings to house a significant amount of the process equipment, and AGDC clarified that these buildings would include seal-welded steel plate sub floors to contain hazardous liquid releases over the entire floor area. Releases from outdoor equipment on the module platforms would be contained by curbing around the perimeter of the outdoor platform area. AGDC indicates that truck transfer stations at the GTP would not transfer liquids above their flashpoints—which would all be above 100°F and well above the maximum ambient temperature of approximately 80°F at the North Slope—or liquids that would be a toxic vapor dispersion concern, with the exception of loading a 10,000-gallon tank of gasoline near the worker camp. Regardless, AGDC would provide buried geo-membranes and curbing to contain the volume of the largest truck compartments being served, in addition to portable urethane "duck ponds" with varying size options under the transfer hoses.

The outdoor storage containers for diesel, tri-ethylene glycol, and acid gas removal solvent would be provided with diked impoundments, typically constructed of earth, masonry, or concrete. A miscellaneous hydrocarbon mixture tank would also be provided with a similar impoundment, and AGDC never responded as to whether any miscellaneous hydrocarbon mixtures would be handled above their flash points. If they would be, it would indicate the potential need for a conveyance trench and impoundment to contain spills from the piping leading to that tank. Although AGDC indicates this transfer piping would be used intermittently, reduced time of use for any hazardous liquid piping or connections would not necessarily reduce the sizing consideration for the impoundment system. Indicating that a component would be in use for limited amounts of time does not mitigate all potential failure modes. In addition, AGDC did not consider a release from the knockout drums because they are not normally in use. However, FERC staff considers it prudent to consider the most significant hazardous composition in knockout drums. In addition, AGDC initially indicated that it proposed no containment for piping carrying hazardous liquid outside of module buildings because the piping would be welded without fittings and have a low probability of leaking. However, flanges and fittings are not the only sources of leaks, and while all piping has a relatively low probability of leaking based on a number of factors, it has not been demonstrated that the likelihood is low enough to counter the potential consequences of having an unconfined spill and negate the benefit spill containment provides for reducing such consequences. For example, if spill containment systems would not be present or appropriately designed, they may not reliably keep fire impacts away from critical components and may lead to cascading damage that could affect the reliability and safety of the GTP. After the draft EIS, AGDC indicated that pipe racks would contain steel troughs sloped to modules that could contain a design spill from hazardous liquid piping; however, for impoundment system sizing purposes, we would consider liquid spills up to full ruptures of hazardous liquid piping, which the steel troughs may not be sized to capture. In addition, the impoundment dimensions and sizing details provided by AGDC could not, in all cases, be verified in the design information, including for the proposed propane refrigerant system. This system would be located outdoors on a platform for which a process building would appear to enclose a majority of the platform floor area and, therefore, the outdoor curb height may need to be increased to contain the full sizing spill in the outdoor area only. A number of other general impoundment sizing details could also not be fully verified. We recommend in section 4.18.9 that AGDC provide the final detailed design of the impoundment systems for review and approval prior to construction of the final design, and demonstrate that all hazardous liquids, such as those with toxic vapor hazards and those handled above their flash points, would be provided with spill containment constructed of appropriate materials, with sizing based on the largest flow capacity from a single pipe for 10 minutes, accounting for de-inventory, or the liquid capacity of the largest vessel served, whichever is greater. AGDC has agreed to provide final design information in accordance with the timing of the recommendation.

AGDC indicates that temporary pumps for the removal of rainwater and snowmelt would be provided for the secondary hazardous liquid containment areas, which would be used when a measurable depth of water that would cover the suction device had accumulated in an impoundment. AGDC also indicates that curbed or walled impoundments would provide an extra 10-percent capacity plus 1-inch depth to account for accumulated snow not removed by regular maintenance, and that regular maintenance would be intended to ensure the full impoundment capacity would be available at all times to contain a potential hazardous liquid release. Snow removal in troughs would need to be addressed as well to ensure that spill conveyance to the impoundment would be available. To verify that adequate snow removal would be provided for the final design of the impoundment system, we recommend in section 4.18.9 that AGDC should provide details, for review and approval, prior to the construction of the final design. AGDC has agreed to provide detailed information in accordance with the timing of the recommendation.

If the Project is authorized and constructed, AGDC would install spill impoundments in accordance with its final design, after review and approval, and FERC staff would verify during construction inspections that the spill containment system including dimensions, slopes of curbing and trenches, and volumetric capacity matches final design information. In addition, we recommend in section 4.18.9 that

Project facilities be subject to regular inspections throughout the life of the facility to verify that impoundments are being properly maintained.

Liquefaction Facilities

In the event of a release at the Liquefaction Facilities, sloped areas at the base of storage and process facilities would direct a spill away from equipment and into the impoundment system. This arrangement would minimize the dispersion of flammable vapors into confined, occupied, public areas, or into areas where uncontrolled ignition sources may be present, and minimize the potential for heat from a fire to affect adjacent equipment, occupied buildings, or public areas if ignition were to occur.

Title 49 CFR 193.2181, under Subpart C specifies that each impounding system serving an LNG storage tank must have a minimum volumetric liquid capacity of 110 percent of the LNG tank's maximum design liquid capacity for an impoundment serving a single tank, unless surge is accounted for in the impoundment design. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 Subpart C and would be subject to PHMSA's inspection and enforcement programs. For full containment LNG tanks, we also consider it prudent to provide a barrier to prevent liquid from flowing to an unintended area (i.e., outside the plant property). The purpose of the barrier is to prevent liquid from flowing off the plant property; it does not define containment or an impounding area for thermal radiation or flammable vapor exclusion zone calculations or other code requirements already met by sumps and impoundments throughout the site. AGDC proposes two full containment LNG storage tanks for which the outer wall would serve as the impoundment system. In addition, AGDC would also install a berm around the storage tank area, which would meet our recommendation that a barrier be provided to prevent liquid in the storage tank area from flowing off plant property.

Under NFPA 59A (2001) section 2.2.2.2, for all of PHMSA regulated facilities under 49 CFR 193 Subpart C the capacity of impounding areas for vaporization, process, or LNG transfer areas must equal the greatest volume that can be discharged from any single accidental leakage source during a 10-minute period or a shorter time period based upon demonstrable surveillance and shutdown provisions acceptable to PHMSA. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193, Subpart C and would be subject to PHMSA's inspection and enforcement programs. The impoundment system design for the Marine Terminal would be subject to the Coast Guard's 33 CFR 127, which does not specify a spill or duration for impoundment sizing. Nonetheless, we evaluated whether all hazardous liquids would be provided with spill containment based on the largest flow capacity from a single pipe for 10 minutes, accounting for de-inventory, or the liquid capacity of the largest vessel served (or total of vessel capacities where multiple hazardous liquid vessels would share a common impoundment and would not be mitigated from cascading failure), whichever is greater.

We also note that the Coast Guard regulations in 33 CFR 127 incorporate NFPA 59A (1994) section 21.2, which would require provisions for the retention of spilled LNG within the limits of plant property. The Coast Guard also issued a letter on June 23, 2016 with conditions on this Project's use of pipe-in-pipe as containment for the LNG line from the LNG tank area to the dock. PHMSA regulations have similar provisions as well as provisions prohibiting use of covered impoundments. However, PHMSA regulations in 49 CFR 193.2001(b)(3) exclude the marine transfer lines and arms from the scope of Part 193 except for siting. AGDC is proposing a similar pipe-in-pipe system for its LNG liquefaction rundown line and BOG quench lines, where PHMSA would have authority on the design and would need to evaluate a special permit for the use of pipe-in-pipe as spill containment for the LNG liquefaction rundown line and BOG quench lines. We also evaluated whether the pipe-in-pipe systems would be effective in capturing

releases, including whether they can withstand the cryogenic and mechanical forces that could be induced by the releases, as described below.

AGDC would install curbing, paving, and trenches to direct hazardous liquid spills from process and transfer areas to impoundments, except for the pipe-in-pipe transfer lines, which are intended to use the 304 stainless steel outer pipe as spill containment. This containment method is proposed for the LNG marine loading lines between the LNG storage tank area and the dock, including portions of the attached BOG quench lines, as well as for the LNG liquefaction rundown lines between the LNG storage tank area and the liquefaction processing trains. AGDC indicates that the outer 304 stainless steel pipe would be designed to the same pressure as the inner Invar pipe, which would be wrapped with either Aerogel or Izoflex insulation, and that a leak detection system would be installed to monitor for any loss of inner pipe containment. AGDC also indicated that sub-atmospheric pressures in the annular space of the pipe-in-pipe system would inhibit LNG from remaining a liquid if released through a crack in the inner pipe. However, the spill containment system for these LNG transfer lines would be expected to handle all spill sizes up to a full rupture of the inner pipe, including the combined force and sudden thermal shock of these LNG releases, rather than just a release from a crack in inner pipe. The use of stainless steel for this impoundment is questionable. The stainless steel outer pipe would exist at a warmer temperature than the inner LNG pipe, and stainless steel may need to be provided with a gradual cool down time while subject to mechanical loads before handling cryogenic liquid in order to prevent cracking and other effects. AGDC provided oil and gas (OLGA) simulations, computational fluid dynamics (CFD) analyses, and finite element analyses to demonstrate that local and global stresses in the pipe-in-pipe system would remain within acceptable tolerances for use of the outer pipe as an impoundment for a significant release. This included evaluation of the stresses between the outer and inner pipe due to differing amounts of thermal contraction of their materials and concluded that these stresses would not have potential to impact integrity of the system during a release into the outer pipe. However, both of the pipe-in-pipe designs being considered by AGDC may not have been included in the stress modeling. Therefore, we included a recommendation in section 4.18.9 for AGDC to provide stress modeling based on the selected design of the pipe-in-pipe system, for review and approval prior to construction of the final design. Also, these models were not used to evaluate the propensity to develop or propagate cracks when considering the jetting release forces combined with the sudden cryogenic temperature shock effects. AGDC indicates that the pipe-in-pipe system would have multiple layers of insulation blankets and a layer of sheet-metal steel or foil within the annulus that would impede the inner pipe release and keep the full impacts from reaching the outer pipe. However, AGDC has not provided an analysis demonstrating the insulation would actually remain intact for all pressurized release scenarios up to a full inner pipe failure, and sudden cryogenic releases onto piping materials under load have not been demonstrated that they would not initiate or propagate cracks. Therefore, it is still unclear whether or not pressurized cryogenic releases from the inner pipe may initiate and propagate similar cracking in the outer pipe. AGDC commits to providing modeling of release effects during the detailed design phase, using the final design of the pipe-in-pipe system. CFD analysis would be conducted to determine the worst case jetting release sizes from the inner pipe, and AGDC indicates that modeling could be validated by large scale tests to determine whether additional materials would need to be included within the insulation layers to improve jetting force resistance. If the outer pipe system would not actually contain releases from the inner pipe, AGDC indicates that the public would not be affected by the consequences. However, the consequence modeling results provided by AGDC show that a full release at the sloped portion of the marine trestle would have the potential to adversely affect personnel or off-site public on the beach or local water areas near the marine transfer line, which could have significant impacts if not mitigated. We note that there is a potential right-of-way or lease being pursued; however, the details of that agreement are not known, and it has not been executed. Therefore, we recommend in section 4.19.8 that, prior to construction of the final design, AGDC file for review and approval an analysis and/or tests that demonstrate either that the pipe-in-pipe system would maintain integrity and not initiate and propagate cracks when subjected to sudden cryogenic temperatures and forces from the full range of jetting release

sizes or, alternatively, that the spill containment design for this piping be revised to include a conventional trough and impoundment system.

In addition, since AGDC has not yet selected a vendor for the pipe-in-pipe system, full information on the detailed piping design, leak testing procedures, plans for vapor handling from a large spill into the annular space, plans for draining a large spill from the annular space, and integrity management procedures have not yet been developed. Therefore, we recommend in section 4.19.8 that this information be provided, for review and approval, prior to construction of the final design.

On the dock, AGDC proposes that a spill occurring from a full rupture of a conventional LNG line between the pipe-in-pipe marine loading header to the marine loading arm would be directed by curbing to an impoundment adjacent to the dock platform and limited by shutdown systems to a duration of 1 minute. However, AGDC has not yet demonstrated that the curbing proposed on the dock would generally capture the liquid from large jetting releases and retain the liquid within the impoundment system. Full guillotine releases would be expected to depressurize, rather than jet liquid for a significant distance. Possibly, if certain release sizes jet liquid over the edge of the dock, the liquid could vaporize before reaching the water, but AGDC did not provide modeling to demonstrate the full range. AGDC has indicated that the dock support structures would be constructed using low temperature carbon steel with an outer wrapping also constructed of low temperature carbon steel. AGDC notes that this steel would typically have Charpy impact tests at -40°F. However, this material and installation may not be suitable for contact with LNG at -260°F, in addition to tug boats and other vessels in the area. Therefore, we have included a recommendation in section 4.18.9 for AGDC to demonstrate, prior to construction of the final design, that the design of the marine impoundment system would capture liquid rainout resulting from jetting releases up to a full guillotine rupture of a dock transfer line, which could cause impacts on dock or trestle supports, nearby public, berthed LNG marine vessels and tugs, or other cascading impacts.

AGDC provided information to justify the use of a 1-minute sizing spill at the dock, based on having a surveillance and shutdown system with a reliability equivalent to safety integrity level (SIL) 2. In this system, gas, flame, and low temperature detectors at the dock would have the capability to automatically shut the ESD valves immediately downstream of the pipe-in-pipe transitions to conventional piping at the dock, as well as the onshore ESD valve just upstream of the marine transfer header line on the trestle. AGDC sized the design of the dock impoundment to contain the 1-minute flow rate plus de-inventory of associated piping on the dock. However, the failure of any of the six piping connection areas on the docks, between the first dock ESD valve and the pipe-in-pipe termination, would allow all of the transfer piping length on the trestle to de-inventory. AGDC proposes to contain additional de-inventory volumes on the flat portion of the trestle between the two berths. An explanation was not provided for how this trestle containment would be accomplished without having LNG back up onto the dock surface, and details were not provided on whether revisions would be needed to the structural support design of the trestle area between the berths to accommodate the liquid weight. Moreover, while an ESD system with a demonstrable surveillance system that can shutdown and isolate in less than 10 minutes and a higher reliability may be appropriate for limiting the spill volumes in the impoundment, we do not believe it is good practice to size an impoundment for a 1-minute release, excluding pipe-in-pipe de-inventory, which would cause de-inventory volumes to back up into the dock surface and trestle where people, evacuation routes, and equipment could be located within the pool fire or radiant heat impacts from a pool fire. We also believe that a 10-minute release should be prevented from overflowing the impoundment system and also should not result in cascading damage. Therefore, we recommend in section 4.18.9 that AGDC provide details, for review and approval, prior to construction of the final design, demonstrating that 1-minute releases as well as pipe-in-pipe de-inventory would be fully contained in the impoundment, and the overall impoundment system would contain a 10-minute release as well as pipe-in-pipe de-inventory without resulting in cascading failures to equipment or structural supports given the potential impacts of overflowing the impoundment system onto the water.

Within the plant, given that the outer pipe of the pipe-in-pipe lines has not been demonstrated to contain all potential release sizes without cracking, as discussed above, releases from the LNG liquefaction rundown line or from onshore portions of the marine transfer line could possibly spread over large areas and under or around equipment. Modeling results provided by AGDC showed that flammable vapor dispersion from a single train liquefaction rundown line may not extend beyond the local process area. However, the potential for offsite impacts to occur due to a rupture of an LNG marine transfer line in onshore areas or a rupture of the LNG rundown header, which combines the single train flows, was not evaluated. Therefore, as discussed above, we recommend in section 4.19.8 that, prior to construction of the final design, AGDC file for review and approval an analysis and/or tests that demonstrate that either the pipe-in-pipe system would maintain integrity and not initiate and propagate cracks when subjected to sudden cryogenic temperatures and forces from the full range of jetting release sizes or, alternatively, that the spill containment design for this piping be revised to include a conventional trough and impoundment system.

Spills from the conventional portions of the LNG lines between the LNG storage tanks would be directed through trenches to the LNG Storage Tank Impoundment Sump. Liquid spilled on the LNG tank rooftop area is proposed to be directed, with the use of concrete curbing on the roof, to a stainless steel down-comer pipe running from the tank top to the spill containment trench at the base of the tank for direction to the spill impoundment. However, it is not clear whether the spill curbing system on the tank top would be designed to capture all significant jetting releases up to the full rupture of piping on the tank top. AGDC indicates that LNG can be safely conveyed along the concrete outer tank for the 10-minute sizing spill duration without affecting the outer wall, but has not provided information on where an LNG release landing outside of the intended collection system would be contained. Although the tertiary berm around the LNG tank area may limit the potential LNG collection to certain areas, likely following the stormwater system, AGDC has also not provided information on the potential impacts on equipment and personnel in the event that pooled LNG would ignite in those locations or the potential increased vaporization due to this spilled LNG not being directed to the trench system. Therefore, we recommend in section 4.18.9 that prior to construction of final design, AGDC file, for review and approval, an analysis that demonstrates that releases up to a full guillotine rupture from the LNG tank top area that are not captured by the tank top LNG spill collection system would not significantly increase the radiant heat or vapor dispersion hazard compared to directing those spills to the trench and impoundment.

AGDC would direct other hazardous liquid spills to impoundment sumps with the use of paving, curbing, and trenching, including separate impoundments for each of the following areas: Liquefaction Train area, Liquefaction Compressor area, Fractionation area, BOG Compressor area, Refrigerant Storage area, and Truck Loading area. Spill containment for flare knock out drums would be accomplished with local curbing to contain the maximum liquid volume. In addition, the condensate, off-spec condensate, and diesel storage tanks are all proposed to be in one impoundment dike, and the Slop Oil Tank Dike would be provided to contain spills from that tank. However, AGDC has not indicated how the liquid lines between the pipe rack and the condensate, diesel, and slop oil storage tank impoundments would be provided with spill containment. After the draft EIS, AGDC agreed to provide detailed information on this in accordance with the timing of the spill containment recommendation in section 4.18.9, for review and approval. Also, diagrams indicate an ESD valve in onshore portions of the pipe-in-pipe lines for LNG marine transfer, and it had not been clear how the outer pipe would serve as continuous containment at the valve location or whether this valve would be in an area with conventional spill containment. After the draft EIS, AGDC clarified these ESD valves would be located within the LNG tank tertiary berm and any liquid releases from that valve area would not change the sizing criteria for the LNG tank area impoundment. Other connections to the pipe-in-pipe system, such as for valves and reliefs, would also be located within areas of conventional containment. AGDC agreed to provide detailed information on this in accordance with the timing of the spill containment recommendation in section 4.18.9, for review and approval. In addition, AGDC proposed no spill containment for the liquid nitrogen package, stating that modeling in PRO/II 9.3 and PHAST v6.7

indicated no rainout for a catastrophic rupture of a liquid nitrogen storage tank. However, it is not clear whether the models have been validated for this type of rainout calculation and, if so, whether there would potentially be overpressures to consider from the apparent rapid phase transition that would likely occur for no rainout of the entire liquid contents to occur upon a vessel failure. After the draft EIS, AGDC indicated that validation for the rainout calculations for a catastrophic failure of a liquid nitrogen vessel would be provided prior to construction of the final design. In addition, AGDC provided spreadsheet calculations, using a methodology described by Molkov and Kashkarov, to indicate that 1-psi overpressures from a burst of the liquid nitrogen tank may extend 670 feet from the tank, assuming that no liquid rainout would occur for this scenario. However, the methodology is dependent on the amount of liquid and gas in the vessel and on the conditions at the burst pressure selected, which were not conservatively selected and may not be likely to be reflective of the actual burst conditions. In addition, AGDC did not characterize potential for distances projectiles might be thrown or the potential for cascading impacts on nearby facilities, such as refrigerant storage and instrument air equipment. Therefore, FERC staff evaluated the potential impacts across the full range of the percent fill volumes and burst pressures that assume the pressure relief valve may or may not work to limit the pressure. This results in burst pressures based on ASME BPVC Section VIII allowances above the design pressure in a fire exposure case for sizing pressure relief valves operating (i.e., 1.2*MAWP) and burst pressures based on the safety factors built into the design requirements of ASME BPVC Section VIII (i.e., 4*MAWP). Based on these burst pressures, and cases ranging from completely full of liquid and completely full of gas, FERC staff calculated 1-psi overpressure distances that would not be much different than the 670 feet calculated by AGDC, and FERC staff calculated that the majority of projectiles would be thrown within 1,000 feet. However, projectiles would have about a 10-percent probability of being thrown more than 1 mile and about a 1-percent probability of being thrown more than 2 miles. FERC staff estimates rainout of approximately 20 to 60 percent depending on burst conditions. The assumptions and calculated impact distances are in line with historic incidents of catastrophic failures of liquid nitrogen storage tanks. For example, in 1992, a liquid nitrogen tank catastrophically failed in Japan, causing an impact radius of approximately 1,300 feet and projectiles to be thrown up to 1,150 feet. The tank was found with the pressure relief valves isolated. In 2006, a liquid nitrogen tank catastrophically failed at a Texas A&M laboratory. The tank was found with its pressure relief valves replaced with plug valves and reported pressures built up to 1,000 psi prior to failing.[149] Therefore, we recommend in section 4.18.9 that, prior to construction of the final design, AGDC file validation data supporting the calculation of no rainout or revise their design to provide spill containment for the liquid nitrogen tank. AGDC agreed to provide updated rainout calculations with modeling validation or provide liquid nitrogen spill containment in accordance with the timing of our recommendation.

As discussed above, we evaluated whether the proposed impoundments would contain either the largest flow capacity from a single pipe for 10 minutes accounting for de-inventory or the maximum liquid capacity of the largest vessel served (or total for vessels within a common impoundment), whichever is greater. Pipe flow release scenarios for the LNG loading pumps, de-ethanizer reflux pumps, and the condensate pumps are proposed to be provided with an interlock, having an SIL of 2 or higher, to prevent the activation of additional installed pumps that would have the potential to increase the total flowrate of these scenarios. In addition, all pump driven scenarios were conservatively considered at 40-percent pump run out flowrates, except the LNG loading pump scenario for which modeling was provided to justify a lower run out rate. In certain areas, AGDC indicates that firewater overages during an impoundment fire event would be directed to the local impoundment in addition to the spill but would be vaporized by the impoundment fire before collecting in the impoundment, although this has not yet been quantitatively demonstrated. Certain trench sizing has not yet been fully defined, and the method for continuing adequate spill collection along the paving under pipe racks where these racks would cross in-plant roadways is not clear, since the curbing would not be able to cross the road to assist with collection for spills occurring over

[149] The pressure relief valves would be outfitted with isolated valves that are car sealed open to prevent inadvertent isolation. In addition, FERC staff recommend that AGDC provide mitigation from external fires that could cause catastrophic failures of the liquid nitrogen tanks.

the road. In addition, the most recent spill containment plot plans show a grated hazardous liquid trench crossing a grated storm water trench, and AGDC has indicated that the Project would have no elevated troughs. After the draft EIS, AGDC clarified that the stormwater conveyance design would be revised to transition to a culvert before reaching this hazardous spill trench, in order to avoid a conflict. Therefore, we included recommendations in section 4.18.9 for AGDC to demonstrate an appropriate design for the above issues and provide additional information on the final design of the impoundment systems for review and approval prior to construction of the final design. AGDC has agreed to provide detailed design information in accordance with the timing of the recommendations.

AGDC states that storm water removal pumps meeting the requirements of 49 CFR 193.2173 under Subpart C would be installed in all hazardous liquid impoundments. AGDC also indicates that if very low temperature (i.e., below MDMTs typically at -20°F) liquid would be present, any automatically activated sump pumps would be shut down or prevented from activating by redundant shutdown controls based on temperature detection. Automatically activated pumps do not appear to be proposed in areas where hazardous liquid spills at or above ambient temperatures would also be expected, so accidental discharge of these hazardous liquids from automatic stormwater removal pump activation is not of concern.

AGDC also indicated that a depth of 12 inches would be provided above the working depth of trenches and impoundments to account for snowfall. AGDC also provided general preliminary options for removing hardened snow within curbed spill collection areas, as well as any excess in impoundments and trenches, including potential impoundment systems that could be heated only when necessary, mechanical removal, and snowmelt/de-icing agents. We recommend in section 4.18.9 that AGDC provide an analysis and final design of the mitigation for snow and ice in the impoundment system, for review and approval, prior to construction of the final design. AGDC has agreed to provide detailed design information in accordance with the timing of the recommendation.

If the Project is authorized, AGDC would install spill impoundments in accordance with its final design, and FERC staff would verify during construction inspections that the spill containment system—including dimensions, slopes of curbing and trenches, and volumetric capacity—matches final design information. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to verify that impoundments are being properly maintained.

Spacing and Plant Layout

The spacing of vessels and equipment play an important role in the safety of a facility. The spacing and plant layout typically will separate facilities handling hazardous fluids from facilities handling non-hazardous fluids, and then further group equipment together into smaller discrete curbed areas to minimize the spread of a release and minimize subsequent hazards in one area affecting other areas. The spacing between these discrete areas will typically be designed to minimize the risk of cascading damage and the risk of ignition. Further, they will be spaced away from the property line to minimize the risk of any off-site impacts. In addition, facilities handling fluids with other unique process conditions (e.g., temperature and pressures) or hazardous properties (e.g., combustible, flammable, toxic, and corrosive) may be segregated from each other to separate and better manage the unique hazards of those facilities.

GTP

The GTP facilities primarily handle materials with combustible, flammable, toxic, and asphyxiation properties, with the majority of the equipment and piping within buildings to protect the personnel and equipment from the extreme temperatures and conditions at the North Slope, but with some equipment and interconnecting piping located outside that may not require personnel to frequently perform operation or maintenance.

To minimize the risk for flammable or toxic vapor ingress into buildings at the GTP, we recommend in section 4.18.9 that AGDC conduct a technical review of the final design of the facility, for review and approval prior to construction of the final design, identifying all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release to an outdoor area; and verify that these areas would be adequately covered by hazard detection devices that would isolate or shut down any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. AGDC has agreed to provide this information in accordance with the timing of the recommendation. AGDC has indicated that, for the GTP, it would provide flammable gas detection at all combustion and ventilation air intakes as well as toxic gas detection at all ventilation air intakes for CO_2 and H_2S detection. AGDC further describes that the flammable gas detection would be provided with an alarm at 20 percent of the LFL, with a second alarm and automatic shutdown of the air intake at detection of 40-percent LFL. AGDC indicates that the toxic gas detection would be provided with alarms as well as executive actions appropriate to the hazards in the area. As noted above, we recommend in section 4.18.9 that the final design of these systems be provided for review and approval, and that Project facilities be subject to periodic inspections during construction to verify flammable/toxic gas detection equipment is installed in heating, ventilation, and air conditioning (HVAC) intakes of buildings at appropriate locations, as well as at combustion air intakes. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facilities to continue to verify that flammable/toxic gas detection equipment installed in building and combustion air intakes function as designed and are being maintained and calibrated.

In addition, AGDC's proposed design includes CO_2/H_2S byproduct send out piping at approximately 4,000 psi, which would be expected to produce significant overpressures (from a physical explosion from release, not from ignition of a flammable/combustible fluid) and asphyxiation or toxic hazards, if breached. FERC staff issued a data request for AGDC to file an engineering analysis of the type and extent of the pipe ruptures that could physically occur upon a puncture or other breach of the high pressure piping. In response, AGDC indicated that a catastrophic release would not result, based on information in its fracture control plan for the CO_2/H_2S pipelines, and then analyzed the release volumes from 2-inch diameter holes only. However, the fracture control plan only indirectly addressed the data request. Instead of engaging the puncture scenario, this plan put forth a general theory that the pipe has material properties that would self-arrest fractures, with the objective of arresting them within a few pipe joints. AGDC did not provide substantive calculations to demonstrate the self-arresting property, and FERC staff are skeptical that self-arresting would occur under these environmental conditions. FERC staff identified that the pipe wall thickness allowances do not adequately account for the pipe wall thickness design. This is substantial, as an inadequate pipe wall thickness means that a fracture would not self-arrest within a few pipe joints, and subsequent piping failures would occur.

Even if AGDC increased the pipe thickness, other factors indicate that a local rupture could still result from a puncture. For example, AGDC did not provide the requisite inputs for the lowest temperature in which pipe stress exceeds threshold stress (MDT-BF) or the limits for when brittle fracture would not propagate under dynamic load (DWTT). Likewise, ADGC does not provide or plan to assess the fracture propagation transition temperature, a design input based on pipe thickness, even though this is a relevant correction factor for the DWTT. AGDC instead explains how it considers dynamic testing to be "the most reliable way" to establish fracture behavior, but then never conducts this testing. Without this fundamental design information, the Fracture Control Plan is merely conceptual and does not demonstrate actual pipe performance under a puncture or impact scenario. For these reasons, FERC staff cannot discount the potential for significant rupture if the proposed pipe sustains puncture damage or other impacts affecting its structural integrity.

AGDC initially modeled vapor dispersion from a 2-inch hole in the high-pressure CO_2/H_2S piping in an attempt to be consistent with the design spill releases used for the Liquefaction Facilities. To

determine a toxic endpoint, AGDC used a weighted average of the CO_2 immediately dangerous to life or health (IDLH) value and the 10-minute H_2S Acute Exposure Guideline Level (AEGL) and also included a factor of 2 to account for uncertainty in the Phast dispersion model. The toxic vapor dispersion distance results provided for a 2-inch hole reached roughly halfway to the adjacent PBU CGF plant pad, and this appears to be very close to the edge of the land leased by that company.

However, it is not immediately clear if the Phast model is validated for such a high pressure release, and modeling as a pipeline rupture may be more appropriate since it appears plausible that a puncture could result in fracture propagation; this would have potential to increase the calculated dispersion distance. Therefore, we recommended in the draft EIS that AGDC analyze the vapor dispersion and overpressure impacts on plant components and occupied buildings in the event of a breach and rupture of high pressure piping, or provide detailed technical justifications to address those issues, for the high pressure CO_2/H_2S lines in the plant and along the off-site route, as well as for the treated gas send out lines within the plant. We also recommended that AGDC provide any mitigation necessary to prevent significant impacts. To address dispersion from a pipe rupture, after the draft EIS, AGDC provided catastrophic vessel rupture modeling in Phast versions 6.7 and 8.22 using the volume in an amount of piping that was limited without providing the requested justification for that limitation. The requests had included prompts for consideration of volumes in the larger piping and longer lengths as well as for the timing and reliability of any ESD valves if they would be expected to isolate fluid volumes during a rupture dispersion scenario. In addition, the fluid mass available in the limited pipe volume assumed by AGDC was calculated by Phast to have significantly less mass than the Heat and Material Balance sheets indicate would be present for that volume. AGDC also modeled the CO_2/H_2S liquid in Phast at a significantly colder temperature than indicated on the Heat and Material Balance sheets. AGDC indicates this temperature adjustment was necessary to force the Phast model to recognize the liquid state of the fluid, but it is not clear whether the significantly lowered temperature could have caused the "rainout" portion of the CO_2 release to have artificially precipitated out of the dispersing vapor cloud. AGDC did not explain the effects that these issues and up to a 4,000-psi release pressure may have on the validity of using the Phast model for this scenario, and also did not explain how the Phast rainout calculation would be valid for predicting solid CO_2 precipitation effects. The general validation documentation provided with Phast v8.11, which is available to FERC staff, only a review of up to 1-inch-diameter releases from CO_2 systems, at up to roughly 2,200 psi, which would not appear to be fully representative of the scenarios in question for this Project. Although it is not clear whether Phast is an appropriate model for the Project scenarios, we note that if modeling this scenario in Phast as a "line rupture" for a large volume de-inventory, the results would indicate that toxic and/or asphyxiation impacts could reach over the adjacent PBU CGF plant pad and the GTP personnel camp. AGDC indicates a belief that a "line rupture" scenario would be expected to depressurize due to activation of shutdown systems and result in reduced dispersion, but AGDC did not provide a justified technical analysis to demonstrate that reaction and valve closure times would occur rapidly and reliably enough in comparison to the rupture release rate to prevent significant loss of hazardous fluid, as well as consideration of whether the valves or operators could have been affected by the rupture. In addition, several of the above modeling issues may be relevant to the dispersion of release scenarios from the high pressure natural gas piping as well, which were indicated to have shorter potential dispersion distances than the H_2S/CO_2 scenarios. AGDC also modeled the potential impacts of the overpressures of a high pressure pipe rupture. AGDC used the Phast vessel BLEVE model and considered 10 to 50 pipe lengths of the largest CO_2/H_2S or natural gas piping to contribute to this event. This resulted in a maximum distance of 366 feet to 1 psi from the 42-inch natural gas sendout piping and 232 feet to 1 psi from the large 24-inch CO_2/H_2S header piping. However, AGDC did not clarify how the assumptions discussed above do not affect the validity of using this model to calculate overpressures, including the lowered fluid temperature, and did not characterize the potential for cascading impacts on nearby facilities. In addition, there is some uncertainty associated with the dispersion of mixtures within Phast. Therefore, for the above reasons, we are unable to conclude that the high pressure piping would not pose a significant safety impact on persons off site of the GTP process facilities, although we note that the GTP facilities and these hazard zones would

be located at an adjacent CGF plant within Alaska's PBU area, which is not accessible to the general public without an escort. We recommend in section 4.18.9 that ERPs for potential large ruptures at the GTP would be coordinated with the adjacent PBU CGF plant and include consideration of impacts on the GTP operator camp site. To demonstrate potential safety impacts on persons offsite of the GTP process facilities and inform the ERPs, we also recommend that AGDC provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure pipe systems at the GTP. As discussed in section 4.18.1, PHMSA has clarified that the CO_2/H_2S pipelines, after the GTP outlet, would be subject to the requirements in 49 CFR 195.

To evaluate flammable vapors reaching areas that could result in cascading damage from explosions, AGDC modeled the vapor dispersion of a refrigerant vessel leakage source as well as the overpressures associated with ignition of that vapor cloud both within congestion and underneath a module platform. The flammable vapor dispersion from this liquid refrigerant release did not reach beyond the adjacent modules, but the center of the overpressure zone calculated for this scenario would be near the high pressure pipelines and equipment. AGDC did not address the potential for cascading events due to overpressure impacts onto the high pressure pipeline facilities, including the potential for impacts on the module platforms themselves due to an explosion directly underneath them and an assessment of any resulting damage to facilities above that platform area. If a rupture of the high pressure piping systems could occur, this could lead to potential significant safety impacts on personnel and off-site persons, as discussed above. Therefore, we recommend that AGDC analyze the potential for the overpressures from vapor cloud ignition underneath the module platforms to affect the platforms and the high pressure equipment above them—such as the treated gas chillers and associated piping as well as CO_2/H_2S piping—and provide any measures needed to prevent significant cascading damage and safety impacts, for review and approval, prior to construction of the final design. AGDC has agreed to analyze the potential for the overpressures from vapor cloud ignition to affect high pressure equipment and provide mitigation in accordance with the timing of the recommendation. In addition, as discussed in the Ignition Controls section, AGDC indicates that explosion control would be provided as needed for buildings and structures at the GTP containing flammable and combustible fluids.

To minimize the risk of jet and pool fires causing structural supports and equipment from heating above their maximum design metal temperatures to a point of failure, FERC staff also evaluated the spacing of plant facilities to determine if there could be potential for cascading damage and to inform what fire protection measures may be necessary to reduce the risk of cascading damage. The spacing of the propane system facilities and the high-pressure gas chillers would present a concern for jet fire impingement, especially because firewater streams would not be available for cooling. Jet fires would also be a concern in other areas of the plant as well, including inside module buildings in areas where fluids may be handled above their flash points. Water mist systems are proposed in specific indoor areas, but primarily only to protect certain equipment. AGDC indicates that the plant design would include ESD systems to isolate inventory and blowdown systems to decrease pressures, but AGDC has not yet provided details on the effectiveness and reliability of this active measure and the provision of passive protection. If jet fires due to ignition of a flammable vapor release would not be sufficiently mitigated, these hazards may lead to cascading damage that could affect personnel or off-site persons, which could be a significant impact. Therefore, in order to mitigate the risk of a potential significant impact on less than significant levels, we recommend in section 4.18.9 that AGDC demonstrate that the potential for jet fires to cause cascading hazards would be effectively mitigated by systems with a reliability equivalent to SIL 2, for review and approval, prior to construction of the final design. AGDC has agreed to provide details demonstrating that the potential for jet fires to cause cascading hazards in any area of the GTP would be effectively mitigated by a system with a reliability equivalent to SIL 2 or higher. In addition, AGDC has not yet defined the potential for pressurized vessels to be exposed to a significant duration of high radiant heat from indoor or outdoor process impoundment fires. AGDC has agreed to provide an assessment of the mitigation necessary to prevent cascading damage or significant safety issues due to the hazardous

conditions from pool fires by a system with a reliability equivalent to SIL 2. Therefore, we recommend in section 4.18.9 that AGDC identify and analyze the pressure vessels and any trucks within the 4,000 Btu/ft^2-hr zones and structural components within the 4,900 Btu/ft^2-hr zones from potential jet and pool fires, and provide any mitigation necessary to prevent cascading impacts, for review and approval, prior to construction of the final design.

If the Project is authorized and the above recommendations are resolved, AGDC would finalize the plot plan; we recommend in section 4.18.9 that AGDC provide any changes for review and approval to ensure capacities and setbacks are maintained. If the facilities are constructed, AGDC would install equipment in accordance with the spacing indicated on the final plot plans, after review and approval. In addition, we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify equipment is installed in appropriate locations and the spacing is met in the field. We also recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment setbacks from other equipment and ignition sources are being maintained during operation.

Liquefaction Facilities

For all of PHMSA regulated facilities under 49 CFR 193, the spacing of vessels and equipment between each other, from ignition sources, and to the property line must meet the requirements of 49 CFR 193 Subparts C, D, and E, which incorporate NFPA 59A (2001). NFPA 59A (2001) further references NFPA 30, NFPA 58, and NFPA 59 for additional spacing and plant layout requirements. If the facilities are authorized, constructed, and operated, AGDC must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. FERC staff also evaluated the spacing of plant facilities to determine if there could be potential for cascading damage and to inform what fire protection measures may be necessary to reduce the risk of cascading damage. The Liquefaction Facilities would primarily handle materials with cryogenic, flammable, combustible, toxic, and asphyxiation properties.

To minimize the risk of cryogenic spills causing structural supports and equipment from cooling below their MDMT, AGDC would generally locate cryogenic equipment away from non-cryogenic process areas and would direct cryogenic releases to remote impoundment basins. In addition, AGDC would protect the piping, equipment, and structural supports for areas that would have cryogenic equipment and could be exposed to cryogenic temperatures, as discussed under Passive Low Temperature and Fire Protection.

To minimize risk for flammable or toxic vapor ingress into buildings, AGDC indicated that the air intakes for occupied buildings and combustion equipment within 200 feet of hydrocarbon processing equipment would include flammable gas detection, unless dispersion modeling of flammable gas scenarios showed farther dispersion. However, the flammable gas dispersion modeling appears to reach most plant areas. Therefore, additional justification would be needed for any combustion or ventilation air intakes that would not be provided with gas detection, such as for the Consolidated Building. We recommend in section 4.18.9 that AGDC conduct a technical review of the facility, for review and approval prior to the construction of the final design, identifying all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release, and verifying that these areas would be adequately covered by hazard detection devices that would isolate or shut down any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. AGDC has agreed to provide information in accordance with the timing of the recommendation. We also recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify flammable/toxic gas detection equipment is installed in HVAC intakes of buildings at appropriate locations. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular

inspections throughout the life of the facilities to continue to verify that flammable/toxic gas detection equipment installed in building air intakes function as designed and are being maintained and calibrated.

To minimize flammable vapors reaching areas that could result in cascading damage from explosions, AGDC proposed design of the process facilities minimizes confinement and congestion with the exception of a few areas described. In particular, we evaluated how flammable vapors would be prevented from accumulating within confined areas, such as underneath the LNG storage tanks and process modules. After the draft EIS, AGDC clarified that the process modules at the liquefaction site would have grated floors, which would be expected to reduce the potential for partial confinement of flammable vapor under a module floor, but could cause a vapor cloud to envelope multiple floors. As the porosity of the grating increases, the less congestion there might be, but the ability for a larger cloud to develop would exist. FERC staff evaluated the potential for a larger vapor cloud explosion developing, and results indicate that if there is medium congestion there is a relatively high potential for cascading impacts if a larger vapor cloud develops, but if there is low congestion or a significant vapor cloud is not able to develop there is less potential for cascading impacts. Therefore, we included a recommendation in section 4.19.8 for AGDC to provide an evaluation of the final design of grated module platforms at the Liquefaction Facilities that demonstrates a vapor cloud explosion of significant magnitude would not develop from a design spill such that it results in cascading damage that could have impacts offsite, for review and approval, prior to construction of the final design. The LNG storage tanks would be located away from process equipment. However, AGDC provided hazard analyses indicating that flammable vapors could reach both LNG storage tanks. Ignition of a flammable vapor cloud extending under the tanks could produce overpressures in these semi-confined areas, and if not sufficiently mitigated, may have potential to lead to cascading damage that could affect personnel or off-site public, which could be a significant impact. After the draft EIS, AGDC indicated that a flexible material wrap would be provided around the base of the LNG tank to prevent entry of flammable vapors into the semi-confined space. Therefore, we recommend in section 4.18.9 that AGDC provide the detailed design of the flexible material barrier proposed to prevent flammable vapor from collecting under the LNG tanks, including measures that would prevent freezing temperatures in that space, for review and approval, prior to construction of the final design.

We also evaluated heat fluxes from jet and pool fires, as well as overpressures from vapor cloud explosions, at plant buildings. AGDC provided a building siting analysis and separate hazard analyses to satisfy siting requirements that showed that overpressures could extend to 1 psi at any of these structures. However, the building siting analysis evaluated relatively smaller release events, up to 2-inch diameter holes, using a rationale based on statistical information and findings from the DNV Technica study—*A Guide to Quantitative Risk Assessment for Offshore Installations*—although AGDC's rationale did not appear to adequately account for potential piping system failures. We recommend that the building siting study be based on the hazard analyses done for siting requirements, which use primarily 2- to 4-inch-diameter releases. AGDC indicates that buildings would be designed for the maximum predicted heat flux and blast overpressure, especially occupied and critical operations buildings, as calculated in a *Facility Siting Study Report* by Baker Risk. However, in addition to limiting the evaluation to 2-inch holes, this report appears to have used a very preliminary plot plan and does not appear to have considered all occupied buildings in the building list for the current design, including all five Field Operations Center Buildings. Also, the building near the condensate and diesel storage impoundment appears to need consideration of heat impacts on operators inside the building. Potential revisions to the plant design may also need to be considered to address the siting of the marine control room, which is currently planned to be located within the 10,000 Btu/ft^2-hr heat flux zone from a potential fire in the impoundment on the trestle between the marine berths, which was proposed after the draft EIS and is discussed further in the next paragraph. Also after the draft EIS, AGDC indicated that an updated building siting study would be provided in accordance with API 752. However, API 752 does not define the release scenarios to be modeled, and FERC staff experience has shown that this is one of the most critical parameters in the building siting analysis and greatly affects the risk. Therefore, we recommend in section 4.18.9 that occupied buildings be relocated to

avoid or demonstrated to withstand impacts of jet fires and overpressures and projectiles from 2- to 4-inch-diameter releases (i.e., design spills), as well as heat flux from pool fires, for review and approval, prior to construction of the final design. AGDC indicated it would provide an analysis that occupied buildings at the Liquefaction Facilities would be able to withstand radiant heats from pool and jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release, in accordance with the timing of our recommendation.

In addition to building impacts, AGDC has also not yet demonstrated how the LNG tanks, emergency equipment, and refrigerant storage and pressure vessels would be designed to withstand the heat fluxes, as well as vapor cloud overpressures, calculated in the Hazard Analysis Report. AGDC indicates the highest pressure onto the LNG tanks from these design spill scenarios was found to be 7.66 psi and that the tanks are designed to maintain structural integrity and vapor seal after being subjected to a blast overpressure of about 8 psi. AGDC commits to, after the updated leak source scenarios and resulting overpressures are defined in detailed design, assigning the necessary parameters and designing the LNG tanks to withstand the calculated overpressures. AGDC further commits that modeling would be developed to validate the design of the structure, considering the spatial and temporal variation associated with blast loading. In addition, AGDC indicated that pressure vessels would be in areas that could be affected by high radiant heat levels, but has not yet provided a detailed analysis of how proposed mitigation would adequately prevent cascading impacts—including BLEVEs and pressure vessel bursts—as well as potential impacts on other critical components, such as overpressures onto the firewater tank. Also, the hazard analyses, using LNGFIRE3 and Phast models, indicate that in certain locations—including near the bluff, dock, and in-plant areas—the pipe-in-pipe system could experience significant amounts of radiant heat due to impoundment fires or overpressures from vapor cloud ignition. AGDC indicates that the pipe-in-pipe system would withstand plant hazards associated with the operation of the Liquefaction Facilities, but has not yet quantitatively demonstrated its capabilities. AGDC indicates that the pipe-in-pipe system would withstand overpressures similarly or better than a pipe within an elevated trough because both systems would be designed to withstand the same wind speeds and the pipe-in-pipe would have a shape that would not allow for as much side-on overpressure impact. It is still not clear whether overpressures from vapor cloud ignition near the bluff could cause cascading damage to the pipe-in-pipe system that would allow for a release that could affect the public beach area below. In addition, radiant heat hazards could be especially significant at the dock where the piping could be within the 10,000 Btu/ft^2-hr zone from a fire in the dock impoundment. Further, AGDC provided an LNGFIRE3 result plot for radiant heat zones from a fire in the impounding area proposed for the trestle between the marine berths, but the plotted zone did not appear to account for both the front and side result distances. Based on staff calculations using LNGFIRE3, this fire scenario could cause the marine area control building, about half of either berthed LNG marine vessel, and dock equipment—including the drain/surge pressure vessel—to be well within a 10,000-Btu/ft^2-hr zone, although the duration of this trestle fire would be much shorter than the dock impoundment fire. AGDC indicates it would continue to optimize the marine containment design during the final design phase of the Project and had indicated that hazard control devices on both the LNG marine vessel and the berth could help mitigate cascading impacts in that area, but this has not been demonstrated for the current hazard scenarios. Therefore, we included recommendations in section 4.18.9 for AGDC to demonstrate the above facilities could withstand these impacts or that measures would be in place to prevent potential cascading damage or significant safety hazards due to the above issues, for review and approval, prior to construction of the final design. After the draft EIS, AGDC indicated the fireproofing design would be revised in the final design phase to include areas based on pool and jet fires that could result in failure of the pressure vessels, structural components, or other critical components (e.g., critical wiring, control systems, and ESD valves). AGDC would provide the resulting design in accordance with the timing of our related recommendation. In addition, AGDC indicated it would provide an analysis that demonstrates safety-related equipment (e.g., firewater pump buildings, control buildings, and other emergency equipment), as well as refrigerant storage tanks at the Liquefaction Facilities, would be able to withstand radiant heats from

pool and jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release, in accordance with the timing of our related recommendation.

To minimize the risk of jet fires from causing cascading damage that could exacerbate the initial hazard, AGDC would implement methods for minimizing flanges and potential leakage sources. They would also install ESD systems to isolate inventory, decrease pressure, and limit a jet fire duration; firewater systems to cool equipment and structures; and passive fire protection in accordance with API 2218 and International Organization for Standardization (ISO) 22899-1, as described in subsequent sections. In addition, we recommend in section 4.18.9 that AGDC file drawings of the passive structural fire protection for review and approval for structural supports and equipment.

If the Project is authorized and the above recommendations are resolved, AGDC would finalize the plot plan; we recommend in section 4.18.9 that AGDC provide any changes for review and approval to ensure capacities and setbacks are maintained. If the facilities are constructed, AGDC would install equipment in accordance with the spacing indicated on the final plot plans, after review and approval. In addition, we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify equipment is installed in appropriate locations and the spacing is met in the field. We also recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facilities to verify that equipment setbacks from other equipment and ignition sources are being maintained during operation.

Ignition Controls

GTP

AGDC's overall plant areas for the GTP would be designated with an appropriate hazardous electrical classification in accordance with NFPA 70, 496, and 497; and API Recommended Practice (RP) 500. Depending on the risk level, plant areas would either be classified as non-classified, Class 1 Division 1, or Class 1 Division 2. In addition, equipment in these areas would designed such that in the event a flammable vapor is present, the equipment would have a minimal risk of igniting vapor. FERC staff evaluated the GTP's electrical classification drawings to verify AGDC would meet these electrical area classification requirements in NFPA 70, 496, and 497; and API RP 500. FERC staff noted in some instances the basis for electrical classification was unclear. Specifically, the fuel storage area is classified as Class 1 Division 2, however, the diesel storage and trucking area is shown as non-classified. AGDC filed information on July 16, 2019 that included a revised electrical area classification drawing that addressed classifying the diesel storage and trucking area as Class 1 Division 2. However, FERC staff identified other areas that remain unclassified, such as the majority of outdoor pipe racks that house piping containing hazardous fluids. AGDC stated in a response filed on October 11, 2019 that these pipe racks would be unclassified as they would not contain manual valves, flanged fittings, threaded connections, or power actuated valves larger than 1 inch. However, AGDC also indicated that these outdoor pipe racks would contain steel troughs sloped to modules that can contain a design spill from hazardous liquid piping, indicating a potential for a leak from the outdoor piping. In addition, AGDC stated that the GTP's hazardous electrical classification would comply with NFPA 59A in addition to the codes and standards referenced above. Based on this information, designating these pipe rack areas as unclassified would not be considered good engineering practice and do not appear to be consistent with NFPA 59A and API RP 500. In addition, AGDC did not provide preliminary cross-sectional drawings that show the electrical classification for major equipment reliefs, valves, operational bleeds, vents, or drains, truck loading/unloading area, dikes/spill containment systems, and storage containers. In an information request issued on January 15, 2019, FERC staff requested cross-sectional drawings that show the hazardous electrical classification. AGDC filed a response on July 16, 2019 that included electrical area classification drawings of cross-sectional areas of the process module buildings, inlet gas area, etc., which would

generally be classified as Class 1 Division 2. Cross-sectional drawings depicting hazardous electrical classification for other areas such as major equipment reliefs were not provided as AGDC stated the design would not include major equipment reliefs that would relieve to atmosphere. Major equipment reliefs would be tied into a relief header that would be sent to the flares. AGDC's response also did not include cross-sectional drawings for the truck loading/unloading areas, spill containment areas, and storage containers. In a data request issued on September 17, 2019, FERC staff requested that AGDC explain how the Project intends to treat electrical classification of curbed areas for the process modules. AGDC responded that this information would be provided prior to construction of the final design. Therefore, we recommend in section 4.18.9 that AGDC provide final electrical classification drawings, including cross-sectional drawings, for review and approval, for all areas of the GTP that demonstrate the design meets applicable codes and standards such as NFPA 59A, 70, 496, and 497; and API RP 500. AGDC has agreed to provide information in accordance with the timing of the recommendation.

FERC staff also evaluated whether buildings that handle flammable and toxic substances would be designed to adequately ventilate a potential flammable vapor or toxic release in order to minimize hazardous accumulation and risk of vapor ignition. Although the GTP is not required to meet NFPA 59A, AGDC stated in a response filed on October 11, 2019 that electrical area classification at the GTP would comply with NFPA 59A. In addition, AGDC indicated in a response filed on September 17, 2019 that explosion control would be provided as needed for buildings and structures containing flammable fluids in accordance with the International Building Code (IBC) section 414.5.1, International Fire Code (IFC) section 911, and NFPA 68 and/or NFPA 69. Buildings at the GTP would be classified and include design features that would prevent accumulation of flammable and toxic vapors. However, the process module buildings would contain Local Electrical Rooms (LER) that would be unclassified. FERC staff note that API RP 500 recommends that an enclosed area that is adjacent to a classified area, such as in this case of the LERs, and that is separated from a classified area by a vapor tight barrier, is unclassified. AGDC has not indicated whether the LERs would be surrounded by vapor tight barriers; however, API RP 500 also states that it may be possible to reduce the classification of an enclosed area adjacent to a classified area if the enclosed area is purged in accordance with NFPA 496. In a supplemental response filed on October 11, 2019, AGDC indicated the LERs would be positively pressurized and would conform with NFPA 496. AGDC also added that in order to limit the possibility of a flammable gas release from entering the LER via the HVAC air intakes, air flow direction would be from non-classified areas. We recommend in section 4.18.9 that AGDC provide final design details and specifications of the LERs located within the process modules including, but not limited to, the pressurization system, HVAC air intake system, and any openings such as personnel entry door(s), electrical cable entries, and air conditioning unit(s). In addition, in a response filed on June 2, 2017, AGDC stated that the building ventilation design would meet the ventilation rate of 1 cubic foot per minute of air per ft^2, as prescribed in NFPA 59A (2001) section 2.3.2.2. The HVAC system would employ a dual rate mechanical ventilation system that would increase the number of air changes per hour upon gas detection, which is consistent with NFPA 59A (2001) section 2.3.2.1 part (3). Lastly, AGDC indicated that the building design would also include an exhaust system that would exhaust air from low levels in order to remove hydrocarbons and other chemical vapors that are heavier than air, which is also consistent with NFPA 59A (2001) section 2.3.2.3. Based on FERC staff review of the proposed conceptual building ventilation design, we recommend in section 4.18.9 that AGDC file information, for review and approval, on the final design that demonstrates the GTP buildings include an adequate ventilation system that would effectively prevent accumulation of flammable and toxic vapors. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Liquefaction Facilities

AGDC's plant areas for the Liquefaction Facilities would be designated with an appropriate hazardous electrical classification and process seals commensurate with the risk of the hazardous fluids being handled in accordance with NFPA 59A (2001), 70, and 497; and API RP 500. If authorized,

constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs, which require compliance, by incorporation by reference, with NFPA 59A (2001). NFPA 59A (2001) subsequently references NFPA 70 (1999) for installation of electrical equipment wiring. The marine facilities must comply with similar electrical area classification requirements of NFPA 59A (1994) and 70 (1993), which are incorporated by reference into the Coast Guard regulations in 33 CFR 127. Depending on the risk level, these areas would either be classified as non-classified, Class 1 Division 1, or Class 1 Division 2. Similar to the GTP, equipment in these areas would be designed such that in the event a flammable vapor is present, the equipment would have a minimal risk of igniting the vapor. FERC staff evaluated electrical area classification drawings for the Liquefaction Facilities to determine whether AGDC would meet the electrical area classification requirements and good engineering practices in NFPA 59A, 70, and 497; and API RP 500, as applicable. Below grade spill trenches and impoundments would be Class 1 Division 1, with the exception of a portion of the spill trench for the LNG rundown piperack west of the liquefaction air fin coolers, which would be Class 1 Division 2. In a response filed on May 24, 2019, AGDC explained that this portion of the LNG rundown line transitions from conventional piping to a pipe-in-pipe technology. The pipe-in-pipe technology utilizes the outer pipe for containment; therefore, AGDC indicated there is no need for a spill trench and hence an electrical classification of Class 1 Division 2. However, FERC staff note that this same piperack would also contain process piping (i.e., refrigerants) that would require spill trenches to be Class 1 Division 1. Therefore, we recommend in section 4.18.9 that AGDC file information that revises or justifies the electrical classification of Class 1 Division 2 for the spill trench that would serve the portion of the LNG rundown piperack west of the air fin coolers that would contain process piping. AGDC has agreed to provide information in accordance with the timing of the recommendation. Similar to the LNG liquefaction rundown lines, AGDC also proposes to use the same pipe-in-pipe technology for the LNG marine transfer lines from the LNG storage tank area to the PLF. However, in contrast to the LNG liquefaction rundown lines, the LNG marine transfer lines would be unclassified until they reach the dock area, at which point the dock area would be classified as Class 1 Division 2. In a response filed on October 11, 2019, AGDC stated that the LNG marine transfer lines would employ a pipe-in-pipe technology that does not require a spill trench. AGDC added that the lines would be fully-welded with no equipment, flanges, fittings, discharge points (relief valves, bleeds, drips or drains), or connection points; therefore, the marine transfer line area does not need to be classified. This is inconsistent with the LNG liquefaction rundown lines, which would be classified as Class 1 Division 2. In addition, the marine transfer pipe-in-pipe would transition to conventional piping at the marine vessel loading header to the marine vessel loading arms in the marine berth area. As described in the Spill Containment section, spills from this portion of conventional piping would be directed by curbing to the dock impoundment; however, AGDC has classified both marine berth areas as Class 1 Division 2. In addition, AGDC indicated in a response filed on December 23, 2019 that the flat portion of the trestle located in between the two marine berths would be used as spill containment, which AGDC has specified as an unclassified area. The electrical classification of these spill containment areas does not appear to be consistent with the design basis used for other spill containment areas at the Liquefaction Facilities, which would be classified as Class 1 Division 1, and it also does not appear to meet the applicable codes and standards such as NFPA 59A and API RP 500. Therefore, we recommend in section 4.18.9 that AGDC file information that revises or justifies the electrical classification of the spill containment systems for the PLF, including the marine trestle area.

AGDC provided cross-sectional drawings showing the electrical classification for equipment pressure reliefs, operational bleeds, vents or drains, truck loading/unloading system, spill containment system, storage containers, and marine loading arms, which would meet API RP 500 and NFPA 59A, as applicable. We recommend in section 4.18.9 that AGDC provide final electrical classification drawings, for review and approval, for all areas of the Liquefaction Facilities. AGDC has also agreed to provide information in accordance with the timing of the recommendation.

The Liquefaction Facilities would also have submerged pumps and instrumentation that must be equipped with electrical process seals and instrumentation in accordance with NFPA 59A (2001) and 70 at each interface between a flammable fluid system and an electrical conduit or wiring system. AGDC provided preliminary drawings that show the pump electrical process seals would include a primary seal, a gap that would be continuously purged with nitrogen and vented to a safe location, and a secondary seal. The drawings indicate that the primary and secondary seal would be monitored by the nitrogen purge system installed in between the primary and secondary seal through a pressure and/or temperature transmitter including alarms. We recommend in section 4.18.9 that AGDC provide, for review and approval, final design drawings showing process seals installed at the interface between a flammable fluid system and an electrical conduit or wiring system that meet the requirements of NFPA 59A (2001) and 70. In addition, we recommend in section 4.18.9 that AGDC file, for review and approval, details of an air gap or vent equipped with a leak detection device that should continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to ensure electrical process seals for submerged pumps continue to conform to NFPA 59A and 70, and that air gaps are being properly maintained. AGDC has agreed to provide information in accordance with the timing of the recommendations.

If the Project is authorized, AGDC would finalize the electrical area classification drawings and would describe changes made from the FEED design. We recommend in section 4.18.9 that AGDC file the final design of the electrical area classification drawings for review and approval. If facilities are constructed, AGDC would install appropriately classed electrical equipment, and we recommend in section 4.18.9 that the Project facilities be subject to periodic inspections during construction for FERC staff to spot check electrical equipment and verify that equipment is installed per classification and properly bonded or grounded in accordance with NFPA 70. We also recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to ensure electrical equipment is maintained (e.g., bolts on explosion proof equipment properly installed and maintained, and panels provided with purge), and electrical equipment is appropriately de-energized, locked out, and tagged out when being serviced. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Hazard Detection, Emergency Shutdown, and Depressurization Systems

AGDC would also install hazard detection systems to detect cryogenic spills, flammable and toxic vapors, and fires throughout the GTP and Liquefaction Facilities. The hazard detection systems would alarm and notify personnel in the area and control room to initiate an ESD, depressurization, or initiate appropriate procedures, and would meet NFPA 72, ISA Standard 12.13 and other recommended and generally accepted good engineering practices. However, AGDC did not provide specifications for the fire safety systems for the GTP and Liquefaction Facilities based on the FEED. Therefore, we recommend in section 4.18.9 that AGDC provide specifications, for review and approval, of the final design of the fire safety specifications, including hazard detection, hazard control, and firewater systems. AGDC has agreed to provide information in accordance with the timing of the recommendation.

FERC staff also evaluated the adequacy of the general hazard detection type, location, and layout to ensure adequate coverage to detect cryogenic spills, flammable and toxic vapors, and fires near potential release sources (i.e., pumps, compressors, sumps, trenches, flanges, and instrument and valve connections) at both the GTP and Liquefaction Facilities.

GTP

AGDC did not provide hazard detection layout drawings for certain areas within the GTP such as the flare and flare knockout drum area, refrigeration compressors and chillers area, power generation area, essential diesel generator area, AGRU and diesel storage area, building heat medium utility heater area, GTP operations center, inlet facilities, etc. FERC staff requested this information in an information request issued on January 15, 2019, and AGDC filed a response on July 16, 2019 that only included hazard detection layout drawings for the power generation area. The drawings show that no flammable gas or flame detectors would be provided for the power generators, which would be natural gas turbines located in enclosed modules. However, in response to a follow-up data request filed on October 11, 2019, AGDC agreed to provide flammable gas detection inside all enclosed modules where flammable gases would be present. AGDC stated that the flare area, inlet facilities area, and other areas that would not be enclosed would not have fire and gas detection; therefore, drawings for these areas are not available. In addition, the hazard detection layout drawings that were provided for the process train modules did not appear to show adequate coverage for equipment handling flammable, combustible, and toxic fluids than is typical, which may not provide as rapid of detection of an incident. Specifically, our review identified an insufficient number and limited redundancy of toxic detectors based on revised hazard detection layout drawings filed on May 24, 2019. The revised hazard detection layout drawings do not appear to address figure 3 of the October 4, 2017 *GTP Hazard Analysis Report*, which shows the ½-AEGL-2 for CO_2/H_2S would affect most buildings within the GTP process area. For other process areas for which drawings were not provided, such as the flare knockout drum area, refrigerant compressors and chillers area, essential diesel generator area, AGRU and diesel storage area, etc., FERC staff was unable to determine whether adequate hazard detection coverage would be provided in these specific areas. AGDC has indicated that the hazard detection layout provided is based on a preliminary design and would be subject to revisions during detailed design. It is also unclear whether AGDC would include other types of flammable gas detectors such as open path detectors. AGDC indicated that these design details would be determined during final design. In response to our recommendation in the draft EIS, on August 30, 2019, AGDC filed a preliminary fire protection evaluation, which recommended combustible gas detectors be provided in the inlet gas area, treated gas chilling area, flare knockout drum area, and inside all enclosed modules where natural gas would be present. AGDC would evaluate all these recommendations during final design and would need to provide technical justification for any recommendations that would not be incorporated in the final design. AGDC noted that flammable gas and toxic detectors would be located at all HVAC unit air intakes. In a supplemental response filed on October 4, 2017, AGDC stated that the flammable gas detectors in the air intakes would pre-alarm at 20-percent LFL, and that 40-percent LFL would activate the air intake system to automatically shut; however, alarm set points and shut down capabilities for the toxic detectors in the air intakes was not provided. Based on this review, we recommend in section 4.18.9 that AGDC should provide hazard detection layout drawings for all areas of the plant. AGDC has agreed to provide information in accordance with the timing of the recommendation. We also recommend in section 4.18.9 that AGDC provide hazard detection study to evaluate the effectiveness of the flammable and gas detection system in accordance with ISA 84.00.07 or equivalent methodologies in having two or more detectors that would detect 90 percent or more of releases (unignited and ignited) that could result in an off-site impact—or a cascading impact that could extend off site—resulting in isolation and de-inventory within 10 minutes. The analysis should revise the hazard detection coverage to include outside process areas, or adequately demonstrate that failure to detect releases due to a lack of hazard detection coverage would not be needed in outside process areas and would not result in direct or indirect off-site impacts, including projectiles from potential BLEVEs resulting from undetected fire events. The analysis should also take into account the set points, voting logic, and different wind speeds and directions.

AGDC does not propose to include low oxygen detectors at the GTP. In an information request response filed on June 16, 2017, AGDC stated that low oxygen detectors are not required since any leakage from nitrogen bottles or the heated AGRU would be dispersed within the normal module air changes. In

addition, in a response filed on October 11, 2019, AGDC stated that flammable gas and toxic gas detectors would be used to detect oxygen deficient atmospheres within the enclosed modules. However, it's unclear how effective using flammable gas and toxic gas detectors would be to detect low oxygen, as these devices are typically used for measuring the lower flammability limit of flammable and toxic gases. Low oxygen detectors are more commonly used and are typically calibrated to measure oxygen deficiencies in the atmosphere in accordance with oxygen concentration levels defined in OSHA's *Respiratory Protection Standard.*[150] Therefore, we recommend in section 4.18.9 that AGDC provide an evaluation of the normal module air changes and whether there are alarms and notifications in the event the ventilation equipment is not operating or functioning, as designed, to determine whether oxygen detectors are needed in order to notify operators of a potential nitrogen release and ensure safe entry into a module/building. AGDC also has not indicated in any filings, including the most recent response filed on October 11, 2019, that hydrogen gas detectors would be provided in battery rooms. Therefore, we recommend in section 4.18.9 that AGDC file an analysis of the off gassing of hydrogen in battery rooms and ventilation calculations that limit concentrations below the LFLs (e.g., 25-percent LFL) as well as provide hydrogen detectors that alarm and initiate mitigative actions. AGDC has agreed to provide information in accordance with the timing of the recommendations.

FERC staff also reviewed the fire and gas cause and effect matrices that typically indicate how each detector would initiate an alarm, shutdown, depressurization, or conduct other action. However, the cause and effect matrices did not include all hazard detection devices (i.e., toxic detectors) and did not specify the hazard detector device type, device tag number, voting logic, and set points that would initiate any type of action. Therefore, we recommend in section 4.18.9 that AGDC provide, for review and approval, the cause and effect matrices for process instrumentation, fire and gas detection system, and ESD system for the GTP. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Liquefaction Facilities

The hazard detection drawings provided for the Liquefaction Facilities also did not appear to show adequate coverage of certain flammable process equipment (i.e., propane coolers, refrigerant compressors, refrigerant storage area, etc.). In an information request response filed on May 24, 2019, AGDC stated that hazard detector coverage is indicated on notes on the drawings; however, this information does not show device locations in order to verify coverage. In addition, there appears to be an overall lack of low temperature detectors in the LNG and hydrocarbon spill trenches as well as in the refrigerant storage impoundment and condensate/refrigerant trucking impoundment. FERC staff verified that flammable gas detectors would be provided at air intakes of equipment (i.e., gas turbines) and HVAC intakes of buildings. In addition, AGDC proposes to set the flammable gas detectors to indicate a high alarm at 25-percent LFL and high-high alarm at 40-percent LFL. Similar to the GTP, we recommend in section 4.18.9 that AGDC provide a hazard detection study on the Liquefaction Facilities to evaluate the effectiveness of the flammable and gas detection system in accordance with ISA 84.00.07 or equivalent methodologies in having two or more detectors that would detect 90 percent or more of releases (unignited and ignited) that could result in an off-site impact—or a cascading impact that could extend off site—resulting in isolation and de-inventory within 10 minutes. The analysis should take into account the set points, voting logic, and different wind speeds and directions. In a response filed on October 7, 2019, AGDC indicated that a formal hazard detection study would be performed in accordance with ISA 84.00.07, or equivalent, during final design. Furthermore, we recommend in section 4.18.9 that AGDC provide additional information, for review and approval, on the final design of all hazard detection systems (e.g. manufacturer, model, and

[150] U.S. Department of Labor, Occupational Safety and Health Administration, Respiratory Protection Standard, 63 Fed. Reg. 1152–1300, January 1998 (https://www.osha.gov/laws-regs/federalregister/1998-01-08).

elevations) and hazard detection layout drawings. AGDC has agreed to provide information in accordance with the timing of the recommendations.

At this time, AGDC also has not proposed to include low oxygen detectors in the liquid nitrogen storage area to notify operators of a potential nitrogen release. Therefore, we also recommend that AGDC provide oxygen detectors be provided at the Liquefaction Facilities to notify operators of a potential liquid nitrogen releases. AGDC indicated that hydrogen detectors would be provided in the battery room as needed; however, since AGDC has not determined at this time whether hydrogen detectors would be provided, we recommend in section 4.18.9 that AGDC file an analysis of the off gassing of hydrogen in battery rooms and ventilation calculations that limit concentrations below the LFLs (e.g., 25-percent LFL) as well as provide hydrogen detectors that alarm and initiate mitigative actions or alarms and mitigative actions in the event the ventilation equipment is not operating or functioning, as designed. AGDC has agreed to provide information in accordance with the timing of the recommendations.

FERC staff reviewed the preliminary fire and gas system cause and effect matrices and noted that the cause and effect matrices do not include details on the specific piece of equipment or valve on the hazard detector or the associated interlock that would initiate any type of shutdown. FERC staff also noted that the cause and effect matrices were missing fire and gas equipment such as the low temperature detectors, and that set points were also blank for the heat detectors (i.e., a fusible plug). Therefore, we recommend in section 4.18.9 that AGDC provide, for review and approval, the cause and effect matrices for process instrumentation, fire and gas detection system, and ESD system. AGDC has agreed to provide information in accordance with the timing of the recommendation.

If the Project is authorized, constructed, and operated, AGDC would install hazard detectors according to its specifications, and we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify hazard detectors and ESD pushbuttons are appropriately installed per approved design and functional based on cause and effect matrixes prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to verify hazard detector coverage and functionality are being maintained and are not being bypassed without appropriate precautions. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Hazard Control

GTP

If ignition of flammable vapors occurred, hazard control devices would be installed to extinguish or control incipient fires and releases. AGDC indicates the hazard control layout and design would meet NFPA 10, 12, 15, 17 and 2001; API 2510A; as well as other recommended and generally accepted good engineering practices. We evaluated the adequacy of the number and availability of handheld, wheeled, and fixed fire extinguishing devices throughout the GTP site based on the FEED. We also evaluated whether the spacing of the fire extinguishers would meet NFPA 10. In a response filed on May 24, 2019, AGDC filed revised hazard control drawings that only included the process train area and control building and did not provide hazard control drawings for other areas such as the flare and flare knockout drum area, refrigeration compressors and chillers area, power generation area, essential diesel generator area, AGRU and diesel storage area, building heat medium utility heater area, operations center, inlet facilities, etc. In a response filed on July 16, 2019, AGDC provided the hazard control layout drawings only for the power generation area which appear to show an insufficient quantity of portable fire extinguishers would be provided. In addition, the fire extinguishers do not appear to be meet the NFPA 10 travel distances to components that would contain flammable or combustible fluids. AGDC did not provide hazard control drawings for other areas referenced above; therefore, it is unclear whether sufficient hazard control would

be provided. According to information provided in the application, the process train area would include both portable fire extinguishers and wheeled units; however, the drawings do not differentiate between the portable and wheeled units. Therefore, it is unclear whether the fire extinguisher layout would meet the travel distances specified in NFPA 10. AGDC indicated that a differentiation between portable and wheeled fire extinguishers has not yet been determined and proper coverage would be confirmed during final design. We recommend in section 4.18.9 that AGDC provide, for review and approval, a complete set of hazard control drawings that clearly show the location of fire extinguishers and hazard control details of all fire extinguishing systems (i.e., type, location, and capacity). In addition, all final details for extinguishers such as NFPA 10 travel distances, installation heights, visibility, flow rate capacities, and other requirements should be confirmed in final design and in the field where design details, such as manufacturer, obstructions, and elevations, would be better known. AGDC has agreed to provide information in accordance with the timing of the recommendations.

We also evaluated whether clean agent systems would be installed in all electrical switchgear and instrumentation building systems in accordance with NFPA 2001, and CO_2 or water mist system in gas turbine enclosures in accordance with NFPA 12 or NFPA 750. AGDC indicated that a clean agent fire extinguishing system would be used to protect critical equipment and instrumentation buildings, including the control building and LERs located inside process modules, in accordance with NFPA 2001. Additionally, AGDC indicated that depending on gas turbine generators enclosure details and vendor selection, the fire suppression system may be CO_2 in accordance with NFPA 12, or a water mist system in accordance with NFPA 750. We recommend in section 4.18.9 that AGDC file additional information on the final design of these systems, for review and approval, where details are yet to be determined and where the final design could change as a result of these details or other changes in the final design of the Project. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Liquefaction Facilities

AGDC indicates that the hazard control layout and design for the Liquefaction Facilities would meet NFPA 59A (2001); NFPA 10, 12, 15, 17, and 2001; API 2510A; as well as other recommended and generally accepted good engineering practices. As described above, we conducted the same evaluation on the hazard control design for the Liquefaction Facilities. The hazard control design would include portable and wheeled potassium bicarbonate dry chemical fire extinguishers and units. In an information request issued on January 15, 2019, FERC staff noted that although the hazard control drawings include a note specifying a travel distance of 50 feet between fire extinguishers, the hazard control layout drawings actually show the fire extinguisher locations to be greater than the 50-foot spacing requirement. In a response filed on June 28, 2019, AGDC stated that the placement of portable fire extinguishers, along with the type and size, would be reviewed during detailed design in accordance with NFPA 10. Based on our review of the hazard control design of the Liquefaction Facilities, we recommend in section 4.18.9 that AGDC provide, for review and approval, a complete set of hazard control drawings that clearly show the location of fire extinguishers and hazard control details of all fire extinguishing systems (i.e. type, location, and capacity). In addition, all final details for extinguishers such as NFPA 10 travel distances, installation heights, visibility, flow rate capacities, and other requirements should be confirmed in final design and in the field where design details, such as manufacturer, obstructions, and elevations, would be better known. AGDC has agreed to provide information in accordance with the timing of the recommendation.

In the event of a pressure relief valve fire on top of the LNG storage tank, AGDC would install a nitrogen snuffing system and dry chemical system for each LNG storage tank that would be sized to extinguish a fire from the tank pressure relief valves relieving at full capacity. Both of these systems would be initiated from the control room or a local panel in the LNG storage tank area. AGDC would also install a clean agent system in areas enclosing critical electrical equipment, which AGDC noted would only be the Central Control Room in accordance with NFPA 2001. Therefore, FERC staff recommends in

section 4.18.9 that AGDC provide a clean agent system in accordance with NFPA 2001 in all other buildings that would house instrumentation and electrical equipment that serve safety and security systems. In addition, portable CO_2 extinguishers would be provided in the Central Control Room, electrical and power substations, switchgear rooms, and other rooms or buildings where electrical hazards would be present. AGDC also indicated that, depending on gas turbine generators enclosure details and vendor selection, the fire suppression system may be CO_2 in accordance with NFPA 12, or a water mist system in accordance with NFPA 750. We recommend in section 4.18.9 that AGDC file additional information on the final design of these systems, for review and approval, where details are yet to be determined and where the final design could change as a result of these details or other changes in the final design of the Project. AGDC has agreed to provide information in accordance with the timing of the recommendations.

If authorized, constructed, and operated, AGDC would install hazard control equipment, and we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify hazard control equipment is installed in the field and functional prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to verify in the field that hazard control coverage is being properly maintained and inspected. AGDC has agreed to provide information in accordance with the timing of the recommendations.

Passive Low Temperature and Fire Protection

If low temperature releases and fires could not be mitigated from affecting facility components to insignificant levels, passive protection (e.g., fireproofing structural steel and low temperature protection) should be provided to prevent failure of structural supports of equipment and pipe racks. PHMSA incorporates NFPA 59A (2001) by reference in 49 CFR 193.2101 under Subpart C for design, 49 CFR 193.2301 under Subpart D for construction, 49 CFR 193.2401 under Subpart E for equipment, 49 CFR 193.2521 under Subpart F for operational records, and 49 CFR 193.2693 under Subpart G for maintenance records. NFPA 59A (2001) section 6.4.1 requires pipe supports, including any insulation systems used to support pipe whose stability is essential to plant safety, to be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure. We also note that 49 CFR 193.2801 under Subpart I for fire protection only incorporates sections 9.1 through 9.7 and 9.9 of NFPA 59A (2001), which requires an evaluation of methods necessary for protection of equipment and structures from effects of fire exposure, but does not reference requirements for passive cryogenic protection. In addition, NFPA 59A (2001) does not address passive cryogenic equipment or structures other than pipe supports. Moreover, NFPA 59A (2001) does not provide the criteria anywhere for determining if pipe supports, equipment, or structures are subject to cold liquid or fire exposures or the level of protection needed to protect the pipe supports, equipment, or structures against such exposures. In addition, the GTP would not be subject to PHMSA regulations under 49 CFR 193 but would fall under OSHA's Process Safety Management of Highly Hazardous Chemicals standard and the EPA Risk Management Plan, which do not have any explicit requirements for low temperature or fire structural passive protection. Under OSHA's Process Safety Management of Highly Hazardous Chemicals standard regulations in 29 CFR 1910, there are several requirements pertaining to meeting RAGAGEPs. However, which RAGAGEPs to use is not prescribed, and recommended practices and guidance documents may not be enforceable and may contain provisions that are subject to interpretation. Therefore, FERC staff evaluated whether passive cryogenic and fire protection would be applied to pressure vessels and structural supports to facilities that could be exposed to low temperature liquids (i.e., below the MDMT) or to radiant heats of 4,000 Btu/ft^2-hr or greater from fires with durations that could result in failures[151] and that they are specified in accordance with recommended and generally accepted good engineering practices, such as

[151] Pool fires from impoundments are generally mitigated through use of ESDs, depressurization systems, structural fire protection, and firewater; jet fires are primarily mitigated through the use of ESDs, depressurization systems, and firewater with or without structural fire protection.

ISO 20088, API 2001, API 2010A, API 2218, ASCE/Society of Fire Protection Engineers (SFPE) 29, American Society for Testing and Materials (ASTM) E84, ASTM E2226, Institute of Electrical and Electronics Engineers (IEEE) 1202, ISO 22899, National Association of Corrosion Engineers (NACE) 0198, NFPA 58, NFPA 290, OTI 95 634, Underwriters Laboratories (UL) 723, UL 1709, and/or UL 2080, with a cryogenic temperature and duration and fire protection rating commensurate to the exposure.

GTP

AGDC indicated that cryogenic structural protection would not be applicable to the GTP. This appears to be accurate, and while we also determined there would not appear to be potential for liquid release temperatures below the minimum design ambient temperature, there is the possibility for equipment indoors to have releases that would result in temperatures below the MDMT of equipment, piping, and structural supports. AGDC indicated that the module flooring of the impoundment area would be designed to handle depressurizing propane releases but had not addressed the impacts on equipment and supports. In addition, AGDC did not address liquids during winter start-ups, including outdoor liquids that could be at the lowest potential ambient winter temperatures being conveyed into indoor areas. Therefore, we recommend in section 4.18.9 that AGDC provide low temperature protection on piping, equipment, and structural supports where they could be exposed to temperatures below its MDMT. AGDC has agreed to provide this information in accordance with the timing of the recommendation.

For fireproofing, AGDC indicates that it would follow the IBC, as prescribed in Title 13 AAC Chapter 50; that the extent of fireproofing required is dependent on the occupancy classification and the size of the module building; and that, where required, the design of the GTP would follow the principles and guidelines for assessment, installation, and maintenance of fireproofing in accordance with API 2218, which would cover process areas. AGDC also indicates that ISO 22899-1, Determination of the Resistance to Jet Fires of Passive Fire Protection Materials - Part 1: General Requirements, would be used in the fireproofing design. API 2218 requires structural fire protection in certain areas and recommends fire envelopes be defined based on potential fire scenarios for defining where passive fire protection is needed. API 2218 also recommends the use of UL 1709 for performance requirements of passive fire protection in areas that are determined to be subjected to pool fires and provides more limited guidance on defining what jet fire scenarios to consider or the performance requirements of passive fire protection. However, API 2218 does not define the pool fire or jet fire scenarios or the radiant heats to be used to determine the extent of passive fire protection. AGDC provided preliminary information on the material selection options and the thickness of its proposed fireproofing material for certain structural components. Fireproofing would be applied to equipment supports, structural steel members, and other critical components, as required. However, the general areas stated as being considered for this fireproofing do not appear to include all areas where flammable or combustible fluids would be handled above their flashpoint, and drawings indicating the specific fireproofing locations were not provided. In addition, the vessel insulation information is incomplete. Therefore, we recommend in section 4.18.9 that AGDC file drawings and specifications for the passive fire protection and calculations or test results (e.g., ISO 22899, NFPA 290, and OTI 95 634) that demonstrate the effectiveness of the passive fire protection. We also recommend that passive protection be defined based on scenarios that could lead to off-site impacts or cascading damage, where structural supports may fail as low as 4,900Btu/ft^2- hr,[152] and where pressurized equipment may fail

[152] FERC staff's heat impact preliminary analyses indicate most carbon structural steels (e.g., ASTM A36), will begin to have a noticeable loss of strength at 570°F (300°C), lose approximately one-third of strength at 840°F (450°C), and lose approximately one-half of strength at 1,000°F (540°C). These temperatures would correspond to black body radiant heats of approximately 2,000 Btu/ft^2-hr (6.1 kW/m^2), 4,900 Btu/ft^2-hr (15.5 kW/m^2), and 7,750 Btu/ft^2-hr (24.5 kW/m^2), respectively, and the latter radiant heats may correspond to when structural steel begins to exceed yield strengths and suffer possible structural damage based on allowable stress/strength designs in structural and mechanical design codes (e.g., ASCE 7, American Institute of Steel Construction 360, ASME B31.3, and ASME BPVC), which most commonly limit stresses to one-half to two-thirds of yield strength. In addition, these values are in line with NFPA 59A (2016 and 2019 editions) that recommend similar temperature and corresponding radiant heats for steel, ABS Consulting, *Consequence Assessment*

as low as 4,000 Btu/ft^2-hr,[153] while recognizing that pool fire tests under UL 1709 are for 65,000 Btu/ft^2-hr (2,000°F) in 5 minutes and a 1-hour duration, which would provide thicker passive protection than may be necessary to prevent failure in some areas and thinner passive protection than may be necessary to prevent failure in other areas. We also note the application of fireproofing is sometimes prescribed in API 2218 to be 20 to 40 feet high, which may be less than or more than a pool fire height or jet fire flame length. Therefore, we also recommend in section 4.18.9 that AGDC file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each significant component within the 4,000 Btu/ft^2-hr zone from pool or jet fires that could cause failure of the component. AGDC has agreed to provide information in accordance with the timing of the above recommendations. Trucks at the truck loading/unloading areas should be included in the analysis. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires should be provided that demonstrate effectiveness and reliability. Effectiveness of passive mitigation should be supported by calculations for the thickness limiting temperature rise, and active mitigation should be justified with calculations demonstrating flow rates and durations of any cooling water that would mitigate the heat absorbed by the vessel. In addition, we recommend in section 4.18.9 that AGDC file the final design of these mitigation measures, for review and approval prior to construction of the final design, to demonstrate cascading events would be mitigated. AGDC has agreed to provide detailed design information in accordance with the timing of the recommendation. FERC staff also evaluated whether the GTP would include blast or fire walls inside buildings/modules, and whether the GTP would include blast or fire walls between transformers per NFPA 850. AGDC indicated that the control building would be designed and constructed as a blast-resistant structure if the overpressure scenarios analyzed indicate the control building is not proposed sufficiently far enough away from the hazards. In addition, electrical rooms that are adjacent to compressor modules and share one or two walls with the adjacent compressor would be designed to withstand overpressures if determined by the fire and gas explosion analysis that AGDC stated would be completed in the FEED. Therefore, we recommend in section 4.18.9 that AGDC file these analyses to ensure passive protection design features would be included in the final design of buildings/modules. AGDC indicates that the need for blast resistant rooms and buildings at the GTP would be assessed within the updated fire protection evaluation and has agreed to provide final design information in accordance with the timing of the recommendations. Also, AGDC indicates that, while there would be no direct access between pressurized rooms adjoining process areas, an analysis would be filed prior to construction of the final design to indicate whether the local equipment rooms would be required to specify fire walls rated and tested for hydrocarbon fires. In addition, it had been unclear as to whether AGDC would separate or have fire-rated barriers between transformers to prevent cascading damage. After the draft EIS, AGDC clarified that it would provide separation or fire-rated barriers between transformers, in accordance with NFPA 850, to prevent cascading damage. Therefore, we recommend in section 4.18.9 that AGDC provide specifications and drawings of this mitigation in accordance with NFPA 850. AGDC has agreed to provide this final design information in accordance with the timing of the recommendation. Additional information related to passive protection was provided on October 11, 2019 in which AGDC indicated that the engine enclosures for the compressor modules would be designed in accordance with NFPA 37, which would include provisions for venting of an explosion, ventilation from a nonhazardous area, and at least a 1-hour fire

Methods for Incidents Involving Release from Liquefied Natural Gas Carriers, 2004 that reports long-term exposures at about 8,000 Btu/ft^2-hr (25 kW/m^2), steel surfaces experience serious dislocation as well as paint peeling, and structural elements undergo substantial deformation according to damage resulting from thermal radiation for various materials, and Sandia National Laboratories *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*, 2004, that reports durations of more than 10 minutes at approximately 12,000 Btu/ft^2-hr causes temperatures to rise to 980°F (530°C) and result in a 25- to 40-percent loss in steel strength and damages structures.

[153] FERC staff recognize that pressurized equipment in accordance with ASME BPVC allows for pressure relief valves to pressures to rise to 1.2 times the design pressure, which would lower the pressure in the vessel to less than the bursting pressure of typically 3 to 4 times the design pressure, but adds stress to the equipment above normal design conditions and causes a reduction in temperature and subsequent reduction in radiant heat from 4,900 to 4,000 Btu/ft^2-hr for when pressurized equipment may fail. We also recognize that 4,000 Btu/ft^2-hr is a commonly used endpoint in fire analyses.

resistance rating for interior walls, floors, and ceilings. We recommend in section 4.18.9 that AGDC provide final design specifications for these systems.

If the Project is authorized, constructed, and operated, AGDC would install fire protection according to its final design, after review and approval, and we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify fire protection and any cold release protection is properly installed in the field as designed prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to continue to verify that passive protection is being properly maintained.

Liquefaction Facilities

AGDC indicates the structural fire protection would comply with NFPA 59A (2001 or 1994)[154] and other recommended and generally accepted good engineering practices. NFPA 59A (2001) section 6.4.1 and NFPA 59A (1994) section 6-2.1.2 require pipe supports—including any insulation systems used to support pipe whose stability is essential to plant safety—to be resistant to or protected against fire exposure, escaping cold liquid, or both, if they are subject to such exposure. However, NFPA 59A (2001) does not provide the criteria for determining if they are subject to such exposure or the level of protection needed to protect the pipe supports against such exposures. In addition, NFPA 59A does not address pressure vessels or other equipment.

AGDC indicates that equipment that could potentially be in contact with pooled LNG, heavy hydrocarbons, or refrigerant would be designed to withstand the cold contact or would be protected by cryogenic insulation to prevent embrittlement. The specific locations where the above philosophies would be applied have not yet been provided, and the materials and thicknesses that would provide this protection have not yet been specified. Therefore, we recommend in section 4.18.9 that AGDC provide additional information, including drawings and specifications, for these cold contact protection systems for equipment and supports, for review and approval, prior to construction of the final design. AGDC has agreed to provide information in accordance with the timing of the recommendation.

In addition to complying with NFPA 59A (2001 or 1994) and similar to the GTP, AGDC indicates that the structural fire protection would also be in accordance with other recommended and generally accepted good engineering practices, such as API RP 2218, ISO 22899-1, and UL 1709. AGDC provided preliminary information on material selection options and the thickness of its proposed structural fireproofing material, as well as a list of the types of structural components to which the fireproofing would be applied. While the details were not provided for fireproofing on vessel skirts and supports, AGDC does indicate that fireproofing would be applied directly to these components in fire exposed areas. In addition, drawings were provided of the areas considered to be fire exposed, as well as typical cross-sectional details of the fireproofing application on racks and piping supports. However, the fire exposed areas on the drawings do not appear to cover certain components that may be reached by high radiant heat from potential impoundment system fires, such as the pipe-in-pipe and other transfer piping adjacent to the dock impoundment, some air coolers in the liquefaction area, the liquid nitrogen storage tanks, and areas where flame heights and other heat transfer effects could affect the height of the needed fireproofing. In addition, AGDC had stated that fireproofing would be generally applied to vessels that contain more than 5,000 gallons of flammable or combustible liquids at high liquid level in congested areas, if not protected with a fixed water spray system. However, pressure vessels with less than 5,000 gallons of any liquid may still be of concern for BLEVEs or bursts, unless other measures with adequate reliability would be applied for their protection. Fireproofing details for critical wiring and control systems have also not yet been provided. After the draft EIS, AGDC indicated that the fireproofing design would be revised in final design to include

[154] 49 CFR 193 incorporates NFPA 59A (2001), and 33 CFR 127 incorporates NFPA 59A (1994).

areas based on pool and jet fires that could result in failure of pressure vessels, structural components, or other critical components (e.g., critical wiring, control systems, ESD valves, etc.). AGDC indicates that any fireproofing material used in areas having a risk of LNG splashing would be designed to handle the cold contact without losing its structural integrity or fireproofing ability. Specifying the fireproofing material to withstand cold temperature pooling, jetting, or splashing liquids may be appropriate in other areas as well, including the fractionation area and potentially areas with refrigerants. Therefore, similar to the GTP, we recommend in section 4.18.9 that AGDC provide additional information on the final design of these fireproofing systems, for review and approval prior to construction of the final design, where details are yet to be determined (e.g., calculation of structural fire protection materials and thicknesses) and where the final design could change as a result of these details or other changes in the final design of the Project. AGDC has agreed to provide this design information in accordance with the timing of the recommendation.

FERC staff also evaluated whether the Liquefaction Facilities would include blast or fire walls inside buildings/modules, and whether the Liquefaction Facilities would include blast or fire walls for transformers per NFPA 850. AGDC indicated that electrical substations would generally be outside the blast zone, however, if a substation is required to be within a hazardous zone, then the substation would be pressurized. In addition, fire walls, barriers, and partitions would be provided inside buildings. AGDC also indicated that substations and power transformers would include fire walls or adequate separation in accordance with NFPA 850. AGDC also noted that blast walls would be provided for certain equipment such as the refrigerant storage vessels. Since the final location of these blast walls, fire walls, barriers, partitions, and adequate separation distances are yet to be determined, we recommend in section 4.18.9 that AGDC provide final design information of these systems in order to prevent cascading damage.

If the Project is authorized, constructed, and operated, AGDC would install structural cryogenic and fire protection according to its final design, and we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction to verify structural cryogenic and fire protection is properly installed in the field as designed prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to continue to verify that passive protection is being properly maintained.

Firewater Systems

GTP

The GTP on the North Slope would not include any firewater standpipe, hydrants, monitors, foam, or hose equipment for the process areas. AGDC indicated that the primary fire protection strategy is to rely on the fire and gas detection system to detect, alarm, and, when appropriate, initiate isolation and blowdown of the affected area. Certain passive protection measures would also be implemented. However, for specific equipment within the process modules (i.e., equipment with liquid seals with potential exposure to high temperature systems), a fine water mist system would be employed to protect that equipment and the space immediately around the equipment, rather than to extinguish any associated fire. Each fine water mist system would have its own water storage within the heated module building, and water would be trucked in, as required, to fill the fine water mist system tanks. Water for the fire water mist systems would be supplied by the operations camp potable water system. The fine water mist systems would be designed, tested, and maintained to meet NFPA 750 and API 2030, as applicable. AGDC indicates that fine water mist systems may also be selected for use in the occupied control building, but this would be determined after consideration of other options. As discussed under Spacing and Plant Layout above, equipment at the GTP would need to be protected from potential fire impacts using other measures that are demonstrated to have high reliability.

Liquefaction Facilities

AGDC would provide firewater systems including firewater monitors, sprinkler systems, fixed water spray systems, and firewater hydrants and hoses for use during an emergency to cool the surface of storage vessels, piping, and equipment exposed to heat from a fire. In addition, low expansion foam would be provided in certain areas to suppress diesel or condensate fires. These firewater systems would be designed, tested, and maintained to meet NFPA 59A (2001), 11, 13, 14, 15, 20, 22, 24, 25, 30, and 750 requirements.

We evaluated the adequacy of the general firewater and foam system coverage, and verified the appropriateness of the associated firewater demands of those systems and worst case fire scenarios to size the firewater and foam pumps. Preliminary firewater coverage drawings appeared to show some gaps in firewater coverage, such as for the piping between the LNG tanks and the LNG transfer piping from the marine area. AGDC indicates that, during final design phase, AGDC would file firewater drawings illustrating firewater coverage by two or more hydrants or monitors accounting for obstructions for areas that contain flammable or combustible fluids. The assumed reach of the hydrants and monitors has also not yet been substantiated. AGDC indicates that the updated fire protection evaluation, provided in accordance with the timing of our recommendation, would include these justifications. In addition, the hydrants and monitors used for coverage would be relatively near the hazard in many cases, so AGDC would need to demonstrate that the manual monitors and hydrants, including necessary extents of hoses, could be used in an emergency to provide the intended reach, and in which locations the monitors may be automatically oscillating or remotely-controlled. AGDC indicates that overlapping monitor coverage would be provided in the process areas so that if one monitor cannot safely be accessed, other monitors in the area could be utilized. Further, the governing firewater demand case appears to have been selected based on the demand associated with activating only the deluge systems for certain refrigerant storage tanks (plus hydrant and monitor) and not those for the adjacent refrigerant storage tanks. The responders would likely activate the deluge systems for all of these storage tanks plus firewater for other nearby facilities. In general, the fire hazard areas should be reconsidered to incorporate the adjacent discrete hazard areas into larger demand areas that could be affected by a fire within a particular zone. AGDC indicates that fire water demand would be refined prior to construction of the final design to confirm appropriate coverage has been provided based on design densities, surface area, and throw distances. As discussed, the demand case areas should also be re-evaluated. If the firewater demand is increased, we note that the size of the firewater tank may need to be revised to reflect the higher demand. Also, the deluge water capacities in certain areas, such as for the refrigerant storage tanks nearest to the potential impoundment fire, may need further consideration of whether the intended water density would be adequate for the specific fire scenario. Appendix section A.7.4.2 in NFPA 15 includes discussion indicating that higher discharge densities than prescribed in its main text are sometimes needed. AGDC indicates an analysis would be performed prior to construction of final design to determine appropriate radiant heat levels and confirm that appropriate coverage would be provided. As discussed, the discharge water densities may also need to be justified in areas of high radiant heat. In addition, the low expansion foam system appeared to be considered as providing mitigation for radiant heat from a fire in the impounding area for the condensate, off-spec condensate, and diesel tanks, but the foam system did not appear to be sized for the impoundment area. AGDC acknowledged the need for further evaluation of mitigation for a fire in the condensate impoundment. Therefore, we recommend in section 4.18.9 that AGDC provide additional details indicating that the potential flammable and combustible gas and liquid hazard areas would have adequate firewater flow and coverage, for review and approval prior to construction of the final design. AGDC indicated that it would provide information in accordance with the timing of the recommendations.

In addition, as discussed above, AGDC has proposed to install automatic sprinkler systems in multiple buildings, including the Consolidated Building that would include the main control building, Central Control Room, emergency response building, operations support room, etc. AGDC indicates that

a sprinkler system would be provided with manual activation because the Central Control Room would house critical control equipment. More commonly, control rooms are provided with an automatic activation and time delayed activation clean agent systems so that discharge does not impair or destroy sensitive instrumentation or electrical equipment. We had recommended that, prior to the end of the comment period, AGDC explain how the manual sprinkler system would not impair or destroy the Central Control Room operational capabilities if activated, and describe its purpose given an automatic clean agent system is also proposed. In a response filed on September 18, 2019, AGDC stated that the design would be revised to remove the manually activated sprinkler system located in the Central Control Room. The automatic clean agent system would provide the fire protection for electrical equipment and control systems in the Central Control Room. AGDC also indicates that a stand-alone fine water mist system may be selected to protect the gas turbine enclosures and, if so, would be designed to NFPA 750.

We also assessed whether the reliability of the firewater pumps and firewater source or on-site storage volumes would be appropriate. Firewater would be supplied from the fresh water tank and pumps, and the firewater tank would hold 200 percent of the required 2-hour firewater supply. AGDC indicates that the firewater tank would meet NFPA 22 and that the water discharge to the firewater system would have both diesel and electric pumps available. However, the firewater data sheet indicates that the inflow would fill the tank in more than 8 hours, which is not in accordance with NFPA 22. Additionally, details required by NFPA 22, such as anti-vortex devices, are to be determined. Therefore, we recommend in section 4.18.9 that AGDC design the firewater tank in accordance with NFPA 22, including, but not limited to, requirements for inflow piping refilling the tank within 8 hours, wall thicknesses, venting, manholes, anti-vortex plates, and discharge requirements. AGDC indicates that it would provide detailed final design information in accordance with the timing of the recommendations related to the firewater tank and storage volume. AGDC also indicates that it would specify that firewater pump shelters are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane, in accordance with the timing of our recommendation in section 4.18.9.

If the Project is authorized, constructed, and operated, AGDC would install the firewater and foam systems as designed, and we recommend in section 4.18.9 that Project facilities be subject to periodic inspections during construction and that AGDC provide results of commissioning tests to verify the firewater and foam systems are installed and functional as designed prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility to ensure firewater and foam systems are being properly maintained and tested.

4.18.6 Geotechnical and Structural Design

AGDC provided geotechnical and structural design information for its three facilities—the GTP, Mainline Pipeline, and Liquefaction Facilities—to demonstrate the site preparation and foundation designs would be appropriate for the underlying soil characteristics, and to evaluate the structural design of the Project facilities against federal regulations, standards, and recommended and generally accepted good engineering practices. Our review focuses on the resilience of the GTP and Liquefaction Facilities against natural hazards—including extreme geological, meteorological, and hydrological events—such as subsidence, earthquakes, tsunamis, seiche, hurricanes, tornadoes, floods, sea level rise, landslides, ice, snow, volcanic activity, wildfires, and geomagnetism. This section discusses the GTP and Liquefaction Facilities individually below. The pipeline is discussed in section 4.18.10.

4.18.6.1 Geotechnical Evaluation

FERC regulations under 18 CFR 380.12(h)(3) require geotechnical investigations. In addition, FERC regulations under 18 CFR 380.12(o)(14) require an applicant to demonstrate compliance with

regulations under 49 CFR 193 and NFPA 59A (2001). All facilities, once constructed, must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. PHMSA regulations incorporate by reference NFPA 59A (2001). NFPA 59A (2001) section 2.1.4 requires soil and general investigations of the site to determine the design basis for the facility. However, no additional requirements are set out in 49 CFR 193 or NFPA 59A on minimum requirements for evaluating existing soil site conditions or evaluating the adequacy of the foundations. In addition, the GTP are precluded from 49 CFR 193, and there are no explicit requirements for geotechnical investigations under 49 CFR 192, 29 CFR 1910.119 or 40 CFR 68. However, we recognize a need to address the geotechnical design for all facilities and, therefore, FERC staff evaluated the existing site conditions, geotechnical investigations, and proposed foundations to ensure they are adequate for the facilities, as described more fully below.

GTP

The GTP would be between the Point Thomson and Prudhoe Bay Production Units on the rural North Slope of Alaska. The North Slope of Alaska is confined by the Beaufort and Chukchi Seas—marginal seas of the Arctic Ocean—creating a natural northern boundary. The Brooks Mountain Range, a mountain range spanning 700 miles from east to west, serves as the southern boundary of the North Slope. Within these natural confines, features characteristic of the North Slope include barren arctic tundra supporting little vegetation and no trees, rolling hills, and coastal planes subject to flooding from freeze-thaw cycling in the permafrost soil. Approximately 1,100 acres would be required to construct the GTP, and 710 acres would regularly support operation. Persistent cold temperatures accompanied by wind chill and regular snowfall present unique challenges for sustaining resilient infrastructure and reliable mechanized equipment.

Due to the natural terrain, AGDC would not clear or grub vegetation to construct the GTP. AGDC indicated that it may clear land to construct roads leading to the GTP, but would implement construction restrictions to minimize impact on the tundra. Once built, roads leading to the GTP would be covered by granular materials for additional protection. AGDC would also place granular materials on the construction laydown site to minimize disturbance on the land. Dredging the site or nearby coastline would not be required.

Regarding the geological characteristics beneath the proposed GTP site on the North Slope, AGDC provided FERC a geotechnical investigation entitled *GTP Geotechnical Exploration*, authored by PND Engineers, Inc. (PND Engineers) in 2015. Originally, the purposes of this investigation were to delineate an industrial water reservoir pit within the GTP Project area, and to discover and delineate minable construction materials. PND Engineers drilled 28 boreholes to a depth of 80 feet below existing grade. The boreholes were retrieved within the permit limits of the proposed GTP Project, but not where proposed structures for the GTP would be built. PND Engineers performed 1,014 lab tests, including 449 tests for moisture content with classification across four boreholes, 6 density tests, 98 soil grade tests, 22 fines content tests, 304 mechanical property analyses, 131 tests for salinity across four boreholes, and 4 specific gravity tests in general accordance with pertinent ASTM standards. However, PND Engineers performed no cone penetration tests, no seismic cone penetration tests, no temporary piezometers to measure groundwater levels, and no corrosion potential tests (pH, sulfate, chloride, and electrical resistivity). As a result of the locations not coinciding with equipment and structures and the lack of certain tests, we recommend in section 4.18.9 the need for a site-specific geotechnical investigation with additional parameters as further described throughout this section. AGDC has agreed to provide information in accordance with the timing of the recommendation.

The coring results from PND Engineers taken from grade indicate that the soil profile includes frozen peat bearing excess water from 0 to 4 feet; icy silty sand from 5 to 12 feet; and poorly-graded gravel

with silty sand intrusions from 13 to 65 feet. Well-graded gravel is occasionally detected approximately 20 feet subsurface. In this instance, the distinction between well-graded (large variety in particle size) and poorly-graded gravel (uniform particle size) is insignificant from a soil strength design perspective, as it is all encased in icy permafrost. This permafrost is the dominant hazard in the soil profile as, according to PND Engineers, it produces excess water when thawed. When thawing occurs, the previous icy inclusions turn to water, leaving voids in their former place and introducing potential for local erosion and soil degradation. The repeated freeze-thaw cycling on this permafrost is called thermokarsting. PND Engineers confirmed two prominent thermokarst varieties in its boring investigation. FERC staff finds that unmitigated thermokarsting would pose a credible risk to the GTP. Therefore, FERC staff has recommended in section 4.18.9 that this be taken into account in a site-specific geotechnical investigation prior to initial site preparation. AGDC has agreed to provide a site-specific geotechnical investigation in accordance with the timing of the recommendation.

In addition, PND Engineers identified salinated permafrost within the proposed GTP Project area—at least one salinated interval had approximately the same concentration of salt as sea water. Salt concentrations within the permafrost would not degrade soil strength because sand and gravel inclusions are not cohesive. However, it may degrade certain concrete formulations that would be used for building structures on the permafrost. PND Engineers did not perform corrosion tests on the soil. Soil pH, chloride ion concentration, and sulfate ion concentration tests should be performed to assess the corrosion potential of the on-site near-surface soils on the buried steel and concrete. The potential for corrosion is likely high due to the historic presence of sea water, indicated by the salinated intervals in the soil profile, since seawater contains corrosive constituents. Possible measures to address corrosion include assuming sacrificial thickness based on predicted steel losses due to corrosion (i.e., use a heavier steel section) or using a protective coating. Measures which could be used to protect buried concrete elements and concrete piles include using a high density concrete that is less permeable to sulfate ions. In addition, electrical resistivity tests are commonly done to aid in the determination of corrosion potential and potential solutions. Therefore, we recommend in section 4.18.9 that soil pH, chloride ion concentration, sulfate ion concentration, and electrical resistivity testing be taken into account as part of the site-specific geotechnical investigation prior to initial site preparation. FERC staff also recommends in section 4.18.9 that AGDC account for salinated soils in this geotechnical investigation to prevent material degradation in its foundation designs. AGDC has agreed to provide a site-specific geotechnical investigation in accordance with the timing of the recommendation.

AGDC stated in its application and subsequent information request responses that it would provide a geotechnical field investigation prior to final design. AGDC filed a statement of future work to be conducted by AECOM, but did not commit to a date by which the work would be performed, or when a findings report would be provided to FERC. This statement of future work would include dynamic soil properties, ground temperature monitoring, field ice volume, soil identification, and unspecified laboratory testing along with justified foundation design recommendations. AGDC responded to a FERC information request for a geotechnical investigation by reiterating its borehole plan and by providing a geotechnical field investigation prepared for the proposed ASAP on the North Slope one quarter mile away from the proposed GTP Project site. ASAP is owned by AGDC but is not affiliated with this Project. FERC staff recognizes that this geotechnical investigation provides FERC general context about the geological conditions at the North Slope, such as permafrost depths, and is in accordance with results presented by PND Engineers; however, it does not provide much other data that would be useful for the GTP site and, therefore, FERC staff does not consider it an adequate substitute for the site-specific investigation that is recommended. Based on the known subsurface conditions in the area from the limited geotechnical investigations, shallow foundations may not be appropriate to use to support settlement-sensitive structures and would only be suitable for select very lightly loaded or settlement insensitive structures. Therefore, all settlement-sensitive and heavily loaded structures should be supported on deep foundations. AGDC indicated that it intends to utilize modular construction for the facility and would utilize “adfreeze piles” as

the foundation system for the modules, but detailed justification for pile capacities or stiffness has not been provided. AGDC did provide some preliminary concepts of the foundation in drawings and states that the adfreeze pile diameters would range from 12 to 48 inches, connected together with module legs to form into a single pile support system. The foundation(s) of the warehouse structure is unique in that it would be supported with slab-on-grade, not adfreeze piles. The slab-on-grade would have granular pads and a cooling system to prevent thaw migration beneath the warehouse slab. These preliminary foundation design concepts seem, at their face, reasonable pending additional information from a site-specific geotechnical investigation. Since the publication of the draft EIS, AGDC commented that it would file a site-specific geotechnical investigation to ensure proper foundation design of the GTP.

Settlement occurs when structural loads exert compressive vertical stresses on the underlying geological profile, causing shear failure of soils and brittle failure of rock. The GTP is susceptible to settlement due to permafrost conditions. The geotechnical investigation conducted by PND Engineers identifies at least 65 feet of permafrost. Depending on the frost abundance and a variety of other factors that would be known with a site-specific geotechnical investigation, the frost among the near-surface soils could potentially restrict displacement when subjected to a structural load. If the frost melts due to freeze-thaw cycling and thermokarst development, any structural benefit provided by the frost would diminish. Advanced freeze-thaw cycling and thermokarst development could reduce soil strength and increase the risk of settlement as ice inclusions melt and leave voids behind.

AGDC indicated that it anticipates the ad-freeze pile foundations to experience 1 inch of "creep" over a 30-year design life. AGDC also states that differential settlement, which occurs when the site experiences unequal settlement rates, would be limited in the module platforms over the life of the facility. FERC staff agrees that there is potential for settlement, potentially more than the 1-inch estimate AGDC provided. However, an informed settlement estimate requires a site-specific geotechnical report. Therefore, FERC staff recommend in section 4.18.9 that settlement potential be assessed as part of the site-specific geotechnical investigation prior to initial site preparation.

Both soil and rocks have the mechanical property of elasticity, and thus will partially deform before failure. A salt formation, such as a dome, subjected to constant stress may "creep." Salt creep is a geomechanical deformation that alters the stress-strain profile and reduces material strength necessary to support exerted loads. Though PND Engineers identified salinated soils, the high saline content is not indicative of salt domes, salt flows, or related salt geological formations. The salt content identified by PND Engineers is not from a continuous geological formation. Instead, it was likely interspersed and deposited among the soil profile through past contact with sea water. Therefore, FERC staff does not consider settlement due to salt creep to be a credible risk to the GTP facility.

Aside from settlement from structural loads, the ground elevation can suddenly sink or gradually settle downward with little or no horizontal motion, caused by movements on surface faults or by subsurface mining or pumping of oil, natural gas, or ground water. This phenomenon is known as subsidence. In arctic environments, subsidence results from advanced thermokarsting in the permafrost. AGDC has not addressed the risk of subsidence at the GTP in any context. Therefore, FERC staff have determined that a site-specific geotechnical field investigation is necessary prior to initial site preparation to ensure proper foundation design with regard to subsidence. In particular, the geotechnical investigation for the local geological conditions under the proposed foundations should indicate the susceptibility to frost heave, thermokarsting, subsidence, load-bearing settlement, and concrete material degradation.

The preliminary results of AGDC's very limited geotechnical investigations near the GTP site and surrounding area indicate that the subsurface conditions may be suitable for the proposed facility if the recommended geotechnical investigations are undertaken to confirm that the subsurface conditions are suitable for the identified foundation designs for the site, and confirm whether similar site preparation,

foundation design, and construction methods should be implemented in addition to the satisfaction of proposed recommendations.

Liquefaction Facilities

The Liquefaction Facilities would be near Nikiski on the north central side of the Kenai Peninsula, surrounded by glacial lowlands, plains, and outwash fans. The facility would be built on a bluff overlooking Cook Inlet with a ranges from +120 to +140 feet North American Vertical Datum of 1988 (NAVD88) clearance over the water. The site would be cleared, grubbed, and prepared using standard earthmoving and compaction equipment. Stripping would occur after site clearance to an average depth of 30 inches. According to the *LNG Facilities Onshore Geotechnical Data Report* (Geotechnical Data Report) prepared by Fugro, some of the parcels to be cleared are heavily vegetated.

AGDC would plan to dredge the approach and berths at the MOF to a depth of -32 feet MLLW, or -24.68 feet NAVD88, with the potential for approximately 2 feet of over-dredge at the marine facilities. There would be two disposal sites for the dredged material selected based on their relatively deep water (between -50 to -130 feet MLLW) with strong currents (over 6.5 knots peak flood and over 5.5 knots peak ebb). AGDC would disperse dredged sediment at either site and prevent the material from mounding. Each disposal site has the capacity to receive all of the anticipated dredged material. Maintenance dredging would likely be necessary at the MOF berths and approach during the later construction seasons. Retreat rates along the coastal bluff where the AGDC facility would be located have been measured to range from 1 to 5 feet per year. In the *LNG Facilities Geologic Hazard Report*, Fugro finds coastal erosion along the bluff to be a potential hazard to the facilities.

In particular, Fugro states that the bluff upon which the facility would be built is susceptible to coastal erosion caused by waves, currents, and vessel wakes. Such erosion may also be a precursor to coastal landsliding. Weathered debris flows have already been observed in several locations along the coast, as evidenced by head scarps. Using photogrammetry over a 32-year period, Fugro estimates that five locations experienced 30 to 65 feet (+/- 20 feet) of retreat in land mass by erosion around the bluff. The existing bluff has a slope of 35 to 45 degrees from the beach to the crest of the bluff. The crests could erode as a result of waves (particularly during powerful storms) undercutting the base of the bluff, followed by shallow sliding, raveling, and gullying of the bluff face.

In response to a recommendation in the draft EIS, AGDC proposed a Bluff Stabilization and Maintenance Plan that would encompass monitoring of erosion, potential bluff/shoreline protection measures, and maintenance of the bluff. AGDC would monitor the bluff using LiDAR data from aerial surveys to generate three-dimensional models detailing surface characteristics of the bluff and shoreline, including digital elevation models and a digital surface model that would measure erosion by identifying variations and morphological features. As a preventative measure, AGDC would implement protective measures such as beach nourishment and/or rock armor revetment as needed. Additionally, AGDC's preliminary civil rough grading drawings propose cutting back the bluff so it would have a 3 to 1 slope (H/V). Cutting back the slope to a significantly shallower angle in combination with proper slope benching or equivalent slope stabilization measures, drainage, ground cover, and toe protection should sufficiently mitigate the coastal erosion of the bluff issue. AGDC would continue to monitor the bluff using LiDAR mapping on an annual basis and potentially extend the timeframe between surveys depending on initial results from the first few years of survey and assessed rates of change. AGDC would also monitor beach levels to evaluate the effectiveness of the beach nourishment and/or rock revetments.

Beyond this Bluff Stabilization and Maintenance Plan, AGDC would also account for the risk posed by erosion by moving the liquefaction onshore facilities sufficiently inland to reduce any long-term bluff erosion impact. Fugro estimates that if this location is subjected to a major weather event, erosion

could remove 50 horizontal feet of land if erosion mitigation is not implemented. FERC staff evaluated the proposed Bluff Stabilization and Maintenance Plan and consider the prevention and mitigative steps proposed therein adequate to protect the facility against a potential significant impact posed by coastal erosion.

Fugro and its subcontractor, Denali Drilling, collected a total of 43 borings between May 16 and August 24, 2016 from beneath the proposed Project site, including the proposed Marine Terminal. At 41 boring locations, the proposed completion depth of 200 feet was achieved; however, two beach borings, B-190 and B-191, were prematurely terminated at 97.1 and 114.2 feet below ground surface, respectively. Bore logs indicated the presence of loose top soil and fill materials from 0 to 10 feet and sand with silt and gravel from approximately 10 to 60 feet below grade. In the top 20 feet, the bore log occasionally identified oxidation staining, likely of a ferrous origin. Clay is first encountered at approximately 70 feet subsurface, with intermittent intervals of sand and gravel as the core extends deeper.

FERC staff evaluated this geotechnical investigation to ensure the adequacy in the number, coverage, and types of the borings and other tests, and found them to adequately cover all major facilities, including the marine facilities, LNG storage tanks, liquefaction areas, pretreatment areas, flare system, buildings, power generation, and berms. While Fugro conducted no cone penetration tests, no seismic cone penetration tests, and no temporary piezometers to measure groundwater levels, AGDC also contracted out seismic reflection surveying that identified structural geological features not immediately identifiable via coring. FERC staff considers the seismic reflection investigations to be an adequate equivalent.

Based on the test borings conducted, the site is mainly composed of well-graded sand with gravel and silty sand. Except for the few feet of topsoil, soils above the assumed groundwater table are sand-gravel mixes. Lean clay is first encountered at approximately 60 to 70 feet below the bored surface. This soil profile has notably low shear strength, as sand and silt grains are not cohesive. Furthermore, Fugro examined 15 soil samples for frost susceptibility and 21 soil samples for corrosion. The frost susceptibility samples identified a gravelly sand layer that experienced a maximum heave of 2.4 percent in laboratory tests. Based on this testing, Fugro finds the foundations installed below the frost penetration depth would not be affected by frost-heave. For samples tested for corrosion, most showed moderately-corrosive to corrosive properties based on moderate to low soil resistivity and high pH. In particular, one sample showed highly corrosive properties based on low soil resistivity, high pH, and high sulfate concentration. Based on these results, and as suggested by the presence of oxidation present in the bore logs, the Project is susceptible to corrosion and concrete degradation if not considered in the design. AGDC stated it would use appropriate corrosion mitigation measures consistent with standard engineering practice in the design of concrete and steel structures.

Based on the geotechnical investigations, AGDC would use fill material to enhance the near surface soil quality prior to construction. The fill material would consist of various layers, with several different classifications of fill including structural, select, general, and flowable. This fill is defined in the Geotechnical Data Report and, with the exception of flowable fill, would be compacted to a relative density of at least 80 percent as determined by the relative density test methods (ASTM D4253 and D4254). In addition, Fugro presented recommendations for both shallow and deep foundations. AGDC indicated equipment and structures (with the exception of the marine transfer area) would be supported by shallow foundations. However, AGDC also indicated that driven steel piles could be used if calculated settlements, lateral loads, or overturning moments are determined to be too high for shallow foundations during detailed design. Therefore, FERC staff recommends in section 4.18.9 that AGDC submit a complete list of foundations indicating whether they would be shallow or deep as well as an updated foundation design and foundation design drawings along with associated calculations, including prefabricated and field constructed structures, that would incorporate any recommendations from Fugro that are intended to be

implemented. AGDC has agreed to provide the information in accordance with the timing of the recommendations.

Fugro predicts that over 90 percent of the expected total settlement of 8.5 to 10 inches would occur during construction and hydrotesting immediately upon installation. Foundations would be constructed with pile supports to protect equipment and interconnecting piping from differential movement. FERC staff recommend in section 4.18.9 that AGDC submit, for review and approval, settlement results during hydrostatic tests of the LNG storage containers and periodically thereafter to verify settlement is as expected and does not exceed the applicable criteria in API 620, 625, and 653; and ACI 376. In addition, FERC staff recommend in section 4.18.9 that AGDC equip the LNG storage tanks and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and record the relative settlement between the LNG storage tank and adjacent piping to ensure settlement limits between the storage tank and interconnected piping are not exceeded. AGDC has agreed to provide the information in accordance with the timing of the recommendation.

Aside from settlement from structural loads, the ground elevation can suddenly or gradually sink from subsidence. Regional subsidence (called co-seismic subsidence) can also be caused by megathrust subduction zone earthquakes. The site is in a megathrust subduction zone, and Fugro mentions historical instances of co-seismic subsidence in the Geotechnical Data Report. For example, Cook Inlet experienced 0.9 feet of subsidence in response to the 1964 moment magnitude 9.2 Great Alaskan earthquake. During and immediately following a megathrust earthquake, there can be significant sudden subsidence of several feet depending on the location relative to the megathrust fault zone. Over time, the zone of the subsidence will rebound and uplift will occur. AGDC suggests that NOAA measurements show a current trend of land uplift, not subsidence. The rate of uplift is currently greater than projected sea level rise so the relative sea level rise would be negative. However, during a Maximum Considered Earthquake level megathrust earthquake, FERC staff expects there would likely be subsidence of approximately 1 foot at the site, which should be accounted for in the marine trestle design.

4.18.6.2 Structural and Natural Hazard Evaluation

FERC regulations under 18 CFR 380.12 (m) requires applicants to address the potential hazard to the public from failure of facility components resulting from accidents or natural catastrophes, evaluate how these events would affect reliability, and describe the design features and procedures that would be used to reduce potential hazards. In addition, 18 CFR 380.12 (o) (14) require an applicant to demonstrate how they would comply with 49 CFR 193 and NFPA 59A.

The GTP would not be subject to PHMSA regulations under 49 CFR 193 or Coast Guard regulations under 33 CFR 127 or 33 CFR 105, but it would be subject to 40 CFR 68 and 29 CFR 1910.119, which require use of RAGAGEPs. While not prescriptive on which RAGAGEPs are required for facilities, there are a number of standards that have requirements and recommendations for structural design of facilities, including hazardous facilities, such as NFPA 59A, ASCE 7, International Code Council (ICC) 500, and many others. The regulations under 40 CFR 68 and 29 CFR 1910.119 also require consideration of previous incidents and facility siting. While there are no incidents associated with this facility, and facility siting may be argued to only consider equipment layout and/or protection from hazardous releases, a number of facilities have been affected by natural hazards and the site selection would dictate the risk of a natural hazard, including wind. However, it is not clear what requirements, if any, are required to meet the OSHA regulations as there are no requirements for which RAGAGEPs must be applied and various RAGAGEPs can have different requirements or recommendations. We assessed the GTP facilities using an approach consistent with that in Part 193 and in accordance with OSHA requirements for RAGAGEPs, as detailed for each hazard discussed in the subsections below for the GTP.

The Liquefaction Facilities would be subject to PHMSA regulations under 49 CFR 193 and Coast Guard regulations under 33 CFR 127, which both incorporate NFPA 59A (2001 and 1994 editions, respectively). The PHMSA regulations under 49 CFR 193 have some specific requirements on designs to withstand certain loads from natural hazards and also incorporates by reference NFPA 59A (2001 and 2006) and ASCE 7-05 and 7-93 via NFPA 59A (2001). NFPA 59A (2001) section 2.1.1 (c) also requires consideration of the plant site location in the design of the Project with respect to the proposed facilities being protected, within the limits of practicality, against natural hazards, such as from the effects of flooding, storm surge, and seismic activities. We assessed the Liquefaction Facilities using the federal regulations and incorporated portions of NFPA 59A. If authorized, constructed, and operated, all LNG facilities, as defined by 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to the DOT's inspection and enforcement programs.

Additionally, most facilities would be designed to satisfy the requirements in the 2009 IBC and ASCE 7-05, and some of the GTP would be designed to satisfy 2012 IBC and ASCE 7-10. These standards require various structural loads to be applied to the design of the facilities, including live (i.e., dynamic) loads, dead (i.e., static) loads, and environmental loads. FERC staff also evaluated the potential of the engineering design to withstand impacts from natural hazards, such as subsidence, earthquakes, tsunamis, seiche, hurricanes, tornadoes, floods, rain, sea level rise, landslides, ice, snow, volcanic activity, wildfires, and geomagnetism. FERC staff recommend in section 4.18.9 that AGDC file final design information (e.g., drawings, specifications, and calculations) and associated quality assurance and quality control procedures, with the documents reviewed, approved, and stamped and sealed by a professional engineer of record registered in Alaska. AGDC has agreed to provide the information in accordance with the timing of the recommendation.

Earthquakes, Tsunamis, and Seiches

FERC regulations under 18 CFR 380.12 (h)(5) requires evaluation of earthquake hazards based on whether there is potential seismicity, surface faulting, or liquefaction. Earthquakes and tsunamis have the potential to cause damage from shaking ground motion and fault ruptures. Earthquakes and tsunamis often result from dynamic activity in the earth's crust. The damage that could occur as a result of seismic ground motions is affected by the type/direction and severity of the fault activity and the distance and type of soils the seismic waves must travel from the hypocenter (or point below the epicenter where seismic activity occurs). The Richter Scale is widely quoted to compare the magnitude of earthquakes and is based on the amplitude of seismic waves recorded by seismographs that are adjusted to compensate for the distance from the hypocenter. Earthquakes with magnitude of about 2.0 or less on the Richter Scale are usually called micro-earthquakes, which are not commonly felt by people and are generally recorded only on local seismographs. Earthquakes with magnitudes of about 4.5 or greater are strong enough to be recorded by sensitive seismographs; earthquakes with magnitudes of about 6.0 and above are typically considered strong earthquakes; and earthquakes with magnitudes of 8.0 are generally considered great earthquakes. While the Richter Scale is used to express earthquake intensity, it does not necessary correspond to damage since the epicenter may not be near populated areas. Therefore, another scale called the Modified Mercalli Intensity (MMI) Scale is used to categorize earthquake observed effects into 12 separate levels, ranging from I where an event is not felt except by a very few under especially favorable conditions; to VI where an event is felt by all, heavy furniture may be moved, but damage is slight; to XII where an event causes total damage with lines of sight and surfaces distorted and objects are thrown into the air.

Seismic events can also result in soil liquefaction in which saturated, non-cohesive soils temporarily lose their strength/cohesion and liquefy (i.e., behave like viscous liquid) as a result of increased pore pressure and reduced effective stress when subjected to dynamic forces such as intense and prolonged ground shaking. Areas susceptible to liquefaction may include saturated soils that are generally sandy or

silty. Typically, these soils are located along rivers, streams, lakes, and shorelines or in areas with shallow groundwater.

To address the potential ground motions at the site, PHMSA regulations in 49 CFR 193.2101(b) under Subpart C require that field-fabricated LNG tanks must comply with section 7.2.2 of NFPA 59A (2006) for seismic design. NFPA 59A (2006) requires LNG storage tanks to be designed to continue safely operating with earthquake ground motions at the ground surface at the site that have a 10-percent probability of being exceeded in 50 years (475-year mean return interval), termed the operating basis earthquake (OBE). In addition, section 7.2.2 of NFPA 59A (2006), as incorporated by reference in 49 CFR 193.2101 under Subpart C, requires that LNG tanks be designed to have the ability to safely shut down when subjected to earthquake ground motions that have a 2-percent probability of being exceeded in 50 years (2,475-year mean return interval) at the site's ground surface (termed the safe shutdown earthquake [SSE]). The PHMSA regulations in 49 CFR 193.2101 under Subpart C also incorporate by reference NFPA 59A (2001), which require piping systems conveying flammable liquids and flammable gasses with service temperatures below -20°F to be designed as required for seismic ground motions. The facilities, once constructed, would be subject to PHMSA's inspection and enforcement programs.

In addition, FERC staff recognizes AGDC would also need to address hazardous fluid piping with service temperatures at -20°F and higher and equipment other than piping and LNG storage containers. We also recognize the current FERC regulations under Title 18 CFR 380.12(h)(5) continues to incorporate NBSIR 84-2833. NBSIR 84-2833 provides guidance on classifying stationary storage containers and related safety equipment as Category I and classifying the remainder of the LNG structures, systems, and components as either Category II or III, but does not provide specific guidance for their seismic design requirements. Absent any other regulatory requirements, this guidance recommends that other LNG structures classified as Seismic Category II or III be seismically designed to satisfy the Design Earthquake and seismic requirements of the ASCE 7-05 in order to demonstrate there is not a significant impact on public safety. ASCE 7-05 is recommended since it is a complete American National Standards Institute consensus design standard, its seismic requirements are based directly on the National Earthquake Hazards Reduction Program Recommended Provisions, and it is referenced directly by the IBC. Having a link directly to the IBC and ASCE 7 is important to accommodate seals by the engineer of record because the IBC is directly linked to state professional licensing laws, while the National Earthquake Hazards Reduction Program Recommended Provisions are not.

Seismic events in bodies of water can lead to a sudden rise or fall of the earth's crust under or near the body of water, which can lead to tsunamis and seiches. Landslides, volcanic eruptions, meteorite impacts, or even a very rapid decrease in atmospheric pressure can also cause tsunamis. Tsunamis can generate large waves that propagate through water at high velocities. Unlike the wind-driven waves, tsunamis have much longer wavelengths (up to hundreds of miles between wave crests or hours apart) and can travel faster (up to 500 mph in deep open water) without substantial energy loss. The relatively small loss of energy due to the long wavelengths allows them to travel long distances from a distant source location to shorelines. As the front of the wave approaches shallow water near shorelines, it slows down while the back of the wave is still traveling relatively faster. This is called shoaling, which causes the effective wavelength to decrease, but increase the effective height from what may be a foot or so to what is called the run-up height that can be tens of feet or more. The severity of the tsunami is dependent on its wavelength, velocity, and run-up height, which are all dependent on severity of the seismic or other event that causes it and the area's bathymetry and topography. Depending on these conditions, a tsunami can appear to be a fast rising tide that lasts prolonged periods to massive breaking waves.

The resilience of the GTP and Liquefaction Facilities from seismic events and tsunamis are further discussed below.

GTP

The USGS maintains a database containing information on surface and subsurface faults and folds in the United States that are believed to be sources of earthquakes of greater than 6.0 magnitude occurring during the past 1.6 million years (Quaternary Period).[155] There are no mapped faults or folds within 0.25 mile of the proposed GTP (USGS, 2018g).

Although the locations and magnitudes have been atypical, strike-slip events commonly occur in the Brooks Range, producing a few magnitude 4 to 5 earthquakes per year (AEC, 2018). The Alaska State Seismologist said that the August 12, 2018 earthquake followed "tectonic patterns of previous, smaller earthquakes that have historically occurred in the area," suggesting the earthquake was not related to factors such as permafrost thawing from climate change or oil field activity (DeMarban, 2018).

As mentioned, AGDC did not conduct a site-specific geotechnical field investigation for the GTP. Because soil profiles of the North Slope typically consist of approximately 1,800 feet of permafrost, a Site Class of B[156] is typically used. However, AGDC proposes the conservative Site Class of C for design purposes. A Site Class of C will experience more ground motion amplification during a seismic event than a Site Class of B. Sites with Site Class C soil conditions could experience minor amplifications of surface earthquake ground motions.

AGDC determined the seismic design ground motions for the GTP site in accordance with IBC (2012) and, by reference, ASCE 7-10. The results of the derivation concluded that the GTP would be designed to a 0.2-second design spectral acceleration value of 0.200 g, and a 1.0-second design spectral acceleration of 0.110 g. These ground motions are relatively low compared to other locations in the United States, and much lower than those at the proposed Liquefaction Facilities. AGDC states the OBE and SSE are not applicable to the GTP because the GTP is not an LNG-handling facility. FERC staff independently evaluated the OBE peak ground acceleration (PGA), SSE PGA, S_{DS}, and S_{D1} values for the site using the Applied Technology Council (ATC) Seismic Hazards Tool[157] for all occupancy categories (I through IV). We determined that the SSE PGA, OBE PGA, and 5-percent damped spectral design accelerations (S_{DS} and S_{D1}) used by AGDC for the GTP are acceptable.

There have been approximately 1,830 earthquakes registering above a magnitude 2 recorded between January 2015 and January 2019 within approximately 100 miles of the GTP site, with the vast majority—1,465 earthquakes—registering from 2.0 to 2.9, along with 311 from 3.0 to 3.9, 49 from 4.0 to 4.9, 4 from 5.0 to 5.9, and only 1 at 6.0 and higher. With few exceptions, these earthquakes tend to occur in a tight cluster at the eastern part of the North Slope. The only earthquake above 6.0 was a 6.4 magnitude earthquake on August 12, 2018 recorded about 52 miles southwest of Kaktovik in the Sadlerochit Mountains and about 25 miles south of the Beaufort Sea. There were several aftershocks associated with this earthquake, with the highest measured approximately 20 miles east of the mainshock with a magnitude of between 6.0 and 6.1. This is the largest recorded earthquake on the North Slope; however, there were negligible ground motions (<0.010 g) recorded near the GTP site. AGDC would be designing facilities to ground motions that exceed these historical events.

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155 *USGS Earthquake Hazards Program: Quaternary Fault and Fold Database of the United States*, https://earthquake.usgs.gov/hazards/qfaults/, accessed June 2019.

156 There are six different site classes in ASCE 7-05, A through F, that are representative of different soil conditions that affect the ground motions and potential hazard ranging from Hard Rock (Site Class A), Rock (Site Class B), Very Dense Soil and Soft Rock (Site Class C), Stiff Soil (Site Class D), and Soft Clay Soil (Site Class E), to soils vulnerable to potential failure or collapse, such as Liquefiable Soils, Quick and Highly Sensitive Clays, and Collapsible Weakly Cemented Soils (Site Class F).

157 *ATC Hazards by Location*, https://hazards.atcouncil.org/, accessed June 2019.

ASCE 7-05 also requires determination of the Seismic Design Category based on the Occupancy Category (or Risk Category in ASCE 7-10 and 7-16) and severity of the earthquake design motion. The Occupancy Category (or Risk Category) is based on the importance of the facility and the risk it poses to the public.[158] FERC staff has identified the Project as a Seismic Design Category B based on the ground motions for the site and an Occupancy Category (or Risk Category) of II or III; this seismic design categorization would also appear to be consistent with the 2012 IBC and ASCE 7-10.

Seismic events can also result in soil liquefaction in which saturated, non-cohesive soils temporarily lose their strength/cohesion and liquefy as a result of increased pore pressure and reduced effective stress when subjected to dynamic forces such as intense and prolonged ground shaking. Soil liquefaction can only occur among liberated granular sediments. Areas susceptible to liquefaction may include saturated soils that are generally sandy or silty. Typically, these soils are located along rivers, streams, lakes, and shorelines or in areas with shallow groundwater. The GTP underlying surface is permafrost created when soils are partially or entirely frozen, and is a prominent soil condition at the North Slope where the GTP would be constructed. Because soil grains are essentially rigid when subject to permafrost conditions, they would not be able to freely displace when subject to seismic activity and behave like a liquid. Therefore, FERC staff considers the GTP to be subject to a low risk of liquefaction.

Seismic events in waterbodies can also cause tsunamis or seiches by sudden displacement of the sea floors in the ocean or standing water. Tsunamis and seiche may also be generated from volcanic eruptions or landslides. Tsunami wave action can cause extensive damage to coastal regions and facilities. The North Slope of Alaska has not experienced a recorded tsunami event between 1737, with the earliest records available, and the present day, and there are no seismic sources that could generate a significant tsunami wave. Therefore, FERC staff considers the GTP to be subject to a low risk of tsunami impacts.

Liquefaction Facilities

The Liquefaction Facilities would be on the Coastal Trough physiographic province, which is characterized by anticlinal wrinkle-like folds that can grow from seismic activity and is in an area of high seismic activity; however, projects in areas of high seismic activity can still operate safety provided all facilities are adequately designed to withstand the corresponding ground motions. FERC staff used the same aforementioned USGS database to evaluate surface and subsurface faults and folds in the United States that are believed to be sources of earthquakes greater than 6.0 magnitude occurring during the past 1.6 million years (Quaternary Period). The Project location is surrounded by several large fault series, including the Patton Bay Fault, the Cook Inlet Folds, and the Castle Mountain Fault. In addition, a recent report titled *Active Faulting and Seismic Hazards in Alaska* authored by the State of Alaska Division of Geological and Geophysical Surveys identified several fault series near the proposed Project site as potential sources of strong seismic ground motion. In particular, the report states that the Castle Mountain Fault Series is the main source for local shallow crustal earthquakes. These fault series are all near the subduction zone of the Pacific and North American Plate, which produces earthquakes that can drive subsidence, rifting, and uplift. While the presence of faults can require special considerations, the presence or lack of faults immediately under the Project site does not govern the overall potential impact faulting

[158] ASCE 7-05 defines Occupancy Categories I, II, III, and IV. Occupancy Category I represents facilities with a low hazard to human life in even of failure, such as agricultural facilities; Occupancy Category III represents facilities with a substantial hazard to human life in the event of failure or with a substantial economic impact or disruption of day to day civilian life in the event of failure, such as buildings where more than 300 people aggregate, daycare facilities with capacities greater than 150, schools with capacities greater than 250 for elementary and secondary and greater than 500 for colleges, health care facilities with 50 or more patients, jails and detention facilities, power generating stations, water treatment facilities, and telecommunication centers; Occupancy Category IV represents essential facilities such as hospitals; fire, rescue, and police stations; emergency shelters, power generating stations and utilities needed in an emergency; aviation control towers; water storage and pump structures for fire suppression; national defense facilities; and hazardous facilities that could substantially affect the public; and Occupancy Category II represents all other facilities. ASCE 7-10 changed the term to Risk Categories I, II, III, and IV with some modification.

may have when subjected to seismic activity. These faults have all been considered in the site-specific seismic hazard study performed by AGDC by Fugro. AGDC used seismic reflection profiling data to interpret the geometry and locations of faults and folds near the site. The seismic reflection surveying identified multiple local monoclines, two blind thrust faults within a 5-mile radius of the proposed Project site, and geological unconformities, all of which are structural geological features indicative of tectonic activity. While these geological features are telling about the seismic history of the region, their presence alone would not pose a risk to the facility construction or operation. The site-specific geology directly beneath the proposed facility location is informative from a risk perspective. AGDC's *LNG Facilities Geologic Hazard Report* includes the examination of surface and growth faults in the region of the Project area. According to the report, the hazard associated with surface faulting at the LNG Plant site is low, as no tectonic faults are present below the proposed site. Furthermore, the report said faulting via lateral spreading is possible but unlikely.

The geotechnical investigation of the proposed site indicates the site is classified as Site Class D based on a site average shear wave velocity that ranged between 686 and 1138 feet per second with an average of approximately 938 feet per second in the upper 100 feet of strata. This is in accordance with ASCE 7-05, which is incorporated directly into 49 CFR 193 for shop fabricated containers less than 70,000 gallons and via NFPA 59A (2006) for field fabricated containers. This is also in accordance with IBC (2006). Sites with soil conditions of this type could experience significant amplifications of surface earthquake ground motions.

Fugro performed a site-specific seismic hazard study for the site. The study concluded that the site would have an OBE PGA of 0.528 g, a SSE PGAs of 0.897 g (onshore) and 0.901 g (nearshore), DE 0.2-second design spectral accelerations (S_{DS}) of 1.00 g (onshore) and 1.02 g (nearshore), DE 1.0-second design spectral accelerations (S_{D1}) of 0.640 g (onshore) and 0.690 g (nearshore), and DE PGAs of 0.598 g (onshore) and 0.601g (nearshore). FERC staff independently evaluated the OBE PGA, SSE PGA, S_{DS}, and S_{D1} values for the site using the ATC Seismic Hazards Tool for all occupancy categories (I through IV). We determined that the SSE PGA, OBE PGA, and 5-percent damped spectral design accelerations (S_{DS} and S_{D1}) used by AGDC for the Liquefaction Facilities are acceptable.

There have been 9,269 earthquakes registering above a magnitude 2 recorded between January 2015 and January 2019 within about 100 miles of the Liquefaction Facilities, with the vast majority—8,235 earthquakes—from 2.0 to 2.9, 1,096 from 3.0 to 3.9, 140 from 4.0 to 4.9, 14 from 5.0 to 5.9, and 3 at 6.0 and higher. These earthquakes tend to occur in close proximity to the west of the site along Cook Inlet. As discussed in section 4.1.3, during FERC staff review of the AGDC application, on November 30, 2018, a moment magnitude 7.1 earthquake occurred north of Anchorage, about 70 miles northeast of the LNG site. The earthquake induced a PGA of 0.843 g at the epicenter. Nearby seismic monitoring stations in the Anchorage area, less than 15 miles from the earthquake epicenter, recorded PGAs ranging between 0.123 and 0.470 g. On the Kenai Peninsula, seismic monitoring station CAPN (Captain Cook Nikiski), approximately 10 miles northeast of the AGDC site, recorded a PGA of 0.188 g. These recorded accelerations are less than AGDC's OBE and SSE PGAs. Additionally, the USGS has published intensity contours derived from data collected during the earthquake. These contours show the Project site to be in an MMI scale zone of 5.5,[159] which is defined by the USGS as "felt by nearly everyone; many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop." Additionally, a magnitude 9.2 earthquake, the second largest earthquake ever recorded in world history, occurred in 1964 about 55 miles east of the LNG site. Monitoring stations on the Kenai Peninsula near the proposed Liquefaction Facilities site recorded PGAs ranging from 0.238 to 0.253 g. These accelerations are also less than AGDC's OBE and SSE PGAs. The location of the proposed Liquefaction Facilities site falls within

[159] USGS Earthquake Hazards Program, AEC, M7.1-14km NNW of Anchorage, Alaska, https://earthquake.usgs.gov/earthquakes/eventpage/us1000hyfh/shakemap/intensity, accessed June 2019.

an MMI scale zone of 7.0, which is defined by the USGS as "damage negligible in buildings of good design and construction; light to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken." The previously mentioned accelerations of these two earthquakes, when considered in tandem with the MMI intensity ratings of 5.5 and 7.0 and compared to the design accelerations AGDC determined, lead to the conclusion that earthquakes of these magnitudes would cause very minimal, if any, damage to the AGDC facility and would not affect its safe operation.

ASCE 7-05 also requires determination of the Seismic Design Category based on the Occupancy Category (or Risk Category in ASCE7-10 and 7-16) and severity of the earthquake design motion. The Occupancy Category (or Risk Category) is based on the importance of the facility and the risk it poses to the public. FERC staff has identified the Project as a Seismic Design Category D based on the ground motions for the site for all Occupancy Categories (or Risk Categories), I through IV, consistent with the IBC (2006) and ASCE 7-05 (and ASCE 7-10).

Seismic events can also result in soil liquefaction in which saturated, non-cohesive soils temporarily lose their strength/cohesion and liquefy as a result of increased pore pressure and reduced effective stress when subjected to dynamic forces such as intense and prolonged ground shaking. Areas susceptible to liquefaction may include saturated soils that are generally sandy or silty. Typically, these soils are located along rivers, streams, lakes, and shorelines or in areas with shallow groundwater. AGDC collected onshore borings from the Liquefaction Facilities to assess the potential for soil liquefaction at the site in accordance with the NFPA 59A 2006 and ASCE 7-05 requirements. The evaluation determined that continuous liquefiable layers were not present at the site, though certain horizons classified as sandy silt and lean clay were recognized as having the potential to liquefy. However, these lenses were found to be thin and intermittent, and it was determined that any liquefaction of the horizons would be localized with an estimated displacement of less than 0.5 inch (Fugro, 2015b). Similarly, nearshore borings were evaluated to determine the likelihood that liquefaction could occur on the marine transfer area footings. The analysis found that potential liquefiable horizons were within the uppermost 10 feet. However, the estimated settlement of the horizons in the construction area was less than 0.5 inch, and the lenses were thin and discontinuous. Any liquefaction that could occur near the marine transfer area footing would be localized (Fugro, 2015b).

Due to its location in southern Alaska adjacent to a coastline and in an area where many earthquakes have been recorded, AGDC conducted a probabilistic tsunami hazard assessment for the Liquefaction Facilities. The *Probabilistic Tsunami Hazard Assessment* (Fugro, 2017) modeled wave propagation based on the bathymetry of Cook Inlet and worst-case tsunamigenic sources, including a submarine landslide in Cook Inlet, earthquake similar to the 1964 Great Alaskan Earthquake, and collapse and debris flow from Augustine Volcano. According to the assessment, the probabilistic maximum considered tsunami, as defined by ASCE standards (ASCE, 2016) using a 2,475-year return period,[160] caused by a local submarine landslide in Cook Inlet would range from about 23 to 29 feet above MLLW, approximately 15.68 to 21.68 feet NAVD88, from seven observation points near the southern portion of the Mainline and Liquefaction Facilities (Fugro, 2017). The use of the maximum considered tsunami as the marine facility design basis to ensure the facilities could withstand the predicted tsunami is consistent with the ASCE standard (ASCE, 2016). At this range of maximum crest heights, the waves would be below the pile cap on the marine trestle, which range from 42 to 85 feet above MLLW (37.7 to 77.7 feet NAVD88) and, therefore, would not pose a threat of washing over the top of the trestle or otherwise causing damage to the trestle. As a precaution, AGDC would coordinate with the National Tsunami Warning Center in Palmer, Alaska, to monitor for potential tsunami hazards during Project construction and operation. In addition, two qualitative tsunami studies corroborate the low tsunami risk in central Cook Inlet near the Liquefaction Facilities (Pacific Alaska LNG Association, 1978; Kenai Peninsula Borough, 2014). FERC staff finds the

[160] 2.0-percent probability of exceedance in 50 years.

design elevation for the proposed Project site is higher than the maximum landslide-induced tsunami wave height and would be sufficient to avoid potential impact on the facility. Therefore, based on the information available, FERC staffs does not anticipate tsunamis to pose substantial risk to the proposed Project site.

AGDC proposes to use a seismically isolated double concrete slab supported on structural fill for the LNG storage tank foundation. Fugro recommends building the tanks on seismic base isolator foundations, which would consist of tank bottoms supported on isolators, under which a shallow mat foundation with a reinforced concrete slab would lay. The two reinforced concrete slabs in the foundation would be separated by plinths that rest on friction pendulum isolators. The double slab foundation would provide an air gap that AGDC states would eliminate the need for foundation heating.

The proposed tank design is a low-profile, full-containment, all-precast concrete tank. The tank consists of a concrete dome and inner and outer wall made of precast concrete panels on sliding bases and a tank base slab supported by a seismic base isolation system on concrete pedestals and a foundation slab. AGDC states the tank would be subjected to significant lateral and vertical seismic acceleration because of the high seismicity at the proposed Project site. The use of a base isolation system is one of the most efficient ways to reduce the seismic lateral base shear of structures in high seismic zones. AGDC has proposed the use of a triple pendulum system, which, while fairly uncommon in LNG facilities, is commonly used in high rise structures and abroad in high seismic risk areas. The tank foundation contains a base concrete slab and a foundation concrete slab. The foundation slab is a mat footing on the ground that distributes the vertical loads from the seismic isolators that are mounted on pedestals, providing a gap between the two slabs for access to the isolators. The base slab would transfer the tank loads into the isolators that are distributed evenly throughout the slab. The base shear is transferred into the ground by soil friction. While designing seismic isolation bearings for tanks, simple static linear calculations do not account for the sloshing mass dynamic and the effect of the convective mass on the effective damping and stiffness of the triple pendulum bearing. Therefore, we recommend in section 4.18.9 that AGDC should file the non-linear dynamic analysis (modal response-spectrum analysis, response-history analysis, linear time-history analysis, and nonlinear time-history analysis) for the LNG tank and isolation system that would include all three components of ground motion, the response spectra of the time history, vertical component of motion envelope, and the site-specific vertical design response spectra developed for the Project. The analysis should also account for horizontal components rotated so that one of the components for each set of motions is the maximum component of response at the isolated period of the tank. The Peer Review of the design should be performed as required by Chapter 17 of ASCE 7-05. AGDC has agreed to provide the information in accordance with the timing of the recommendations.

In addition, we recommend in section 4.18.9 that AGDC file the finite element analysis (FEA) modeling that contains the input and output reports for tanks design, base concrete slabs and foundation concrete slabs design with analysis related calculation support materials. AGDC has agreed to provide the information in accordance with the timing of the recommendation. In the report, AGDC should determine the Seismic Isolation system for the LNG tanks and comply with the design, analysis, and testing requirements of Chapter 17 of ASCE 7-05. The Peer Review of the design should be performed as required by Chapter 17 of ASCE 7-05. For the seismic isolations, AGDC proposes to use triple pendulum system isolators for the LNG tanks. The pendulum type bearings become unstable and collapse when the displacement capacity is exceeded. Therefore, we recommend in section 4.18.9 that AGDC should file the completed reserve capacity test report to determine the vertical load, shear load, and overturning/uplift displacement capacities of the triple pendulum seismic isolator type bearing; provide non-linear analysis for maximum and minimum design liquid levels of the LNG tanks and the displacement during the empty tank condition; and provide separated non-linear analysis performance for variations of design stiffness, minimum values of friction, and other properties as required by Chapter 17 of ASCE 7-05. Also, according to the proposed Project site location with specific peak ground motion, we recommend in section 4.18.9 that at least one free-field triaxial accelerometer should be provided at site, and additional instruments on

the tank and its foundation should be considered. AGDC has agreed to provide the information in accordance with the timing of the recommendations.

FERC staff also reviewed preliminary calculations of the sloshing wave height for the proposed LNG tank that were provided by AGDC and found that the estimated sloshing wave heights were lower than anticipated. As a result of our review, we recommend in section 4.18.9 that AGDC should file the updated freeboard height and sloshing wave height design calculation comply with code requirements, including but not limited to ASCE 7-05; API 620, 625, and 650; and ACI 350 and 376. AGDC stated that the seismic isolation enables reduction of the base shear to compare to a fixed base, and the vertical acceleration, which cannot be reduced, remains close to peak-ground accelerations for wall uplift. Because of the large footprint of the low-profile tank, the combination of overturning moment and seismic vertical acceleration does not cause uplift of the inner tank wall during a base isolation event. AGDC also indicated the uplift and shear of the external wall would be handled with the seismic tendons in combination with shear keys; however, calculations were not provided that indicate shear keys would be sufficient. We recommend in section 4.18.9 that AGDC should file design calculations to confirm the combination of overturning moment and seismic vertical acceleration inducing any uplift and shear of the external wall can be handled with the seismic tendons in combination with shear keys. We also recommend in section 4.18.9 that AGDC file the design analysis to determine the precast panel outer wall behavior for operating and spill conditions and to ensure panel and joint leak tightness. AGDC should file the cryogenic protection plan for the LNG tanks foundation concrete slabs and triple pendulum seismic isolator concrete pedestal supports during spill conditions. Due to the unique design of the LNG tank with base isolation foundation, we recommend in section 4.18.9 that AGDC should file an analysis of the structural integrity of the outer containment, tank foundation concrete slabs, tank base concrete slabs, and seismic isolator concrete pedestals, demonstrating that they are designed to withstand all loads and combinations that comply with code requirements, including but not limited to ASCE 7-05; ACI 318, 350, and 376; and API 620, 625, and 650. AGDC has agreed to provide the information in accordance with the timing of the recommendations.

AGDC performed dynamic slope stability evaluations of the bluff area in the vicinity of the LNG tanks and trestle abutment for OBE and SSE design ground motions. These evaluations indicated that the top of the bluff could horizontally displace significantly towards the Cook Inlet. The amount of horizontal displacement was dependent on the distance from the top of the bluff and the level of ground motion. To limit horizontal displacements to acceptable levels for conventional shallow foundations, AGDC has elected to offset the LNG tanks and most of the other LNG facilities at least 427 feet from the top of bluff. The trestle abutment and the LNG spill containment basin that would be closer to the top of bluff would need to accommodate larger slope horizontal displacements and would likely require specially designed deep pile foundations in order to resist these movements.

Hurricanes, Tornadoes, and other Meteorological Events

Hurricanes, tornadoes, and other meteorological events have the potential to cause damage or failure of facilities due to high winds and floods, including failures from flying or floating debris. The severity of these events is often determined on the probability that they would occur, which is sometimes referred to as the average number of years that the event is expected to re-occur, or in terms of its mean return/recurrence interval.

GTP

Between 1930 and present time, NOAA reported zero hurricanes within 100 miles of the North Slope. Similarly, there have been no recorded tornadoes. However, relatively strong winds are still possible and ASCE 7-16 would require Risk Category III facilities to withstand 148 mph 3-second gusts, equivalent

to a 1,700-year return period wind event, and 130 mph for tornadoes based on the ICC 500 design wind speed of 130 mph, equivalent to a 10,000-year return period tornado event. AGDC states that the GTP would be designed to withstand a 140-mph 3-second gusts. A 140-mph 3-second gust would convert to a sustained wind speed of 110 mph using the Durst Curve in ASCE 7-05 or using a 1.23 gust factor recommended for offshore winds at a coast line in the World Meteorological Organization's *Guidelines for Converting between Various Wind Averaging Periods in Tropical Cyclone Conditions*. This wind speed would be less than ASCE 7-16 for Risk Category III facilities; therefore, FERC staff recommend in section 4.18.9 that AGDC design facilities to be based on ASCE 7-16 commensurate with the risk category of the facilities. AGDC has agreed to file its wind speed criteria prior to initial site preparation in accordance with ASCE 7-16 or the equivalent.

Flooding on the North Slope of Alaska could occur from one of or a combination of storm surge, sea level rise, and snowmelt. Storm surge data on the North Slope is not extensively available (there are no published FEMA Flood Insurance Maps, FEMA Flood Insurance Studies, or NOAA Sea, Lake and Overland Surges from Hurricanes (SLOSH) maps for the North Slope of Alaska); however, the Department of Interior has recorded storm surges as high as 10 feet (3 meters) through 1978. Additionally, according to the current relative sea level trends published by NOAA, Prudhoe Bay would likely experience up to 0.4 foot of sea level rise. Because the GTP final site grade is +30 feet above MSL, the threat of flooding from storm surge and sea level rise is considered insignificant.

The North Slope is also susceptible to flooding from snow/glacial melt and extreme rainfall events. An examination of snowmelt and rainfall floods conducted by the University of Alaska near the Upper Kuparuk River catchment shows that most annual floods on the North Slope are due to snowmelt. Over a 17-year period, 16 of the 17 maximum annual floods were due to snowmelt, while only one was due to an extreme rainfall event. However, rainfall events can still cause significant flooding on the North Slope. Precipitation typically falls in much greater amounts in the foothill topography to the south of the North Slope; this precipitation in combination with the steep gradients from the foothills to the North Slope coast, as well as permafrost preventing any considerable water infiltration into the ground, can cause significant runoff events (Kane et al., 2003). Because snowmelt runoff flooding is a topic that has gained recent scientific interest, minimal flood level data from snowmelt events is available. Historically, tundra flooding in the flat terrain of the Prudhoe Bay Region due to runoff has typically been caused by blocked drainage of snowmelt waters by roads and other infrastructure. As a result, AGDC's GTP storm drainage design would incorporate several design measures to aid in the mitigation of potential flooding due to snowmelt and precipitation events. Additionally, the final grade of the GTP's process and control area would range between +5 and +7 feet above the existing grade, with all process equipment and building modules being installed on elevated pile foundations. Therefore, the flooding due to a snowmelt runoff event would be not pose a significant impact on the facilities.

Historical climate data from Prudhoe Bay also indicates the average snow depth near the GTP through the winter months is approximately 4 inches, with a substantial portion of any snow and ice precipitation being lost to sublimation. Because of the typically low amount of standing snow depth, flooding of the GTP due to localized snowmelt would be unlikely. Additionally, the GTP is located within the Kuparuk River Sub-basin and near the Putuligayuk River Catchment. There are no glaciers within this sub-basin and, therefore, the potential for flooding due to glacial melt would be insignificant. To ensure flooding risk for the GTP would remain insignificant, we recommend in section 4.18.9 that AGDC provide a monitoring and maintenance plan that has been stamped and sealed by the professional engineer of record registered in Alaska that would ensure the site grade would be maintained to prevent flooding throughout the life of the facility considering settlement, subsidence, thermocycling, and sea level rise.

AGDC did not provide any data or analysis concerning the potential for erosion to affect the GTP at the North Slope. Peer-reviewed scientific research identifies the arctic as having one of the most rapid

rates of coastal erosion in the world (Jones, 2009). Aerial photogrammetry indicates an erosion rate of 44.6 feet (13.6 meters) per year as of 2007, which is an increase from the historic rate of 22.3 feet (6.8 meters) per year during 1955 to 1979 (Jones, 2009). During 2007, a particular spot along the Alaskan Beaufort Coast experienced 82.0 feet (25.0 meters) of erosion absent a storm event (Jones, 2009). Another scientific study states that the rates of coastal erosion near Drew Point on the Beaufort Coast dramatically increased since the early 2000s (Ravens, 2012). Erosion rates in this geography are high due to high ice content and fineness of the sediment grains (Ravens, 2012). Areas with continuous permafrost are uniquely susceptible to the mechanical and thermal erosion from ocean waves (Ravens, 2012). FERC staff acknowledges that coastal erosion could pose substantial risk to the GTP. Therefore, we recommend in section 4.18.9 that AGDC conduct site-specific analysis for coastal erosion and propose a prevention and mitigation plan prior to commencement of construction.

AGDC has also listed in their codes and standards list that the GTP facilities would be designed to meet NFPA 780, *Standard for the Installation of Lightning Protection Systems*, which would protect them from lightning in the event of a storm.

Liquefaction Facilities

Similar to the GTP site, FERC staff evaluated historical tropical storm, hurricane, and tornado tracks in the vicinity of the Project facilities using data from the DHS Homeland Infrastructure Foundation Level Data (HIFLD) and NOAA historical Hurricane Tracker. There is no historical hurricane or storm that has been reported within 100 nautical miles of the proposed Liquefaction Facilities site. Hurricanes do not occur near the LNG terminal site as the environment does not support these barotropic, warm core system. However, because of its location, the Liquefaction Facilities could be subject to powerful Pacific storms with hurricane level force winds during the life of the Project. AGDC states that all Liquefaction Facilities and Marine Facilities associated with the LNG terminal would be designed to comply with 49 CFR 193.2067 to withstand a sustained wind velocity of 150 mph, which converts to 183-mph, 3-second gust wind speed at 33 feet above ground. AGDC must meet 49 CFR 193.2067 under Subpart B for wind load requirements. In accordance with the MOU, PHMSA will evaluate in its LOD whether an applicant's proposed project meets the PHMSA siting requirements under Part 193, Subpart B. If the Project is constructed and becomes operational, the facilities would be subject to PHMSA's inspection and enforcement programs. Final determination of whether the facilities are in compliance with the requirements of 49 CFR 193 would be made by PHMSA staff.

AGDC states that both extreme and operational wind loads would be considered in the PLF, which includes an access trestle, product loading platform, marine operations building and platform, and berthing and mooring structures. AGDC also indicates that the wind load calculation for the PLF would comply with 49 CFR 193.2067 and ASCE 7. For extreme wind loads, a basic wind speed of 183 mph, 3-second gust would be used for wind calculation along with Importance Factor 1.15, Occupancy Category III, and Exposure Category D. For operating wind speed, all mooring and breasting equipment, loading arms and structures would be designed to withstand the worst mooring line tensions, fender loads, and vessel motions. It was modeled using OPTMOOR using a 360-degree wind sweep and a constant (static) wind profile with the design condition of a wind speed at 60 knots (69 mph) (30-second mean). LNG carriers are expected to be able to safely berth and undergo normal operating procedures, and it was modeled with a maximum operational condition of a wind speed at 40 knots (46 mph) (30.2 knots hourly mean). AGDC also indicated that the extreme wave with a 100-year return period, operational waves (maximum wave conditions with vessels at berth), and an extreme current of 4.1 knots (6.92 feet/second) would be considered in the marine facilities design. Based on the wind design speeds AGDC proposes, FERC staff do not anticipate wind to pose a substantial risk to the safety and reliability of the proposed infrastructure.

At this time, AGDC has not committed to installing current or vessel velocity monitors, and the WSA did not specify any weather or current restrictions. However, the Coast Guard's Sector Anchorage Waterways Management Division handles day-to-day waterway issues and concerns, such as tidal ranges and sea ice conditions, that arise in the Western Alaska Captain of the Port Zone, which would include Cook Inlet. Specifically, the Coast Guard's Sector Anchorage Waterways Management Division has a navigation safety advisory on *Operating Guidelines for Ice Conditions in Cook Inlet.*[161] These guidelines include best practices and mitigation measures for vessels operating in Cook Inlet that address ice and current conditions. AGDC also indicated the tidal fluctuation at Cook Inlet near Nikiski is the second largest in the world and has been observed to exceed 30 feet, but is more commonly between about 17 to 20 feet between low and high tides. Therefore, we recommend that AGDC demonstrate that a representative range of tidal levels at the PLF do not exceed transfer arm safe operating envelopes.

In addition, as noted in the limitation of ASCE 7-05 section 6.5.4.3 and ASCE 7-10 section 26.5.4, tornadoes were not considered in developing basic wind speed distributions. FERC staff evaluated the potential for tornadoes. FERC staff used the ATC Hazards tool and ASCE 7-16 wind speed maps to confirm the design review. Later editions of ASCE 7 (ASCE 7-16) would require Risk Category III and IV facilities to withstand 142- and 149-mph 3-second gusts, respectively, and make reference to ICC 500, *Standard for Design and Construction of Storm Shelters*, for 10,000-year tornadoes. The ATC website determined that if a tornado were to occur, it would exert a wind speed with about a 130-mph 3-second gust. Appendix C of ASCE 7-05 makes reference to American Nuclear Society 2.3 (1983 edition), *Standard for Estimating Tornado and Extreme Wind Characteristics at Nuclear Power Sites*. This document has since been revised in 2011 and reaffirmed in 2016 and is consistent with NUREG/CR-4461, *Tornado Climatology of the Contiguous United States,* Revision 2 (NUREG, 2007).[162] As suggested in NUREG, a maximum wind speed of about 100 mph is appropriate for tornadoes with a best estimated probability of a 10,000-year mean return period for regions of the United States with similar design wind speeds. In addition, no historical tornado has been reported within 100 nautical miles of the proposed Liquefaction Facilities site. As a result, FERC staff conclude that the use of an equivalent 183-mph 3-second gust, at 33 feet above ground, is adequate for the proposed LNG storage tanks and is conservative from a risk standpoint for the other liquefaction facilities and hazardous facilities.

ASCE 7 also recognizes the facility would be in a windborne debris region. Wind borne debris has the potential to perforate equipment and the LNG storage tanks if not properly designed to withstand such impacts. The potential impact would be dependent on the equivalent projectile wind speed, characteristics of projectile, and methodology or model used to determine whether penetration or perforation would occur. Unfortunately, no criteria is provided in 49 CFR 193 or ASCE 7 for these specific parameters. However, NFPA 59A (2016) recommends CEB 187 be used to determine projectile perforation depths. AGDC is proposing to use a composite concrete cryogenic tank (C^3T) at the Liquefaction Facilities. The C^3T design is a relatively new tank design and has not been widely used in LNG applications within the United States. The design calls for primary and secondary container walls made of post-tensioned precast concrete panels without outer carbon steel liners and a 9%-Ni steel inner tank. FERC staff issued an information request on December 26, 2018 addressing several viability and design related questions and are awaiting a response from AGDC. Among the questions was, most importantly, a concern regarding the thickness of the precast concrete panels as compared to a conventional cast-in-place concrete double containment tank and the C^3T tank design's ability to withstand an impact form a wind-borne projectile. In order to address the potential impact, we recommend in section 4.18.9, in conjunction with the viability and design related questions in the December 26, 2018 information request, that AGDC provide a projectile analysis, for review and approval, to demonstrate that the precast concrete panels of a C^3T tank could withstand wind borne

[161] USCG, *Operating Guidelines for Ice Conditions in Cook Inlet*, accessed at https://www.pacificarea.uscg.mil/Our-Organization/District-17/17th-District-Units/Sector-Anchorage/-Waterways-Management/.

[162] NUREG, *Tornado Climatology of the Contiguous United States*, Revision 2, accessed at https://www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr4461/.

projectiles prior to construction of the final design. The analysis should detail the projectile speeds and characteristics and method used to determine penetration or perforation depths. FERC staff would compare the analysis and specified projectiles and speeds using established methods, such as CEB 187, and the DOE and Nuclear Regulatory Commission guidance. AGDC has agreed to provide information in accordance with the timing of the recommendation.

The Liquefaction Facilities would be situated atop a coastal bluff over 100 feet above sea level; thus, the threat of flooding due to sea level rise, storm surge, and subsidence is considered insignificant. The marine loading area, however, could be subject to flooding from the previously listed hazards. Potential flood levels may be informed from the FEMA Flood Insurance Rate Maps, which identify Special Flood Hazard Areas (base flood) that have a 1-percent probability of exceedance in 1 year to flood (or a 100-year-mean return interval). According to the FEMA National Flood Insurance Rate Maps (FEMA, 2013), the 100-year base flood, including wave action, along the coastline of the Kenai Peninsula at the location of the marine loading area, is +31 feet NAVD 88. Typically, FERC staff also reviews the elevations of floods from applicants relative to the 500-year flood as well; however, there is no 500-year flooding data available from FEMA for the location of the Kenai Peninsula near the AGDC Liquefaction Facilities. Typically, the 500-year flood is 1 to 3 feet higher than the 100-year flood. The pile cap elevations of the marine loading area range in elevation from +42 feet above MLLW to above +85 feet above MLLW (34.7 to 77.7 feet NAVD 88). The estimated 100-year surge at NOAA station 9455760 is approximately +3.8 feet MLLW. Lastly, the sea levels in the Nikiski area are expected to lower 1.42 feet between 2020 and 2060 according to the NOAA relative sea level change scenarios. Therefore, considering the elevations of the marine platform in relation to the previously discussed flood levels, FERC staff have determined that the threat of flooding of the marine platform from storm surge and sea level rise would be insignificant. The flooding potential from tsunamis has been previously discussed.

AGDC has also listed in their codes and standards list that the Liquefaction Facilities would be designed to meet NFPA 780, *Standard for the Installation of Lightning Protection Systems*, which would protect them from lightning in the event of a storm.

Landslides and other Natural Hazards

GTP

The GTP would be in the Beaufort Coastal Plain physiographic region. Gentle slopes are characteristic of this region, which declines seaward at 4 feet per mile. Due to the low relief across the proposed GTP site, there is little likelihood that landslides are a realistic hazard aside from seismic activity. The terrain has continuous permafrost, which traps water in the soil. Poorly-drained permafrost soils have reduced cohesion and increased rates of weathering, which can lead to landsliding when induced by a seismic force.

According to the NRCS Prudhoe Bay weather station, the annual average snow level over the past 5 years for the North Slope area is 6.7 inches, with the maximum snow depth of 27 inches. Due to the colder temperatures of the North Slope, snow tends to persist October through July and can become more dense as it thaws and re-freezes. As a result of the extended cold weather and snowfall, structures may be subjected to higher snow loads that would require additional design consideration. AGDC stated that snow clearing would be performed to maintain access to critical equipment; however, no plan for snow removal from equipment has been provided. AGDC has committed to clearing snow on access roads, platforms, and stairs to equipment. AGDC indicates in their application that protection from falling ice would be considered and implemented during the final design phase; however, a detailed plan was not provided in the application. AGDC also stated that structures and coverings for employees would be designed to handle snow and ice loads, but detailed calculations, designs, and drawings have not yet been provided. As a

result, FERC staff recommend in section 4.18.9 that AGDC file a snow removal plan for critical equipment or provide calculations that prove that support structures and equipment adequately account for snow loads. In addition, FERC staff recommend in section 4.18.9 that AGDC file an analysis indicating areas susceptible to falling ice and snow, and file drawings of structures and coverings that would protect people, piping, and equipment from falling snow and ice. AGDC has agreed to provide the information in accordance with the timing of the recommendations.

There are no documented volcanoes near the North Slope of Alaska. The closest one, called the Koyuk-Buckland monogenetic volcano, is about 15 miles northwest of the town of Buckland over 400 miles away from the proposed GTP. According to the USGS Alaska Volcano Observatory, Koyuk-Buckland is responsible for some of the largest basalt fields in Alaska, though their age is not known. The volcano is not seismically monitored. FERC staff does not consider the GTP to be subject to high volcanic risk.

Wildfires on the North Slope of Alaska occur, but are partially limited due to the lack of vegetation growth in the tundra. In 2007, the Anaktuvuk River Fire became the largest and the longest burning wildfire on record at the North Slope (Jones et al., 2009). This fire occurred mostly in the arctic foothills of the Brooks Range approximately 94 miles southwest of Prudhoe Bay. According the USFS, four wildfires were recorded in 2007 and only 18 others were reported in the region during the past 56 years.[163] The Prudhoe Bay on the northern slope is less susceptible to these wildfires due to the many kettle ponds. AGDC indicated that they would provide ERPs for the GTP, but did not specify whether these plans would include response to wildfires. We recommend in section 4.18.9 that AGDC develop the ERPs with federal, state, and local agencies, and FERC Staff would review ERPs for adequate preparedness for wildfire.

Geomagnetic disturbances (GMDs) may occur due to solar flares or other natural events with varying frequencies that can cause geomagnetically induced currents, which can disrupt the operation of transformers and other electrical equipment. USGS provides a map of GMD intensities with an estimated 100-year-mean return interval. The USGS intensity map indicates the AGDC site could experience GMD intensities of 20 to 200 nano-Tesla with a 100-year-mean return interval. However, the GTP would be designed such that if a loss of power were to occur, actuated process and ESD valves would move into a fail-safe position.

Liquefaction Facilities

The Liquefaction Facilities would be in the Cook Inlet Basin Ecoregion, marked by gently sloping lowland with fine-textured lacustrine deposits. Relief is generally low with gently sloping plains of glacial outwash. There is no permafrost at this location. AGDC reports several different types of potential slope instabilities that could affect the Liquefaction Facilities: deep or shallow landslides, slope creep, debris flows, rock falls, or snow or rock avalanches. Deep landslides are distinguished from shallow landslides by a characteristic rotational or translational slide, but both types of landslides generally occur along a rupture surface. Slope creep is a slow flow that commonly occurs where fine-grained soils or certain types of weathered bedrock compose the slope surface (Highland and Botrowsky, 2008). In contrast, debris flows are typically triggered by heavy precipitation and form when water mixes with soil, rock, and/or organic material in a flow that travels quickly downslope (Highland and Botrowsky, 2008). Avalanches and rock falls are similarly rapid and can be triggered by freeze-thaw cycles, seismic activity, or human-generated vibrations. Gravity is the dominant force driving all of these instabilities, but water, wind rain and earthquakes reduce slope stability as well.

According to the Western Regional Climate Center, in partnership with NOAA, the Kenai region experiences an average annual snowfall of 61.2 inches. The Liquefaction Facilities would thus be subject

[163] USFS, *Fire Regimes of Alaskan Tundra Communities*, accessed at https://www.fs.fed.us/database/feis/fire_regimes/AK_tundra/all.html.

to snowfall. FEMA recognizes that buildings may be vulnerable to structural risks unless preventative measures are incorporated prior to a snow loading event or that additional design consideration be given for snow loads.[164] AGDC would design structures to withstand 70 pounds per square foot of ground snow (50-year return period) in accordance with ASCE 7. While AGDC would provide snow clearing for access to critical equipment, it did not commit to also clearing snow off of the critical equipment. AGDC has not submitted calculations demonstrating how the structures would withstand snow and ice loads. As a result, FERC staff recommends in section 4.18.9 that AGDC file with the Secretary a snow removal plan for critical equipment or provide calculations that prove that support structures and equipment adequately account for snow loads. The snow, along with more limited daylight and marine fog, can also affect visibility in the winter months, which can pose a hazard for LNG marine vessel transit and berthing. These visibility concerns were identified as a potential navigational hazard in the WSA, and AGDC indicated a general safeguard to establish operational limitations and simulation training is planned for the Transit Management Plan. However, there were no specific operational limitations recommended for day or night visibility, and the LNG marine vessel simulations provided to date assumed additional aids to navigation to improve limited visibility and still resulted in potential failures under certain high wind, high current, and ice conditions. As previously stated, the Coast Guard's Sector Anchorage Waterways Management Division handles day-to-day waterway issues and concerns that arise in the Western Alaska Captain of the Port Zone. Responsibilities include distributing broadcast notice to mariners, safety zones, security zones, and marine event permits, as well as vessel navigation advisories that address sea ice and severe weather condition.

Aside from snow, ice loads can form on both horizontal and vertical piping, exerting force that can deform and eventually shear piping. Likewise, falling ice can collide with people or equipment, affecting the equipment's functionality. Therefore, FERC staff recommend that AGDC file an analysis indicating areas susceptible to falling ice and snow, and file drawings of structures and coverings that would protect people, piping, and equipment from falling snow and ice. Sea ice is also prevalent at the Nikiski site location in winter months and can pose a hazard to the LNG marine vessel and LNG marine facilities. AGDC has acknowledged this hazard and has provided preliminary analysis of sea ice loads. However, AGDC has not yet demonstrated that the LNG carrier or berth could withstand these loads. In addition, LNG marine vessel simulations indicate potential failures under certain ice conditions with high wind, high current, and high waves. The Coast Guard's Sector Anchorage Waterways Management Division has a navigation safety advisory on *Operating Guidelines for Ice Conditions in Cook Inlet.*[165] These guidelines include best practices and mitigation measures for vessels operating in Cook Inlet during winter ice conditions. In order to address sea ice and ice buildup on the PLF, we recommend in section 4.18.9 that AGDC file an analysis stamped and sealed by a professional engineer in the State of Alaska that demonstrates the PLF can withstand the impact from sea ice that historically occurs at the Nikiski site location, and that the PLF structural load conditions consider sea ice and ice buildup.

Volcanic activity is primarily a concern along plate boundaries on the West Coast and in Alaska. The *2018 Update to the U.S. Geological Survey National Volcanic Threat Assessment* actively monitors 161 volcanoes in the United States, 86 of which are in Alaska. Five of the 18 "very high threat" volcanos nationwide are in Alaska near population centers. Furthermore, volcanoes in Alaska dominate the high and moderate threat categories as they tend to have higher rates of activity and explosiveness. The Project would be within close proximity of the Aleutian Arc Range, a formation of active volcanoes.

Eruptions can eject ash into the atmosphere, posing hazards both to human health and operability of equipment. Fugro listed volcanic ash fall as a potential hazard to the onshore liquefaction and marine

[164] FEMA (2013), *Snow load Safety Guide* FEMA P-957.

[165] USCG, *Operating Guidelines for Ice Conditions in Cook Inlet*, accessed at https://www.pacificarea.uscg.mil/Our-Organization/District-17/17th-District-Units/Sector-Anchorage/-Waterways-Management/.

facilities. Since 1976, five eruptions in the Aleutian Range deposited ash where the Project would be located. The nearest volcanoes to the proposed Project site are approximately 50 miles away or more. If an eruption occurred, Fugro states that the thickness of ash could be several inches. FERC staff requested AGDC to provide plans and/or mitigating measures that would be implemented to protect sensitive plant equipment from an ash fall event. On May 3, 2019, AGDC responded that air intake systems for equipment and buildings would be designed for a potential impact of volcanic ash such as the air inlet system for the gas turbine equipment and air intakes for the diesel driven air compressors and firewater pumps. HVAC filters for buildings, control rooms, motor control centers, and local equipment rooms would be replaced on a more frequent basis, and buildings and rooms would be equipped with arctic entryways that would reduce ash ingress through doorways. In addition, sensitive equipment in buildings/rooms would require filters on their ventilation for dust control and would be monitored during an ashfall event. FERC staff recommend in section 4.18.9 that AGDC provide a mitigation plan, based on the final design, to reduce the impact of an ashfall event on facility equipment and ingress into buildings/rooms that house critical electrical equipment.

Eruptions can also eject tephra, or molten fragmented rock, into the atmosphere. Pieces of tephra greater than 2.5 inches in diameter are called volcanic bombs. The distance tephra travels depends on the mass of the ejecta, height of the volcano, magnitude of eruptive force, air temperature, and wind. Pieces of tephra with large mass settle close to the volcano, while smaller ash-sized pieces can disperse tens of miles before depositing. Although the proposed Project site is close enough to potentially be affected by ash, FERC staff does not consider volcanic bombs or smaller tephra ejecta to pose a credible risk to the Project.

A lahar is debris flow of rock, soil, and water materials downslope of a volcano commonly associated with those in the Aleutian volcanic arc in Alaska and the western United States. According to the USGS, lahars are known to increase in volume as they move and can grow up to 10 times their initial size. The USGS has documented lahars moving at rates up to 120 mph, though this rate is highly variable and depends on mineralization of the flow, slope of the land upon which it is traveling, resistance posed by colliding with large debris and structures, water content, and a variety of other factors. Some lahars have traveled over one hundred miles before ceasing. They are known to cause serious damage to roads, bridges, and structures. Though typically triggered by volcanic seismic activity, substantial rain fall, ice melt, and erosion of fine-grained sediments can trigger a lahar. The proposed Project location is in a range that could be affected by a lahar originating from Mt. Redoubt, as the 2009 eruption produced a lahar that flowed into Cook Inlet. However, because large eruptions are rare, FERC staff does not consider a volcanic-induced lahar to be a substantial risk to the Project.

The Pacific Northwest is often associated with the potential of wildfires. According to the Alaska Department of Natural Resources Division of Forestry, there is a history of wildfires occurring within 100 miles of the Project site. None have occurred within the immediate vicinity of the proposed Project site. In June 2019, a wildfire in Swan Lake northeast of Sterling about 22 miles from the proposed Project site produced smoke that drifted into South Anchorage due wind blowing from the southwest. It is noteworthy that the proposed Project site is surrounded by water with Cook Inlet on the southwest side, which would protect against the spread of wildfires from that direction. The proposed Project site is approximately 2,000 feet away from the nearest dense vegetation, which is to the northeast. If a wildfire were close by, it would not affect the Project site due to the sea breeze. The sea breeze is a thermally produced wind blowing from the cool ocean onto the adjoining warm land. It is caused by the difference in the rates of heating between the land and the ocean. The bigger the difference in the temperature, the stronger the wind. Therefore, it is unlikely that a wildfire would affect the Project site. In addition, AGDC indicated that they would provide ERPs for the Project site, but did not specify whether this would include a response to wildfires. FERC staff would review ERPs for adequate preparedness for wildfire.

GMDs may occur due to solar flares or other natural events with varying frequencies that can cause geomagnetically induced currents, which can disrupt the operation of transformers and other electrical equipment. USGS provides a map of GMD intensities with an estimated 100-year-mean return interval.[166] The USGS GMD intensity map indicates the AGDC site could experience GMD intensities of 70 to 400 nano-Tesla with a 100-year-mean return interval. However, AGDC would be designed such that if a loss of power were to occur, actuated process and ESD valves would move into a fail-safe position.

4.18.7 External Impacts

To assess the potential impact from external events, FERC staff conducted a series of reviews to evaluate transportation routes, land use, and activities within both the proposed Liquefaction Facilities and GTP sites and surrounding each proposed Project site, and the safeguards in place to mitigate the risk from events, where warranted. FERC staff coordinated the results of the reviews with other federal agencies to assess potential impacts from vehicles and rail; aircraft impacts on and from nearby airports and heliports; pipeline impacts from nearby pipelines; impacts on and from adjacent facilities that handle hazardous materials under EPA's Risk Management Plan regulations; and power plants, including nuclear facilities under Nuclear Regulatory Commission regulations. Specific mitigation of impacts from use of external roadways, rail, helipads, airstrips, or pipelines are also considered as part of the engineering review done in conjunction with the NEPA review.

FERC staff uses a risk-based approach to assess the potential impact of the external events and the adequacy of the mitigation measures. The risk-based approach uses data based on the frequency of events that could lead to an impact and the potential severity of consequences posed to the Project sites and the resulting consequences to the public beyond the initiating events. The frequency data is based on past incidents and the consequences are based on past incidents and/or hazard modeling of potential failures.

4.18.7.1 Road

FERC staff reviewed whether any truck operations would be associated with the Project and whether any existing roads would be near the Liquefaction Facilities and GTP sites. FERC staff uses this information to evaluate whether the Project sites and any associated truck operations could increase the risk along the roadways and subsequently to the public, and whether any pre-existing unassociated vehicular traffic could adversely increase the risk to Project sites and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. PHMSA regulations under 49 CFR 193.2155(a)(5)(ii) under Subpart C require that structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by or explosion of a tank truck that could reasonably be expected to cause the most severe loading if the Liquefaction Facilities should adjoin the right-of-way of any highway. Similarly, NFPA 59A (2001), section 8.5.4, requires transfer piping, pumps, and compressors to be located or protected by barriers so that they are safe from damage by rail or vehicle movements. However, PHMSA regulations and NFPA 59A (2001) requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. FERC staff evaluated consequence and frequency data from these events to evaluate these potential impacts.

[166] USGS Magnetic Anomaly Maps and Data for North America, https://mrdata.usgs.gov/magnetic/map-us.html#home, accessed August 2018.

FERC staff evaluated the risk of the truck operations based on the consequences from a release, incident data from the FHWA,[167] the DOT National Highway Traffic Safety Administration (NHTSA),[168] PHMSA,[169] EPA, NOAA,[170] and other reports,[171,172,173] and frequency of trucks and proposed mitigation to prevent or reduce the impacts of a vehicular incident.

Incident data from the FHWA, NHTSA, and PHMSA indicates hazardous material incidents are very infrequent (4e-3 incidents per lane mile per year), and that nearly 75 to 80 percent of hazardous material vehicular incidents occur during unloading and loading operations, while the other 20 to 25 percent occur while in transit or in transit storage. In addition, approximately 99 percent of releases are 1,000 gallons or less, and catastrophic events that would spill 10,000 gallons or more make up less than 0.1 percent of releases. In addition, less than 1 percent of all reportable hazardous material incidents with spillage result in injuries and less than 0.1 percent of all reportable hazardous material incidents with spillage result in fatalities.

The EPA and NOAA report that 80 percent of fires that lead to container ruptures results in projectiles and that 80 percent of projectiles from LPG incidents, which constitute the largest product involved in BLEVEs, travel less than 660 feet. The EPA also reports that on average container ruptures would result in less than four projectiles for cylindrical containers and 8.3 for spherical vessels. FERC staff evaluated other reports that affirmed the EPA estimates based on data for approximately 150 experimental and accidental PVBs and BLEVEs with approximately 683 total projectiles (4.6 average fragments per incident) that showed approximately 80 percent of fragments traveled 490 to 820 feet and within 6.25 times the estimated or observed fireball radius. The data also showed projectiles have traveled up to 3,900 feet for large LPG vessels and 1,200 feet for LPG rail cars. In all the documented cases, the projectiles traveled less than 15 times the fireball diameter, but one of the reports indicated up to 30 times the fireball diameter is possible, albeit very rare.

Unmitigated consequences under average ambient conditions from releases of 1,000 gallons through a 1-inch hole would result in distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to 175 feet for jet fires. Unmitigated consequences under worst case weather conditions from catastrophic failures of trucks proposed at the sites generally can range from 200 to 2,000 feet for flammable vapor dispersion, 275 to 350 feet for radiant heat of 5 kW/m^2 from jet fires, 800 to 1,050 feet to a 1 psi overpressure from a BLEVE, 850 to 1,500 feet for a heat dose equivalent to a radiant heat of 5 kW/m^2 over 40 seconds from 250 to 325 radii fireballs burning for 5 to 15 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. Based on distribution function of the projectile distances, FERC staff estimate approximately 90 percent of all projectiles for a 10,000-gallon tanker truck would be within 0.5 mile, and that there is about a 1-percent probability they would extend beyond 1 mile and less than 0.1-percent probability they would extend 30 times the fireball diameter. These values are also close to the distances provided by the FHWA[174] for designating hazardous material trucking routes (0.5 mile for

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167 FHWA, Office of Highway Policy Information, Highway Statistics 2016, https://www.fhwa.dot.gov/policyinformation/statistics/2016/, accessed March 2019.

168 NHTSA, Traffic Safety Facts Annual Report Tables, https://cdan.nhtsa.gov/tsftables/tsfar.htm, accessed March 2019.

169 PHMSA, Office of Hazardous Material Safety, Incident Reports Database Search, https://hazmatonline.phmsa.dot.gov/IncidentReportsSearch/Welcome.aspx, accessed March 2019.

170 EPA, NOAA, ALOHA®, User's Manual, The CAMEO® Software System, February 2007.

171 Birk, A.M., BLEVE Response and Prevention Technical Documentation, 1995.

172 AiChE CCPS, *Guidelines for Vapor Cloud Explosion, Pressure Vessel Burst, BLEVE, and Flash Fire Hazards, Second Edition, 2010*.

173 Lees, F.P, Lees *Loss Prevention in the Process Industries, Hazard Identification, Assessment, and Control, Volume 2, Second Edition, 1996*.

174 FHWA, Office of Highway Safety, *Guidelines for Applying Criteria to Designate Routes for Transporting Hazardous Materials*, September 1994.

flammable gases for potential impact distance) and PHMSA[175] for emergency response (0.5 to 1 mile for initial evacuation and 1 mile for potential BLEVEs for flammable gases).

GTP

During construction of the GTP, the majority of the construction supplies would be barged in with additional supplies being transported by truck. During operation of the GTP, AGDC estimates between 2 to 5 nitrogen trucks, 74 to 89 diesel trucks, 52 to 65 gasoline trucks, 3 amine trucks, 1 tri-ethylene glycol truck, and 1 hydrocarbon waste disposal vacuum truck would visit the site annually. This would result in approximately 133 to 164 annual truck deliveries to and from the GTP site during operation. However, AGDC did not indicate the anticipated number of truck deliveries during construction. Therefore, we had recommended in the draft EIS that, prior to the end of the comment period, AGDC discuss the anticipated frequency of truck deliveries during construction of the GTP. AGDC filed a response to this recommendation on September 25, 2019 that estimated 11,098 trucks would be delivered to the GTP site over the 8-year construction phase.

The existing Dalton Highway and existing Prudhoe Bay access roads would be used to reach the GTP site. The main access roads that would be used to access the GTP site would be the existing K Pad Road and the West Dock Causeway, which are both non-public roads. These existing access roads would be upgraded to support module delivery and facilitate two-way traffic through widening and adding turnout areas. The new access road, the module haul road, would be constructed by AGDC and would serve as the main access road to the GTP site and would connect the existing K Pad Road directly to the northwest corner of the GTP site. AGDC would also construct a new emergency egress road that would be on the east side of the GTP site and would connect to the existing adjacent PBU CGF. The new emergency egress road would serve as an egress road as well as an access point for emergency support services via the existing PBU CGF. A third new access road, the mine/reservoir access road, would be constructed at the southwest corner of the GTP site and would connect to a water reservoir and granular material mine.

There would be no major highways or roads within close proximity to piping or equipment containing hazardous materials at the GTP that would raise concerns of direct impacts from a vehicle affecting the site. In-plant roads would have a maximum speed limit, clearance heights, and signs posted adjacent to roadways. AGDC indicated that bollards and vehicle protection are not required at this time; however, the need for bollards and vehicle protection would be re-evaluated in detailed design. Therefore, we recommend in section 4.18.9 that AGDC install bollards and vehicle protection to safeguard equipment containing hazardous fluids and to further mitigate accidental and intentional vehicle impacts. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Due to the low risk of a vehicular incident occurring that could directly affect the site, the low risk of hazardous material truck incidents affecting the site that would cause cascading damage that could affect the public, and the proposed and recommended mitigation, we conclude that the Project would not pose a significant risk or significant increase in risk to the public from external impacts occurring on the road.

Liquefaction Facilities

During startup and operation of the Liquefaction Facilities, AGDC estimates up to 2,200 tanker trucks per year would be used to transport condensate off site. AGDC also estimates the diesel driven backup air compressors and diesel driven firewater pump would consume approximately 90,500 gallons of diesel per year, which equates to 23 4,000-gallon diesel fuel deliveries per year, or approximately one every 2 weeks. AGDC would produce nitrogen on site; however, the design also includes the capability to receive

[175] PHMSA, *Emergency Response Guidebook*, 2016.

liquid nitrogen trucks. However, the number of liquid nitrogen trucks that would be required during startup was not clear. Therefore, we recommended in the draft EIS prior to the end of the comment period that AGDC discuss the frequency of truck deliveries for all commodities required for startup and operation of the plant (i.e., liquid nitrogen, refrigerants, condensate, etc.). AGDC filed a response to this recommendation on September 25, 2019 that estimates 27 nitrogen trucks would be required for initial startup activities and about 2,450 trucks for construction activities over the 8-year construction duration.

Currently, the KSH, which runs along the coast, would intersect the Liquefaction Facilities. AGDC has proposed several alternatives to relocate the KSH to the east side of the site such that the road would not intersect the site. Of several alternative KSH re-routings, AGDC prefers the "West LNG" alternative route proposed in their August 15, 2018 filing. If this alternative is chosen, the relocated KSH would run parallel against the property line to the north and then divert around the property line in the southern direction. This alternative relocation would not be in close proximity to piping or equipment containing hazardous materials at the site; additionally, this alternative is the closest to the site of all those proposed in their August 15, 2018 filing. For site access using the "West LNG" route, AGDC would use the remnant segments of the existing KSH, which would be tied into the relocated KSH to access the site from the north (emergency access/egress) and the south (main access/egress). The north intersection would be a new 30-mph design speed alignment between the remnant of the KSH and Miller Loop Road intersection. A cul-de-sac north of the intersection would be installed to segregate the remnant and relocated KSH spurs. This design would also prevent straight-line access to the Liquefaction Facilities from the existing KSH north of the new intersection. The intersection outside of the southern entrance would have a 25-mph design speed and stop conditions for minor roads such as Miller Loop Road and the KSH remnant. The north and south entrances would have electrically operated gates with widths equal to that of the access roads. All gates would confirm to ASTM F900 for swing gates and ASTM F1184 for slide gates. AGDC would develop gate details, including physical protection (e.g., vehicle barriers) during detail design. Exit gates would conform to NFPA 59A requirements for the two exit gates to provide rapid escape capability. FERC staff also reviewed potential consequence distances for various postulated release scenarios following an accident of a hazardous materials truck on the relocated segment of the KSH. We reviewed potential releases of LNG, ethane, ethylene, propane, diesel fuel, and liquid nitrogen from a hazardous materials truck on the KSH under various release scenarios and found that none of the hazard distances encroached on any process vessels or equipment. Therefore, we conclude that the risk posed to the Liquefaction Facilities following a potential hazardous materials trucking accident on the relocated segment of the KSH is insignificant. We recommend in section 4.18.9 that AGDC install bollards and vehicle protection to safeguard equipment containing hazardous fluids and to further mitigate accidental and intentional vehicle impacts. AGDC has agreed to provide information in accordance with the timing of the recommendation.

4.18.7.2 Rail

FERC staff reviewed whether any rail operations would be associated with the Project and whether any existing rail lines would be near the GTP and Liquefaction Facilities. We use this information to evaluate whether the Project and any associated rail operations could increase the risk along the rail line and subsequently to the public, and whether any pre-existing unassociated rail operations could adversely increase the risk to the GTP and Liquefaction Facilities and subsequently increase the risk to the public. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. PHMSA regulations under 49 CFR 193.2155(a)(5)(ii), Subpart C, states that if an LNG facility adjoins the right-of-way of any railroad, the structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of a collision by or explosion of a train or tank car that could reasonably be expected to cause the most severe loading.

Section 8.5.4 of NFPA 59A (2001), incorporated by reference in 49 CFR 193, requires transfer piping, pumps, and compressors to be located or protected by barriers so that they are safe from damage by rail or vehicle movements. However, PHMSA regulations and NFPA 59A (2001) requirements do not indicate what collision(s) or explosion(s) could reasonably be expected to cause the most severe loading. Therefore, FERC staff evaluated consequence and frequency data from these events to evaluate these potential impacts.

FERC staff evaluated the risk of the rail operations based on the consequences from a release, incident data from the DOT Federal Rail Administration and PHMSA, and frequency of rail operations near the Liquefaction Facilities and GTP sites. Incident data from the Federal Rail Administration and PHMSA indicates hazardous material incidents are very infrequent (6e-3 incidents per rail mile per year). In addition, approximately 95 percent of releases are 1,000 gallons or less, and catastrophic events that would spill 30,000 gallons or more make up less than 1 percent of releases. In addition, less than 1 percent of hazardous material incidents result in injuries, and less than 0.1 percent of hazardous material incidents result in fatalities.

As previously discussed, the EPA and NOAA report that 80 percent of fires that lead to container ruptures results in projectiles and that 80 percent of projectiles from LPG incidents, which constitute the largest product involved in BLEVEs, travel less than 660 feet. The EPA also reports that on average container ruptures would result in less than four projectiles for cylindrical containers and 8.3 for spherical vessels. FERC staff evaluated other reports that affirmed the EPA estimates based on data for approximately 150 experimental and accidental PVBs and BLEVEs with approximately 683 total projectiles (4.6 average fragments per incident) that showed approximately 80 percent of fragments traveled 490 to 820 feet and within 6.25 times the estimated or observed fireball radius. The data also showed projectiles have traveled up to 3,900 feet for large LPG vessels and 1,200 feet for LPG rail cars. In all the documented cases, the projectiles traveled less than 15 times the fireball diameter, but one of the reports indicated up to 30 times the fireball diameter is possible, albeit very rare.

Unmitigated consequences under average ambient conditions from releases of 1,000 gallons through a 1-inch hole would result in much more modest distances ranging from 25 to 200 feet for flammable vapor dispersion, and 75 to 175 feet for jet fires. Unmitigated consequences under worst case weather conditions from catastrophic failures of rail cars containing various flammable products generally can range from 300 to 3,000 feet for flammable vapor dispersion; 450 to 575 feet for radiant heat of 5 kW/m^2 from jet fires; 1,225 to 1,500 feet to a 1-psi overpressure from a BLEVE; 1,250 to 2,100 feet for a heat dose equivalent to a radiant heat of 5 kW/m^2 over 40 seconds from 350- to 450-foot radii fireballs burning for 7 to 20 seconds from a BLEVE, and projectiles from BLEVEs possibly extending farther. Based on distribution function of the projectile distances, FERC staff estimate approximately 80 percent of all projectiles for a 30,000-gallon rail car would be within 0.5 mile, and that there is approximately a 5-percent probability they would extend beyond 1 mile and less than 0.1-percent probability they would extend 30 times the fireball diameter. These values are also close to the distances provided by PHMSA for emergency response (0.5 to 1 mile for initial evacuation and 1 mile for potential BLEVEs for flammable gases).

There would be no rail transportation associated with the Liquefaction Facilities and GTP. The closest rail line to the GTP site would be about 375 miles away, and the closest rail to the Liquefaction Facilities would be about 59 miles away. These distances would be farther than the consequence distances under unmitigated worst-case weather conditions and events. Given the distance from the rail lines and lack of rail associated with these facilities, we conclude the Project would not pose a significant risk or significant increase in risk to the public from proximity of the Project sites to the rail lines.

4.18.7.3 Air

FERC staff reviewed whether any aircraft operations would be associated with the Project and whether any existing aircraft operations would be near the GTP and Liquefaction Facilities. FERC staff uses this information to evaluate whether the Project and any associated aircraft operations could increase the risk to the public and whether any pre-existing unassociated aircraft operations could adversely increase the risk to the Project sites and subsequently increase the risk to the public. In addition, if authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. PHMSA regulations under 49 CFR 193.2155 (b), under Subpart C require that an LNG storage tank must not be within a horizontal distance of 1 mile from the ends, or one quarter mile from the nearest point of a runway, whichever is longer, and that the height of LNG structures in the vicinity of an airport must comply with FAA requirements. In addition, FERC staff evaluated the risk of an aircraft impact from nearby airports.

There would be no aircraft associated with the GTP and Liquefaction Facilities (e.g., helipads) that would warrant a review that would increase the risk to the public from aircraft operations. FERC staff identified one airport and four heliports within a 22-mile radius of the GTP site. The closest general aviation airport to the GTP site is Deadhorse Airport, which is about 8.9 miles southeast of the GTP site. This airport is farther than the quarter mile distance referenced in the PHMSA regulations, 49 CFR 193.2155(b).

There are a total of 25 airports and 3 heliports within a 22-mile radius of the Liquefaction Facilities. The closest general aviation airport to the Liquefaction Facilities, Johnson Airport, is approximately 2.3 miles south of the Liquefaction Facilities. The closest general aviation airport with an appreciable volume of air traffic is the Kenai Municipal Airport, about 7.4 miles southeast of the Liquefaction Facilities. These are all farther than the quarter mile distance referenced in the PHMSA regulations.

The FAA regulations in 14 CFR 77 require AGDC to provide a notice to the FAA of its proposed construction at the GTP and Liquefaction Facilities. This notification should identify all equipment that is more than 200 feet above ground level or lesser heights if the facilities are within 20,000 feet of an airport (at 100:1 ratio or 50:1 ratio depending on length of runway) or within 5,000 feet of a helipad (at 100:1 ratio). In addition, mobile objects, including the LNG marine vessel that would be above the height of the highest mobile object that would normally traverse it would require notification to the FAA. The FAA aeronautical study would identify which structures and mobile objects (e.g., LNG marine vessels) exceed obstruction standards and would indicate if the identified structures would be a hazard to air navigation. Based on this study, FAA would issue a determination for each structure and mobile object that exceeds the obstruction standards.

Both the Liquefaction Facilities and GTP would include equipment taller than 200 feet and would use construction cranes that could reach up to 473 feet. Therefore, the regulations in 14 CFR 77 apply to this equipment and require AGDC to provide notice to the FAA of its proposed construction. On November 20, 2017, AGDC submitted notice to the FAA for an aeronautical obstruction under 14 CFR 77 for the tallest structures within the GTP property boundaries. On April 19, 2018, the FAA issued a determination of no hazard to air navigation provided the structure is marked/lighted in accordance with the FAA circular *70/7460-1 L Change 1, Obstruction Marking and Lighting, red lights – Chapters 4,5 (Red), &12*. These determinations expired on October 19, 2019; however, the FAA granted an extension on October 23, 2019 with an expiration date of April 23, 2021.

On November 20, 2017, AGDC submitted notice to the FAA for an aeronautical obstruction under 14 CFR 77 for the tallest structures within the liquefaction property boundaries. On December 8, 2017, the FAA issued a determination of no hazard to air navigation provided the structure is marked/lighted in accordance with FAA circular *70/7460-1 L Change 1, Obstruction Marking and Lighting, a med-dual*

system – Chapters 4,8 (M-Dual)), &12. These determinations expired on June 8, 2019; however, the FAA granted an extension on June 10, 2019 with an expiration date of December 9, 2020.

AGDC would need FAA Determination letters for the temporary construction cranes that exceed a height of 200 feet and would be used at the GTP and Liquefaction Facilities in accordance with 14 CFR 77.9. Lastly, LNG marine vessels would not be above the height of the highest mobile objects (i.e., cruise ships) that also transverse the waterway and, therefore, would not require FAA notification.

In addition, FERC staff analyzed existing aircraft operation frequency data based on the airports identified above and their proximity to the LNG storage tank and process areas, the type and frequency of aircraft operations, take-off and landing directions, and the non-airport flight paths using the DOE Standard, DOE-STD-3014-2006, *Accident Analysis for Aircraft Crash into Hazardous Facilities*. DOE Standard 3014 uses a 22-mile radius from the hazardous facility as the threshold for consideration of hazards posed by airport and heliport operations. Per the DOE Standard 3014, heliports need only be considered if there are local overflights associated with facility operations and/or area operations; because AGDC does not have facility or area-associated helicopter flights, and does not have an on-site heliport, the impact risk due to heliport operations is considered insignificant for both the GTP and Liquefaction Facilities.

For the GTP site, neither the one airport—Deadhorse Airport—or the three heliports identified within the 22-mile radius, required an analysis because the location of the GTP site relative to the local airports fell out of distance criteria that allows for the DOE Standard 3014 crash location probability assignment.

For the Liquefaction Facilities, as discussed above, there are a total of 25 airports (a mixture of commercial airports, general aviation airports, and private airstrips) and three heliports within the 22-mile radius. Of the airports and heliports for the Liquefaction Facilities, a total of 11 airports fell within the analysis criteria for consideration; that is, these airports fell within a 22-mile radius of the proposed sites, had documented air traffic, and were in locations that fell within distance criteria that allows for the DOE Standard 3014 crash location probability assignments. The total aircraft crash probabilities at the Liquefaction Facilities were calculated to be 1.47E-05 for the liquefaction area and 3.14E-06 for an LNG storage tank. Because these crash probabilities are 3E-05 or lower, the risk was found to be insignificant.

Based upon PHMSA requirements, FAA determinations, and our review, we conclude the Project would not pose a significant risk or significant increase in risk to the public due to nearby aircraft operations as a result of the potential consequences, incident data, and distance and position of the closest aircraft operations relative to the populated areas near the GTP and Liquefaction Facilities.

4.18.7.4 Pipelines

FERC staff reviewed whether any pipeline operations would be associated with the Project and whether any existing pipelines would be near the Liquefaction Facilities and GTP sites. FERC staff uses this information to evaluate whether the Project and any associated pipeline operations could increase the risk to the pipeline facilities and subsequently to the public, and whether any pre-existing unassociated pipeline operations could adversely increase the risk to the Project sites and subsequently increase the risk to the public. In addition, pipelines associated with this Project must meet the PHMSA regulations under 49 CFR 192 and are discussed in section 4.18.9. If authorized, constructed, and operated, LNG facilities, as defined in 49 CFR 193, must comply with the requirements of 49 CFR 192 and 49 CFR 193 and would be subject to PHMSA's inspection and enforcement programs. FERC staff evaluated the risk of a pipeline incident affecting the Project sites and the potential of cascading damage increasing the risk to the public

based on the consequences from a release, incident data from PHMSA, and proposed mitigation to prevent or reduce the impacts of a pipeline incident from the Project.

GTP

For existing pipelines near the GTP, FERC staff identified an existing 10-inch-diameter natural gas liquids pipeline operated by BP about 0.8 mile east of the GTP site and a 10-inch-diameter natural gas pipeline operated by Hilcorp about 0.5 mile southwest of the GTP site that is currently not in service. We evaluated the potential risk from an incident from these pipelines and its' potential impacts by considering the design and operating conditions and locations of the pipelines. FERC staff determined that these nearby pipelines would not pose a significant risk or increase in risk to the public. We recommended in the draft EIS that AGDC file an analysis on the external impact of the 10-inch-diameter natural gas liquids pipeline to verify the preliminary evaluation performed by FERC staff. AGDC filed a response to this recommendation on September 18, 2019 that determined the 10-inch-diameter natural gas liquids pipeline would not cause an adverse impact on the reliability or safety of the GTP or increase the risk to the public.

FERC staff also noted that the new emergency egress road discussed in the Road section would cross new aboveground pipelines associated with the GTP. In response to an information request filed on March 1, 2019, AGDC indicated that the road crossing would be constructed with a granular fill embankment over the pipelines. Each pipeline would be cased and cradled on a framed support structure, which would be designed to support the granular fill load. AGDC also stated that live load and soil loading conditions on the pipe casing would be evaluated during detailed design. Therefore, FERC staff recommend in section 4.18.9 that AGDC provide an analysis of traffic loads anticipated along temporary and permanent road crossings to determine whether provisions are needed to dissipate the loads on the aboveground pipelines. AGDC has agreed to provide information in accordance with the timing of the recommendation.

Liquefaction Facilities

For existing pipelines near the Liquefaction Facilities, FERC staff identified an existing 16-inch-diameter natural gas pipeline owned by Agrium about 0.75 miles northwest of the proposed Liquefaction Facilities site and a 20-inch-diameter natural gas pipeline owned by Hilcorp Kenai Nikiski Pipeline that runs parallel to the existing KSH and would bisect the Liquefaction Facilities. AGDC indicated that the existing segment of the 20-inch-diameter natural gas pipeline in the proposed Liquefaction Facilities site would be relocated parallel to Miller Loop Road and then would turn south to run parallel to the eastern boundary just within the Liquefaction Facilities fence line. The re-routed pipeline would then turn southwest from the fence at the southeast corner of the Liquefaction Facilities, rejoin the existing 20-inch-diameter pipeline south of the Liquefaction Facilities, and continue to run parallel along the existing KSH. Based on this information, FERC staff evaluated the potential risk from an incident from these pipelines and its' potential impacts by considering the design and operating conditions and locations of the pipelines. Given the proximity of the 16-inch-diameter natural gas pipeline to the proposed Liquefaction Facilities site, we conclude the Liquefaction Facilities would not pose a significant risk or increase in risk to the public. For the relocated 20-inch-diameter natural gas pipeline, including the portion that would be within the property boundary, FERC staff found the risk for cascading damages to process vessels and structural supports to be insignificant. However, FERC staff determined there would be a potential significant impact on the control building in the event an explosion and subsequent fire were to occur at this pipeline. Therefore, we recommend in section 4.18.9 that AGDC file with the secretary an ERP that details processes and procedures that would be in place to ensure the plant would be placed in a safe shut down prior to an evacuation of personnel from the central control building.

FERC staff also identified one new road crossing as a result of relocating the 20-inch-diameter natural gas pipeline. The road crossing would be at Miller Loop Road north of the Liquefaction Facilities property boundary. AGDC indicated that the new crossing would be validated for thickness in accordance with API 1102, *Steel Pipelines Crossing Railroads and Highways*. Therefore, FERC staff recommend in section 4.18.9 that AGDC provide an analysis including calculations demonstrating the loads on buried pipelines and utilities at temporary and permanent crossings would be adequately distributed. The analysis should be based on API RP 1102 or other approved methodology. AGDC has agreed to provide information in accordance with the timing of the recommendation.

4.18.7.5 Hazardous Material Facilities and Power Plants

FERC staff reviewed whether any EPA Risk Management Plan regulated facilities handling hazardous materials and power plants were near the proposed GTP and Liquefaction Facilities sites to evaluate whether the facilities could adversely increase the risk to the Project sites, and whether the Project sites could increase the risk to the EPA Risk Management Plan facilities and power plants and subsequently increase the risk to the public.

GTP

The GTP would be in an industrial area adjacent to several chemical and petroleum storage facilities. The closest facilities to the GTP site handling hazardous materials would be the adjacent PBU's CGF about 0.5 miles to the east, and the Lisburne Production Center about 3.5 miles to the southeast. In addition, the closest nuclear power plant is the Bilibino Nuclear Station in Russia about 1,000 miles away. The CGF and Lisburne facilities are existing and regulated under EPA Risk Management Plan regulations. FERC staff evaluated the EPA Risk Management Plan worst case distances and in certain cases could affect the GTP.

If an incident were to occur at the CGF or GTP, AGDC indicated that there would be notifications between the GTP and CGF in the form of alarms as well as emergency response procedures that would address how to respond to the alarms. These procedures would be further developed prior to construction. Therefore, we recommend in section 4.18.9 that AGDC file finalized emergency response procedures—including coordination with federal, state, and local agencies and neighboring facilities such as the CGF—that includes processes and procedures to be used in the event of an incident at the GTP or neighboring facility.

Given the distances and locations of the facilities relative to the low populated areas of the North Slope area and recommendation to coordinate ERPs, we conclude the GTP would not pose a significant increase in risk to the public or that the hazardous material facilities and nuclear power plant would not pose a significant risk to the Project and subsequently to the public.

Liquefaction Facilities

The Liquefaction Facilities would be along the coastline of Nikiski along with other industrial facilities. The closest facilities to the Liquefaction Facilities handling hazardous materials would be the Agrium Kenai Nitrogen Operations and Fertilizer Plant about 1 mile away and the Marathon Kenai Refinery & Cogeneration Plant about 1.3 miles away. The closest power plants would be the Nikiski Combined Cycle Plant about 1 mile away and the Bernice Lake Combustion Turbine Plant about 2 miles away. FERC staff evaluated the EPA Risk Management Plan worst case distances and found that none would affect the Liquefaction Facilities site. In addition, the closest nuclear power plant would be Bilibino Nuclear Station in Russia about 1,300 miles away. AGDC indicated that an ERP would be developed prior to operation that would include emergency response coordination and notification with these nearby facilities.

Therefore, FERC staff recommend in section 4.18.9 that AGDC develop an ERP, prior to initial site preparation, in coordination with federal, state, and local agencies and nearby facilities that includes processes and procedures to be used in the event of an incident at the Liquefaction Facilities or neighboring facility.

Given the distances and locations of the facilities relative to the populated areas of the Kenai Peninsula, we conclude that the Liquefaction Facilities would not pose a significant increase in risk to the public or that the hazardous material facilities and nuclear power plant would not pose a significant risk to the Project and subsequently to the public.

4.18.8 On-Site and Off-Site Emergency Response Plans

As part of its application, AGDC indicated that the Project would develop a comprehensive ERP with local, state, and federal agencies and emergency response officials to discuss the facilities. AGDC would continue these collaborative efforts during Project development, design, and construction. The emergency procedures would provide for the protection of personnel and the public as well as the prevention of property damage that could occur as a result of incidents at the Project facilities. The facility would also provide appropriate personnel protective equipment to enable operational personnel and first responder access to the area.

As required by 49 CFR 193.2509 under Subpart F, AGDC would need to prepare emergency procedures manuals that provide for a) responding to controllable emergencies and recognizing an uncontrollable emergency; b) taking action to minimize harm to the public including the possible need to evacuate the public; and c) coordination and cooperation with appropriate local officials. Specifically, 49 CFR 193.2509(b)(3) requires "Coordinating with appropriate local officials in preparation of an emergency evacuation plan…," which sets forth the steps required to protect the public in the event of an emergency, including catastrophic failure of an LNG storage tank. PHMSA regulations under 49 CFR 193.2905 under Subpart J also require at least two access points in each protective enclosure to be located to minimize the escape distance in the event of emergency.

Title 33 CFR 127.307 also requires the development of emergency manual that incorporates additional material, including LNG release response and ESD procedures; a description of fire equipment, emergency lighting, and power systems; telephone contacts; shelters; and first aid procedures. In addition, 33 CFR 127.207 establishes requirements for warning alarm systems. Specifically, 33 CFR 127.207 (a) requires that the LNG marine transfer area to be equipped with a rotating or flashing amber light with a minimum effective flash intensity, in the horizontal plane, of 5000 candelas with at least 50 percent of the required effective flash intensity in all directions from 1.0 degree above to 1.0 degree below the horizontal plane. Furthermore, 33 CFR 127.207 (b) requires the marine transfer area for LNG to have a siren with a minimum one-third octave band sound pressure level at l meter of 125 dB referenced to 0.0002 microbars. The siren must be located so that the sound signal produced is audible over 360 degrees in a horizontal plane. Lastly, 33 CFR 127.207 (c) requires that each light and siren must be located so that the warning alarm is not obstructed for a distance of 1.6 km (1 mile) in all directions. The warning alarms would be required to be tested in order to meet 33 CFR 127. AGDC would be required to meet the warning alarms requirements specified in 33 CFR 127.207.

In accordance with the EPAct 2005, FERC must also approve an ERP covering the terminal and ship transit prior to construction. Section 3A (e) of the NGA, added by Section 311 of the EPAct 2005, stipulates that in any order authorizing an LNG terminal, the Commission must require the LNG terminal operator to develop an ERP in consultation with the Coast Guard and state and local agencies. The final ERP would need to be evaluated by appropriate emergency response personnel and officials. Section 3A (e) of the NGA (as amended by EPAct 2005) specifies that the ERP must include a Cost-Sharing Plan that contains a description of any direct cost reimbursements the applicant agrees to provide to any state and

local agencies with responsibility for security and safety at the LNG terminal and in proximity to LNG marine vessels that serve the facility. The Cost-Sharing Plan must specify what the LNG terminal operator would provide to cover the cost of the state and local resources required to manage the security of the LNG terminal and LNG marine vessel, and the state and local resources required for safety and emergency management, including:

- direct reimbursement for any per-transit security and/or emergency management costs (for example, overtime for police or fire department personnel);
- capital costs associated with security/emergency management equipment and personnel base (for example, patrol boats and firefighting equipment); and
- annual costs for providing specialized training for local fire departments, mutual aid departments, and emergency response personnel; and for conducting exercises.

The cost-sharing plan must include the LNG terminal operator's letter of commitment with agency acknowledgement for each state and local agency designated to receive resources.

As stated above, AGDC would develop a combined ERP that would include the GTP, Liquefaction Facilities, and the Mainline Facilities. Within this combined ERP would be individual ERPs that would meet regulatory requirements and address site-specific hazards and scenarios associated with the Project. We recommend in section 4.18.9 that AGDC provide additional information, for review and approval, on development of the ERPs prior to initial site preparation. We also recommend in section 4.18.9 that AGDC file three dimensional drawings, for review and approval, that demonstrate there is a sufficient number of access and egress locations. If this Project is authorized, constructed, and operated, AGDC would coordinate with local, state, and federal agencies on the development of an ERP and cost sharing plan. We recommend in section 4.18.9 that AGDC provide periodic updates on the development of these plans for review and approval, and ensure they are in place prior to introduction of hazardous fluids. In addition, we recommend in section 4.18.9 that Project facilities be subject to regular inspections throughout the life of the facility and would continue to require companies to file updates to the ERP. Additionally, FERC requested an ERP considering the coordination with the nearby PBU CGF; AGDC indicated that Standard Operation Procedures and ERP would be developed in the final design stage. Therefore, we recommend in section 4.18.9 that AGDC provide ERP with adequate coordination with the neighboring facilities. AGDC has agreed to provide information in accordance with the timing of these recommendations.

4.18.9 Recommendations from FERC Preliminary Engineering and Technical Review

Based on FERC staff's preliminary engineering and technical review of the reliability and safety of the Project, we recommend the following mitigation measures to the Commission to incorporate as conditions to an order. These recommendations would apply to both the GTP and Liquefaction Facilities unless otherwise noted and would be implemented prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility to enhance the reliability and safety of the facility and to mitigate the risk of impact on the public.

- **<u>Prior to construction of final design</u>, AGDC should file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska:**
  - **a. site preparation drawings and specifications for the Liquefaction Facilities and GTP;**

b. a list of the foundation systems to be used for each structure;

c. all Liquefaction Facilities and GTP structures and foundation design drawings as well as associated calculations, including prefabricated and field constructed structures;

d. seismic specifications for procured equipment for the Liquefaction Facilities and GTP; and

e. quality control procedures to be used for civil/structural design and construction.

In addition, AGDC should file, in its Implementation Plan, the schedule for producing this information.

- **Prior to construction of final design, AGDC should file with the Secretary a monitoring and maintenance plan, stamped and sealed by the professional engineer-of-record registered in Alaska, that ensures the grade of the GTP site would be maintained to prevent flooding throughout the life of the facility considering settlement, subsidence, thermocycling, and sea level rise.**

- **Prior to construction of final design, AGDC should file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska, related to the LNG storage tank and foundation detailed design documents, including but not limited to:**

  a. LNG storage tank base concrete slabs calculations and drawings;

  b. LNG storage tank seismic isolator concrete pedestal calculations and drawings; and

  c. LNG storage tank foundation concrete slabs calculations and drawings.

  AGDC should request written authorization from the Director of the OEP before proceeding with construction of final design and until the Director of the OEP, or designee, provides a notice to proceed.

- **Prior to construction of final design, AGDC should file with the Secretary documentation that confirms the various tidal levels at the PLF do not exceed transfer arm safe operating envelopes or otherwise demonstrate provisions would be in place to prevent disconnection from the transfer arms during loading operations.**

- **Prior to construction of final design, AGDC should file with the Secretary an analysis stamped and sealed by a professional engineer in the State of Alaska that demonstrates the PLF can withstand the impact from sea ice that historically occurs at the Nikiski site location and that the PLF structural load conditions consider sea ice and ice buildup. The basis of design for the loads induced by sea ice should be filed with the Secretary for the review and written approval by the Director of the OEP, or the Director's designee.**

The following recommendations should apply to both the GTP and Liquefaction Facilities, unless otherwise specified. Information pertaining to these specific recommendations should be filed

with the Secretary, for review and written approval by the Director of the OEP, or the Director's designee, within the timeframe indicated by each recommendation. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, should be submitted as critical energy infrastructure information pursuant to 18 CFR 388.113. See Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016). Information pertaining to items such as off-site emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements would be subject to public disclosure. All information should be filed a minimum of 30 days before approval to proceed is requested.

- **Prior to initial site preparation, AGDC should file an overall Project schedule, which includes the proposed stages of the commissioning plan.**

- **Prior to initial site preparation, AGDC should file procedures for controlling access during construction.**

- **Prior to initial site preparation, AGDC should file quality assurance and quality control procedures for construction activities.**

- **Prior to initial site preparation, AGDC should file a site-specific geotechnical investigation to ensure proper foundation design of the GTP. The geotechnical investigation should include a location plan that demonstrates the soil conditions are suitable or could be made suitable for all major foundations and evaluate local geological conditions under the proposed foundations, including the susceptibility to frost heave, thermokarsting, subsidence, load-bearing settlement, and concrete material degradation that are projected to occur over the life of the facilities. Also, the soil PH, chloride ion concentration, sulfate ion concentration, and electrical resistivity testing should be taken into account as part of the site- specific geotechnical investigation. In addition, the geotechnical investigation must demonstrate that the local conditions and those contained in the ASAP report supporting its foundation recommendations are sufficiently analogous.**

- **Prior to construction of final design, AGDC should file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan prior to commencement of construction.**

- **Prior to initial site preparation, AGDC should file a response plan for a significant snow event, or provide calculations that prove the current support structures and equipment would be able to support snow loads.**

- **Prior to initial site preparation, AGDC should file the updated freeboard height and sloshing wave height design calculation comply with code requirements, including but not limited to ASCE 7-05, API 620, API 625, API 650, ACI 350 and ACI 376.**

- **Prior to initial site preparation, AGDC should file the updated reserve capacity test report to determine the vertical load, shear load, and uplift displacement capacities of the triple pendulum seismic isolator type bearing. The test report should include an analysis for maximum and minimum design liquid levels of the LNG tanks, and the displacement during the empty tank condition. In addition, a separate analysis for variations of design stiffness, minimum values of friction and other properties as required by Section 17.2 and 17.5 of ASCE 7-05 should be performed.**

- **Prior to initial site preparation, AGDC should file its design wind speed criteria for all GTP facilities to be designed to withstand wind speeds commensurate with the risk and reliability in accordance with ASCE 7-16 or equivalent.**

- **Prior to initial site preparation, AGDC should file calculations demonstrating the loads on buried pipelines and utilities at temporary crossings would be adequately distributed. The analysis should be based on API RP 1102 or other approved methodology.**

- **Prior to initial site preparation, AGDC should develop an ERP (including evacuation) and coordinate procedures, as applicable, with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan should include at a minimum:**

  a. designated contacts with state and local emergency response agencies;

  b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

  c. procedures for notifying residents and recreational users within areas of potential hazard;

  d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

  e. locations of permanent sirens and other warning devices; and

  f. an "emergency coordinator" on each LNG marine vessel to activate sirens and other warning devices.

  AGDC should notify FERC staff of all planning meetings in advance and should report progress on the development of its ERP at 3-month intervals.

- **Prior to initial site preparation, AGDC should file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. This comprehensive plan should include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. AGDC should notify FERC staff of all planning meetings in advance and should report progress on the development of its Cost Sharing Plan at 3-month intervals.**

- **Prior to initial site preparation, AGDC should provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure CO_2/H_2S and natural gas pipe systems at the GTP, and provide revised modeling to account for any changes made to the assumptions. The results of this modeling should be used to inform the ERPs.**

- **Prior to initial site preparation, AGDC should demonstrate that ERPs include processes and procedures that ensure the plant would be placed in a safe shut down prior to an evacuation of staff from the central control building in the event of a pipeline incident, including an incident originating from the relocated Hilcorp pipeline, which could affect the Liquefaction Facilities' central control building.**

- **Prior to initial site preparation, AGDC should demonstrate that ERPs for potential large pipeline ruptures at the GTP have been coordinated with the adjacent PBU CGF plant and include consideration of impacts on the GTP operator camp site.**

- **Prior to construction of final design, AGDC should file lighting drawings. The lighting drawings should show the location, elevation, type of light fixture, and lux levels of the lighting system and should illustrate adequate coverage, in accordance with federal regulations (e.g., 49 CFR 193, 33 CFR 127, 33 CFR 105, 29 CFR 1910, 29 CFR 1915, and 29 CFR 1926) and API 540 or equivalent, of the perimeter of the facility and along paths/roads of access and egress.**

- **Prior to construction of final design, AGDC should file security camera and intrusion detection drawings. The security camera drawings should show the locations, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, and mounting height) to verify coverage of the entire perimeter with redundancies and cameras interior to the facility to enable rapid and reliable monitoring of the facility. The intrusion detection drawings should show or note the location of the intrusion detection to verify coverage of the entire perimeter of the facility.**

- **Prior to construction of final design, AGDC should file drawings of the security fence at the Liquefaction Facilities. The fencing drawings should provide details of fencing (e.g., dimensions and gauge of fence meshes, posts, and barbed or razor wire) that demonstrates it would restrict and deter access around the entire facility and has a 10-foot clearance from exterior features (e.g., power lines and trees) and from interior features (e.g., piping, equipment, and buildings).**

- **Prior to construction of final design, AGDC should file specifications, drawings, and details of crash rated vehicle barriers at each facility entrance for access control that can mitigate accidental and intentional vehicle impacts.**

- **Prior to construction of final design, AGDC should file change logs that list and explain any changes made from the front end engineering design provided in AGDC's application and filings. A list of all changes with an explanation for the design alteration should be provided and all changes should be clearly indicated on all diagrams and drawings.**

- **Prior to construction of final design, AGDC should file information/revisions pertaining to its responses to numbers 55, 58, 70, 71, 73, and 75 of the July 7, 2017 information request; responses to numbers 8, 14, 16, 19, and 21 of the December 26, 2018 information request; responses to number 2 and 5 of the December 26, 2018 (non-public enclosure); responses to numbers 3, 11, 17, 18, 21, 22, and 23 of the January 15, 2019 information request; and responses to numbers 4, 5, 14–17, 20–22, 24, 27, 29, 32–34, 42, 46, and 57 of the September 17, 2019 information request, which indicated features to be included or considered in the final design of the GTP.**

- **Prior to construction of final design, AGDC should file information/revisions pertaining to its responses to numbers 2, 3, 5, 7, 8, 11, 24, 28, 29, 31, 34, 38, 46, 47, and 51 of the July 7, 2017 information request; responses to numbers 32, 34, 35, 37, 41, 42, 46, 54–61, 66, 69–72, 74, and 75 of the December 26, 2018 information request; responses to numbers 8, 9, 10, and 13–15 of the December 26, 2018 information request (non-public enclosure); responses to numbers 56, 60, 66, 70–73, 75–81, and 83 of the January 15, 2019 information request; responses to numbers 63, 71, 74, 93b, and 97 of the September 17, 2019 information request; and responses to numbers 3 and 9 of the November 22, 2019 information request, which indicated features to be included or considered in the final design of the Liquefaction Facilities.**

- **Prior to construction of final design, AGDC should file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems.**

- **Prior to construction of final design, AGDC should file documentation that demonstrates the multi-use truck unloading/loading facilities at the GTP and Liquefaction Facilities incorporates safety design features including but not limited to process control and monitoring instrumentation including alarm and automatic shutdown capabilities; configuration of transfer valves, equipment, and hazard mitigation equipment to be activated remotely; unique hose couplings and fill line connections for each type of hazardous fluid; and pipe marking and identification of transfer equipment.**

- **Prior to construction of final design, AGDC should file the updated LNG tank design that incorporates AGDC's proposed top and bottom filling capabilities in order to mitigate LNG tank stratification and rollover. Also, AGDC should file procedures to mitigate stratification and potential rollover based on differences in transferring or loading LNG with different compositions and the time it takes to detect stratification and induce sufficient mixing of the LNG storage tank contents based on the flow rate and storage volume compared to the time it takes for the detected stratification to develop into a potential rollover condition.**

- **Prior to construction of final design, AGDC should file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion.**

- **Prior to construction of final design, AGDC should file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications should include:**

  a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, and blast resistant buildings);

  b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, and other specialized equipment);

  c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable, and other electrical and instrumentation); and

  d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, and firewater).

- **<u>Prior to construction of final design</u>, AGDC should file a summary of all applicable codes and standards and the final specification document number(s) where they are referenced.**

- **<u>Prior to construction of final design</u>, AGDC should file a complete LNG storage tank specification and design drawings. The specification should define the battery limits (i.e., engineering design, structural design, supports, piping components, piping connections, electrical power, control, and utilities) of the LNG storage tank.**

- **<u>Prior to construction of final design</u>, AGDC should file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances.**

- **<u>Prior to construction of final design</u>, AGDC should file up-to-date process flow diagrams and P&IDs, including vendor P&IDs. The process flow diagrams should include heat and material balances. The P&IDs should include the following information:**

  a. equipment tag number, name, size, duty, capacity, and design conditions;

  b. equipment insulation type and thickness;

  c. storage tank pipe penetration size and nozzle schedule;

  d. valve high pressure side and internal and external vent locations;

  e. piping with line number, piping class specification, size, and insulation type and thickness;

  f. piping specification breaks and insulation limits;

  g. all control and manual valves numbered;

  h. relief valves with size and set points; and

  i. drawing revision number and date.

- **<u>Prior to construction of final design</u>, AGDC should file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities.**

- **<u>Prior to construction of final design</u>, AGDC should file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs.**

- **<u>Prior to construction of final design</u>, AGDC should file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions).**

- **<u>Prior to construction of final design</u>, AGDC should include a check valve or other means in the sour gas inlet piping to the AGRU absorber to prevent backflow into the inlet piping.**

- **Prior to construction of final design, AGDC should include LNG storage tank fill flow measurement with high flow alarm.**

- **Prior to construction of final design, AGDC should include BOG flow measurement from each LNG storage tank.**

- **Prior to construction of final design, AGDC should evaluate and demonstrate the design pressure of the Process Heat Medium Expansion Drum and associated relief valves is consistent with the heating medium circulation system.**

- **Prior to construction of final design, AGDC should include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control.**

- **Prior to construction of final design, AGDC should file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD system for review and written approval. The cause-and-effect matrices should include alarms and shutdown functions, details of the voting and shutdown logic, and set points.**

- **Prior to construction of final design, AGDC should specify that all ESD valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS)/SIS.**

- **Prior to construction of final design, AGDC should file an evaluation of ESD valve closure times. The evaluation should account for the time to detect an upset or hazardous condition, notify plant personnel, and close the ESD valve.**

- **Prior to construction of final design, AGDC should file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump startup and shutdown operations.**

- **Prior to construction of final design, AGDC should file a HAZOP review of the final design P&IDs, a list of the resulting recommendations, and action taken on the recommendations. The issued for construction P&IDs should incorporate the HAZOP recommendations and justification should be provided for any recommendations that are not implemented.**

- **Prior to construction of final design, AGDC should file specifications that demonstrate the materials of construction have MDMTs that can withstand the minimum expected temperature at the North Slope or that AGDC demonstrates that equipment and piping would be fully depressurized in the event the ambient temperature becomes less than the MDMT with sufficient reliability through SIS or through written procedures.**

- **Prior to construction of final design, AGDC should demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators.**

- **Prior to construction of final design, AGDC should file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks.**

- **<u>Prior to construction of final design</u>, AGDC should file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations should be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). This evaluation should include justification for blast resistant walls or buildings at the GTP. The justification for the flammable and combustible gas detection and flame and heat detection should be in accordance with ISA 84.00.07 or equivalent methodologies that would demonstrate 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de-inventory within 10 minutes or less for impoundments that are not sized for 10 minute releases and de-inventory. The analysis should revise the hazard detection coverage, including, but not limited to, the GTP's outside areas, or adequately demonstrate that failure to detect releases due to lack of hazard detection coverage would not result in direct or indirect offsite impacts, including projectiles from potential BLEVEs resulting from undetected fire events. The analysis should take into account the set points, voting logic, wind speeds, and wind directions. The justification for firewater should provide evaluation of the total area that may experience firewater demand due to each governing scenario; calculations for all firewater demands (including firewater coverage on the LNG storage tanks) based on design densities, surface area, and throw distance; and specifications for the corresponding hydrant and monitors needed to reach and cool equipment.**

- **<u>Prior to construction of final design</u>, AGDC should file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comer that would transfer spills from the tank top to the ground-level impoundment system. The spill containment drawings should show containment for all components that could contain hazardous liquids, including all liquids handled above their flashpoint and those with toxic or asphyxiant vapor hazards, from the largest flow from a single line for 10 minutes, including de-inventory and specifying a reliability equivalent to SIL 2 or higher for any pump interlock systems, or the maximum liquid from the largest vessel (or total of impounded vessels), or otherwise demonstrate that providing spill containment would not significantly reduce the vapor dispersion or radiant heat consequences of a spill, including for any tank top LNG releases up to a full guillotine that would not be captured to the tank area impoundment. Spill containment systems should be constructed of materials that can withstand the liquid hazards. In addition, the rainout calculations for a liquid nitrogen vessel failure should be provided with validation, or liquid nitrogen containment should be provided. Also, AGDC should provide details of collection for spills occurring at the onshore pipe-in-pipe ESD valve, over road crossings, details of hazardous liquid trenches crossing storm water trenches, containment for the condensate, slop oil, and diesel piping in the area near their storage tank impoundments at the Liquefaction Facilities; and details on whether the miscellaneous hydrocarbon fluid at the GTP site would be handled above its flash point, as well as confirming that the most significant hazardous compositions in knockout drums have been considered.**

- **Prior to construction of final design, AGDC should file an analysis and/or tests that demonstrate either the pipe-in-pipe system at the Liquefaction Facilities would maintain integrity and not initiate and propagate cracks when subjected to sudden cryogenic temperatures and forces from the full range of jetting release sizes, or alternatively, revise the spill containment design for this piping to include a conventional trough and impoundment system.**

- **Prior to construction of final design, AGDC should file with the Secretary the following for the final design of the pipe-in-pipe systems at the Liquefaction Facilities, including:**

  a. the detailed design and a plot plan layout of the pipe-in-pipe system, including identification of all conventional process lines extending from or attached to the pipe-in-pipe, as well as the locations of any reliefs, instrumentation or other connections along the inner or outer pipes;

  b. an assessment of the vapor production and vapor handling capacities within the annular space during a full inner pipe rupture or smaller release into the outer pipe;

  c. stress analysis for the pipe-in-pipe systems, including at bulkheads and including the differential stresses between the inner pipe and outer pipe for a full inner pipe rupture, or any smaller release, at any location along the system;

  d. leak testing details and pressures for the outer pipe;

  e. details of the maintenance procedures that would be followed over the life of the facility to determine that the outer pipe would be continuing to adequately serve as spill containment;

  f. plans for purging or draining LNG from the outer pipe; and

  g. details of any features that would protect against external common cause failures of the inner and outer pipes, including heavy equipment accidents.

- **Prior to construction of final design, AGDC should demonstrate that the design of the marine impoundment system would capture liquid rainout resulting from jetting releases up to a full guillotine rupture of a dock transfer line, which could cause impacts on dock or trestle supports, nearby public, berthed LNG marine vessels and tugs, or other cascading impacts.**

- **Prior to construction of final design, AGDC should provide details of how LNG spills at the dock would be fully contained in impoundment areas without resulting in cascading failures to structural supports, including how LNG would be collected on the trestle containment system without spreading over the dock surface and ensuring the structural supports would accommodate the liquid weight.**

- **Prior to construction of final design, AGDC should provide the following on the water, snow, and ice handling systems for impoundments:**

a. water removal pumps for locally-curbed hazardous liquid impoundments at the Liquefaction Facilities, such as those around knockout drums; and

b. details on how hardened snow would be assured to not inhibit the spill flow path (e.g., maintenance plans and/or details of snowmelt methods), including in spill collection areas and trenches leading to impoundments, and be assured to not reduce the volume of any part the impoundment system beyond the extra height allowed in the impoundment system specifically for snow accumulation.

- **<u>Prior to construction of final design</u>, AGDC should file detailed calculations to confirm that the final fire water volumes would be accounted for when evaluating the capacity of the impoundment system during a spill and fire scenario.**

- **<u>Prior to construction of final design</u>, AGDC should analyze the potential for the overpressures from vapor cloud ignition underneath the module platforms to cause movement of or damage to the platforms that could affect the high pressure equipment above them, such as the treated gas chillers and associated piping as well as CO_2/H_2S piping, and provide any measures needed to prevent significant cascading damage and safety impacts.**

- **<u>Prior to construction of final design</u>, AGDC should file details of the mitigation measures that would prevent flammable vapors from entering the semi-confined spaces underneath the LNG storage tanks, including details of the measures that would prevent temperatures in this space that could impair the functionality of the seismic isolators or cause frost heave.**

- **<u>Prior to construction of final design</u>, AGDC should file electrical area classification drawings including cross-sectional drawings. The drawings should demonstrate compliance with NFPA 59A, NFPA 70, NFPA 497, and API RP 500, or equivalents, In addition, the drawings should include revisions to the electrical area classification design or provide technical justification that supports the electrical area classification of the following areas using most applicable API RP 500 figures (e.g., figures 20 and 21) or hazard modeling of various release rates from equivalent hole sizes and wind speeds (see NFPA 497 release rate of 1 pound/minute) for the spill trench that would serve the portion of the LNG liquefaction rundown pipe rack located west of the air fin coolers, which would contain process piping, the spill containment systems for both marine berth areas, and the LNG marine transfer lines and marine trestle area.**

- **<u>Prior to construction of final design</u>, AGDC should file design details and specifications of the LERs located within the GTP's process modules including, but not limited to, the pressurization system, HVAC air intake system, and any openings such as personnel entry door(s), electrical cable entries, and air conditioning unit(s). The design details and specifications should demonstrate compliance with NFPA 59A, NFPA 70, NFPA 496, NFPA 497, and API RP 500, or equivalents.**

- **<u>Prior to construction of final design</u>, AGDC should file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001).**

- **<u>Prior to construction of final design</u>, AGDC should file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap should vent to a safe location and be equipped with a leak detection device that should continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems.**

- **<u>Prior to construction of final design</u>, AGDC should file a drawing showing the location of the ESD buttons. ESD buttons should be easily accessible, conspicuously labeled, and located in an area which would be accessible during an emergency.**

- **<u>Prior to construction of final design</u>, AGDC should file complete drawings and a list of the hazard detection equipment. The drawings should clearly show the location and elevation of all detection equipment. The list should include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment.**

- **<u>Prior to construction of final design</u>, AGDC should file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of the hazard detectors when determining the lower flammable limit set points for methane, propane, ethane, and condensate.**

- **<u>Prior to construction of final design</u>, AGDC should file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of hazard detectors when determining the set points for toxic components such as natural gas liquids and H_2S.**

- **<u>Prior to construction of final design</u>, AGDC should file a technical review of facility design that:**

  a. identifies all combustion/ventilation air intake equipment and the elevations and distances to any possible flammable gas or toxic release; and

  b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency.

- **<u>Prior to construction of final design</u>, AGDC should file analysis of the buildings containing hazardous fluids and the ventilation calculations that limit concentrations below the LFLs (e.g., 25-percent LFL), including an analysis of off gassing of hydrogen in battery rooms, and should also provide hydrogen detectors that alarm (e.g., 20- to 25-percent LFL) and initiate mitigative actions (e.g., 40- to 50percent LFL) in accordance with NFPA 59A and NFPA 70, or equivalents.**

- **<u>Prior to construction of final design</u>, AGDC should provide low oxygen detectors to notify operators of liquid nitrogen releases at the Liquefaction Facilities.**

- **Prior to construction of final design, AGDC should provide an evaluation of the normal module air changes within buildings at the GTP and reliability of the ventilation system to determine whether oxygen detectors are needed as an additional layer of protection to notify operators of a potential nitrogen release and ensure safe entry into a module/building. The evaluation should also address whether there would be alarms and notifications in the event ventilation equipment is not operating or functioning as designed.**

- **Prior to construction of final design, AGDC should file an evaluation of the voting logic and voting degradation for hazard detectors.**

- **Prior to construction of final design, AGDC should file facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Plan drawings should clearly show the location and elevation by tag number of all fixed dry chemical systems in accordance with NFPA 17, wheeled and handheld extinguishers location travel distances are along normal paths of access and egress in accordance with NFPA 10. The list should include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units.**

- **Prior to construction of final design, AGDC should file a design that includes clean agent systems in the instrumentation and electrical equipment buildings that serve safety and security systems.**

- **Prior to construction of final design, AGDC should file facility plan drawings showing the proposed location of the firewater and any foam systems. Plan drawings should clearly show the location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam system, water-mist system, and sprinkler. The drawings should also include piping and instrumentation diagrams of the firewater and foam systems. The firewater coverage drawings should illustrate firewater coverage by two or more hydrants or monitors accounting for obstructions (or deluge systems) for all areas that contain flammable or combustible fluids.**

- **Prior to construction of final design, AGDC should specify remotely operated or automatic firewater monitors at the Liquefaction Facilities in areas inaccessible or difficult to access in the event of an emergency.**

- **Prior to construction of final design, AGDC should demonstrate that the firewater tank would be in compliance with NFPA 22 or an equivalent or better level of safety.**

- **Prior to construction of final design, AGDC should include or demonstrate the firewater storage volume for its facilities has minimum reserved capacity for its most demanding firewater scenario plus 1,000 gpm for no less than 2 hours.**

- **Prior to construction of final design, AGDC should specify that firewater pump shelters are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane.**

- **<u>Prior to construction of final design</u>, due to the absence of firewater monitor coverage, AGDC should demonstrate that the potential for pool and jet fires to cause cascading hazards in any area of the GTP would be effectively mitigated by systems with a reliability equivalent to SIL 2 or higher.**

- **<u>Prior to construction of final design</u>, AGDC should file drawings and specifications for the passive protection systems at the GTP and Liquefaction Facilities to protect equipment and supports from cold temperature releases, including for liquids conveyed indoors during winter start-ups at design ambient temperatures at the GTP.**

- **<u>Prior to construction of final design</u>, AGDC should file calculations or test results for the structural passive protection systems at the GTP and Liquefaction Facilities to demonstrate that equipment and supports are protected from low temperature releases that are below the MDMT of equipment and supports.**

- **<u>Prior to construction of final design</u>, AGDC should file drawings and specifications for the structural passive protection systems at the GTP and Liquefaction Facilities to demonstrate the equipment and supports are protected from pool and jet fires, including that the fireproofing material would remain effective after potential exposure to the cold temperature of pooling, jetting, or splashing liquids.**

- **<u>Prior to construction of final design</u>, AGDC should file a detailed quantitative analysis to demonstrate that adequate mitigation would be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from a pool or jet fire; each critical structural component (including the LNG marine vessel and outer pipe of the pipe-in-pipe containment system) and emergency equipment item that could fail within the 4,900 BTU/ft^2-hr zone from a pool or jet fire; and each occupied building that could expose unprotected personnel within the 1,600 BTU/ft^2-hr zone from a pool or jet fire. Trucks at truck transfer stations should be included in the analysis of potential pressure vessel failures. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires should be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation should be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation should be supported by reliability information by calculations or test results, such as demonstrating that flow rates and durations of any cooling water would mitigate the heat absorbed by the component. The total firewater demand should account for all components that could fail due to a pool or jet fire.**

- **<u>Prior to construction of final design</u>, AGDC should provide an analysis demonstrating occupied buildings at the Liquefaction Facilities would be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC should file an analysis demonstrating the occupied buildings at the Liquefaction Facilities have been relocated or provided with passive and active measures that would prevent impacts.**

- **Prior to construction of final design, AGDC should file an analysis demonstrating safety related equipment (e.g., firewater pump buildings, control buildings, and emergency generators) at the Liquefaction Facilities would be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC should file an analysis demonstrating the safety related equipment at the Liquefaction Facilities have been relocated or provided with passive and active measures that would prevent impacts.**

- **Prior to construction of final design, AGDC should file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities would be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC should file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities have been relocated or provided with passive and active measures that would prevent impacts.**

- **Prior to construction of final design, AGDC should file specifications and drawings demonstrating how cascading damage of transformers would be prevented (e.g., firewalls or spacing) in accordance with NFPA 850 or equivalent.**

- **Prior to construction of final design, AGDC should file an evaluation of the final design of grated module platforms at the Liquefaction Facilities that demonstrates a vapor cloud explosion of significant magnitude would not develop from a design spill such that it results in cascading damage that could have impacts offsite.**

- **Prior to construction of final design, AGDC should file an analysis demonstrating the LNG storage tank outer walls can withstand the overpressures generated from ignition of vapor clouds from design spills in adjacent plant areas.**

- **Prior to construction of final design, AGDC should file a projectile analysis that demonstrates each LNG storage tank can withstand projectiles from explosions and high winds. The analysis should detail and justify the projectile speeds and characteristics and method used to determine penetration or perforation depths.**

- **Prior to construction of final design, AGDC should file drawings of internal road vehicle protections, such as guard rails, barriers, and bollards to protect all equipment containing hazardous fluids or that are safety related (e.g., hydrants and monitors) to ensure that they are located away from roadway or protected from inadvertent damage from vehicles.**

- **Prior to construction of final design, AGDC should file documentation demonstrating the Seismic Isolation system for the LNG tanks complies with the design, analysis, and testing requirements of Chapter 17 of ASCE 7-05, or equivalent. The Peer Review of the design should be performed as required by Chapter 17 of ASCE 7-05, or equivalent.**

- **<u>Prior to construction of final design</u>, AGDC should file an analysis of the structural integrity of the outer containment, tank foundation concrete slabs, tank base concrete slabs, and seismic isolator concrete pedestals, demonstrating they are designed to withstand all loads and combinations that comply with code requirements, including but not limited to ASCE 7-05, ACI 318, ACI 350, ACI 376, API 620, API 625 and API 650, or equivalents.**

- **<u>Prior to construction of final design</u>, AGDC should file the FEA modeling with the inputs and outputs reports for tanks design, base concrete slabs and foundation concrete slabs design, including details of splicing of precast concrete LNG tank panels, connections to be used between the outer LNG walls and the vapor barrier dome and demonstrate the results of the FEA modeling are within design limits.**

- **<u>Prior to construction of final design</u>, AGDC should file a detailed analysis and any associated drawings that demonstrate seismic sliding and overturning resistance of the LNG tank's inner tank would not result in failure of the tank.**

- **<u>Prior to construction of final design</u>, AGDC should file design calculations to confirm the combination of overturning moment and seismic vertical acceleration that induce any uplift and shear of the external wall can be handled with the seismic tendons in combination with shear key.**

- **<u>Prior to construction of final design</u>, AGDC should file the non-linear dynamic analysis (modal response-spectrum analysis, response-history analysis, linear time-history analysis, and nonlinear time-history analysis) for the LNG tank and isolation system that would simultaneously include the time history, vertical component of motion envelope, and the site-specific vertical design response spectra developed for the Project. The analysis should also account for horizontal components rotated so that one of the components for each set of motions is the maximum component of response at the isolated period of the tank. The Peer Review of the design should be performed as required by Chapter 17 of ASCE 7-05 or equivalent to demonstrate the LNG tank and isolation system is designed to withstand ground motion without loss of structural or functional integrity.**

- **<u>Prior to construction of final design</u>, AGDC should file design details of the seismic monitoring system for the proposed Project site location with specific peak ground motion data and include at least one free-field triaxial accelerometer at the site, as well as additional instruments on each tank and its foundation.**

- **<u>Prior to construction of final design</u>, AGDC should file a detailed analysis and any associated drawings of the omega joints detailed in to be used between the bottom LNG tank plate and the bottom of the outer tank wall to demonstrate the final tank design incorporates wall-to-base connections that is consistent with criteria specified in ACI 376 or equivalent.**

- **<u>Prior to construction of final design</u>, AGDC should file a detailed analysis and any associated drawings detailing the LNG tank secondary bottom design that demonstrates protection of the LNG tank slab and seismic isolators from any cryogenic temperatures it would be exposed to during a spill.**

- **<u>Prior to construction of final design</u>, AGDC should file the cryogenic protection plan for the LNG tanks foundation concrete slabs and triple pendulum seismic isolator concrete pedestal supports during spill condition.**

- **<u>Prior to construction of final design</u>, AGDC should file the design analysis to determine the precast panel outer wall behavior for operating and spill conditions and to ensure panel and joint leak tightness.**

- **<u>Prior to construction of final design</u>, AGDC should file a snow removal plan for critical equipment or provide calculations that prove that support structures and equipment adequately account for snow loads.**

- **<u>Prior to construction of final design</u>, AGDC should file an analysis indicating areas susceptible to falling ice and snow, and file drawings of structures and coverings that would protect people, piping, and equipment from falling snow and ice.**

- **<u>Prior to construction of final design</u>, AGDC should file calculations demonstrating the loads induced by vehicles, including cranes and other heavy equipment, associated with operations and maintenance of the Liquefaction and GTP Facilities that may exceed the design of buried pipelines and utilities (or encasements) at permanent crossings would be adequately distributed. The analysis should be based on API RP 1102 or other approved methodology.**

- **<u>Prior to commissioning</u>, AGDC should file a detailed schedule for commissioning through equipment startup. The schedule should include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. AGDC should file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued.**

- **<u>Prior to commissioning</u>, AGDC should file detailed plans and procedures for: testing the integrity of on-site mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service.**

- **<u>Prior to commissioning</u>, AGDC should file the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3. The procedures should include a line list of pneumatic and hydrostatic test pressures.**

- **<u>Prior to commissioning</u>, AGDC should file a plan for clean-out, dry-out, purging, and tightness testing. This plan should address the requirements of the American Gas Association's Purging Principles and Practice, and should provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing.**

- **<u>Prior to commissioning</u>, AGDC should file the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, simultaneous operational procedures, and management of change procedures and forms. In addition, AGDC should include an LNG storage tank stratification monitoring, prevention, and correction procedure to be included as part of the facility's operation and maintenance procedures.**

- **Prior to commissioning, AGDC should file truck transfer procedures that require facility personnel to verify, through written checklists, ignition sources are eliminated (e.g., no smoking, ground wire, and engine shutoff) within at least 50 feet prior to transfer operations; transfer connections are marked or labeled and match truck contents prior to transfer operations; and truck transfer operations are constantly attended or visually monitored to physically or remotely shut down truck transfer operations. In addition, the procedures should include recognition of abnormalities and use of emergency shutoff mechanisms. Operators should be trained on these procedures and requirements.**

- **Prior to commissioning, AGDC should tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves.**

- **Prior to commissioning, AGDC should file a plan to maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff has completed the required training. In addition, AGDC should file signed documentation that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation.**

- **Prior to commissioning, AGDC should equip the LNG storage tanks and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and record the relative settlement between the LNG storage tank and adjacent piping. The settlement record should be reported in the semi-annual operational reports.**

- **Prior to commissioning, AGDC should file settlement results from hydrostatic tests of the LNG storage containers and should file a plan to periodically verify settlements are as expected and do not exceed applicable criteria in API 620, API 625, API 653, and ACI 376, or equivalents.**

- **Prior to introduction of hazardous fluids, AGDC should complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS/SIS that demonstrates full functionality and operability of the system.**

- **Prior to introduction of hazardous fluids, AGDC should develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms.**

- **Prior to introduction of hazardous fluids, AGDC should complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant should be shown on facility plot plan(s).**

- **Prior to introduction of hazardous fluids, AGDC should complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review should include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, should be filed.**

- **Prior to introduction of hazardous fluids, AGDC should file finalized ERP(s), including coordination with federal, state, and local agencies and neighboring facilities, such as the PBU CGF and other facilities handling hazardous materials, and should include processes and procedures to be used in the event of an incident at the GTP, Liquefaction Facilities, and neighboring facilities.**

- **AGDC should file a request for written authorization from the Director of the OEP prior to unloading or loading the first LNG commissioning cargo. After production of first LNG, AGDC should file weekly reports on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports should include a summary of activities, problems encountered, and remedial actions taken. The weekly reports should also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports should include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude should be reported to FERC within 24 hours.**

- **Prior to commencement of service, AGDC should notify FERC staff of any proposed revisions to the security plan and physical security of the plant.**

- **Prior to commencement of service, AGDC should label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001).**

- **Prior to commencement of service, AGDC should provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring.**

- **Prior to commencement of service, AGDC should develop procedures for handling off-site contractors including responsibilities, restrictions, and limitations and for supervision of these contractors by AGDC staff.**

- **Prior to commencement of service, AGDC should file a request for written authorization from the Director of the OEP. Such authorization would only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA of 2002, and the Security and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by AGDC or other appropriate parties.**

In addition, the following measures should apply throughout the life of the Liquefaction Facilities and GTP, unless otherwise specified.

- **The facility should be subject to regular FERC staff technical reviews and site inspections on at least an annual basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, AGDC should respond to a specific information request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, should be submitted.**

- **Semi-annual operational reports should be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities should include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from off-site vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also should be reported. Reports should be submitted within 45 days after each period ending June 30 and December 31. In addition to the above items, a section entitled *Significant Plant Modifications Proposed for the Next 12 Months (dates)* should be included in the semi-annual operational reports. Such information would provide FERC staff with early notice of anticipated future construction/maintenance at the LNG and GTP facilities.**

- **In the event the temperature of any region of the LNG storage container, including any secondary containment and imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission should be notified within 24 hours and procedures for corrective action should be specified.**

- **Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site and suspicious activities) should be reported to FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification should be made immediately, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification should be made to FERC staff within 24 hours. This**

notification practice should be incorporated into the LNG Plant's emergency plan. Examples of reportable hazardous fluids-related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of hazardous fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of a facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of a facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in a facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20-percent reduction in operating pressure or shutdown of operation of a pipeline or a facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the GTP or Liquefaction Facilities; or

m. an event that is significant in the judgment of the operator and/or management even though it does not meet the above criteria or the guidelines set forth in an LNG terminal's incident management plan.

In the event of an incident, the Director of the OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG Plant to cease operations. Following the initial company notification, FERC staff would determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports should include

investigation results and recommendations to minimize a reoccurrence of the incident.

4.18.10 Pipeline Facilities

The transportation of natural gas by pipeline involves some incremental risk to the public due to a potential for an accidental release of natural gas. In the unlikely event of a leak, natural gas, which is lighter than air, should dissipate into the atmosphere. However, a spark or ignition at the point of the release could result in a fire following a pipeline rupture. Those risks are mitigated by pipeline design and safety regulations mandated by PHMSA and measures that would be implemented by AGDC as part of its ERPs.

Methane, the primary component of natural gas, is colorless, odorless, and tasteless. It is nontoxic, but is classified as a simple asphyxiant, possessing a slight inhalation hazard. If breathed in high concentrations, oxygen deficiency can result in serious injury or death. Methane has an auto-ignition temperature of about 1,000°F and a flash point of about -306°F. It is flammable at concentrations between 5 and 15 percent in air. Unconfined mixtures of methane can ignite but are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. Methane is buoyant at atmospheric temperatures and disperses rapidly in air, reducing the potential for ignition.

4.18.10.1 Pipeline Safety Standards

PHMSA regulates and enforces a regulatory program to provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities under 49 USC 601. PHMSA's OPS administers the national regulatory program to ensure the safe transportation of natural gas and other hazardous materials by pipeline. It develops safety regulations and other approaches to risk management that ensure safety in the design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the required safety standards. The PHMSA pipeline standards are published in 49 CFR 190−199. Part 192 specifically addresses the minimum federal safety standards for transportation of natural gas by pipeline.

PHMSA's mission is to protect people and the environment from the risks of pipeline incidents. PHMSA works closely with state pipeline safety programs and others at the federal, state, and local level. PHMSA provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing, at a minimum, the federal standards. A state may also act as PHMSA's agent to inspect interstate facilities within its boundaries; however, PHMSA is responsible for any enforcement action. Currently, Alaska does not have a state program, so PHMSA has full regulatory oversight over both interstate and intrastate pipelines in Alaska.

Under a *Memorandum of Understanding on Natural Gas Transportation Facilities* (Natural Gas Memorandum) dated January 15, 1993, between PHMSA and FERC, PHMSA has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of FERC's regulations require that an applicant certify that it will design, install, inspect, test, construct, operate, replace, and maintain the facility for which authorization is requested in accordance with federal safety standards and plans for maintenance and inspection. PHMSA may certify that an applicant has been granted a waiver of the requirements of the safety standards by PHMSA in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act. FERC accepts this certification and does not impose additional safety standards other than the PHMSA standards. If the Commission becomes aware of an existing or potential safety problem, there is a provision in the Natural Gas Memorandum to promptly alert PHMSA. The Natural Gas Memorandum also provides for referring complaints and inquiries

made by state and local governments and the general public involving safety matters related to pipelines under the Commission's jurisdiction.

Section 5(a) of the Natural Gas Pipeline Safety Act provides for a state agency to assume all aspects of the safety program for intrastate facilities by adopting and enforcing the federal standards, while Section 5(b) permits a state agency that does not qualify under Section 5(a) to perform certain inspection and monitoring functions. Alaska has not been delegated authority to inspect its intrastate pipeline facilities.

The Mainline Pipeline, PTTL, PBTL, and related aboveground facilities associated with the Project would be designed, constructed, operated, and maintained by AGDC in accordance with PHMSA's *Transportation of Natural Gas and Other Gas by Pipeline* in 49 CFR 192. The regulations at 49 CFR 192 are intended to ensure adequate protection for the public and to prevent natural gas facility accidents and failures. Part 192 specifies material selection and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion. Part 192 also defines area classifications based on population density in the vicinity of the pipeline, and specifies more rigorous safety requirements for populated areas.

4.18.10.2 Pipeline Safety Program

In accordance with the PHMSA regulations, the Mainline Pipeline, PTTL, and PBTL would be subject to a prescribed safety program. The pipelines would be regularly inspected for leakage and potential pipeline hazards such as construction activity, encroachments, and evidence of recent unmonitored excavations. During scheduled operation and maintenance, the following inspections would occur:

- physically walking and inspecting the pipeline corridor periodically;
- conducting fly-over inspections of the right-of-way as needed;
- inspecting and maintaining aboveground facilities; and
- conducting leak surveys using external gas detection equipment at least once every calendar year or as required by regulations.

PHMSA requires pipeline operators to place pipeline markers at frequent intervals along the pipeline rights-of-way, such as where a pipeline intersects a street, highway, railway, or waterway, and at other prominent points along the route. Pipeline right-of-way markers can help prevent encroachment and excavation-related damage to pipelines. Pipeline markers identifying the owner of the pipeline and a 24-hour telephone number would be placed for "line of sight" visibility along the entire pipeline length, except in active agricultural crop locations and in waterbodies in accordance with PHMSA's requirements. Alaskan state law requires excavators to call the one call "Dig Line" in advance of digging to locate underground utilities.

A Gas Control Center would monitor system pressures, flows, and customer deliveries. The Gas Control Center would be manned 24 hours a day, 365 days a year. Additionally, AGDC would operate a Backup Control Center. The backup control center would be used in the event the Gas Control Center becomes unavailable. AGDC would also operate a regional operation and maintenance office in Alaska where personnel could respond appropriately to emergency situations and direct safety operations as necessary. Data acquisition systems would be present at all meter and compressor stations along the Project's system. If system pressures were to fall outside a predetermined range, an alarm would be activated and notice would be transmitted to the Gas Control Center, indicating that pressures at the station are not within an acceptable range. Real time monitoring and control of pipeline flows, pressure, and temperature of at least 11 of the MLVs (those at compressor stations, the heater station, and both ends of the Mainline Pipeline) would be managed from the Gas Control Center. Monitoring would enable diagnosis

of pressure transients and, if necessary, the remote closure of MLVs and shut-down of compression equipment.

The continuous monitoring and operation of the pipeline system would be accomplished principally through a SCADA system, which is a computer system for gathering and analyzing data from real-time systems and operating remote facilities connected to the pipeline. The SCADA system would gather information from locations along the pipelines, such as meter stations and compressor stations; transmit the information back to the Gas Control Center; compare collected data to pre-set safe operating data points; and organize and display the data including alarm displays for actual operating points that do not meet pre-set operating criteria.

The minimum standards for operating and maintaining pipeline facilities are prescribed in 49 CFR 192, including the requirement to establish a written plan governing these activities. Under 49 CFR 192.615, each pipeline operator must establish an emergency plan that includes written procedures to minimize hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for the following:

- receiving, identifying, and classifying emergency events, gas leakage, fires, explosions, and natural disasters;
- establishing and maintaining communications with local fire, police, and public officials, and coordinating emergency response;
- ESD of system and safe restoration of service;
- making personnel, equipment, tools, and materials available at the scene of an emergency; and
- protecting people first and then property, and making them safe from actual or potential hazards.

AGDC would provide training to all employees responsible for operation and maintenance of the pipelines, compressor stations, and meter stations installed as part of the Project, including review of routine and emergency procedures. Employees responsible for future support of the facilities would be given hands-on training to familiarize them with new equipment. In addition to in-house training, equipment vendors would provide training prior to start-up of new facilities.

The federal pipeline safety regulation, Part 192, defines four pipe area classifications based on population density in the vicinity of pipeline facilities, and specifies more rigorous safety requirements for populated areas. The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1 – location with 10 or fewer buildings intended for human occupancy;
- Class 2 – location with more than 10 but less than 46 buildings intended for human occupancy;
- Class 3 – location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of any building, or small well-defined outside area occupied by 20 or more people at least 5 days a week for 10 weeks in any 12-month period; and
- Class 4 – location where buildings with four or more stories aboveground are prevalent.

Class locations representing more populated areas require higher safety factors in pipeline design, testing, and operation. For example, pipelines constructed on land in Class 1 locations must be provided with a minimum cover of 30 inches in normal soil or 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil or 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in normal soil or 24 inches in consolidated rock. Per 49 CFR 192.327, where a minimum cover condition cannot be achieved (e.g., aboveground installation), the pipeline is to be provided with addition protection to withstand anticipated external loads. AGDC has stated it would provide a minimum burial depth of 36 inches for buried sections of the pipeline, regardless of class location.

Section 192.179 specifies the maximum distance from a point on a pipeline to a sectionalizing block valve: each point on a pipeline in a Class 1 location must be within 10.0 miles of a block valve; in a Class 2 location, the distance is 7.5 miles; and in Class 3 and 4 locations, the distance is 4.0 and 2.5 miles, respectively. Pipeline wall thickness and pipeline design pressures, hydrostatic test pressures, MAOPs, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas. A Special Permit allows for deviations from some of these requirements in certain segments. PHMSA has granted AGDC Special Permits to allow for strain based design, use of multi-layer coating, and changes to MLV spacing and crack arresting spacing (see section 4.18.10.3).

Based on the definitions in 49 CFR 192, the PTTL, which consists of 62.5 miles of 32-inch-diameter aboveground pipeline, would be entirely within Class 1 areas. The PBTL, which is a 1.0-mile-long, 60-inch-diameter aboveground pipeline, would also be entirely within a Class 1. The Mainline Pipeline, which consists of an 806.9-mile, 42-inch-diameter pipeline primarily belowground, would be in multiple class locations. About 800.3 miles (99 percent) of the Project would be in Class 1 areas, 5.1 miles (less than 1 percent) would be in Class 2 areas, and 0.5 mile (less than 1 percent) would be in Class 3 areas (see table 4.18.10-1).

TABLE 4.18.10-1

U.S. Department of Transportation Class Locations for the Mainline Pipeline

Beginning Milepost	Ending Milepost [a]	Length (miles)	Class Location
0.0	536.0	536.0	1
536.0	537.2	1.2	3
537.2	798.7	261.8	1
798.7	801.3	2.6	2
801.3	803.8	2.5	1
803.8	806.3	2.5	2
806.3	806.6	0.3	1
Total	**N/A**	**806.9**	**N/A**

N/A = Not applicable

[a] Mileposts are included as reference points and may not correspond with the actual length along the pipeline.

Since the passing of the Pipeline Safety Improvement Act (House Report 3609), gas transmission operators are required to develop and follow a written integrity management program that contains all the elements described in 49 CFR 192.911 and addresses possible risks on each transmission pipeline segment. Specifically, the regulation requires pipeline operators to establish an integrity management program that applies to all high consequence areas (HCA).

An HCA may be defined using one of two methods. In the first method, an HCA includes:

- current Class 3 and 4 locations;
- any area in Class 1 or 2 locations where the potential impact radius[176] is greater than 660 feet and there are 20 or more buildings intended for human occupancy within the potential impact circle;[177] or
- any area in Class 1 or 2 locations where the potential impact circle includes an identified site.

In the second method, an HCA includes any area within a potential impact circle that contains:

- 20 or more buildings intended for human occupancy; or
- an identified site.

An identified site is an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period; a building that is occupied by 20 or more persons on at least 5 days a week for any 10 weeks in any 12-month period; or a facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

AGDC calculated a potential impact radius of 1,466 feet for the Mainline Pipeline. Using the first method, AGDC has identified 10 segments of the Mainline Pipeline, totaling 14.9 miles, that qualify as HCAs as shown in table 4.18.10-2. Two segments of the PTTL qualify as HCAs as detailed in table 4.18.10-3.

TABLE 4.18.10-2

High Consequence Areas Associated with the Mainline Pipeline [a]

Description	Length (miles)	Milepost Range	Class Location
Marion Creek Campground	1.2	236.1 – 237.3	1
Hotspot Cafe	1.1	352.2 – 353.3	1
RV Park and Motel	1.2	529.2 – 530.4	1
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	2.2	535.5 - 537.7	1 and 3
Nenana Pedestrian Bridge Crossing	0.1	537.0 – 537.1	3
Denali Perch Resort	1.0	551.3 – 552.3	1
ADOT&PF Cantwell Station	1.4	565.8 – 567.2	1
Byers Lake Campground (73 units)	1.6	629.8 – 631.4	1
Trappers Creek Pizza Pub	0.8	633.7 – 634.5	1
Nikiski Middle/High School, Kenai Heliport, Commercial Buildings, Industrial Sites	1.6	797.7 – 799.3	1 and 2
Andeavor Kenai Refinery	2.7	803.4 – 806.1	1 and 2
Total	**14.9**		

[a] We received a scoping comment about the location and classification of the pipeline in the area near the Susitna Valley High School. The high school is over 5 miles east of the Mainline Pipeline at about MP 679.0 and is therefore outside the potential impact radius calculated for the Mainline Pipeline.

[176] The potential impact radius is calculated as the product of 0.69 and the square root of the MAOPs of the pipeline in psi multiplied by the pipeline diameter in inches.

[177] The potential impact circle is a circle of radius equal to the potential impact radius.

TABLE 4.18.10-2

High Consequence Areas Associated with the Mainline Pipeline [a]

Description	Length (miles)	Milepost Range	Class Location

TABLE 4.18.10-3

High Consequence Areas Associated with the PTTL

Description	Length (miles)	Milepost Range	Class Location
PTU	0.1	0.0 – 0.1	1
GTP	0.1	62.4 – 62.5	1
Total	**0.2**		

We received a comment from the BLM about whether the TAPS pump stations were included in the analysis of HCAs, specifically Pump Stations 3, 4, and 5. The buildings at Pump Stations 3, 4, and 5 would be over 2,200, 2,100, and 3,200 feet, respectively, from the Mainline Pipeline. These pump stations would be outside the potential impact radius of 1,466 feet and are therefore not considered HCAs. The buildings at Pump Station 6 would be within the outer range of the potential impact radius; however, this pump station is currently not pumping oil through TAPS and is now described as the Yukon Response Base, providing equipment, housing, and staging areas for oil response crews in northern Alaska. It does not fit the definition of an identified site, so the area is also not considered an HCA.

The pipeline integrity management rule for HCAs requires inspection of the entire pipeline every 7 years. In-line inspection tools would be used to identify metal loss from corrosion and pipeline deformation. Cathodic protection systems help prevent corrosion of underground pipeline facilities. The pipeline's corrosion protection system would mitigate external corrosion of the buried sections of the pipeline. The corrosion protection system would be operational within 1 year of construction. During the dormant period, the time between the finalization of construction and operation start-up, AGDC would use a passive corrosion protection system using sacrificial anodes. Periodic cathodic protection surveys (yearly surveys not to exceed 15 months between surveys) would be conducted to monitor the status of the corrosion protection system and would adjust systems as required to maintain pipeline system integrity.

On October 1, 2019, PHMSA issued new regulations modifying and expanding the standard pipeline safety standards under 49 CFR 191 and 192. These regulations, in part, established new standards for in-line inspections; requirements for newly established moderate consequence areas (MCA); explicitly require consideration of seismicity and geotechnical risks in its integrity management plan for the pipeline; new regulations on pipeline patrol frequency HCAs, MCAs, and grandfathered pipelines; a policy to reconfirm MAOP for certain pipelines; installation of pressure relief for pig launcher/receivers, and report exceedances of MAOP to PHMSA. These regulations go into effect on July 1, 2020.

4.18.10.3 Special Permit Requests

A Special Permit, as specified in 49 CFR 190.341, is an order from PHMSA that waives compliance with one or more of the pipeline safety requirements listed in 49 CFR 192 for a technically sound alternative. A Special Permit is granted when the Associate Administrator determines that the waiver of the regulation and implementation of the alternative addresses the intended pipeline safety condition. The Special Permit specifies terms and conditions necessary to ensure safety and environmental protection in

lieu of the waived requirement. Proposed changes must maintain equivalent/acceptable levels of safety. AGDC applied to PHMSA for the following Special Permits for the pipeline facilities:

- strain-based design;
- multi-layer coating;
- MLV spacing; and
- crack arrestor spacing.

PHMSA granted four Special Permits in September 2019. The permits have been posted at https://www.regulations.gov/ and on PHMSA's website at www.phmsa.dot.gov.[178] The four Special Permits are summarized below. AGDC has also submitted a fifth Special Permit application for the use of a pipe-in-pipe design at the Liquefaction Facilities.

Strain Based Design

Section 192.103 requires that all external loads be accounted for in the pipeline design. AGDC has been granted an exemption from the requirements of 49 CFR 192.103, as well as 192.105, 192.317, and 192.620, in specific areas subject to geotechnical hazards. Areas subject to time dependent ground movement would require the use of heavy walled pipe with sufficient thickness to withstand the external forces of ground freezing (frost heave) and thawing (thaw settlement). A high pressure gas pipeline built aboveground would require prohibitively expensive steel metallurgy to ensure pipeline integrity commensurate to fulfill the requirements of 49 CFR 192.53 at temperatures as low as -50°F. Therefore, AGDC requested a Special Permit from PHMSA to allow strain based design of several segments of the pipeline. Strain based design involves enhanced metallurgy and engineering to allow the pipe to deform in the longitudinal direction while maintaining its integrity and safety. Strain based design is a technology that enables compliance with 49 CFR 192.53, which requires that materials are "able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated."

PHMSA has issued a Special Permit to AGDC to allow strain-based design to be used for seven segments of the Mainline Pipeline, totaling 34 miles (see table 4.18.10-4). The strain-based design Special Permit requires that a strain based design plan must be developed. This plan would detail the process to determine the amount of axial strain the pipeline can experience, the construction requirements, and the operation and maintenance requirements of the strain based design segments of the pipeline. The strain based design Special Permit requires that the strain based design segments of the pipeline be treated as an HCA. As such, an integrity management program would be required for these segments. Additionally, a supplemental cathodic protection system would be required as part of the Strain Based Design Special Permit. High voltage electric transmission lines can cause stray alternating currents that interfere with the underground pipeline. The Mainline Pipeline would run parallel to transmission power lines for a total of 52 miles. AGDC would evaluate the potential for alternating current interference and would install a grounding system and sacrificial magnesium anodes as part of the cathodic protection system.

[178] The following docket numbers have been assigned for each Special Permit: Docket No. PHMSA-2017-0044 (strain based design); Docket No. PHMSA-2017-0045 (MLV spacing); Docket No. PHMSA-2017-0046 (multi-layer coating); and Docket No. PHMSA-2017-0047 (crack arrestor spacing).

TABLE 4.18.10-4

Strain-Based Design Locations for the Mainline Pipeline

Beginning Milepost	Ending Milepost	Length (miles)
194.0	196.0	2.0
227.0	230.0	3.0
257.0	262.0	5.0
270.0	276.0	6.0
429.0	440.0	11.0
541.0	544.0	3.0
559.0	563.0	4.0
Total	**N/A**	**34.0**

N/A = Not applicable

Sections 192.112, 192.328, and 192.620 specify the MAOPs. The Special Permit allows AGDC requested alternative MAOP requirements in portions of the pipeline subject to strain based design approval. Strain based design requires that the additional design elements be considered when calculating the MAOPs. Additional requirements must be met when utilizing an alternative MAOP, including enhanced pipe manufacturing standards, a fracture control plan, construction quality assurance plan, non-destructive testing of all girth welds, initial strength test reporting requirements, patrol of the right-of-way 12 times per year, assessment of coating conditions, and additional operational and maintenance requirements.

Multi-layer Coating

Section 192.112(f)(1) specifies non-shielding coating requirements. Because the Mainline Pipeline spans the length of the state, segments of the pipeline would have to be transported significant distances for installation in remote areas. Most pipelines utilize fusion bonded epoxy (FBE), which can be damaged in transport if mishandled. AGDC applied for a Special Permit from PHMSA to obtain an exemption from 49 CFR 192.112(f)(1) to use a three-layer polyethylene coating system on the pipeline. The three-layer polyethylene coating system has an increased resistance to mechanical damage and ultraviolet degradation, which would decrease the possibility of damage during transport. The Special Permit identifies coating specifications, quality control testing, inspection requirements, and reporting and certification requirements.

Mainline Valve and Crack Arrestor Spacing

Section 192.179 specifies valve spacing requirements; however, the Administrator may approve alternative block valve spacing that has an equivalent level of pipeline safety. AGDC completed an engineering assessment to determine spacing that provides an equivalent level of pipeline safety and applied for an exemption from PHMSA prescribed block valve spacing requirements in Class 1 remote locations based on the reduced probability of damage or rupture. AGDC found that based on past studies, the probability of incidents due to third-party interference is directly related to the population level with a much lower frequency in Class 1 locations compared to the higher class locations. Approximately 801 miles, corresponding to 99 percent of the Mainline Pipeline route, would be in Class 1 locations. In addition, more than 700 miles of the route would be in areas with no inhabited dwellings within the class location corridor of 220 yards on either side of the pipeline centerline, which further reduces the probability of experiencing mechanical damage or rupture in these regions. In the case of a pipeline hit occurring on the Mainline Pipeline, AGDC's fracture control plan provides for a robust design against fracture initiation in

excess of 200,000 pounds of force. From analysis of the incident databases, the probability of rupture due to third-party mechanical damage is lower for pipelines with wall thickness greater than 0.59 inch. The minimum wall thickness of the Mainline Pipeline is 0.677 inch, which occurs for X80 pipe segments following alternative MAOP requirements in Class 1 locations. AGDC applied for an exemption from PHMSA from the prescribed valve spacing requirements in Class 1 locations based on the reduced probability of damage or rupture.

In the Special Permit application, AGDC requested that MLV spacing be increased from 20 to 50 miles when north of Fairbanks and from 20 to 30 miles when south of Fairbanks. The Special Permit request includes spacing specifications, valve monitoring, control and closure specifications, and reporting and certification requirements. AGDC would have the ability to remotely close the 13 MLVs managed from the Gas Control Center (those at compressor stations, the heater station, and both ends of the Mainline Pipeline). The remaining 17 valves on the system would be Automatic Shut-Off Valves that would be able to sense a leak of a defined size and automatically close without a response from the control center. Table 4.18.10-5 identifies each of the MLVs along with the proposed spacing and valve type.

Section 192.112 specifies crack arrestor spacing requirements. PHMSA has granted a Special Permit for increased spacing in Class 1 remote locations. The Special Permit would allow crack arrestor spacing to increase from 320 to 1,600 feet. The granted Special Permit includes spacing specification, material testing specifications, fracture control plan requirements, and reporting and certification requirements. In areas where strain-based design would be employed, AGDC would use pipe that intrinsically arrests cracks and would not need crack arrestors.

4.18.10.4 Pipeline Accident Data

PHMSA requires all operators of natural gas transmission pipelines to notify the National Response Center at the earliest practicable moment following the discovery of an incident and to submit a report within 30 days to PHMSA. On January 19, 2017, PHMSA issued a final rule entitled, *Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes*. The rulemaking lays out a specific time frame requirement for telephonic or electronic notifications of accidents and incidents. The rule also amends drug and alcohol testing requirements, and incorporates consensus standards by reference for inline inspection and Stress Corrosion Cracking Direct Assessment. The rule addresses mandates included in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. Incidents are defined as any leaks that:

- caused a death or personal injury requiring hospitalization; or
- involved property damage, including cost of gas lost, of more than $50,000 in 1984 dollars (about $115,499.04 in 2016 [Bureau of Labor Statistics, 2016]).

During the 20-year period from 1997 through 2016, a total of 1,039 significant incidents were reported on the more than 297,000 total miles of onshore natural gas transmission pipelines nationwide (PHMSA, 2018a). Additional insight into the nature of service incidents may be found by examining the primary factors that caused the pipeline failures. Table 4.18.10-6 provides the number of each incident by cause and the distribution of the causal factors from 1997 to 2016.

TABLE 4.18.10-5

Mainline Valve Locations

Mainline Valve [a]	Milepost	Spacing (miles)	Location Description	Valve Type
1	0.0	N/A	GTP Meter Station	RCV
2	36.7	36.7	Stand-alone MLV	ASV
3	76.0	76.0	Sagwon Compressor Station	RCV
4	112.0	36.1	Stand-alone MLV	ASV
5	148.5	36.5	Galbraith Lake Compressor Station	RCV
6	194.1	45.6	Stand-alone MLV	ASV
7	240.1	46.0	Coldfoot Compressor Station	RCV
8	286.1	46.0	Stand-alone MLV	ASV
9	332.6	46.6	Ray River Compressor Station	RCV
9A	356.2	23.6	Added for potential Hotspot Café HCA	ASV
10	378.0	21.7	Stand-alone MLV	ASV
11	421.6	43.6	Minto Compressor Station	RCV
12	444.9	23.3	Stand-alone MLV	ASV
13	467.1	22.2	Stand-alone MLV	ASV
14	493.0	25.9	Stand-alone MLV	ASV
15	517.6	24.7	Healy Compressor Station	RCV
16	534.8	17.2	Upstream of Class 3 Location - Nenana Canyon	ASV
18	546.5	7.7	Stand-alone MLV	ASV
19	572.2	25.7	Stand-alone MLV	ASV
20	597.4	25.1	Honolulu Creek Compressor Station	RCV
21	625.8	28.5	Stand-alone MLV	ASV
22	648.2	22.3	Stand-alone MLV	ASV
23	675.2	27.1	Rabideux Creek Compressor Station	RCV
24	703.7	28.4	Stand-alone MLV	ASV
25	725.9	22.3	Stand-alone MLV	ASV
26	749.1	23.2	Theodore River Heater Station	RCV
27	766.0	16.9	Upstream of Cook Inlet crossing	ASV
28	793.3	27.3	Downstream of Cook Inlet crossing	RCV
29	799.9	6.5	Stand-alone MLV	RCV
30	806.6	6.7	LNG Meter Station	RCV

N/A = Not applicable; RCV = remote controlled valves; ASV = automatic shut-off valves

[a] MLV 17 was eliminated upon adoption of the Denali Alternative into the Mainline Facilities.

TABLE 4.18.10-6

Onshore Nationwide Natural Gas Transmission Pipeline Significant Incidents by Cause (1997 to 2016)

Cause	Number of Incidents	Percentage of Total Incidents [a]
Corrosion	184	17.7
Excavation [b]	194	18.7
Pipeline material, weld or equipment failure	341	32.8
Natural force damage	87	8.4
Outside forces [c]	63	6.1
Incorrect operation	42	4.0
All other causes [d]	128	12.3
Total	**1,039**	**100**

Source: PHMSA, 2018a

[a] The total may not equal the sum of the addends due to rounding.

[b] Includes third-party damage.

[c] Fire, explosion, vehicle damage, previous damage, and unintentional damage.

[d] Miscellaneous causes or other unknown causes.

The pipelines included in the data set in table 4.18.10-6 vary widely in terms of age, pipe diameter, and level of corrosion control. Each of these variables influences the incident frequency that may be expected for a specific segment of pipeline. The dominant causes of pipeline incidents are pipeline material, weld, or equipment failure (32.8 percent); and corrosion (17.7 percent), which collectively account for about half of all significant incidents.

The frequency of significant incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents and material failure since corrosion and pipeline stress/strain are time-dependent processes. The use of both an external protective coating and a cathodic protection system, required on all pipelines installed after July 1971, significantly reduces the corrosion rate compared to unprotected or partially protected pipe.

Outside forces, excavation, and natural forces are the cause in 33.2 percent of significant pipeline incidents. These mostly result from the encroachment of mechanical equipment such as bulldozers and backhoes; earth movements due to soil settlement, washouts, or geologic hazards; weather effects such as winds, storms, and thermal strains; and willful damage. Table 4.18.10-7 provides a breakdown of outside force incidents by cause for onshore natural gas pipelines nationwide.

Older pipelines have a higher frequency of outside force incidents partly because their location may be less well known and less well marked than newer lines. In addition, the older pipeline systems contain a disproportionate number of smaller diameter pipelines, which have a greater rate of outside forces incidents. Small-diameter pipelines are more easily crushed or broken by mechanical equipment or earth movements.

Since 1982, operators have been required to participate in "One Call" public utility programs in populated areas to minimize unauthorized excavation activities in the vicinity of pipelines. The "One Call" program is a service used by public utilities and some private sector companies (for example, oil pipelines and cable television) to provide pre-construction information to contractors or other maintenance workers on the underground location of pipes, cables, and culverts. AGDC would utilize Alaska's Dig Line program for staking and marking.

TABLE 4.18.10-7

Nationwide Outside Force Incidents by Cause (1997 to 2016) a

Cause	Number of Incidents	Percent of All Incidents
Third-party excavation damage	155	14.9
Operator excavation damage	24	2.3
Unspecified equipment damage/Previous damage	15	1.4
Heavy rain/floods	25	2.4
Earth movement	28	2.7
Lightning/temperature/high winds	25	2.4
Unspecified natural force	4	0.4
Other natural force damage	5	0.5
Vehicle (not engaged with excavation)	34	3.3
Fire/explosion	10	1.0
Previous mechanical damage	5	0.5
Intentional damage	1	0.1
Fishing or maritime activity	3	0.3
Electrical arcing from other equipment/facility	1	0.1
Other outside force	8	0.8
Unspecified outside force	1	0.1
Total	**344**	**N/A**

N/A = Not applicable

[a] Excavation, outside forces, and natural force damage from table 4.18.10-6.

4.18.10.5 Impact on Public Safety

Although the transportation of natural gas via pipeline involves some degree of risk to the public in the event of an accident and subsequent release of gas, it is important to examine the probabilistic level of risks for pipeline-related events. According to PHMSA, there are 2.5 million miles of pipelines that cross the United States, and those pipelines offer a safe and cost-efficient way to transport natural gas (PHMSA, 2018c). Table 4.18.10-8 presents the annual injuries and fatalities that occurred on onshore natural gas transmission lines between 2005 and 2016. The data have been separated into employees and nonemployees to better identify a fatality rate experienced by the general public. No injuries or fatalities have occurred in Alaska.

The majority of fatalities from pipelines involve local distribution pipelines, which are not regulated by FERC. Natural gas distribution pipelines distribute natural gas to homes and businesses after transportation through interstate natural gas transmission pipelines. In general, distribution pipelines are smaller diameter pipes, often made of plastic or cast iron rather than welded steel, and tend to be older pipelines that are more susceptible to damage. In addition, distribution systems do not have large rights-of-way and pipeline markers common to FERC-regulated natural gas transmission pipelines.

TABLE 4.18.10-8

Nationwide Annual Injuries and Fatalities – Natural Gas Transmission Pipelines (2005 to 2016)

	Injuries		Fatalities	
Year	Employees	Public	Employees	Public
2005	3	2	0	0
2006	2	1	2	1
2007	6	1	1	1
2008	3	2	0	0
2009	4	7	0	0
2010 [a]	3	58	0	10
2011	1	0	0	0
2012	1	6	0	0
2013	0	2	0	0
2014	1	0	1	0
2015	1	15	4	2
2016	2	1	2	1

Source: PHMSA, 2018b

[a] All of the public injuries and fatalities in 2010 were due to the Pacific Gas and Electric pipeline rupture and fire in San Bruno, California on September 9, 2010.

The nationwide totals of accidental fatalities from various manmade and natural hazards are listed in table 4.18.10-9 in order to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. Direct comparisons between accident categories should be made cautiously, however, because individual exposures to hazards are not uniform among all categories. Furthermore, the fatality rate is more than 25 times lower than the fatalities from natural hazards such as lightning, tornados, and floods.

The available data show that natural gas transmission pipelines continue to be a safe, reliable means of energy transportation. From 2007 to 2016, there were an average of 73 significant incidents and two fatalities per year (PHMSA, 2018a). The number of significant incidents over the more than 297,000 miles of onshore natural gas transmission lines indicates the risk is low for an incident at any given location (PHMSA, 2018c). The rate of total fatalities for the nationwide natural gas transmission lines in service is about 0.0067 per year per 1,000 miles of pipeline. Thus, operation of the Project would represent only a slight increase in risk to the nearby public. As described above, the Project would be constructed and operated in accordance with PHMSA requirements, including Special Permits; therefore, we determine that operation of the Project would be safe.

As discussed in section 4.1.3, the Mainline Pipeline crosses several active and potentially active faults. We received comments from the BLM, ADNR, and community of Tyonek concerning the geological risks applicable to the Mainline Pipeline. These comments included requests for information on ground movement and activity at each fault crossing, design measures at each fault crossing to mitigate seismic risk, and how the pipeline would be designed to withstand subsidence and permafrost thaw. The Mainline Pipeline would be designed to withstand exposure to seismic activity and surface fault offsets at pipeline crossing locations of active earthquake fault zones. Active faults are defined as those where there is geologic or geomorphic evidence that the fault experienced offset during the Holocene epoch (i.e., within the past 11,700 years).

TABLE 4.18.10-9

Nationwide Accidental Deaths

Type of Accident	Annual Number of Deaths
All accidents	130,557
Motor vehicle	35,369
Poisoning	38,851
Falls	30,208
Drowning	3,391
Fire, smoke inhalation, burns	2,760
Floods	38
Lightning	26
Tornado	47
Natural gas distribution lines	9
Natural gas transmission pipelines	2

Sources: U.S. Census Bureau, 2012b; NOAA National Weather Service, 2017i; PHMSA, 2018a

The Mainline Pipeline would cross at least seven onshore faults and two offshore geologic structures (anticlines)[179] as shown in the table 4.18.10-10. Active faults crossed by the Mainline Pipeline include the Northern Foothills Thrust fault, Park Road reverse fault, and the Denali and Castle Mountain right lateral strike-slip faults (Koehler et al., 2015). As discussed in section 2.2.2, AGDC would cross the four active fault zones using aboveground construction methods. The Northern Foothills, Denali, and Castle Mountain faults would utilize the sliding support construction method similar to the TAPS crossing of the Denali fault at TAPS MP 589. The Park Road fault would be crossed using a conventional aboveground crossing.

This sliding support construction method consists of cross beams laid on the ground surface with the pipe attached via load distributing shoes, which rest on the cross beams. The shoes would slide on the cross beams in response to ground movement. Each crossing configuration would differ based on the type of fault crossed. Design considerations for the shoes and beams include determining the appropriate size and length to accommodate the expected range of movement of the pipeline and to provide for adequate support. If a pipe shoe were to slide off a support beam during a seismic event, the shoe and pipeline would drop a short distance to the ground, which is unlikely to cause damage to the pipeline.

A variety of aboveground sliding support concepts, which AGDC plans to employ to mitigate complications with frozen soil encasement, could be used for aboveground fault crossings provided they have sufficient sliding capacity to accommodate fault rupture. "Sleeper" supports and grade beams laid on the ground surface are the simplest to design, procure, and install. They also are considered a "fail-safe" concept because of the short drop distance should a pipe shoe slide off a support during a fault offset, minimizing the possibility of damaging the pipeline. More conventional "goalpost" supports consisting of two VSMs and a cross-beam could also suffice, particularly for fault crossings having relatively small design displacements. Regardless of design concept, the pipeline support configuration and geometry must account for thermal expansion, permafrost degradation, internal pressure, and seismic ground motion, in addition to the effects of fault displacement offset.

[179] A geologic fold, generally convex upward, one in which the limbs or sides slope away from the crest, like an inverted trough, and whose core contains stratigraphically older rocks.

TABLE 4.18.10-10

Geologic Fault Crossings and Construction Methods Associated with the Mainline Pipeline

Fault Name	Milepost Range	Approximate Crossing Length (feet)	Fault Type	Single Event Displacement	Crossing Method
Northern Foothills	500.0 to 500.6	3,010	Thrust	3 to 7 feet vertical	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad
Stampede-Little Panguingue Creek	520.0 to 521.0	5,280	Thrust	3 to 10 feet vertical	To be determined following detailed design
Healy Creek	522.4 to 522.5	6,000	Reverse	3 to 10 feet vertical	To be determined following detailed design
Healy	526.9 to 527.0	520	Reverse	3 to 10 feet vertical	To be determined following detailed design
Park Road	537.7 to 537.8	600	Reverse	8 feet vertical	Conventional aboveground crossing
Denali	560.3 to 561.5	6,336	Right lateral strike-slip	9 feet vertical 27 feet horizontal	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad
Castle Mountain	743.2 to 743.4	1,056	Right lateral strike-slip	3 to 5 feet vertical 3 to 7 feet horizontal	Aboveground design with saddles on beams supporting the pipeline, on top of a granular fill pad
Beluga River Anticline	766.0 to 768.0	Unknown	Thrust fault cored anticline	N/A	No special design required for crossing anticlines
North Cook Inlet-SRS Anticline	776.0 to 787.0	Unknown	Fault-cored fold	N/A	No special design required for crossing anticlines

Sources: Koehler et al., 2015; WorleyParsons, 2016a, 2016b; USGS, 2009
N/A = Not applicable

During an earthquake, the sliding support fault crossing concepts described above would ensure that the pipeline moves with the ground motion to lessen the stress and strain exerted on the pipeline. Fault crossing concepts have proven effective in practice. For example, the TAPS crossing of the Denali fault withstood the 2002 moment magnitude 7.9 earthquake on the Denali fault, which caused displacements of 2.5 feet vertically and 18 feet horizontally.

Prior to construction, AGDC would conduct detailed studies of the crossings to determine if some faults could be crossed by burying the pipeline in a well-drained berm configuration above natural grade constructed with uniform-graded granular material or crushed rock, or with loose, well-drained granular fill. This would allow for large strains and deformation to occur without pipe rupture. Similar to the shoe design sliding support method, the pipeline berm would be aligned across the fault zone in an orientation that minimizes the direct axial stress/strain induced into the pipeline.

The Mainline Pipeline would also cross two anticlines within or that trend into Cook Inlet. The Beluga River and North Cook Inlet SRS anticlines are a thrust fault and a fault-cored fold anticline, respectively (Haeussler and Saltus, 2001). In order for the Mainline Pipeline to cross these offshore geologic structures, the pipeline would either rest on the top of the seabed or would be naturally buried nearshore. Due to the proposed unrestrained pipeline configuration, stresses induced by fault movement would be only a small fraction of those that would be developed in a buried pipeline with similar dimensional characteristics and properties. It is possible that offshore faulting associated with these geologic structures could produce a vertical offset that would cause a segment of the pipeline to be elevated above the seafloor for a short distance, and, hence, cause concern for vortex-induced oscillations from water

currents. We do not consider it practical to design for this remote possibility in advance, especially because fatigue damage to the pipeline would not occur in the short term.

As discussed in section 4.2.5, the Mainline Pipeline design would account for the potential for frost-heaving and thaw settlement. Frost heave is a mechanical weathering process in which water embedded in soil freezes and expands, causing vertical movement among near-surface rocks and soils. Climate interaction with the permafrost may cause at-risk ground conditions for the pipeline. Any areas identified as potentially exceeding the pipe strain limits would be designed and constructed per the PHMSA-approved Strain-Based Design Special Permit described in section 4.18.10.3.

A joint field study conducted by the University of Alaska Fairbanks and USGS found that thermokarsting in the Brooks Range of Alaska led to slope instabilities including creep, slumping, viscous flow, blockfall, and sliding (Daanen et al., 2012). Continued thermocycling from climate-soil interactions may exacerbate geological hazards in the soil profile to which the proposed pipeline would be subjected. Prior to construction, AGDC would file with the Secretary, final fault crossing designs and plans for the Northern Foothills, Stampede-Little Panguingue Creek, Healy Creek, Healy, Park Road, Denali, and Castle Mountain faults and the Beluga River and North Cook Inlet-SRS anticlines. These designs and plans would incorporate site-specific design specifications informed by geotechnical field investigations. At a minimum, the field investigations would analyze potential loading from seismically-induced ground motion, repeated cycling from frost heave, thaw settlement, thermokarsting, and permafrost degradation due to climate change. The final fault crossing designs would be stamped and sealed by a professional engineer-of-record registered in Alaska. AGDC has agreed to provide information in accordance with the timing of the recommendation.

We additionally received comments from the BLM on how climate change would affect the potential for subsidence due to increased thawing in the region of the GTP, PTTL, and PBTL. Permafrost thaw can occur through widespread but gradual deepening of the active layer, and through the development of thermokarst landforms at discrete locations. Thermokarst initiation occurs due to interactions of hydrology, soil properties, vegetation, geomorphology, and disturbances, but fundamentally depends on the presence of excess ground ice. Permafrost thaw is likely to increase this century due to projected changes in the climate and the associated higher frequencies of disturbances such as wildfire and floods (Olefeldt et al., 2016).

Nicolsky et al. (2017) have developed several high spatial resolution scenarios of changes in permafrost characteristics in the Alaskan Arctic in response to observed and projected climate change. This model was used to predict impacts on mean annual ground temperature at a depth of 2 meters, as well as active layer thickness on the North Slope under the Intergovernmental Panel on Climate Change Representative Concentration Pathways (RCP) 4.5 and 8.5 GHG emission scenarios. The model predicts that for the RCP 4.5 and 8.5 GHG emission scenarios, mean annual ground temperatures at 2 meters would remain below freezing through the 2050s (Nicolsky et al., 2017). The computer modeling also revealed that by the 2050s, the active layer thickness on the Alaska North Slope may increase by a factor of 1.5 and 2.0 under the RCP 4.5 and 8.5 GHG emission scenarios, respectively (Nicolsky et al., 2017). Despite a significant increase in the active layer thickness, almost no taliks were predicted to be developed by the 2050s; most talik formation occurred after the 2050s in both scenarios (Nicolsky et al., 2017). This is consistent with ground temperatures predicted in the 30-year scenario described above. As discussed in section 4.2.5, AGDC anticipates that potential operational impacts associated with VSMs for the PTTL and PBTL would be similar to the impacts TAPS and other aboveground pipelines in the greater Prudhoe Bay oil and gas operations within the Arctic Coastal Plain.

We also received scoping comments about the crossing of TAPS and concerns about the close proximity of Project facilities to TAPS. Several studies were conducted to identify the potential impact of

the Mainline Pipeline's crossings and encroachments on the TAPS mainline and fuel gas line, its operation, and associated access. These studies assessed potential impacts during construction and operation, and included mechanical and civil design, construction methods, water crossings drainage, cathodic protection and interference mitigation, and the consequences of an incident. Specific concerns addressed were related to pipeline crossings, use of Alyeska Pipeline Service Company access roads, stream crossings in close proximity to the TAPS pipeline or fuel gas line crossings, and construction within 200 feet of the TAPS pipeline or fuel gas lines.

The Mainline Pipeline would meet design and safety requirements at TAPS crossing locations. Cathodic protection interference would be monitored and mitigated as necessary. Additionally, construction of the Mainline Pipeline at crossings and encroachments would be completed with the review and participation of Alyeska Pipeline Service Company.

A pipeline failure consequence analysis was also completed and indicated that a failure of the Mainline Pipeline where it approaches within 200 feet of, but does not cross, TAPS would not result in exposure of TAPS. Therefore, the construction distance is sufficient such that an explosive failure would not affect TAPS. For crossing locations, mitigation measures such as heavy wall pipe and/or crack arrestor location optimization are proposed to reduce overall risk.

As discussed in sections 2.2.2 and 4.3.3, AGDC does not intend to backfill the shore to land crossings associated with the Mainline Pipeline or bury the pipe in Cook Inlet. However, AGDC would incorporate the use of the DMT continuation methodology for the shoreline crossings or provide site-specific justification demonstrating that the methodology is not feasible (see section 4.3.3).[180] AGDC would coat the offshore pipeline with 3.5 inches of concrete coating for stability and added impact and abrasion protection. PHMSA has reviewed the technical information and responses provided by AGDC relative to the design. With regard to 49 CFR 192.327(f)(2), PHMSA is satisfied that AGDC would mitigate any future pipeline safety conditions. Should mitigation of safety conditions (e.g., free spans) be required after detailed design is completed, or determined to be necessary during Project construction or operation, additional environmental analysis by FERC and other permitting agencies may be required depending on the proposed scope and anticipated impacts of implementing the mitigation measures.

As discussed in section 4.9.3, the Mainline Pipeline would be near or cross portions of proposed restricted airspace associated with the Clear AFS. Clear AFS representatives expressed concerns that tall equipment and aircraft associated with the Project could interfere with Clear AFS operations. AGDC stated that Project construction would not require frequent aircraft activity near Clear AFS; however, a helipad would be installed at MLV 14 at MP 493.0. Clear AFS personnel requested that MLV 14 and its helipad be relocated to avoid any conflicts with station operations. According to Clear AFS personnel, even though the helipad could be used as infrequently as once per year, operations at the radar station take place 24 hours a day, 7 days a week, 365 days a year, and conflicts could occur. AGDC stated that it would coordinate with Clear AFS representatives to address traffic and other concerns and to avoid or mitigate impacts on Clear AFS during Project construction and operation. Additionally, AGDC has committed to relocating MLV 14 and its helipad. To ensure these facilities would be relocated to an area that would avoid conflicts

[180] A preliminary feasibility assessment of the DMT continuation methodology concluded that the Beluga Landing approach has a 90-percent probability of success, while the Suneva Lake approach has a 75-percent probability of success.

with Clear AFS, we recommend that AGDC develop a plan for the relocation of MLV 14 and its helipad in coordination with Clear AFS representatives (see section 4.9.3).

4.18.10.6 Terrorism and Security

Safety and security concerns have changed the way pipeline operators as well as regulators must consider terrorism, both in approving new projects and in operating existing facilities. The DHS is tasked with the mission of coordinating the efforts of all executive departments and agencies to detect, prepare for, prevent, protect against, respond to, and recover from terrorist attacks within the United States. Among its responsibilities, the DHS oversees the Homeland Infrastructure Threat and Risk Analysis Center, which analyzes and implements the National Critical Infrastructure Prioritization Program that identifies and lists Tier 1 and Tier 2 assets. The Tier 1 and Tier 2 lists are key components of infrastructure protection programs and are used to prioritize infrastructure protection, response, and recovery activities. The Commission, in cooperation with other federal agencies, industry trade groups, and natural gas companies, is working to improve pipeline security practices, strengthen communications within the industry, and extend public outreach in an ongoing effort to secure pipeline infrastructure.

The Commission, like other federal agencies, is faced with a dilemma in how much information can be offered to the public, while still providing a significant level of protection to energy facilities. Consequently, the Commission has taken measures to limit the distribution of information to the public regarding facility design to minimize the risk of sabotage. Facility design and location information has been removed from FERC's website to ensure that sensitive information filed as Critical Energy Infrastructure Information is not readily available to the public (Docket No. RM06-23-000, issued October 30, 2007 and effective as of December 14, 2007).

We received scoping comments regarding the potential for terrorism given the remoteness of portions of the Mainline Pipeline and the low likelihood that individuals attempting to tamper with the pipeline would be observed. The likelihood of future acts of terrorism or sabotage occurring at or along the Project facilities, or at any of the myriad natural gas pipeline or energy facilities throughout the United States, is unpredictable given the disparate motives and abilities of terrorist groups. Further, the Commission, in cooperation with other federal agencies, industry trade groups, and natural gas companies, is working to improve pipeline security practices including cybersecurity of pipeline SCADA, strengthen communications within the industry, and extend public outreach in an ongoing effort to secure pipeline infrastructure.

In accordance with PHMSA surveillance requirements, AGDC would incorporate air and ground inspection of its facilities into its inspection and maintenance program. Security measures at the new aboveground facilities would include secure fencing. Despite the ongoing potential for terrorist acts along any of the nation's natural gas infrastructure, the continuing need for the construction of these facilities is not eliminated. Given the continued need for natural gas conveyance and the unpredictable nature of terrorist attacks, the efforts of the Commission, PHMSA, and Office of Homeland Security to continually improve pipeline safety would minimize the risk of terrorist sabotage of the Project to the maximum extent practical, while still meeting the nation's natural gas needs. Moreover, the unpredictable possibility of such acts does not support a finding that this Project should not be constructed.

4.18.11 Conclusion

As part of the NEPA review and NGA determinations, FERC staff assesses the potential impact on the human environment in terms of safety and whether the proposed facilities would operate safely, reliably, and securely.

As a cooperating agency, PHMSA assists FERC by determining whether AGDC's proposed design would meet PHMSA's 49 CFR 193 Subpart B siting requirements. On February 4, 2020, PHMSA provided an LOD on the Liquefaction Facilities' compliance with 49 CFR 193 Subpart B for the Commission to consider in its decision to authorize or deny the Project. If the Project is authorized and constructed, the Liquefaction Facilities would be subject to PHMSA's inspection and enforcement program; final determination of whether the Liquefaction Facilities are in compliance with the requirements of 49 CFR 193 would be made by PHMSA staff.

As a cooperating agency, the Coast Guard also assisted FERC staff by reviewing the proposed waterfront facilities handling LNG and the associated LNG marine vessel traffic at the Liquefaction Facilities. The Coast Guard reviewed a WSA submitted by AGDC that focused on the navigation safety and maritime security aspects of LNG marine vessel transits along the affected waterway. On August 17, 2016, the Coast Guard issued an LOR to FERC staff indicating Cook Inlet would be considered suitable for accommodating the type and frequency of LNG marine traffic associated with this Project based on the WSA and in accordance with the guidance in the Coast Guard's NVIC 01-11. If the Project is authorized and constructed, the Liquefaction Facilities would be subject to the Coast Guard's inspection and enforcement program to ensure compliance with the requirements of 33 CFR 105 and 33 CFR 127.

FERC staff conducted a preliminary engineering and technical review of the AGDC design, including potential external impacts based on the site location. Based on this review, we recommend the Commission incorporate into any authorization for the Project, a number of mitigation measures that would ensure continuous oversight prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility, in order to enhance the reliability and safety of the facility to mitigate the risk of impact on the public. With the incorporation of these mitigation measures and oversight, and with the exception described below, FERC staff concludes that AGDC's Project design would include acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could affect the off-site public.

We are unable to conclude that high pressure piping at the GTP would not pose a significant safety impact on persons off site of the GTP process facilities. We are recommending that ERPs for potential large ruptures at the GTP be coordinated with the adjacent PBU CGF plant and include consideration of impacts on the GTP operator camp site. To demonstrate potential safety impacts on persons off site of the GTP process facilities and inform the ERPs, we also recommend that AGDC provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure pipe systems at the GTP.

We coordinated with the DOD regarding the potential for impacts on military operations at Clear AFS and in the Anchorage, Alaska vicinity. The DOD determined that the Project would not adversely affect DOD missions in these areas.

The pipeline would be constructed in compliance with PHMSA pipeline standards (as published in 49 CFR 190–199; 49 CFR 192). However, PHMSA has granted Special Permits for strain-based design, multi-layer coating, MLV spacing, and crack arrestor coating for the Mainline Facilities. In addition, PHMSA has indicated it is satisfied that AGDC would mitigate any future pipeline safety conditions consistent with 49 CFR 192.327(f)(2). AGDC has committed to relocating MLV 14 and its helipad to address the concerns associated with potential conflicts with Clear AFS. Based on the implementation of our recommendations, the required BMPs, adherence to PHMSA standards or Special Permit conditions, and implementation of measures identified by the Clear AFS to address its airspace concerns, the Project would not significantly affect public safety.

4.19 CUMULATIVE IMPACTS

The current environment of the Project area reflects a mixture of natural processes and human influences across a range of conditions. Current conditions have been affected by innumerable activities over thousands of years. Until recently, these changes were relatively minor, caused principally by the subsistence activities of the indigenous population. Even as Europeans began to migrate to the area beginning in the late 18th century, changes to the Alaskan landscape were gradual and incremental. While development and settlement associated with activities such as mining, timber extraction, and commercial fishing changed portions of the landscape, tremendous expanses remained relatively untouched, particularly in the state's interior. The first roadway connecting Alaska to the Lower 48 was not constructed until the 1940s.

The most transformative modern event for the state's natural and human environment was construction of the TAPS between 1975 and 1977 (Cole, 2010). This 800-mile-long crude oil pipeline from Prudhoe Bay to the marine terminal at Valdez allowed for the development of the vast fossil fuel resources of the North Slope. The oil and gas industry ushered in by TAPS has provided about 85 percent of the state's revenue and one-third of the state's jobs for the past 40 years (Alaska Oil and Gas Association, 2015b). In addition, construction and operation of the TAPS required an extensive build-out of support infrastructure into remote interior regions, which has induced or facilitated development up and down the pipeline corridor to varying degrees.

4.19.1 Cumulative Impact Analysis Methods

In accordance with NEPA, we identified other actions near the proposed Alaska LNG Project facilities and evaluated the potential for a cumulative effect on the environment. As defined by the CEQ, a cumulative effect is the impact on the environment resulting from the incremental effect of the action when added to other past, present, and reasonably foreseeable future actions, regardless of which agency or person undertakes such other actions.

This cumulative impact analysis uses an approach consistent with the methodology set forth in relevant guidance (CEQ, 1997a, 2005; EPA, 1999). The CEQ guidance states that "agencies can conduct an adequate cumulative effects analysis by focusing on the current aggregate effects of past actions without delving into the historical details of individual past actions" (CEQ, 2005). In this analysis, we consider the impacts of past projects to have become part of the affected environment (environmental baseline), which is described and evaluated in the preceding environmental analyses; however, ongoing effects of past actions that are relevant to the analysis are also considered. For example, impacts due to construction of TAPS have become part of the environmental baseline, while ongoing operational impacts associated with TAPS have the potential to contribute to cumulative effects.

Under this approach, the determination of whether to include an action in our analysis is based on identifying overlapping resource impacts from the other action with the potential impacts that would result from construction and operation of the Alaska LNG Project. To adequately address and accomplish the purpose of this analysis, an action must first meet the following three criteria:

1. affect a resource that could also be affected by the Project;
2. cause this impact within resource-specific areal regions of influence, referred to as geographic scopes, as described below; and
3. cause an impact within the same time span as the potential impact from the Project.

Consistent with CEQ guidance, and to determine a suitable scope for the analysis, we defined an appropriate "geographic scope" within which other projects, in combination with the proposed Project, could have a cumulative impact on various resources. The geographic scope differs according to the resource affected. The geographic scope for each resource type is defined in table 4.19.1-1.

A nearby project must affect the same resource category in the same geographic scope as the Alaska LNG Project to have a cumulative impact on that resource type. The effects of more distant projects are not assessed because their impacts would generally not be expected to overlap with the Project, and so would not contribute to cumulative impacts. Two resource examples representing opposite ends of the spectrum with regard to geographic scope are cultural resources and air quality. With some exceptions, Project impacts on cultural resource sites are localized in nature. For example, a direct impact on an archaeological site would typically not affect other sites; therefore, the geographic scope for archaeological sites is limited to the area within which sites could be directly or indirectly affected by an action. In contrast, the impact of air emissions could be felt over a relatively large area; therefore, the geographic scope for air quality is larger than for other resources.

As indicated in table 4.19.1-1, our analysis used the HUC12 watershed to define the geographic scope for most resources. The Project facilities would occur within 165 HUC12 watersheds. These watersheds vary in size depending on topography. The average size of the affected watersheds is 59,563 acres, with the total area included in our consideration of cumulative impacts on these resources covering almost 9 million acres.

In addition to the areal relationship between the Project and other reasonably foreseeable future projects, we also consider the temporal relationship. The Alaska LNG Project would be constructed over an approximately 8-year period. The majority of the impacts associated with the Project would occur during construction, and many affected resources (with certain exceptions as noted below) would return to pre-construction conditions within a few years following construction. Therefore, construction-related cumulative impacts could occur if other projects in the geographic scope would affect similar resources within those timeframes. Exceptions to this would include forest clearing, the permanent filling of wetlands and other areas with granular fill, and air/noise and visual impacts related to aboveground facility operation, which would constitute long-term or permanent impacts.[181]

Based on the geographic and temporal criteria discussed above, we identified past, present, and reasonably foreseeable actions with which the Alaska LNG Project could cumulatively affect the environment. Appendix W-1 identifies and describes these actions, including the status of each action, area affected (if available), location relative to the nearest Alaska LNG Project facility, geographic scope, and resources with potential cumulative impacts.

[181] See the introduction to section 4.0 for definitions of long-term and permanent impacts.

TABLE 4.19.1-1

Geographic Scope by Resource Type for the Cumulative Impacts Analysis

Resource Type	Geographic Scope
Geology	Within or adjacent to the Alaska LNG Project footprint, or with overlapping mineral extraction sites
Soils	HUC12 watershed [a]
Groundwater	Same aquifer as the Alaska LNG Project footprint
Surface Water	HUC12 watershed [b]
Wetlands	HUC12 watershed
Vegetation	HUC12 watershed
Wildlife	HUC12 watershed; HUC10 watershed for migratory animals
Fisheries and Aquatic Resources	HUC12 watershed
Special Status Species	HUC12 watershed
Land Use, Recreation, and Special Interest Areas	HUC12 watershed
Visual Resources	The area within 15 miles of the Alaska LNG Project footprint (the viewshed as defined by the Visual Impact Analysis)
Transportation	Roads, railways, ports, waterways, and airports used during Alaska LNG Project construction and operation, as defined in section 4.12
Socioeconomics	Alaska
Cultural Resources	Defined APE
Subsistence	Community subsistence use areas and migratory ranges of subsistence resources
Air Quality	Construction - within 0.25 mile (0.4 km) of the Project footprint. Operation - within 31 miles (50 km) of LNG facilities, the GTP, and compressor stations; includes criteria pollutants, HAPs, and VOCs. GHG emissions do not have a localized cumulative impact with nearby projects.
Noise	Within audible range of construction and operational noise (within 0.25 mile from construction workspaces, 0.5 mile from DMT sites, and 1.0 mile from operating aboveground facilities)
Public Health and Safety	Boroughs, census areas, and villages where there are Project facilities and major Project transportation routes

[a] A watershed is an area of land that drains surface waters and rainfall to a common outlet. Watersheds in the United States are classified into hierarchical units that diminish in size as follows: HUC2 = region; HUC4 = subregion; HUC6 = basin; HUC8 = subbasin; HUC10 = watershed; and HUC12 = sub-watershed. The Alaska LNG Project would cross 165 HUC12 watersheds.

[b] For marine waters, the geographic scope includes Prudhoe Bay and Cook Inlet.

4.19.2 Non-jurisdictional Facilities

Non-jurisdictional facilities are those facilities that do not fall under the jurisdiction of the Commission but are integral to the need for a project and/or are minor components that would be built as a result of the jurisdictional facilities (see section 1.5). Non-jurisdictional facilities associated with the Alaska LNG Project include:

- modifications/new facilities at the PTU (PTU Expansion Project);
- modification/new facilities at the PBU (PBU MGS Project);
- relocation of the Kenai Spur Highway;

- upgrades to the City of Kenai water system;
- in-state gas interconnections; and
- LNG carrier transits to and from the Liquefaction Facilities during operation of the Alaska LNG Project.

Because impacts from these non-jurisdictional projects would be cumulative with those of the Alaska LNG Project, the projects are included in appendix W-1 and discussed in section 4.19.4 with other past, present, and reasonably foreseeable actions. Currently identified environmental impacts associated with the non-jurisdictional facilities are included in the resource sections that follow.

We received comments during scoping about growth-inducing impacts associated with gas production on the North Slope, which would supply the Alaska LNG Project. Construction of the Alaska LNG Project would, for the first time, provide a means for the North Slope's vast natural gas reserves, estimated at 20 trillion cubic feet, to reach consumers (White, 2015). Lacking access to markets, natural gas has been produced by existing infrastructure and then reinjected into the oil-producing formations to bolster reservoir pressures and enhance oil recovery. Currently, over 8 Bcf per day of gas is being produced and reinjected into the ground due to a lack of infrastructure to deliver that gas to market. Some of this gas would now be transported to the GTP and then down to the Liquefaction Facilities via the Mainline Pipeline, rather than being reinjected. Thus, the Project would facilitate the delivery of the natural gas to market.

AGDC states that beyond the PTU Expansion and PBU MGS Projects, and modifications upstream of the GTP, the Alaska LNG Project would not induce development of additional production fields, at least in the initial years of its operation. It is likely that additional wells would be drilled at some point in the future as existing wells are exhausted; however, when or precisely where they would be drilled is unknown, much less what the associated infrastructure and related facilities would be for those wells. AGDC anticipates that the Project would be fully utilized by natural gas produced from wells already drilled on the North Slope for about 20 years before there would be available pipeline capacity for new production. Although new gas wells may be drilled beyond that 20-year time frame that would contribute to cumulative impacts on the environment of the North Slope, the need for additional gas wells to be drilled on the North Slope, the number of wells, and the timing of such drilling, would be market driven and not reasonably foreseeable. Thus, any analysis beyond this 20-year time frame would be speculative.

4.19.2.1 PTU Expansion Project

AGDC estimates that about 25 percent of the natural gas shipped on the Alaska LNG Project would originate from the Point Thomson Reservoir, a high-pressure gas condensate production field operated by Exxon since 2016. Existing facilities at the PTU are used to extract condensate from the reservoir through a process of cycling (i.e., reinjection of natural gas into the reservoir). The PTU Expansion would enhance and expand the existing facilities to produce natural gas for delivery to the Alaska LNG Project rather than reinjecting the gas back into the reservoir.

The PTU Expansion Project would require the incremental expansion of an existing well pad (Central Pad) by 7 acres to accommodate new facilities. An additional 7-acre multi-season ice pad adjacent to the Central Pad would be used over one summer for construction offices, warehousing, and equipment storage. Three new production wells would be drilled at the Central Pad, one existing gas injection well would be converted to a production well, and a new UIC Class I disposal well would be drilled on that same pad. A second existing pad (West Pad) at the production field would not be expanded for the project.

Granular material (e.g., gravel or crushed rock) for the pad would be obtained from an existing PTU stockpile; no new quarrying would be necessary. The pad expansions would be of sufficient thickness to protect the underlying permafrost from thawing. Other design considerations to protect the permafrost include installation of insulated conductors at production and disposal wells, which would minimize heat transfer between hydrocarbon fluids and permafrost. At new wells, installation of thermosiphons would prevent thawing of near-bore permafrost.

The PTU Expansion Project facilities would be fabricated off site with modular components shipped to the project area for installation. Delivery of modular facilities would be accomplished by sealift, which would require dredging about 5,000 cubic yards of material to enable barges to reach the Central Pad for unloading. Dredging would take place in the winter months by cutting through the ice. Any excess material removed by dredging would be placed along the coast to the west of the Point Thomson marine facilities. Minor screeding may take place in summer months immediately prior to the arrival of barges. Maintenance dredging is not anticipated to be required. A barge bridge would be created by ballasting and grounding the oceangoing barges in series to enable module movement to Central Pad. Personnel, materials, and equipment would be brought to the site by year-round air transportation, an annual winter ice road, and in the summer by barge or boat.

Construction of the PTU Expansion would occur over about 2 years beginning in Year 2 and concluding in Year 4 of the Alaska LNG Project. The construction and drilling workforces would be housed in temporary construction camps at Point Thomson as well as camps at Prudhoe Bay and Badami.

With respect to federal regulatory approvals, the PTU Expansion Project would require authorizations from the COE and EPA and consultations with various resource agencies, such as the USFWS and NMFS. The COE would determine whether to issue a permit for construction of the project under Section 404 of the CWA and Section 10 of the RHA. The COE additionally would be the lead agency responsible for conducting an environmental review of the project under NEPA. Exxon has had pre-applications meetings with the COE, but does not currently have a permit application pending for the expansion project.

AGDC indicates that the UIC Class I disposal well to be drilled at the Central Pad has received a permit from EPA under the UIC program governing construction, operation, and closure requirements for injection wells. EPA would also require Facility Response Plans to demonstrate preparedness in case of a worst-case oil discharge, and an SPCC Plan to prevent environmental damage from the discharge of oil, under Section 311 of the CWA. If the project anticipates discharge of any pollutants into waters of the United States, ADEC would determine whether to issue a general or individual APDES permit.

The PTU Expansion Project would be subject to review by the COE to assess impacts on species listed under the ESA. Because there are ESA-listed species in the project area, and the project requires a federal permit, Section 7 consultation would be required with the USFWS and/or NMFS. The PTU Expansion Project would be subject to the MBTA and BGEPA regarding migratory birds and bald and golden eagles, respectively. The COE would examine the project's impacts on wildlife in its Section 404 analysis. Determinations of the project's effects on historic properties would be made by the COE pursuant to Section 106 of the NHPA.

At the state level, the ADNR approved Exxon's *Plan of Development for the PTU Expansion* in December 2017. In September 2018, ADNR and the PTU owners/operators agreed to an extension of a 2012 Settlement Agreement to align work commitments and timelines with the Alaska LNG Project. Under the extension, the PTU owners/operators will provide work plans to ADNR to develop Point Thomson for major gas sales within 90 days of a Final Investment Decision on the Alaska LNG Project.

Permits for water appropriation on a temporary basis and for operational purposes would be required from the ADNR, Division of Mining, Land, and Water. ADEC would determine whether to grant water quality certification under Section 401 of the CWA, a construction stormwater permit under Section 402 of the CWA, and a PSD permit for air pollutant emissions. Wastewater disposal would require APDES permits from ADEC. The ADF&G would determine whether to issue a Fish Habitat Permit for construction activities within fish-bearing streams.

The AOGCC would issue a Permit to Drill for development and injection wells. The AOGCC would also need to authorize gas production from the PTU. The AOGCC oversees oil and gas drilling, development and production, reservoir depletion, and metering operations on all lands subject to the state's police powers. The AOGCC acts to prevent waste and improve ultimate recovery. It also administers the UIC Class II well program for enhanced oil recovery. Currently, PTU gas is reinjected into the field to enhance recovery of condensate. Numerous other minor state and local permits would be required as well.

4.19.2.2 PBU MGS Project

Seventy-five percent of the natural gas expected to be transported by the Alaska LNG Project would come from the Prudhoe Bay field, where the PBU, a large oil producing facility, has been in operation since 1977. Oil and natural gas are extracted from about 900 existing wells on 40 drilling pads at the PBU, but the gas is currently compressed and reinjected into the field. The PBU MGS Project would expand and enhance the existing facilities at the site to produce natural gas for delivery to Alaska LNG rather than reinjecting the gas back into the field. While most of the infrastructure necessary to gather and transport natural gas from existing wellheads is present at the PBU, some new infrastructure would be required, including valve and metering modules and pipelines.

The PBU MGS Project would include a 5-acre expansion of the CGF pad, requiring about 150,000 cubic yards of granular fill material to allow installation of a valve module and a metering module for feed gas at the CGF. Three new feed gas pipelines, currently designed as 48-inch-diameter lines, and a propane gas pipeline would be constructed from the PBU CGF to the new valve module on the CGF Pad. A short, larger diameter pipeline would connect the new valve module with the new metering module on the same pad. After metering, the gas would be delivered to the PBTL that links the PBU CGF metering module with the GTP. An additional 5-mile-long gas pipeline from the Lisburne Production Center to the PBU CGF may be installed at a future date. The PBU MGS Project would also include construction of four new byproduct pipelines measuring 25, 3, 8, and 8 miles in length (diameter to be determined) to send GTP byproduct to existing well pads for reinjection into the field. All of the pipelines would be aboveground, supported by VSMs, permanently affecting a total area of about 1.5 acres.[182] The construction footprint of the PBU MGS Project would total about 514 acres.

About 10 new production and injection wells could be drilled after the Alaska LNG Project is commissioned to enhance gas recovery at the PBU. The number of new wells and schedule for their completion would be based on factors related to gas recovery for sales and byproduct injection into the field. In addition to the new wells, some existing wells would be shut in (i.e., removed from active service) and others worked over (i.e., subjected to major maintenance or remedial treatments), based on factors such as field efficiency, gas sales, gas injection, oil production, GTP byproduct injection, and well integrity. These construction operations would temporarily increase emissions of criteria pollutants, VOCs, HAPs, and GHGs. Operational air emissions and water usage would not be expected to increase within the Prudhoe Bay field because of the PBU MGS Project and would be expected to remain within existing permitted limits.

[182] Based on an assumption of 2,500 dual-based VSMs, each with a footprint of 26 square feet.

Construction of the PBU MGS Project facilities would occur during winter seasons over a 4- to 6-year period beginning in Year 1 and ending in Year 7 of the Alaska LNG Project. Drilling would begin in Year 5 and be completed in Year 9 of the Alaska LNG Project. If necessary to house the construction and drilling workforces, a 200-person camp would be established on one of the existing pads at the PBU.

The PBU MGS Project would require environmental reviews and permits similar to the PTU Expansion Project, other than permits for injection wells, which are not proposed. The COE would be the lead agency for conducting an environmental review of the project under NEPA. An application to the COE for the PBU MGS Project has not been submitted. The AOGCC would also need to authorize gas production from the PBU. Currently, PBU gas is reinjected to enhance oil recovery.

4.19.2.3 Kenai Spur Highway Relocation

Construction of the proposed Liquefaction Facilities would require relocating about 1.3 miles of the existing Kenai Spur Highway, which connects the Sterling Highway (Alaska Highway 1) to a port facility at the north end of Nikishka Beach Road. AGDC would fund, design, and construct a new 3.9-mile-long segment of highway east of the proposed site for the Liquefaction Facilities in accordance with ADOT&PF standards. The roadbed of the highway would be 100 feet wide within a 200-foot-wide right-of-way, encumbering about 93 acres. Construction would be completed before work begins on the LNG Plant at the Liquefaction Facilities.

The relocated highway segment would have two 12-foot-wide travel lanes, 8-foot-wide shoulders to accommodate bicycles and pedestrians, and a 12-foot-wide turn lane to ease additional traffic to the LNG Plant. The design would accommodate anticipated traffic volumes beyond Year 6 of Alaska LNG Project construction. The new highway segment would have a posted speed limit of 55 miles per hour.

AGDC is working with ADOT&PF and Kenai Peninsula Borough on planning the highway relocation. After conducting routing studies and a public outreach program, selection of a preferred alternative route (the West LNG Alternative) was announced in June 2018. The preferred alternative is the shortest length, would affect the fewest individual land parcels, and require the fewest residential relocations of all the alternatives analyzed. The preferred alternative leaves the existing highway alignment near the South Miller Loop Road intersection at about highway MP 19. From there, it heads northeast in an undeveloped area for about 1.0 mile, before turning west at North Miller Loop Road, merging with the existing highway alignment at about highway MP 21.5.

The highway relocation project must comply with federal statutes such as the ESA, MBTA, BGEPA, and the NHPA. Various state permits, including a temporary water use authorization, construction stormwater permit, an air permit for temporary construction facilities, and local permits from Kenai Peninsula Borough, including a conditional use permit, would be required as well. The preferred alignment does not cross wetlands or navigable waters, so a permit from the COE would not be required. Similarly, the preferred alignment is outside mapped floodplains, so floodplain permitting would not be required. While future development could occur along the new segment of relocated highway, no new developments are currently proposed or known.

4.19.2.4 Kenai Municipal Water System Upgrades

AGDC has had discussions with the City of Kenai about using Kenai's municipal water system to supply water for construction and operation of the Liquefaction Facilities. The city's preliminary

engineering studies determined that in order to meet the Liquefaction Facilities' needs, the following upgrades to its water system would be required.

- Water Production: Two new 12-inch-diameter water wells would be drilled, and yard piping would be installed at an existing well site.

- Water Treatment: The existing water treatment plant capacity would possibly be expanded from 1.5 million to 2.5 million gpd. The expansion may not be required if tests determine that existing filters can handle projected increased flowrates. As discussed in more detail in section 4.19.4, arsenic treatment could be required in the event elevated arsenic levels are observed due to increased water production.[183]

- Water Distribution: Two new distribution pump houses would be installed, 500 feet of distribution piping would be replaced, and a new 6.1-mile-long, 16-inch-diameter water pipeline would connect the west end of Kenai's water system with the Liquefaction Facilities. The new pipeline would be built along the Kenai Spur Highway between about highway MPs 14 and 20.

AGDC indicates that, based on a preliminary understanding with the City of Kenai, AGDC would pay for the system upgrades, and the city would construct and own the facilities.

4.19.2.5 In-State Gas Interconnections

AGDC indicated it would install taps or isolation valves at a minimum of three locations along the Mainline Pipeline to allow for future interconnects with lateral pipelines to provide in-state deliveries of natural gas to third-party utility or industrial customers. Moving natural gas from these interconnection points on the Mainline Pipeline to in-state customers would require the construction of additional facilities, such as off-take stations,[184] lateral pipelines, or local distribution systems. To date, AGDC has identified locations for the following three interconnections based on the execution of binding gas delivery agreements with end-use customers:

- Fairbanks/North Star Gas Interconnection near MP 441 would allow for a future lateral (not currently proposed) for gas delivery to the Fairbanks area.

- Anchorage/Matanuska-Susitna Gas Interconnection near MP 764 would allow a future interconnect (not currently proposed) with an existing ENSTAR pipeline for gas delivery to the Anchorage/Matanuska-Susitna Valley area.

- Kenai Peninsula Gas Interconnection near MP 806 would allow a future interconnect (not currently proposed) with an existing ENSTAR pipeline for gas delivery to the Kenai Peninsula area.

These three interconnections would be accessible at the time the Mainline Pipeline is placed into service. Other future interconnections could be established during the life of the Alaska LNG Project to accommodate industrial or residential growth that could occur in communities surrounding the pipeline.

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183 Arsenic naturally occurs in the strata containing the aquifer.

184 Offtake stations, also called distributor regulator stations, would deliver gas from the Mainline Pipeline into low-pressure local distribution systems. The stations would serve as intermediaries between the connections to the Mainline Pipeline and the laterals conveying the gas to the transfer point to end-users. Each station would typically include the following: pressure regulation or control valves; gas heater; gas filter; measurement instrumentation; over-pressure protection equipment; odorization system; telemetry and communication for SCADA instrumentation; and security infrastructure, such as a fence, enclosed structure around the station equipment, or both.

There are currently no plans to construct additional facilities, such as off-take stations, lateral pipelines, or distribution systems, to provide future natural gas deliveries to in-state customers. As discussed in section 3.6.3, a lateral from the Alaska LNG Project to Fairbanks would measure a minimum of 30 miles in length and affect at least 364 acres of land.[185] Because the Project crosses existing ENSTAR pipelines in the Anchorage/Matanuska-Susitna Valley and Kenai Peninsula areas, lateral pipelines most likely would not be required for these interconnections. The extent and scope of any off-take stations or distribution facilities for the Fairbanks, Anchorage, and Kenai interconnections are unknown. Similarly, the location, extent, and scope of off-take stations, laterals, and distribution facilities for any other future interconnections are unknown.

The timing, design, and entities responsible for construction and operation of facilities associated with the in-state interconnections would depend upon commercial agreements between AGDC and its customers. Intrastate natural gas pipelines and utilities are regulated by the Regulatory Commission of Alaska. Permits required for lateral pipelines and associated facilities would depend upon the specific project design, but could include Section 404 permits from the COE for crossings of waters of the United States, including wetlands; easements and construction permits from federal and state land management agencies if public lands are crossed; and various other federal, state, and local permits.

Impacts from the future construction and operation of off-take stations, laterals, or distribution facilities could occur during the construction and operational phases of the Alaska LNG Project, and would, in whole or in part, lie within the Alaska LNG Project's geographic scopes for cumulative effects. Impacts would be similar in kind as those of the Alaska LNG Project but of smaller magnitude.

We received scoping comments about the feasibility of installing an interconnection to provide future service to the Denali Borough and DNPP. The NPS has expressed interest in converting its existing operations, including its bus fleet, to natural gas to reduce air emissions within DNPP. The EPA also recommended this interconnection to support existing public and private businesses and facilities, and future development near the park entrance and visitors center, and within the park boundary. AGDC has indicated that is it feasible to place an interconnection near the DNPP or elsewhere in the borough, but states that an interconnection can only be specifically identified and finalized upon the execution of binding gas delivery commercial agreements. This has not occurred for this location at this time.

We also received comments during scoping about the potential for induced growth due to future service to Alaskan communities not currently able to access natural gas. The gas supplies provided by the Project would be available to communities within a reasonable distance of the Mainline Pipeline. The availability of this gas could induce development of certain natural-gas-intensive industrial uses, such as fertilizer production, which could boost job and population growth in the affected communities. Other existing industrial energy users could find it economical to switch fuels to natural gas from oil or natural gas liquids.

Over time, the improved availability of natural gas could play a role in stimulating new commercial and residential growth by lowering energy costs within the distribution companies' service territories. Distribution systems may in turn need to expand to accommodate commercial, industrial, and residential growth. Over the longer term, the presence of the Alaska LNG Mainline Pipeline could facilitate further development if economic, technical, and public policy factors so warrant. However, the scope, location, and timing of any further induced growth is only speculative at this time. Any resources that could be

[185] The straight line distance from the Alaska LNG Project to Fairbanks is 30 miles. The area of impact is based on an assumed 100-foot-wide construction corridor for the lateral. This length and nominal right-of-way width are the same as analyzed for the ASAP Project's Fairbanks Lateral, as included in the supplemental EIS for that project. On March 4, 2019, BLM and the COE both approved a 12-inch lateral to Fairbanks in association with the ASAP Project.

affected cannot be defined. Therefore, we are unable to include resource impacts from possible future development in this analysis.

4.19.2.6 LNG Vessel Transits to and from the Liquefaction Facilities

Operation of the Alaska LNG Project would require the transit of LNG carrier vessels to and from the Liquefaction Facilities' two loading berths. LNG carriers would range in size between 125,000 and 216,000 cubic meters. The estimated number of vessels per month ranges between 17 and 30, with an average of 21 vessels per month, assuming a nominal 176,000-m^3 LNG carrier design vessel. One LNG carrier would load while another vessel enters and prepares to load at the second berth.

LNG carriers are specially constructed vessels designed to contain liquids stored at a temperature of -260°F. They are equipped with double hulls for additional structural integrity. The space between the inner and outer hulls is used for water ballast, which allows the vessel to maintain a constant draft. A typical LNG carrier would discharge about 9 million to 12 million gallons of ballast water into Cook Inlet during loading operations. LNG carriers are required to install and operate a BWM system that has been approved by the Coast Guard under 40 CFR 162.060 and that meets the applicable ballast water discharge standards as noted in 33 CFR 151.2030.

LNG carriers would be assisted in their navigation of the Cook Inlet and docking/undocking operations by one or more marine pilots, likely from the South West Alaska Pilots Association, based in Homer. A total of five assist tugs are currently planned to support LNG carrier operations, with four of the tugs used to assist the ships during berthing. Tugs used to support berthing and mooring of LNG carriers would be anchored in the vicinity of Nikiski. Emissions from LNG carriers and support vessels are identified in section 4.15.

When ice is present in Cook Inlet, an ice management system would be implemented to support LNG carrier transit to and from the Marine Terminal. Ice-class support tugs would perform patrol/scouting, ice clearing, and ice breaking during winter months.

The Coast Guard has filed a letter of recommendation with FERC recommending Cook Inlet as a suitable waterway for the Alaska LNG Project's Liquefaction Facility and LNG carrier operations. LNG carriers calling at the Marine Terminal would comply with all federal and international standards regarding LNG shipping. The ships would be equipped with an array of cargo monitoring and control systems, such as cargo pressure and temperature monitoring, emergency shutdown of cargo pumps and valves, monitoring of tank cargo levels, and gas and fire detection. We have included a discussion of the expected resource impacts associated with the transit of LNG vessels associated with the Project in the appropriate sections of this EIS.

4.19.3 Past, Present, and Reasonably Foreseeable Cumulative Actions

Appendix W-1 lists and describes actions (projects) that have been constructed, are currently being constructed, or are planned or proposed within the geographic scopes defined for the Alaska LNG Project, and so are considered in this cumulative impacts analysis. These projects were identified by a review of publicly available information; aerial and satellite imagery; consultations with federal, state, and local agencies/officials and development authorities; and information provided by AGDC. The projects, including the non-jurisdictional facilities described above, are shown on figures 4.19.3-1, 4.19.3-2, and 4.19.3-3. More detailed maps showing the projects in relation to the HUC12 and HUC10 watershed boundaries are provided in appendix W-2. With a few exceptions, most of the projects fall into one or more of the following four categories: energy infrastructure, transportation, mining, and marine. Several other current or reasonably foreseeable projects that do not fit into one of these categories were also identified. These include a fertilizer plant and military, recreational, maintenance dredging, and utility projects.

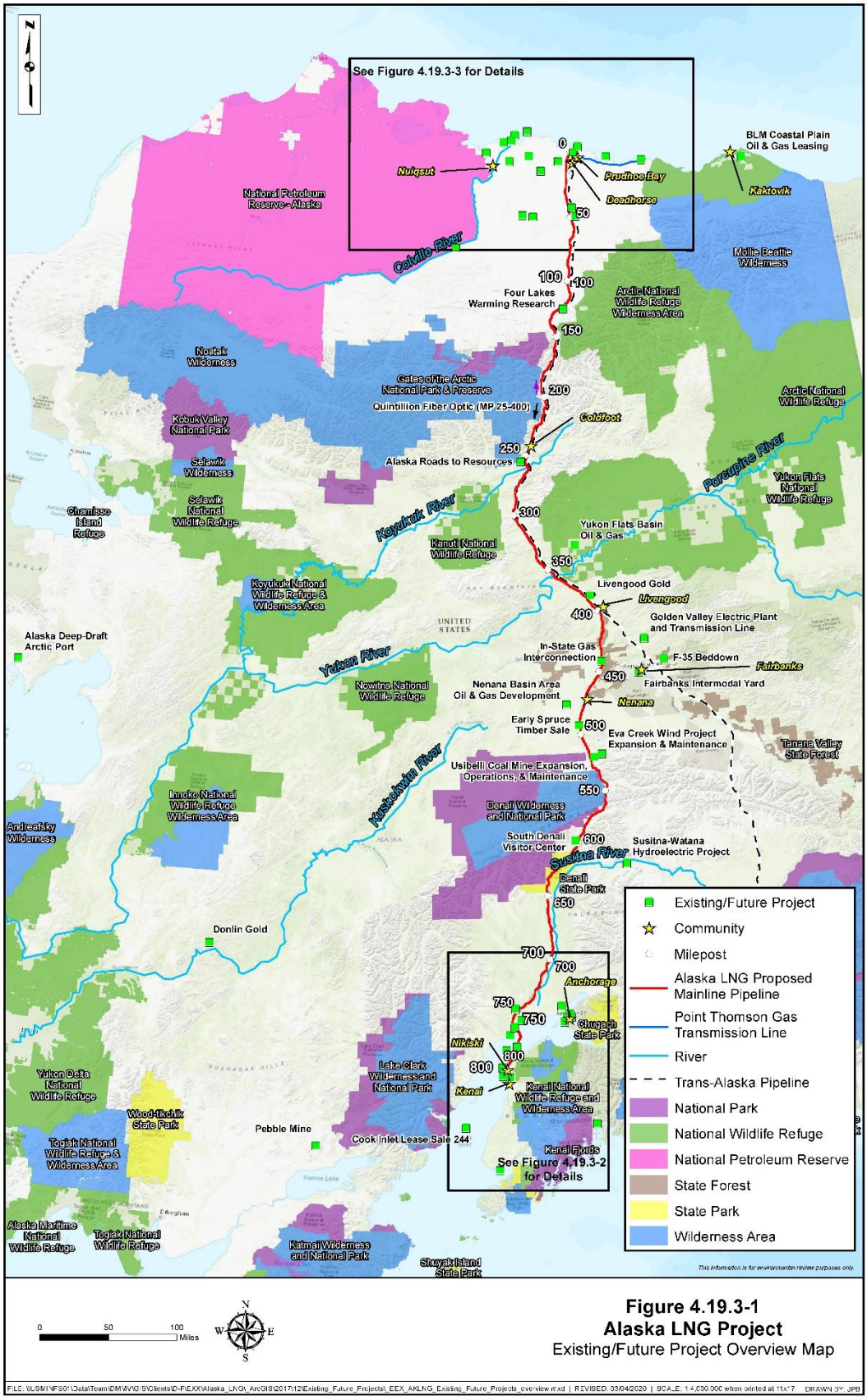


Figure 4.19.3-1
Alaska LNG Project
Existing/Future Project Overview Map

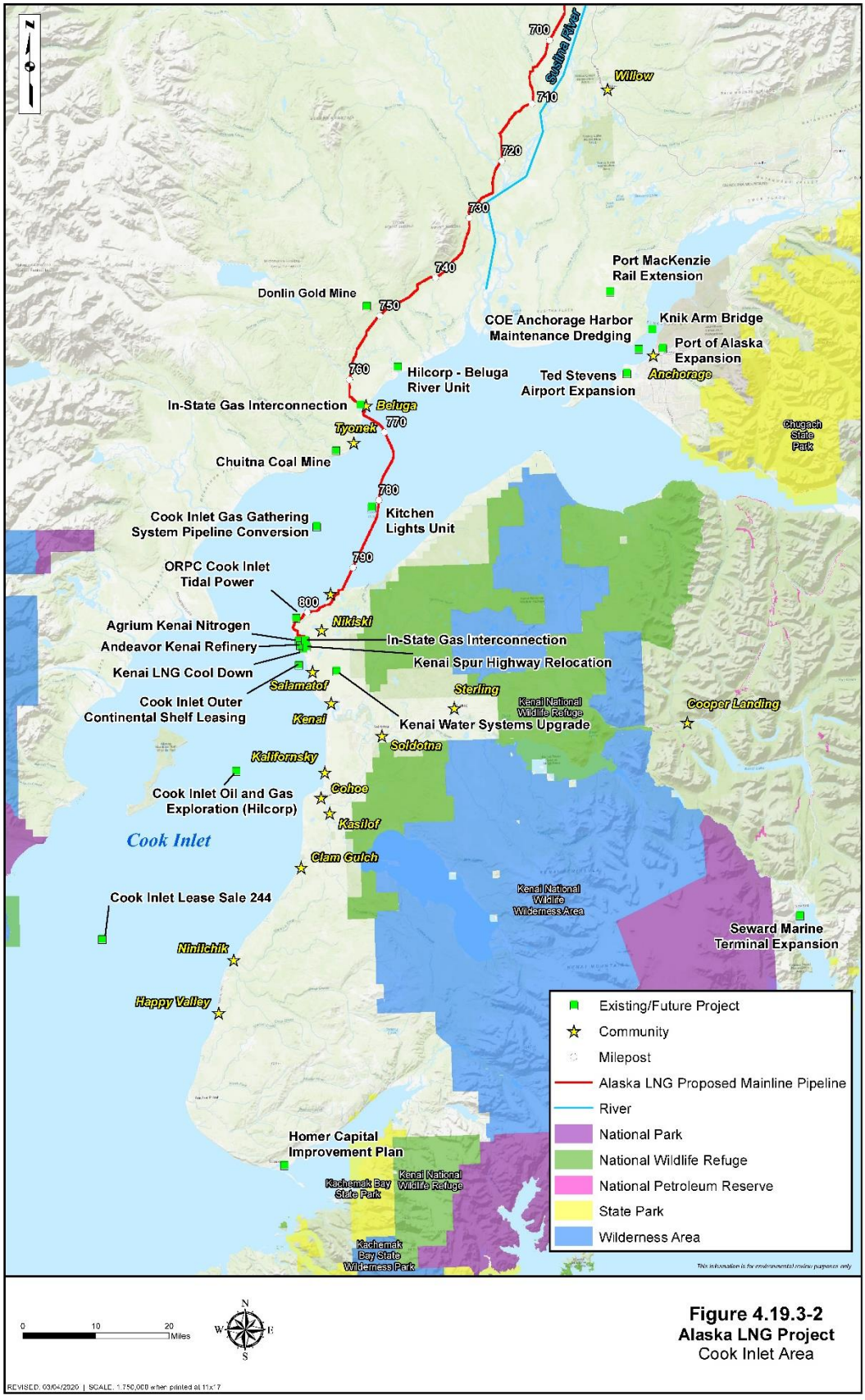


Figure 4.19.3-2
Alaska LNG Project
Cook Inlet Area

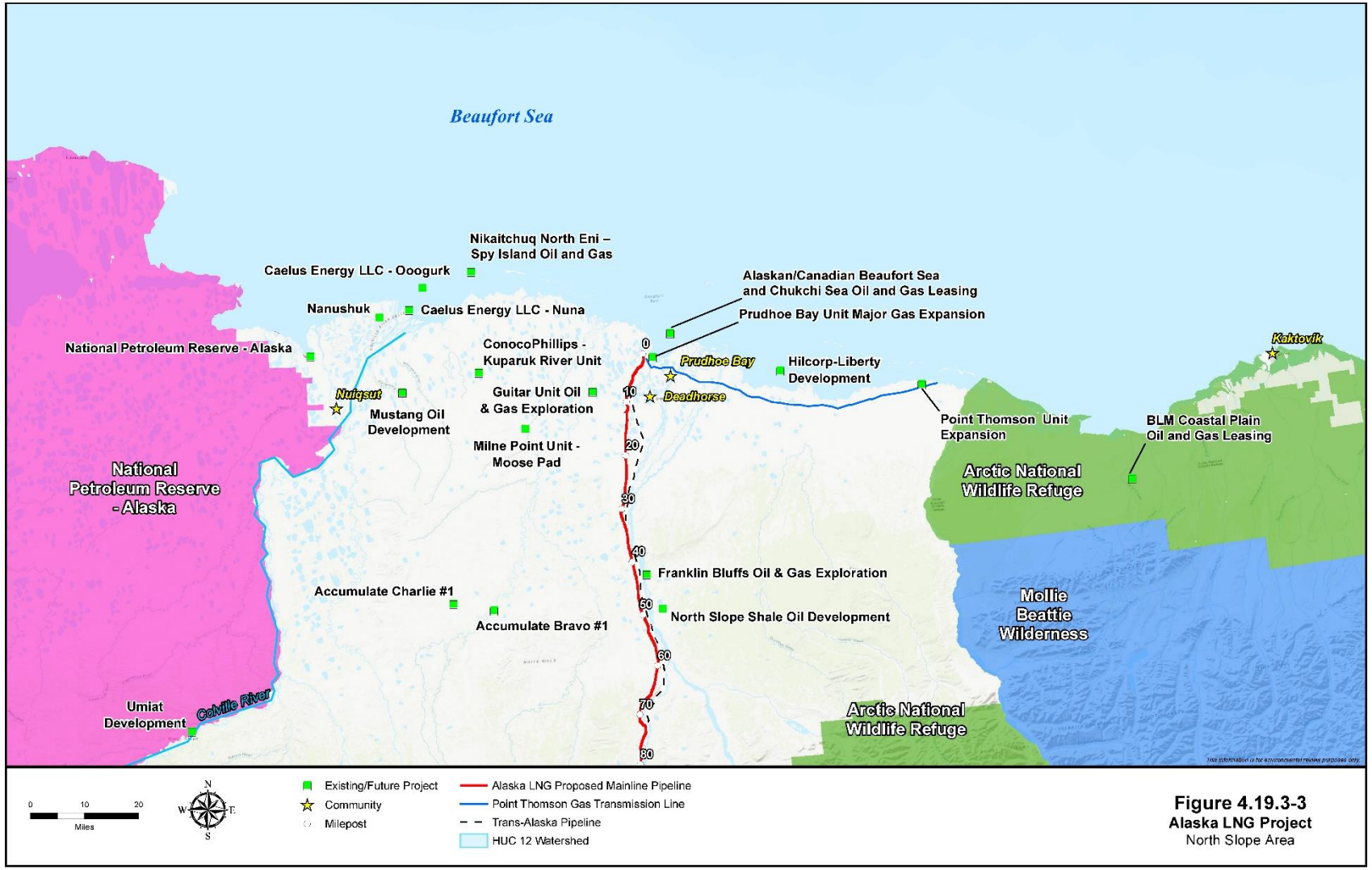


Figure 4.19.3-3
Alaska LNG Project
North Slope Area

The ASAP Project is not included in the list of projects analyzed for cumulative impacts. Under the ASAP Project, AGDC proposed to construct a 733-mile-long, 36-inch-diameter natural gas pipeline from Alaska's North Slope to an existing natural gas distribution system (ENSTAR Natural Gas Company), which serves the south-central region of the state. The ASAP Project does not involve the export of natural gas outside of Alaska. The objectives and regulatory frameworks of the ASAP and Alaska LNG Projects are different, and the projects are therefore evaluated separately. Given the ability of both projects to deliver natural gas from the North Slope to south-central Alaska, AGDC has stated that the ASAP Project would not be built if the Alaska LNG Project proceeds.

The recently proposed Qilak LNG Project would ship LNG from a new liquefaction facility (location to be determined) on the North Slope (see section 3.2.1). The possible environmental impacts of the Qilak LNG Project have not been assessed. In addition, because both the Qilak LNG Project and the Alaska LNG Project would seek to liquefy and ship North Slope gas, it appears unlikely that both projects would be built. Further discussion of the Qilak LNG Project is included in section 3.2.1 of this EIS.

4.19.3.1 Energy Infrastructure Projects

Oil and gas exploration/development projects are the most numerous type of project considered in this cumulative impacts analysis. Pipelines, electric transmission lines, hydroelectric, and wind energy projects are also included. Linear infrastructure facilities tend to run in the same direction as the Alaska LNG Project, except for the future in-state gas interconnection pipelines, which would extend laterally from the Mainline Pipeline.

Including the non-jurisdictional facilities, 16 energy infrastructure projects are located or proposed to be located on the North Slope, 7 are in the interior part of the state, 11 are in the Cook Inlet vicinity, and 1 has components in the interior and Cook Inlet areas. Of these 35 projects, 15 lie entirely or partially within HUC12 watersheds crossed by the Alaska LNG Project. The remaining 20 projects were included in this analysis to account for potential cumulative impacts on groundwater, wildlife, visual resources, transportation, socioeconomics, subsistence, air quality, and/or public health and safety in accordance with the geographic scopes for these resources, as defined in table 4.19.1-1.

4.19.3.2 Transportation Projects

Transportation projects include new road, highway, and bridge construction; ongoing road maintenance projects; and airport and rail projects. Including non-jurisdictional facilities, five transportation projects are in the Cook Inlet vicinity, while three are in interior Alaska. Three projects lie entirely or partially within the same HUC12 watersheds crossed by the Alaska LNG Project. The remainder were included in this analysis to account for potential cumulative impacts on groundwater, wildlife, visual resources, transportation, socioeconomics, subsistence, air quality, and/or public health and safety in accordance with the geographic scopes for these resources, as defined in table 4.19.1-1.

4.19.3.3 Mining Projects

Five mining projects were included in the analysis. Of these, the Usibelli Coal Mine near Healy, and a portion of the gas pipeline associated with the Donlin Gold Mine, lie within the same HUC12 watersheds as the Alaska LNG Project. Mining leases and operations at the Usibelli Coal Mine are currently limited to the area east of the Alaska LNG Project by the Nenana River. Future expansion of the Usibelli Coal Mine is not currently proposed and the company has not exported coal outside the state since 2016. Alaska Governor Bill Walker announced in February 2018 that China might have an interest in importing coal from Alaska, however, which could lead to expansion of the mine site (Juneau Empire, 2018).

4.19.3.4 Marine Projects

Marine projects encompass developments on or just off the coast, including port facilities or industrial facilities with marine components. Three such projects were included in the analysis. Of these, two projects are in Cook Inlet and one is in western Alaska. Many of the energy infrastructure projects included in the analysis, such as LNG terminals and tidal energy projects, also have marine components.

4.19.4 Cumulative Impact Analysis by Resource

The Alaska LNG Project would affect geology, soils, water resources, vegetation, wetlands, wildlife, cultural resources, visual resources, air quality, noise, and some land uses. We conclude that most of the Project-related impacts would be contained within or adjacent to the temporary construction right-of-way and ATWS, which would reduce the Project's contribution to cumulative effects. For example, erosion control measures included in the Alaska LNG Project construction and restoration plans would keep disturbed soils within work areas. Vegetative communities would be cleared, but AGDC would implement a Revegetation Plan with performance standards aimed at restoring functional vegetative communities within 3 to 10 years following construction, depending on the ecoregion. The visual impacts of the Alaska LNG Project would vary depending on location and viewer type, and would be mitigated at select KOPs as described in section 4.10. For other resources, the contribution to regional cumulative impacts would be reduced by the expected recovery of ecosystem function.

Long-term or permanent impacts associated with operation and maintenance of Alaska LNG Project facilities would contribute to cumulative impacts. These would include, for example, air, noise, land use, wetlands, and some visual impacts. Project facilities, particularly those associated with granular fill pads and roads, could result in some resources never returning to pre-construction conditions. An assessment of the cumulative impacts of North Slope oil and gas activities, undertaken by the National Research Council at the request of Congress, concluded that "the effects caused by abandoned and unrestored infrastructure [associated with oil and gas development on the North Slope] are likely to persist for centuries and could accumulate further as new structures are added" (National Research Council, 2003).

4.19.4.1 Geologic Resources

The geographic scope of the cumulative impacts analysis for geological resources is defined as areas within or adjacent to the Alaska LNG Project footprint (including mineral extraction sites). Because most of the past, present, or reasonably foreseeable projects listed in appendix W-1 are outside this area, they are not considered as contributing actions to cumulative effects on geological resources. For projects within or adjacent to the Alaska LNG footprint, such as the PTU Expansion and PBU MGS Projects, cumulative impacts on existing mineral resources and/or future mineral development are possible, but unlikely as described below. Cumulative impacts on other geological resources are not anticipated.

Section 4.1.2 identifies existing mineral resources (e.g., ore deposits, industrial material mines, and oil and gas wells) in proximity to the Alaska LNG Project. In addition to these resources, AGDC identified 9 mineral leases, 8 active mining claims, and 28 industrial materials sites within 0.5 mile of the non-jurisdictional facilities, and 708 oil and gas wells within 2,000 feet of the non-jurisdictional facilities. The Alaska LNG Project and other projects could limit future development of mineral resources within the Project area and immediately adjacent lands. The cumulative impact on development of these resources would be minor. Most mining leases and operations (including coal mining at the Usibelli Coal Mine) occur east of the Alaska LNG Project area by the Nenana River and would not be affected by the Project. Oil and gas activities in the vicinity of the Alaska LNG Project are concentrated to the north in the Beaufort Sea and North Slope region or to the south in the Cook Inlet area. No significant impacts on ongoing oil and gas exploration and production from the Alaska LNG Project and other projects would be anticipated.

Projects in the immediate vicinity of the Alaska LNG footprint would be subject to similar geologic hazards, such as seismicity and mass wasting. As discussed in section 4.1.3, the Alaska LNG Project would be designed and constructed in accordance with required design standards to mitigate impacts from geological hazards. Other projects similarly would be required to implement applicable design standards for hazard mitigation. Therefore, we do not anticipate cumulative impacts due to geologic hazards.

4.19.4.2 Soils and Sediments

Impacts on soils and sediments during Alaska LNG Project construction would occur during blasting, clearing, grading, granular fill placement, trench excavation, backfilling, dredging, and the movement of construction equipment along the right-of-way. While these activities could increase the potential for soil erosion, sedimentation, and compaction, most impacts would be limited to the area of direct disturbance due to the implementation of various mitigation measures (e.g., the installation of erosion and sediment controls, as discussed in section 4.3.2). Construction activities affecting surface vegetation and soils could affect permafrost, with impacts extending beyond the limits of the construction area. Permafrost degradation is also possible during operation due to heat transfer from the pipeline to surrounding soils.

Degradation of permafrost could increase the potential for soil erosion, with sedimentation from soil loss concentrated to common watershed outlets. For this reason, the geographic scope of the cumulative impacts analysis for soils and sediments was defined as the HUC12 watersheds crossed by the Alaska LNG Project. Some of the energy projects identified in appendix W-1, such as the PTU Expansion and PBU MGS Projects and future laterals or distribution facilities associated with the in-state gas interconnections, would require the expansion of existing facilities or construction of new infrastructure, including well pads, access roads, or pipelines. Impacts from construction and operation of natural gas gathering and other pipelines and associated facilities would be similar to those expected from natural gas transmission lines, but on a smaller scale due to the smaller diameter and shorter length of the pipe and smaller size of aboveground appurtenances. Several large diameter pipelines could also be constructed within the same timeframe or shortly after the Alaska LNG Project construction, such as future laterals associated with the in-state gas interconnections, resulting in similar environmental impacts, including permafrost degradation due to soil disturbance or heat transfer from pipelines. The portions of these projects within the same HUC12 watersheds as the Alaska LNG Project could combine to result in cumulative impacts on soils and sediments, including impacts on permafrost. The new pipelines for the PBU MGS Project would be installed above grade on VSMs, which would mitigate some of the cumulative impacts on permafrost.

Two fiber optic projects, the Quintillion Terrestrial and the GCI Alaska United fiber optic projects, were installed adjacent to the Dalton Highway in 2017. Since these projects were built, about 20 segments of their rights-of-way on the North Slope ranging in length from 20 to 500 feet have experienced permafrost thawing, resulting in settlement and ponding in these locations (Alaska Public Media, 2018b). Remedial restoration work is in progress in these areas to avoid impacts on highway stability and erosion into adjacent wetlands and waterbodies. The Alaska LNG Project's Mainline Pipeline parallels the Dalton Highway corridor for its first 400 miles, with varying distances of separation between the highway and proposed pipeline. The current problems associated with the fiber optic lines are contributing to cumulative wetland impacts within the watersheds in which they lie. The magnitude of these cumulative impacts by the time the Alaska LNG Project would be constructed could be lessened, however, depending on the success of the fiber optic projects' remedial restoration work currently under way.

AGDC would minimize direct construction impacts associated with soil erosion, sedimentation, and compaction through the implementation of the mitigation measures and plans described in section 4.2.4 (e.g., the Project Plan, Winter Permafrost Construction Plan, Geohazard Mitigation Approach, and SWPPP). These measures include the installation of erosion and sediment controls, construction of

facilities in winter or frozen ground conditions, and restoration of areas temporarily disturbed by construction. Other projects, including the PTU Expansion and PBU MGS Projects and Kenai Spur Highway Relocation Project, would implement similar measures to avoid or minimize erosion, sedimentation, and compaction as required by federal and state review agencies or as specified in permits. These actions would minimize cumulative impacts on soils and sediments.

Existing facilities, such as the Agrium Kenai Nitrogen Operations Facility, Kenai LNG Cool Down Project, and the Andeavor Kenai Refinery, have had adequate time to become stabilized through revegetation and/or stormwater management and would not contribute to cumulative impacts on soils and sediments. Additionally, no cumulative impacts on soils or sediments from ongoing operation and maintenance activities at these and other existing facilities, including the Usibelli Coal Mine, would be anticipated, and no expansions of these facilities are currently proposed.

Based on the above discussion, we conclude that cumulative effects on soils and sediments due to permafrost degradation are likely for the following reasons: 1) permafrost thawing is an ongoing problem in locations within the same HUC12 watersheds as the Alaska LNG Project (e.g., along the Dalton Highway associated with the fiber optic line projects); 2) thawing of permafrost would occur due to the Alaska LNG Project; and 3) permafrost thawing could occur due to other projects within the same HUC12 watersheds, such as highway maintenance projects or construction of new laterals for the in-state gas interconnections. The success of remediation of impacts on permafrost along the fiber optic line projects is unknown at this time. Because permafrost thaw and the creation of thermokarst can spread laterally beyond the footprint of a project, and impacts on permafrost would affect hydrology and vegetation, the Project, together with other actions, would result in significant cumulative impacts on permafrost. Minor cumulative impacts due to erosion, sedimentation, or compaction, would be anticipated.

4.19.4.3 Water Resources

Groundwater Resources

The Alaska LNG Project could contribute to cumulative impacts on groundwater resources where other actions occur within the same aquifers. As described in section 4.3.1, the Alaska LNG Project and associated non-jurisdictional facilities would be built within three hydrological regimes, i.e., the Arctic, Interior, and South-Central Regimes. Although groundwater within the northern Arctic regime was determined to be unsuitable for use as drinking water, the Alaska LNG Project south of about MP 263 would cross several Quaternary unconsolidated alluvial and colluvial aquifers that are sources of drinking water.

The proposed Alaska LNG Project would cross 29 PWS and be within 150 feet of 137 known public and private water wells and no identified springs. Activities with the potential to affect water quality or yield in these and any other as of yet unidentified nearby wells or springs include clearing, grading, trenching, blasting, and inadvertent spills of fuels or lubricants during construction. To minimize impacts, such as the introduction of sediments or contaminants into well water, AGDC would implement the procedures described in its Water Well Monitoring Plan, SPCC Plan, and Blasting Plan. Other projects with potential to affect wells or springs, including the non-jurisdictional facilities, would likewise be required to implement measures (e.g., spill plans and blasting BMPs) to protect wells and springs as required by permits or in accordance with federal, state, or local regulations. For example, the Kenai Spur Highway Relocation would be required to adhere to ADOT&PF design standards and construction BMPs, which include measures to protect soils and groundwater from contamination caused by spills during construction. Therefore, cumulative impacts on wells and springs are not anticipated. Further, with the implementation of the Project SPCC Plan and Groundwater Monitoring Plan, we do not anticipate any discernable cumulative effects on groundwater as a result of inadvertent spills of fuels or lubricants.

Groundwater withdrawals associated with the Alaska LNG Project could have a cumulative effect on aquifers for which withdrawals are ongoing or planned. These effects would be limited to areas affected by other projects within the same aquifer as the Alaska LNG Project footprint. While the Usibelli Coal Mine[186] and South Denali Visitor Center projects are two of the closest projects to the Mainline Pipeline, they are not within aquifers crossed by the Alaska LNG Project. Several past, present, or proposed actions are within the same aquifer as the Liquefaction Facilities, including the Agrium Kenai Nitrogen Operations Facility, Andeavor Kenai Refinery, and Kenai LNG Cool Down projects. All three facilities require water for their operation, although the quantity and sources are not known.

To provide water to the proposed Liquefaction Facilities, the Kenai Water System would be upgraded to draw upon the aquifer used to supply its municipal water supply system. Based on the *City of Kenai Water System Feasibility Study* provided by AGDC, the Liquefaction Facilities would require flow rates of 250 gpm during the 8-year construction period, 150 gpm during operation, and 1,000 gpm for 24 hours to refill a firewater storage tank following a fire event. The study estimates that the Liquefaction Facilities would have an average daily demand of 360,000 gpd during construction, representing 25 percent of the municipality's total demand during construction; and 220,000 gpd during operation, representing 17 percent of the municipality's total demand during operation.

The target aquifer of the Kenai Water System has an estimated maximum annual yield of 3 million gpd (1.1 billion gallons per year) (Anderson and Jones, 1972). AGDC, in consultation with the City of Kenai, ran numerous scenarios that considered the Kenai service area's future water demands of the municipality and the Liquefaction Facility. During the peak demand year, the combined design maximum daily demand is projected at 2.0 million gpd, with a peak month average daily demand of 1.56 million gpd. Based on these projections, the cumulative draw on the aquifer would be within its capacity.

The *Kenai Water System Feasibility Study* indicates that some private wells potentially could be adversely affected by increased withdrawals at distances up to a few miles away from the City's Well Field No. 2, but noted that these impacts, if they occur at all, could result from increased pumping to meet water demands in Kenai, even if the Alaska LNG Project is not built. The likelihood and degree of any such cumulative impacts on the private wells is unknown. With this exception, we conclude that cumulative impacts on water withdrawals from the Kenai Water System due to the Project would be minor.

The new pipelines and aboveground facilities for the Alaska LNG Project would not be expected to result in significant impacts on groundwater use or quality under typical operating conditions. Impacts could occur if maintenance activities require excavation or repair in proximity to water supply wells or springs. In such cases, the impacts and mitigation would be similar to those described above for construction activities (e.g., implementation of the SPCC Plan and Water Well Monitoring Plan). While three projects with unknown groundwater needs are in the same aquifer as the Liquefaction Facilities, AGDC would obtain water for operation of its facility from the City of Kenai. The proposed withdrawals for the Project are not expected to affect existing or projected water use for the city.

For all the reasons described above, we conclude that significant cumulative impacts on groundwater due to Alaska LNG Project activities combined with other projects in the geographic scope are unlikely.

Freshwater Resources

Project facilities would require crossings of 763 waterbodies by the Mainline Pipeline, PTTL, and access roads. Project facilities (e.g., additional work areas for Mainline Facilities, GTP infrastructure, and the LNG Plant) would affect 18 waterbodies. Both construction and operation of the Project across waterbodies could result in impacts on water availability, flow, and drainage patterns; water quality and

[186] Ongoing operations and maintenance; as noted elsewhere, no expansions are currently proposed for this mine.

chemistry; streambank stability, stream morphology, and riparian habitat; floodplain storage capacities; and permafrost thermal regimes.

Discharge rates are low during the winter for both glacial and non-glacial fed streams due to ice formation. Discharge declines in non-glacial streams during the warm summer months compared to glacial fed streams because of the continuous melting of snow and ice upstream. Glacial streams have high turbidity from fine sediment during the meltwater season but are typically lower in turbidity during winter months. Non-glacial fed streams are characterized by having lower turbidity and higher water temperatures than glacial fed streams, particularly during the summer meltwater periods.

The greatest freshwater impacts would be expected to result from trenching across waterbodies for construction. Additional impacts would occur from erosion of exposed soils in the watershed into waterbodies. This impact is also possible for any of the other projects that involve ground disturbance. With regard to trenching, representative turbidity modeling predicts a maximum downstream distance exceeding water quality standards of about 290 feet, which would last about 1 hour following the cessation of in-stream work. Additive turbidity impacts from other projects would require that the other projects generate plumes within the same waterbody that would occur within the same time interval. We therefore conclude that cumulative turbidity impacts would be unlikely. Erosional runoff impacts within the same HUC12 watersheds are possible, however, if exposed soils from multiple projects experience a simultaneous rainfall event and erosion control measures do not contain the runoff properly.

While cumulative turbidity impacts require that the activities share a spatial and temporal setting, cumulative sedimentation could occur at common depositional stretches within a waterbody affected by more than one project. As the contribution of turbidity by the Project and the other projects considered here is expected to be relatively minor and temporary, we conclude that cumulative sedimentation impacts on freshwater resources would not be significant.

Past, present, or reasonably foreseeable actions that are within the same HUC12 watersheds as the proposed Project in non-marine environments have the potential to contribute to cumulative impacts on freshwater resources. Most of these projects are operating facilities with no known expansion plans; oil and gas leases that have not reached the development stage; or projects on hold for various reasons. The PTU Expansion and PBU MGS Projects, future laterals and other infrastructure associated with the in-state gas interconnections, fiber-optic projects, and the TAPS and highway maintenance and upgrades are most likely to contribute to cumulative impacts on freshwater resources.

Cumulative impacts on freshwater resources could result from the Alaska LNG Project's waterbody crossings, the placement of granular fill for granular fill pads and access roads, water withdrawal and discharge, and spills of fuel and hazardous materials. The only reasonably foreseeable actions within the North Slope HUC12 watersheds crossed by the Project are the PTU Expansion and PBU MGS Projects, portions of which are within the same HUC12 watersheds as the Alaska LNG Project's Gas Treatment Facilities. The PBU MGS Project would cross 3 riverine waterbodies. The pipelines for this project would be aboveground, so the waterbody crossings would be spanned, which would minimize impacts on the bed and banks of the waterbodies. Impacts would also occur where VSM supports for the pipelines are placed within ponds and lakes. Typically, about 100 VSMs are needed per mile of pipeline. While the number of VSM installations within ponds and lakes is unknown, each VSM would have a construction impact of up to about 13 square feet, all within the permanent right-of-way for the pipelines. Given the small area affected by the VSMs, the cumulative impact on waterbodies would be minor.

On the North Slope, placement of granular fill in tundra ponds associated with future oil and gas development or expansion of existing pads would decrease the overall quantity of these freshwater resources within the watershed. While permit requirements and standard construction practices would be expected to limit the number of tundra ponds affected, some ponds are likely to be filled. Because lakes and ponds are numerous in the area, however, the cumulative impact on these features would be minor.

The alignment of the Kenai Spur Highway Relocation Project does not cross any waterbodies, so no freshwater resources would be directly affected. Based on a preliminary engineering study submitted by AGDC, the Kenai Water System Upgrades also appear unlikely to affect freshwater resources, although specific facility locations are yet to be finalized. Future development associated with the in-state interconnections could affect freshwater resources to the extent that pipeline laterals and associated appurtenant facilities are routed near or across waterbodies, which would result in impacts similar to the proposed Project. The locations of any such facilities are not yet known, so the extent of impacts cannot be fully assessed. A potential future lateral to Fairbanks from a point near the Alaska LNG Project's proposed take-off point, however, was analyzed in the EIS for the ASAP Project. The Fairbanks Lateral route analyzed for the ASAP Project has been estimated to require seven stream crossings.

Surface water withdrawals for both the Project and other past, present, or reasonably foreseeable actions would be subject to state permitting requirements, such as volume restrictions and reporting, to ensure adequate volumes of water remain in surrounding freshwater sources to support aquatic life. While water withdrawals could create a temporary drawdown, water levels would be restored, so cumulative impacts on freshwater resources would be minor. Similarly, discharge of hydrostatic test water and wastewater to freshwater resources due to construction and operation of the Project and other actions, such as the PTU Expansion and PBU MGS Projects, would be subject to state regulatory requirements, including the development of project-specific SWPPPs. Therefore, cumulative impacts due to discharges would be minor.

Unlike the existing oil fields and oil infrastructure currently on the North Slope, the proposed Alaska LNG Project would not be extracting or moving large quantities of oil, so there is no potential for cumulative impacts on freshwater from a large-scale oil spill. The release of smaller volumes of hazardous materials or fuel could occur during construction or operation as a result of vehicle refueling, an accident, or from improper material storage. The location and quantity of the release would determine the magnitude and duration of the impact on nearby freshwater resources. AGDC would implement a Project-specific SPCC Plan and BMPs designed to ensure hazardous materials are properly handled and stored. Functionally similar measures would be in place for the PTU Expansion and PBU MGS Projects, and are likely to be required for other projects that would or could be developed within the same HUC12 watersheds as the Alaska LNG Project. These measures would reduce the likelihood and magnitude of a release, such that the overall cumulative impact would be minor, especially when considering the unpredictability and geographic uncertainty associated with the inadvertent nature of material spills.

Freshwater resources previously disturbed by existing facilities, such as the Agrium Kenai Nitrogen Operations Facility, the Kenai LNG Cool Down Project, and the Andeavor Kenai Refinery, have had adequate time to stabilize through the revegetation of disturbed areas in the watershed and/or the implementation of stormwater management plans, and would result in limited cumulative impacts on freshwater resources. Additionally, no cumulative impacts on freshwater resources would be anticipated from ongoing operation and maintenance activities at these and other existing facilities, including the Usibelli Coal Mine, and no expansions of these facilities are currently proposed.

Where new public or private road building and highway improvement/relocation projects intersect the same HUC12 watersheds as the Alaska LNG Project, and would be constructed within the same period, cumulative impacts on freshwater resources could occur. Actions associated with these projects include placement of fill, grubbing, clearing, excavation, paving, equipment staging, and aggregate production. These actions could result in temporary and permanent loss of vegetation and topsoil, increased erosion, alterations to stream flow and water level, increased turbidity and sedimentation, changes to water quality, and increased likelihood of the release of hazardous materials and fuel to surrounding waterbodies. The implementation of construction BMPs, federal and state permitting requirements, SWPPPs, and SPCC plans would reduce the cumulative impact of these individual projects. As noted above, AGDC would have

similar mitigation measures in place to reduce the likelihood and magnitude of similar impacts associated with the Alaska LNG Project. Therefore, the cumulative impact would be minor.

As discussed in the previous section on soils and sediments, recent permafrost thawing on numerous segments of two fiber optic projects adjacent to the Dalton Highway have the potential to cause erosion into waterbodies. Although specific locations of these segments are not identified, the proximity of the Dalton Highway to the Alaska LNG Project alignment suggests that if such problems occur, they could be within the same HUC12 watersheds traversed by the Project. This means that any such impacts would be cumulative to the Project's freshwater resource impacts, most notably temporary turbidity and sedimentation caused by pipeline construction at stream crossings or by thaw bulb formation.

Marine Water Resources

Past, present, or reasonably foreseeable actions that could cumulatively affect marine waters near the West Dock Causeway in Prudhoe Bay are distant from the Alaska LNG Project or not well defined. For example, the Hilcorp Liberty Unit OCS oil development project is 25 miles east of the Project, so cumulative impacts associated with this project would not likely occur. Oil and gas leasing projects such as those in the Beaufort Sea and Chukchi Sea area are nearer to the Project, but have no specific drilling plans as of yet; therefore, the potential scope of cumulative effects from these projects is unknown.

The PTU Expansion Project would require dredging about 5,000 cubic yards of material to enable barges to reach the Central Pad for unloading. Dredging would not be required for the proposed Project, but screeding (subsea scraping) would be conducted in the Dock Head 4 turning basin, affecting about 14 acres. Because dredging for the PTU Expansion Project would occur about 55 miles to the east of the screeding for the Project, there would be no cumulative impacts from these activities.

We received comments from the USFWS about the potential for induced growth associated with the expansion of the West Dock Causeway and construction of Dock Head 4. Although AGDC does not plan to do maintenance dredging or any other expansions during operation of the Alaska LNG Project, it is possible that these activities could be undertaken by others. We are not aware of any specific proposals to do so, however, so the potential cumulative impacts of any induced growth is speculative at this time.

Projects near the Marine Terminal in Cook Inlet include ongoing operations for the Andeavor Kenai Refinery; ongoing operations and new gas well development for Furie Operating Alaska; and potential tidal power projects in Cook Inlet by Ocean Renewable Power Company. The Andeavor Kenai Refinery has no currently planned future projects in marine waters. Furie Operating Alaska, LLC, which until recently owned and operated the Kitchen Lights offshore oil development in Cook Inlet, completed two new offshore gas wells in 2018. Furie Operating Alaska filed for Chapter 11 bankruptcy protection in August 2019 and sold its assets to Hex LLC. Future oil and gas development by Hex LLC in Cook Inlet is possible, but no new projects have been announced or proposed. With respect to the tidal power projects, the preliminary permit for the projects expired in 2016 and the Ocean Renewable Power Company applied to FERC to surrender its license for these facilities. Based on the status of these Cook Inlet projects relative to the proposed Project, they would not contribute to cumulative impacts on marine waters.

AGDC's proposed dredging for the Marine Terminal MOF (about 800,000 cubic yards for construction and 140,000 cubic yards for maintenance) would be cumulative only with annual maintenance dredging by the COE in Cook Inlet (about 600,000 to 1.1 million cubic yards per year). Even if dredging for the Project is concurrent with the annual maintenance dredging by the COE, the cumulative impact would not be significant because turbidity and sedimentation rates are naturally high in Cook Inlet due to the abundance of glacial sediments and strong currents. Conditions would return to normal soon after dredging is complete.

A cumulative increase in marine water vessel traffic associated with the Alaska LNG Project and other projects in Prudhoe Bay or in Cook Inlet would likely increase the risk of spills that could affect marine waters. Given that the vessel traffic associated with the Project and other projects is subject to numerous regulatory requirements intended to prevent spills, and with the implementation of SPCC plans, it is unlikely that spills would occur at the same time and in the same location. Therefore, the overall cumulative impacts of spills on the physical marine water environment would be minimal.

Management of ballast water/withdrawal is an important element in maintaining safe transit of LNG carriers. As described in section 2.1.5, under normal operating conditions, ballast water would be discharged from the ship during LNG loading at the Marine Terminal. A typical LNG carrier of the type in service today would discharge about 12.9 million gallons of ballast water per port call into Cook Inlet during loading operations at the PLF, which would be cumulative to ballast water discharges from other ships in waters near the Kenai site. Estimates of annual ballast discharges from all ships calling at the Kenai Pipeline dock from 1998 to 2001 ranged between 161 million and 260 million gallons (CIRCAC, 2003).

The daily tidal currents and dynamic marine environment in Cook Inlet, along with ship compliance with regulations regarding the management of ballast water, would minimize the potential cumulative impacts of ballast water discharges. As discussed in section 4.7.1, vessels brought into the State of Alaska or federal waters are subject to Coast Guard 33 CFR 151 regulations, which prohibit discharge of untreated ballast water into waters of the United States unless the ballast water has been subject to mid-ocean ballast water exchange (at least 200 nautical miles offshore). The regulations also require a ship-specific BWM Plan, a ballast water record book, an approved ballast water treatment system, and an International Ballast Water Management Certificate for vessels discharging ballast water. Consequently, we do not anticipate discernable cumulative impacts stemming from releases of ballast water.

We received a comment from the USFWS regarding the potential for cumulative impacts on marine waters associated with existing pipelines across Cook Inlet. Several existing oil and gas pipelines in Cook Inlet have experienced leaks due to strong currents, scour, and impacts with boulders and other objects in the subsea environment. As discussed in section 2.2.2, AGDC would coat the offshore pipeline with 3.5 inches of concrete for on-bottom stability as well as protection from impacts on the pipeline. AGDC notes that the concrete coating would protect the pipeline from shipping related impacts (e.g., anchor or container drops) and natural features (e.g., boulders), ice added impact, and abrasion protection, and would be in compliance with the cover requirement in 49 CFR 192.327(f)(2). See sections 2.2.2.2 and 4.3.3.3 for additional information on AGDC's design of the offshore pipeline and the status of PHMSA's review of this design relative to the requirements of 49 CFR 192.327(f)(2).

4.19.4.4 Wetlands

Alaska contains over 175 million acres of wetlands, 99 percent of which are palustrine wetlands traditionally referred to as fresh water marshes, swamps, bogs, and/or fens. The proposed Project has the potential to affect about 11,760 acres of wetlands. Permanent loss of wetlands is estimated at 8,225 acres, of which 6,220 acres would be due to granular fill that would be used for construction and left in wetlands, and the rest from Cook Inlet infrastructure, disposal sites, material sites, and forested wetland conversion. As discussed in section 4.4.4, AGDC has provided a Wetland Mitigation Plan to the COE to address unavoidable impacts on wetlands.

Impacts on wetlands during Project construction and operation would result from the following: clearing, grading, trenching, filling, placement of granular fill material associated with access road construction and installation of VSMs, blasting, material site development, discharge of wastewater and hydrostatic test water, spills of fuel and waste, stormwater runoff, introduction of invasive species, erosion, fugitive dust, permafrost thaw and associated thermokarst, and modifications to natural drainage patterns

and hydrology. These activities would result in the permanent loss of wetlands or conversion of wetland types, increased turbidity and sedimentation, changes to wetland values and functions, and increased likelihood of the release of hazardous materials and fuel to wetlands. Despite numerous avoidance and minimization measures, some wetland functions would not be restored; for such functional losses, compensatory mitigation would be proposed. Cumulative impacts on wetlands would occur where other projects within the same HUC12 watersheds as the proposed Project would affect wetlands.

The PTU Expansion and PBU MGS Projects are reasonably foreseeable actions within the geographic scope of the Alaska LNG Project where the approximate impacts on wetlands are known. The PBU MGS Project would require a 5-acre expansion to an existing granular pad and up to 44 miles of new by-products and gas feed pipelines. Construction and operation of this project would result in the placement of granular fill and installation of VSMs within wetlands. In total, about 91 acres of palustrine emergent wetlands would be affected, of which about 6.5 acres would be permanently lost due to the granular pad and VSMs. The PTU Expansion Project would require the construction of two 7-acre pads (one granular pad and one ice pad), which would affect about 14 acres of palustrine emergent and scrub-shrub wetlands. Of this area, 7 acres of palustrine emergent wetland would be permanently lost due to the granular pad. Because the wetland impacts from both projects would lie within the same HUC12 watersheds as the Project, they would contribute to cumulative impacts on wetlands. The preferred alignment of the Kenai Spur Highway Relocation does not cross any wetlands, so no wetland impacts would result from this project. The proposed water line for the Kenai Water System Upgrades, which would be constructed within the Kenai Spur Highway right-of-way, would lie on the edge of a wetland depression, affecting less than 0.1 acre of the wetland, and at another location would affect about 0.3 acre of riverine wetland and 0.1 acre of disturbed wetland. These wetland impacts would be cumulative with the proposed Project.

Future development at the in-state gas interconnections could result in wetland impacts to the extent that pipeline laterals or other facilities are routed through or sited in wetlands. The locations of any such facilities are not yet known so the extent of impacts cannot be fully assessed. A potential future lateral to Fairbanks from a point near the Alaska LNG's proposed take-off point, however, was analyzed in the EIS for the ASAP Project. The Fairbanks Lateral route analyzed for the ASAP Project was estimated to affect at least 330 acres of wetlands.[187] Cumulative impacts from the release of hazardous materials or fuel into wetlands could occur during construction or operational activities for the Alaska LNG Project and other projects occurring within the same HUC12 watersheds, as a result of vehicle refueling, an accident, or from improper storage of materials near wetlands. The quantity of the release would determine the magnitude and duration of impacts on nearby wetlands. AGDC would implement a Project-specific SPCC Plan to minimize the likelihood of spills and ensure that any spills that do occur are contained and remediated. Sponsors of other projects would be required to develop similar plans by federal or state review agencies. The implementation of these plans would reduce the likelihood and magnitude of releases such that the overall cumulative impacts on wetlands would be minor.

Where highway improvement/relocation projects or TAPS pipeline maintenance activities intersect the same HUC12 watersheds as the Alaska LNG Project, cumulative impacts on wetlands could occur. No specific projects were identified, so wetland impacts from road and pipeline maintenance projects are not known. Actions associated with these types of projects include placement of fill, grubbing, clearing, excavation, paving, equipment staging, and aggregate production/staging in wetlands. While many of these actions would take place in previously disturbed areas, some could result in the permanent loss of or conversion of wetlands, increased turbidity and sedimentation, changes to wetland values and functions, and increased likelihood of the release of hazardous materials and fuel to surrounding wetlands. The

[187] Based on a 100-foot-wide construction right-of-way. Acreage does not take into account any ATWS.

implementation of construction BMPs and compliance with federal and state permits, restoration plans, SWPPPs, and SPCC plans would mitigate or minimize the cumulative impact of these individual projects.

As has been discussed in previous sections, thermokarst erosion of wetlands could occur within the same HUC12 watersheds as the Project, meaning that any such impacts would be cumulative to the Project's wetland impacts, most notably loss of wetlands via fill placement for roads and the temporary impacts of pipeline construction through wetlands. However, quantifying these impacts and considering them cumulatively is not possible. For example, we are aware of the wetland impacts that resulted from the fiber optic projects. But it is not possible to quantify the ultimate significance of these cumulative effects as ongoing remedial work is expected to lessen the existing effects. The magnitude of the cumulative impacts by the time the Alaska LNG Project would be constructed could be lessened depending on the success of the remedial restoration work currently under way for the fiber optic projects.

Projects that would have quantifiable wetland impacts within the same HUC12 watersheds as the proposed Project include the PTU Expansion and PBU MGS Projects, the Kenai Water System Upgrades, the Alaska Roads to Resources (Ambler Road) Project, and the natural gas pipeline component of the Donlin Gold Mine. Adding the other project impacts for which data are available with the Project's impacts on wetlands results in an estimated cumulative wetland impact of about 12,030 acres.[188] Of this, cumulative permanent wetland loss would total about 8,434 acres.[189] Implementation of construction BMPs and permitting requirements (e.g., as imposed through the COE's Section 404 permitting process) would minimize some impacts on wetlands during construction and operation of the Alaska LNG Project and other actions, including the PTU Expansion and PBU MGS Projects. For example, measures such as winter construction (e.g., the use of ice roads) and placement of pipelines on VSMs would reduce the impacts on wetlands from North Slope oil and gas activities. These measures notwithstanding, the Project and other actions would result in significant cumulative impacts due to the permanent loss of wetlands.

4.19.4.5 Vegetation

The Alaska LNG Project could contribute to impacts on vegetation resources where other past, present, or reasonably foreseeable actions, including the non-jurisdictional facilities, are within the same HUC12 watersheds. These projects, along with the Alaska LNG Project, would result in a cumulative effect on a diverse assemblage of vegetation communities.

As previously discussed, the Alaska LNG Project would affect about 26,054 acres consisting of 12,440 acres of forest, 8,080 acres of scrub, and 5,534 acres of herbaceous vegetation. Of this, Project construction and operation would result in the permanent loss or conversion of about 8,512 acres of forest, 4,293 acres of scrub, and 2,199 acres of herbaceous vegetation. These permanent impacts would be due to the effects of fill (including the permanent placement of granular fill), excavation (e.g., for material sites), and long-term vegetation maintenance in the permanent Mainline Pipeline right-of-way. Project impacts would be greatest for forest habitats both in terms of quantity and duration since they would take the longest time to recover in the temporary construction workspace (25 to 100 years)—potentially resulting in about 3,891 acres of additional permanent impacts—or would be permanently converted to upland, herbaceous, and scrub communities in the permanent Mainline Pipeline right-of-way.

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[188] Includes 11,760 acres (Alaska LNG), 14 acres (PTU Expansion), 91 acres (PBU MGS), 84 acres (Donlin Gold Mine natural gas pipeline), 80 acres (Alaska Roads to Resources [Ambler Road]), and less than 1 acre (Kenai Water System Upgrades).

[189] Includes 8,225 acres (Alaska LNG), 10 acres (PTU Expansion), 62 acres (PBU MGS), 57 acres (Donlin Gold Mine natural gas pipeline), 80 acres (Alaska Roads to Resources [Ambler Road]), and less than 1 acre (Kenai Water System Upgrades). Note the other pipeline project estimates are based on the same ratio of permanent to temporary impacts as Alaska LNG. Wetland impacts contributed by the Alaska Roads to Resources (Ambler Road) Project (80 acres) are assumed to be entirely permanent.

In the northernmost subregions crossed by the Alaska LNG Project (i.e., in the Beaufort Coastal Plain and Brooks Foothills Subregions), impacts on vegetation would result from construction and operation of two non-jurisdictional facilities (the PTU Expansion and PBU MGS Projects) and five other projects. The PTU Expansion Project would result in the permanent loss of about 7 acres of herbaceous communities, while the PBU MGS Project would result in the permanent loss of about 6.5 acres of herbaceous communities based on vegetation mapping by the Toolik-Arctic Geobotanical Atlas (Institute of Arctic Biology, 2017) and Viereck et al. (1992). These two projects are within either the same HUC12 watersheds as the Mainline Pipeline and GTP water reservoir and gravel mine (PBU MGS Project), or a portion of the PTTL (PTU Expansion Project), but both are in different HUC12 watersheds from the GTP.

The acreage of affected vegetation from the other projects in the northernmost subregions is unknown, with only leased or no acreages available. The Great Bear Shale Oil Development currently has 500,000 acres of leases available, and the Accumulate Energy Project has 98,182 acres under lease. Neither project has identified specific development plans. The Beaufort Sea Oil and Gas Development is offshore, involving about 0.5 million leased acres as of 2007. Because the Alaska LNG Project is not anticipated to affect known beds of SAV, no substantial cumulative impacts would be anticipated on SAV in the Beaufort Sea. No acreages for general vegetation impacts are available for the other projects.

Impacts on herbaceous and scrub vegetation in the northern subregions could include long-term and permanent direct loss of tundra vegetation through the construction of facilities and access roads, placement of granular fill, and excavation (such as for a material site). Indirect impacts could also occur through stormwater runoff from disturbed areas, incidental spills of hazardous substances, changes in hydrology (e.g., roadside impoundments), air pollution, and fugitive dust, which could result in losses or damage to vegetation. The duration of impacts in the northern subregions could be 10 or more years due to the short growing season and other challenging growing conditions. In particular, lichens, mosses, and BSCs can be sensitive to air pollution and damage, with recovery potentially taking decades. In areas with permafrost and thaw-sensitive soils, ground disturbance could also result in thaw-induced soil subsidence, solifluction,[190] and soil creep or thawed layer detachment. These thaw-induced effects could result in erosion and flooding, which would reduce plant productivity and/or alter the species composition of vegetation communities. Abundant graminoid and scrub herbaceous communities, including BSC, would remain in the HUC12 watersheds relative to the area permanently affected by the Alaska LNG Project in the northern subregions. In addition, air pollution impacts on the lichen community, an important component of the BSC, have been shown to be localized (Kohut et al., 1994). Therefore, cumulative impacts on these vegetation communities would not be significant.

Along the Beaufort Sea coast, less than 1 acre of Arctic tidal marsh, a rare plant community (Boggs et al., 2014), would be permanently removed by the Central Pad expansion for the PTU Expansion Project, in addition to less than 1 acre that would be permanently removed by the proposed West Dock Causeway modifications for the Project. Whether other projects would affect Arctic tidal marsh is not known. Although Arctic tidal marsh is a rare vegetation community with a narrow distribution along the Arctic Ocean coastline, the combined area affected by the Alaska LNG and PTU Expansion Projects would be relatively small compared to the total acreage of Arctic tidal marsh in Alaska (estimated at about 208,557 acres [Boggs et al., 2016b]). Therefore, the cumulative loss of Arctic tidal marsh would be minor.

Because the northern subregions have no known occurrences of NNIS within the Project footprint, cumulative impacts on native vegetation as a result of NNIS are less likely in this area under current conditions. Changing climatic conditions and a growing interest in resource extraction, settlement, and tourism, however, make the arctic region particularly vulnerable to biological invasion (CAFF and

[190] Solifluction is the gradual movement of wet soil or other material down a slope, especially where frozen subsoil acts as a barrier to the percolation of water (Highland and Bobrowsky, 2008).

PAME, 2017). Human activities such as road maintenance are contributing to expanding the range of several NNIS that are present in the northern subregions. Implementation of the proposed Project Invasives Plan, ISPMP, and Revegetation Plan would reduce the Project's contribution to cumulative impacts from NNIS (also see discussion below).

In the southern subregions crossed by the Alaska LNG Project (i.e., from the Brooks Range Subregion south to the Cook Inlet Subregion), impacts on vegetation would result from construction and operation of three non-jurisdictional facilities (the Kenai Spur Highway Relocation Project, Kenai Water System Upgrades, and future laterals and other infrastructure associated with the in-state gas interconnections) and 11 other projects. Of these, the Kenai Spur Highway Relocation Project would result in the permanent removal of about 66 acres of forest and 2 acres of scrub and herbaceous communities. The Early Spruce Timber Sale, planned for 2022 on the Tanana State Forest, would affect 18 acres of forested land near mainline MP 494. The vegetation acreages affected by the other projects are uncertain, with only leased acreages or no acreages available.

The Usibelli Coal Mine is an operating mine with 35,100 acres of coal leases, with no specific expansion plans proposed. The South Denali Visitor Center involves 3 acres and 31 miles of trails, though the extent of impacts on vegetation is unreported. The Cook Inlet Gas Gathering System (CIGGS) Marine Pipeline Conversion and the Furie Operating Alaska Project are offshore in Cook Inlet. Because the Alaska LNG Project is not anticipated to affect known beds of SAV, no substantial cumulative impacts would be anticipated on SAV in Cook Inlet. No information on vegetation impacts is available for the remaining projects within the southern subregions.

Vegetation impacts in the southern subregions would be similar to those in the northern subregions for herbaceous and scrub communities, although recovery time in temporary workspaces would be faster. For forest communities in the southern subregions, long-term or permanent cumulative impacts on forests would result from clearing for construction as well as pipeline, road, and trail maintenance.

Numerous NNIS are found within the footprint of the Alaska LNG Project in the southern subregions, as discussed in section 4.5.8. In addition, five NNIS occur near the Kenai Spur Highway Relocation Project area, including butter and eggs (*Linaria vulgaris*), common dandelion, oxeye daisy, reed canary grass, and white clover. Of these, reed canary grass, common dandelion, and white clover are also found within the Project footprint. Reed canary grass has the highest level of invasiveness while the other species have moderate levels of invasiveness. The presence of NNIS in any of the other past, present, or reasonably foreseeable projects in the southern subregions is unknown. Given the increased levels of disturbance and potential vectors for NNIS dispersal that would occur as a result of increased development in the same HUC12 watersheds as the Project, most projects in the southern subregions could contribute to cumulative impacts on native vegetation by introducing and spreading NNIS.

As discussed in section 4.5.8, AGDC would implement an Invasives Plan and ISPMP, which identify measures for controlling and treating NNIS in the construction area. Other projects, including the non-jurisdictional facilities, may implement treatment measures similar to the Project to manage and control the spread of NNIS as required by federal and state review agencies or as specified in permits. These measures, if implemented, would collectively minimize the cumulative impacts associated with the spread of NNIS in the southern subregions crossed by the Alaska LNG Project.

Based on AGDC's review of GIS data from the ACCS (2017b), there are no known occurrences of rare plant species within the footprint of the Alaska LNG Project or non-jurisdictional projects in the northern and southern subregions. However, 20 rare plant species have been documented within 1.0 mile of the proposed Project (see table 4.5.7-1), three of which have also been documented within 1.0 mile of the PBU MGS Project. Of these, one species, yellow mountain saxifrage, has a state critically imperiled

conservation ranking (secure at the global level). This species was documented within about 0.8 mile of the proposed Project footprint and 0.7 mile of the PBU MGS Project. The two others, Vahl's alkaligrass and bluegrass, occur within about 0.1 mile and no closer than 0.5 mile of the Alaska LNG and PBU MGS Projects, respectively. Vahl's alkaligrass has a state vulnerable conservation ranking, while bluegrass is unranked. No other documented rare plant species occurrences were noted in or near the other projects listed in appendix W-1.

We determined that impacts on rare plant species from the proposed Project would be less than significant (see section 4.5.7). Based on a desktop assessment of known occurrences of rare plants, no rare plants would be affected by the Project; however, in the absence of field surveys, it is impossible to conclude that none would be affected. Cumulative impacts could occur if rare plants are present in the Project's footprint and the same species are present in the footprint of the other projects listed in appendix W-1. The cumulative impacts could be moderate to significant depending on the species' conservation status, whether local extinctions of any plant populations would occur, the number of populations in the state, and the availability of adjacent suitable habitat. For most species near the proposed Project, the probability of cumulative moderate or significant impacts is low based on these factors.

As discussed in section 4.5.2, AGDC would implement a Revegetation Plan, which identifies measures for vegetation restoration in areas temporarily affected by construction. AGDC has committed to filing an updated Revegetation Plan with additional measures for restoration monitoring, performance standards for successful restoration, and recommendations for seed mix composition. These and similar measures, should they be implemented on other projects, would minimize cumulative impacts on herbaceous and scrub vegetation, but impacts on forest vegetation from the Project and other actions would remain high with a longer recovery period. Therefore, we conclude that cumulative impacts on herbaceous and scrub vegetation would not be significant, while cumulative impacts on forest habitat would be significant based on the duration and extent of impacts.

4.19.4.6 Wildlife Resources

The Alaska LNG Project could contribute to cumulative impacts on wildlife resources where other past, present, or reasonably foreseeable actions are within the same HUC12 watersheds (HUC10 watersheds for migratory species, including birds). As noted above, many of the projects included in the geographic scope of the cumulative impacts analysis are operating facilities with no known expansion plans, oil and gas leases that have not reached the development stage, or projects are on hold for various reasons; no cumulative impacts from these projects would be anticipated. The non-jurisdictional facilities, the South Denali Visitor Center, the fiber-optic projects, and the TAPS pipeline and highway maintenance and upgrades are considered the actions most likely to have impacts on terrestrial wildlife resources, due to their likelihood of proceeding within the same time frame as the Alaska LNG Project. Several marine projects in the vicinity of the Alaska LNG Project could contribute to cumulative impacts on marine species.

Terrestrial Wildlife

For most species, the geographic scope for the analysis is the HUC12 watershed. For migratory species such as bear, caribou, Dall sheep, moose, and muskoxen, the HUC10 watershed is considered the geographic scope of the analysis because the range in which these species may occur is larger than for other resources. For migratory species, potential cumulative effects from four additional actions—Cook Inlet oil and gas exploration, Chuitna Coal Mine, Livengood Gold, and Four Lakes Warming Research Projects — are included in the analysis. These are the only identified projects within the HUC10 but outside the HUC12 watersheds crossed by the Project.

Terrestrial wildlife would or could experience cumulative disturbance effects and the potential for injury or mortality from construction and operation of the Project and other actions within the geographic scope of the analysis. Cumulative effects could occur where projects have the following types of effects on terrestrial wildlife:

- changes in habitat, including habitat loss, alteration, creation of edge habitat, and fragmentation (see the above discussion on cumulative impacts on vegetation);
- direct mortality to wildlife species during construction and operation, including those due to vehicle accidents;
- changes in seasonal movement and habitat use, increased injury, and stress due to disturbance; and
- increased mortality from hunting due to an increase in hunter access to previously inaccessible areas.

Construction and operation of the Alaska LNG Project would affect a total of 8,682 acres of tundra, 11,773 acres of boreal forest, and 5,704 acres of transition forest, resulting in permanent habitat loss or conversion. Other projects affecting tundra, boreal forest, or Alaska Range transitional forest, such as the PTU Expansion and PBU MGS Projects, could have similar effects, resulting in cumulative impacts on wildlife in these habitats types. As discussed in section 4.6.1, however, the effect on habitat would be minor given the small area of impact relative to the area of available similar habitats in adjacent areas and throughout Alaska. Moreover, AGDC would implement several measures to reduce impacts on wildlife due to habitat loss or modification, including avoiding unnecessary clearing; limiting activities to approved construction footprints, and restoring areas temporarily disturbed by construction in accordance with the Revegetation Plan. Other projects could also implement similar measures to reduce impacts on wildlife as required by federal and state review agencies or permits.

Cumulative impacts on terrestrial wildlife could result from activities such as clearing and grading, noise, vehicle traffic, and trenching during construction of the Alaska LNG Project and other actions occurring within the analysis area. AGDC would generally clear vegetation for facility construction in winter to the extent practicable, which would avoid impacts on nesting birds (see section 4.6.2). Many small mammals would be in nests or burrows in the winter, however, and could be injured or killed from clearing activities, particularly smaller species such as shrews, voles, and mice. Winter clearing and grading additionally could uncover denning bears or run over hibernating ground squirrels. Other projects requiring clearing or grading in winter, such as the Donlin Gold Mine pipeline, the Early Spruce Timber Sale, or the Alaska Roads to Resources (Ambler Road) construction, could result in similar impacts on wildlife.

Noise from Project activities, including aircraft takeoff, landing, and overflights, could have impacts on terrestrial wildlife. Some species (or sensitive life stages) could suffer temporary or permanent hearing loss or become temporarily displaced from sensitive habitats or distracted during sensitive periods, leading to increased predation risk. Most animals would be capable of avoiding noise that could be physically damaging. Large mammals in some areas are accustomed to human disturbance and may not alter their behavior as a result of temporary noise increases. Other projects resulting in noise at the same time and in the same locations as the Project could result in cumulative impacts on terrestrial wildlife displaced or otherwise affected by the noise.

Impacts on terrestrial wildlife could result from increased vehicular or rail traffic during construction or operation of the Alaska LNG Project and other actions, particularly actions (such as the PTU Expansion Project, the PBU MGS Project, or TAPS or highway maintenance projects) in close

proximity or using the same roads. Increased traffic would increase the potential for collisions resulting in injury or death to terrestrial wildlife species, especially for projects with overlapping construction schedules. Overall, impacts on terrestrial wildlife from increased traffic and construction activities would be directly related to the size and condition of any given population of wildlife, which are variable across the study area.

Trenching would be required for construction of the Alaska LNG Project and several other projects such as the in-state gas interconnections (for future lateral construction), Kenai Water System Upgrades, and Mine Point Unit Moose Pad. Trenching can cause injury or mortality for animals who become trapped in the trench, or displace or block seasonal movements of large terrestrial wildlife unable to cross the trench. Aboveground linear facilities, such as those associated with the PBU MGS Project, Accumulate Energy Alaska Project, and Hilcorp Liberty Unit OCS oil development, could similarly restrict or hamper seasonal wildlife movement depending on the final design of these facilities.

The Alaska LNG Project would lie within the range of three arctic caribou herds (the Central Arctic, Teshekpuk, and Porcupine). As detailed in section 4.6.1, several studies have concluded that aboveground pipelines with ground clearances less than 5 feet formed barriers to movement of the Central Arctic Herd, and that pipeline heights in the range of 7 to 8 feet are more likely to be used by caribou during the winter. Although the PTTL would be installed with a minimum pipeline height of 7 feet, the Project would have significant impacts on the Central Arctic Herd due to its construction during sensitive periods, permanent impacts on sensitive habitats, and its location at the center of the Central Arctic Herd's range. Combined with impacts from other existing and planned oil and gas infrastructure within the Project's geographic scope on the North Slope, cumulative impacts on the Central Arctic Herd would be significant, although the duration of such impacts is uncertain.

Construction of the Alaska LNG Project could increase impacts on terrestrial wildlife due to hunting by providing access to previously inaccessible areas via the pipeline right-of-way and access roads. Cumulative impacts on terrestrial wildlife due to hunting could result from this and other actions which likewise provide pathways for hunters to access previously remote or inaccessible areas. This is addressed in more detail in the section on cumulative impacts on subsistence resources (section 4.19.4.14).

AGDC would implement several measures to minimize impacts on terrestrial wildlife during construction and operation of the Alaska LNG Project. For example, AGDC would avoid scheduling excavation activities during seasons with major wildlife movements across the right-of-way, where practicable; minimize the length of open trench; install trench crossing areas and escape ramps; limit vehicle speeds on the right-of-way and access roads; trim vegetation along roads to improve line-of-sight; restore areas temporarily disturbed by construction; and install blocking measures or post signs to restrict access to the right-of-way. Based on these and other measures described in section 4.6.1, we concluded that the Alaska LNG Project would not result in significant impacts on terrestrial wildlife. Because these measures would reduce impacts, and because the overall footprint of the projects considered here represent such a small percentage of the available similar habitat within each of the affected watersheds, we conclude that the cumulative impact on terrestrial wildlife would be minor, with the exception of the Central Arctic Herd of caribou, for which we conclude the cumulative impact would be significant.

Avian

Potential cumulative impacts on avian resources associated with the Project and other projects listed in appendix W-1 could be caused by the following activities:

- site preparation (e.g., clearing, grubbing, and grading);
- dredging and trenching;

- blasting and pile driving;
- vehicle, aircraft, and vessel traffic;
- accidental fuel and/or oil spills;
- right-of-way maintenance clearing; and
- collisions with aboveground structures.

Activities that disturb nesting birds and/or destroy nesting, foraging, and resting habitat would represent the greatest potential impacts on avian resources. Activities within the same HUC10 watersheds as the Alaska LNG Project could cumulatively cause permanent and temporary habitat loss and alteration for avian species. In general, we consider impacts on vegetation, as discussed above in section 4.19.4.5, as a proxy for impacts on wildlife, including migratory birds.

The incremental loss of habitats due to Project construction and other actions could cause long-term or permanent impacts on migratory birds that depend on these habitats. Avian species dependent on tundra or alpine and boreal forest ecosystems could be at particular risk because these habitats have a slower regeneration time than other affected habitats after disturbance. All impacts on forest communities would be long term or permanent, and would result in permanent impacts on avian resources using those communities. Nesting and foraging habitat could be removed and/or activities could disturb birds establishing territories. Nesting birds would be affected during construction, site preparation, and right-of-way maintenance when such activities overlap with the migratory bird-nesting season. Clearing, trenching, and excavation activities could result in disturbance and temporary displacement of birds from adjacent habitats.

Vehicle, aircraft, and vessel traffic from the Alaska LNG Project and other actions within the same HUC10 watersheds could also contribute to cumulative impacts on avian resources. Birds are vulnerable to collision injury and mortality from air traffic and vehicles. Avian resources most affected by air traffic could include waterfowl, gulls, and raptors. Low-level overflights of nesting colonies can be disruptive to waterfowl, especially to colonial-nesting waterfowl and seabirds. Direct impacts on avian resources could include injury or mortality from collisions, disruption of seasonal movements, displacement from roadside habitats, and/or reduced productivity from disturbance.

Vessel traffic associated with the projects listed in appendix W-1 would occur in the Beaufort Sea, Chukchi Sea, Bering Sea, Cook Inlet, and GOA, and could contribute to cumulative impacts on avian resources. Seabirds, shorebirds, waterfowl, and geese foraging near or moving through these areas could be disturbed and displaced by vessel traffic. In addition to disturbance, the federally listed eider species would be at risk of collisions with vessels during construction and operational activities (see section 4.6.2).

Construction of new infrastructure associated with the projects listed in appendix W-1 could result in cumulative impacts on avian resources as a result of additional buildings, communication towers, and power lines present on the landscape. Birds would be susceptible to collisions with buildings, towers, power lines, and/or guy wires associated with construction and operation of these facilities. Migratory birds are particularly at risk of collision when visibility is impaired by darkness and/or inclement weather, and collisions with structures often result in mortality or injury (Manville, 2005; Weir, 1976; Black, 2004).

Activities associated with the other projects in the Alaska LNG Project's geographic scope could cause cumulative impacts on avian resources through an increase in human disturbance and noise. The South Denali Visitor Center creates an increase in the number of people near the Alaska LNG Project and surrounding areas, for example. New work camps would increase the potential for wildlife–human interactions, and cause changes in avian behavior or habitat use. Birds could also be affected by an increase in hunting pressures from humans and predators due to the creation of new access roads (e.g., Alaska Roads

to Resources [Ambler Road]), relocation of major roads (e.g., the Kenai Spur Highway Relocation), and cleared right-of-way (e.g., associated with the Donlin Gold Mine pipeline).

Noise from blasting, pile driving, drilling, logging (as with the Early Spruce Timber Sale), and testing could result in cumulative impacts on avian resources to the extent that multiple projects would be under construction at the same time as the Alaska LNG Project. Birds could react to noise created from vehicle traffic, airplanes, helicopters, blasting, and human activity associated with construction and operational activities. Sources could include single impulse sounds (e.g., blasting), multiple impulses (e.g., jackhammers, pile driving), and non-strike continuous noise (e.g., construction sounds). Noise from construction activities could have an impact on raptors and bird species during nesting and breeding seasons. Birds are at greatest risk of impacts and/or damage on auditory structures as they near construction rights-of-way and workspaces, but impacts could reach greater distances for activities such as blasting and pile driving. Noise pollution could cause nest abandonment and failure, reduced juvenile growth and survival, and malnutrition or starvation of the young (Francis et al., 2009). Anthropogenic noise from project sites can elicit changes in levels of stress hormones in birds, and in turn can have an effect on nest and/or hatch success. Researchers have concluded that noise can be a chronic stressor for bird communities (Kleist et al., 2018).

As discussed in section 4.6.2, we conclude that impacts on avian resources due to construction and operation of the Project would not be significant. While some impacts would be long term or permanent (e.g., impacts on forest habitat), most impacts would be temporary. Moreover, AGDC would implement several measures to mitigate impacts on birds. AGDC would implement a Migratory Bird Conservation Plan, which identifies various design measures for minimizing impacts on birds during Project operation. Other projects could also implement measures to minimize impacts on birds as required by federal or state review agencies. For these reasons, we conclude that cumulative impacts on avian resources would not be significant.

Marine Mammals

Cumulative impacts on marine mammals could occur even at relatively distant projects, because vessel traffic associated with some of these projects, as well as the Alaska LNG Project, would range across wide areas of Alaska's marine environment. Potential cumulative impacts on marine mammals during Project construction and operation and these other projects primarily include those associated with the following activities:

- additional vessel traffic causing increased risk of vessel strikes and underwater noise;
- in-water construction, including dredging and pile driving, causing habitat loss or modification, and underwater noise; and
- increased aircraft overflights.

During Alaska LNG Project construction and operation, cumulative impacts would primarily be those associated with the transit and operation of vessels serving the various Project facilities while in Cook Inlet; transiting through the GOA from various ports; and transiting to and from the North Slope through the Chukchi Sea, Bering Sea, and Beaufort Sea. As discussed in section 4.6.3, carrier traffic into Cook Inlet due to Project operation would increase by 42 to 74 percent existing traffic levels for ships of 300 gross tons or more. Data regarding vessel traffic for most of the projects listed in appendix W-1 is not available; however, cargo volume at the Port of Alaska is projected to grow at a rate of about 1 percent annually through 2021 (AEDC, 2018).

We received a comment that quantitative information on vessel traffic is available for the Pebble Mine and Cook Inlet Lease Sale 244 projects. The draft EIS for the Pebble Mine project (COE, 2019b) estimated vessel traffic in Cook Inlet during project operations as 110 transits or port calls per year, though it is unclear to what extent vessel traffic from this project and the Project would overlap. The proposed mine site is located approximately 140 miles south/southwest of the Liquefaction Facilities. The port of call proposed for the Pebble Mine project, Amakdedori, is located about 140 miles southwest of the proposed Liquefaction Facilities and approximately 40 miles west of the major Cook Inlet shipping lanes. The draft EIS for the Pebble Mine project concluded that "the incremental addition of vessels associated with the project would be unlikely to result in increased impacts to marine mammals."

The Cook Inlet Lease Sale 244 project area is located about 35 miles south-southeast of the proposed Liquefaction Facilities for the Project. The EIS for the lease sale project assessed potential future oil and gas development in lower Cook Inlet due to the lease sale; it did not evaluate any specific proposals to develop new infrastructure. The final EIS for the Cook Inlet Lease Sale 244 project estimated vessel traffic from potential future development as 3 to 7 vessels during seismic surveys, 1 to 2 supply vessel trips per week during exploration drilling, 1 to 3 supply vessel trips per week per platform during development operations, and 1 to 2 supply vessel trips per week per platform during operations, with 2 to 3 new platforms assumed for the lease area (BOEM, 2016). The final EIS states that "the presence of offshore vessels and exploratory drilling operations would be transient and localized" and that "the physical presence of a limited number of...vessels associated with the Proposed Action would result in small periodic increases in Cook Inlet vessel traffic that would have negligible effects on marine mammals".

Increased vessel traffic from the Project and other projects could increase vessel strikes on marine mammals, especially for vessels traveling at speeds over 12 knots (13.8 miles per hour) (Vanderlaan and Taggart, 2007). As discussed in section 4.6.3, AGDC would implement (or require that vessel operators implement) various measures to avoid or minimize collisions with marine mammals, such as slowing vessel speeds and maintaining watches for marine mammals. These measures would minimize cumulative impacts on marine mammals due to Project construction and operation.

Increased noise in the underwater environment can cause harm to marine mammals by affecting their behavior or by causing direct injury (NMFS, 2016c). Marine mammals use hearing and sound transmission for communication, navigation, predator avoidance, and feeding. Anthropogenic noise can disrupt those behaviors with impacts ranging from minor disturbances and harassment to injury or death. Underwater noise from industrial activities could affect marine mammals miles away from the source of the noise. Some marine mammal species are more susceptible to strandings when exposed to strong underwater sounds such as blasting and sonar (Peng et al., 2015). Anthropogenic noise is also known to create a masking effect on important sounds, which in turn could affect reproductive success of individual marine mammals (Todd et al., 2015).

If dredging or pile driving activities for the Alaska LNG Project occur concurrently and within proximity of any of the applicable projects listed in appendix W-1, impacts on marine mammals would likely be exacerbated as a direct result of each projects' activities. Additionally, noise generated by pile driving in multiple locations could make it difficult for marine mammals to avoid these disturbances. Concurrent project activities could decrease availability of suitable habitat for marine mammals to move away to avoid the activity. Turbidity from dredging is likely to reduce the ability of marine mammals to forage until sediments resettle, while sedimentation due to dredging could smother benthic prey organisms.

As discussed in section 4.19.4.3, dredging in the Beaufort Sea for the PTU Expansion Project would occur about 55 miles east of the screeding for the Project; therefore, no cumulative impacts on marine mammals would result from these activities. In Cook Inlet, AGDC's proposed dredging for the Project could potentially be concurrent with annual maintenance dredging conducted by the COE, but cumulative

impacts due to increased sedimentation and turbidity would not be significant. Turbidity and sedimentation rates are naturally high in Cook Inlet due to the abundance of glacial sediments and strong currents, and conditions would return to normal soon after dredging is complete. If dredging activities in Cook Inlet are concurrent, minor cumulative impacts on marine mammals from noise or collisions are possible.

Ongoing projects in Cook Inlet include operation of the Andeavor Kenai Refinery, operation and potential new oil and gas development for Hex, LLC's Kitchen Lights Unit, and the Ocean Renewable Power Company's (ORPC) Cook Inlet Tidal Energy Project. As discussed in section 4.19.4.3, future expansion or new construction activities associated with these projects would not be expected to overlap with Project construction; therefore, cumulative impacts from these projects on marine mammals are not anticipated. Various oil and gas activities associated with Hilcorp Alaska's leaseholds in and near Cook Inlet could occur within the same frame as construction of the Alaska LNG Project, and so could contribute to cumulative impacts on marine mammals. Planned activities for these projects between 2019 and 2024 include two seismic surveys, about 22 exploratory wells, platform and pipeline maintenance/repair, three geohazard surveys, a well abandonment, and marine construction associated with land-based exploration and development on the Iniskin Peninsula.

Noise and visual stimuli from aircraft overflights have the potential to disturb marine mammals. Marine mammals disturbed by aircraft typically surface for shorter periods of time, dive or turn away from the noise or sight, swim away from the noise or sight, or breach (Patenaude et al., 2002). Commercial aircraft would normally operate at altitudes over 1,500 feet above sea level when in flight, minimizing impacts on marine mammals. Cetacean reactions to overflights would consist of brief behavioral responses such as sudden diving or turning away from the sound or visual source, or no response at all (Nowacek et al., 2007). Helicopters tend to be more disturbing than fixed-wing aircraft (Luksenburg and Parsons, 2009; Born et al., 1999). Pinnipeds tend to react to aircraft overflights by becoming alert and/or entering the water (Luksenburg and Parsons, 2009; Born et al., 1999). Pinnipeds would most likely be affected by low flying aircraft if they were hauled out on land or ice and would react by diving into water. For these reasons, any cumulative effects on marine mammals would be minor, consisting of brief behavioral responses affecting few individuals, and lasting only minutes after the aircraft has passed.

Marine mammal species are protected under the MMPA. The projects identified in appendix W-1 as potentially contributing to cumulative marine mammal impacts would be required to comply with the MMPA (described in detail in section 4.6.3). In May 2018, AGDC, Hilcorp Alaska, and Harvest Alaska submitted to the USFWS a joint petition under ITRs, in which each company's planned activities between 2019 and 2024 were identified and assessed with respect to impacts on marine mammals. Together, the three companies requested an ITA from the USFWS for the incidental take by harassment of small numbers of northern sea otters incidental to oil and gas exploration, development, production, and transportation activities in Cook Inlet. These activities would also affect marine mammals protected by the MMPA and ESA under NMFS jurisdiction (e.g., Cook Inlet beluga whales, harbor porpoises, harbor seals, humpback whales, killer whales, and minke whales). As a result of the MMPA ITA process, NMFS would review potential impacts on marine mammals and provide individual authorization for take, as appropriate. Any projects not requiring an ITA would still require compliance with the MMPA (and with the ESA for federally listed threatened and endangered species and designated critical habitat). Therefore, cumulative impacts on marine mammal species would be minor.

4.19.4.7 Aquatic Resources

Fisheries

The Alaska LNG Project could contribute to cumulative impacts on fisheries resources where other actions are within the same HUC12 watersheds. As noted above, most of these projects are either operating

facilities with no known expansion plans, oil and gas leases that have not reached the development stage, or projects on hold for various reasons.

Section 4.7.1 discusses the Alaska LNG Project's impacts on fisheries. Other actions within the same HUC12 watersheds would generally have similar impacts, although they could vary in intensity and kind. Impacts on fisheries could result from the following activities:

- waterbody crossings;
- dredging, screeding, and trenching;
- underwater pressure and vibrations (e.g., blasting and pile driving);
- infrastructure encroachment;
- material sourcing;
- vessel transportation; and
- degradation of water quality (e.g., due to accidental fuel and/or oil spills).

Waterbody crossing activities that could disturb fisheries would occur in or upstream of spawning areas. Dewatering activities associated with these crossings could affect spawning gravels and kill eggs or larval fish depending on the installation timing. Dewatering activities, if not properly managed, could also result in an increased release of sediments, increased turbidity, and increased sedimentation, and would represent the greatest potential impacts on fisheries resources. Without appropriate crossing method designs, temporary loss of habitats associated with pipeline construction and other projects that directly affect streams could present a long-term impact on fisheries dependent on these habitat types.

The construction schedule for the PBU MGS Project would overlap the timeframe associated with the Alaska LNG Project and portions would be within the same HUC12 watersheds. The PBU MGS Project pipelines would be aboveground and span waterbody crossings, however, which would reduce cumulative impacts on North Slope fisheries caused by construction disturbance in streams.

Future construction activities associated with the planned in-state gas interconnections along the Alaska LNG Project Mainline Pipeline could affect fisheries resources to the extent that laterals or distribution pipelines are constructed via open-cut methods across streams. The alignment of the Kenai Spur Highway Relocation Project does not cross any waterbodies, so no fisheries impacts would result from that non-jurisdictional project. Based on a preliminary engineering study submitted by AGDC, the Kenai Water System Upgrades appear unlikely to affect streams or fisheries resources, although specific facility locations are yet to be finalized.

Maintenance and upgrades of linear facilities such as the Dalton Highway or the TAPS pipeline could involve construction within specific waterways in the same HUC12 watersheds as the proposed Project. No specific maintenance or upgrades have been identified, and any future impacts are likely to be incurred intermittently during the life of these projects. Therefore, any cumulative impacts resulting from the projects would be minor.

In marine environments, dredging, screeding, dredged material placement, foundation placement, backfill, trenching, and pile placement has the potential to disturb the benthic substrate and release any chemicals and metals that may be present in sediments (COE, 2013b). In the absence of proposed mitigation, in-water work directly over fish habitat or dredging/burial of marine substrates have the potential to cause direct mortality of fish and their eggs. Because the dredging associated with the PTU Expansion Project in the Beaufort Sea would occur about 55 miles east of the screeding and filling proposed for the Project, there would be only minimal potential for cumulative impacts on fisheries due to these activities. No projects have been identified in the vicinity of Dock Head 4 that would involve dredging,

screeding, or filling, although future activities associated with offshore oil and gas leasing could cause potential cumulative impacts in this area.

AGDC has proposed dredging and disposal of 800,000 cubic yards (construction) and 140,000 cubic yards (maintenance) of sediment in the Cook Inlet for the Marine Terminal MOF. Except for an existing and operative COE dredged material disposal site 35 miles from the Alaska LNG's proposed dredged material disposal sites, and routine maintenance dredging by the COE, no other actions have been identified that would add to dredging volumes in the vicinity of the proposed Project in Cook Inlet. As discussed above, even if the dredging activities by Alaska LNG and the COE overlap, the cumulative impact would not be significant because turbidity and sedimentation rates are naturally high in Upper Cook Inlet due to the abundance of glacial sediments and strong currents.

The Alaska LNG Project would develop sand and gravel extraction sites within or adjacent to streams on the North Slope. Cumulative impacts on fisheries could occur if other activities within the same HUC12 watersheds involve extraction of sand and gravel from arctic and subarctic floodplains for construction purposes. No such activities have been identified.

Important habitats like Little Panguingue and Panguingue Creeks and waterbodies supporting anadromous fish spawning and rearing that lie adjacent to the Usibelli Coal Mine would be crossed by the Project's Mainline Pipeline (Johnson and Blossom, 2017a,b,c). Expansion of the mine is not currently proposed, however, and mining leases and operations are currently limited to the area east of the Alaska LNG Project by the Nenana River. Therefore, no cumulative impacts would be anticipated.

The Alaska LNG Project would contribute to cumulative increases in vessel transportation within the Beaufort and Chukchi Seas and Cook Inlet. Potential effects on aquatic resources include the loss or damage of fish habitat; alteration through physical damage from shipping and vessel activity (e.g., wake effects, propeller wash); spills, accidents, and malfunctions; barriers to migration; and thermal and acoustic effects. Vessels near or moving through occupied fish habitat could cause permanent alteration and displacement.

Activities in the Beaufort/Chukchi Sea or Cook Inlet areas that require vessels to move material or that involve marine construction could, when combined with the Alaska LNG Project, create cumulative impacts on fisheries resources due to increased ship traffic. In the Beaufort/Chukchi Sea area, these activities could include the Nanushuk, Nikaitchuq North Eni – Spy Island, Caelus Energy LLC-Oooguruk Unit, and Nuna projects; the PTU Expansion and PBU MGS Projects; and possibly other North Slope projects. Some of these projects could entail operations-related vessel traffic, specifically, the off-shore activities such as Nikaitchuq North Eni – Spy Island, Caelus Energy LLC-Oooguruk Unit, and any future activities stemming from oil and gas leasing in the Beaufort Sea. In the Cook Inlet area, activities involving increased vessel traffic in support of construction activities could include the Hilcorp-Beluga River Unit. It is not known whether Hex LLC will develop its newly purchased Kitchen Lights Unit, beyond the currently operating platforms. No specific activities have been identified that would involve increased operation-related vessel traffic in Cook Inlet.

Fish habitat and communities could experience cumulative impacts from direct loss or alteration of fish habitat or through changes in water quality and/or sediment quality arising from the deposition of substances harmful to fish. As discussed in the water resources section above, AGDC would implement Project-specific SPCC plans and BMPs designed to ensure hazardous materials are properly handled. Functionally similar measures would be in place for the PTU Expansion and PBU MGS Projects and are likely to be required for other projects that could be developed within the same HUC12 watersheds as the Alaska LNG Project. These measures would reduce the likelihood and magnitude of a release, and the overall cumulative impact would be minor.

Construction and operational activities associated with other projects in the Alaska LNG Project's geographic scope could have cumulative impacts on fisheries resources through disruption or alteration of fish habitat and direct mortality and alteration of population abundance through disruption of habitat, decreased health, and indirect mortality resulting from changes to water and sediment quality. Projects within marine ecosystems (i.e., Cook Inlet and Prudhoe Bay) also have the potential to cause cumulative effects. Many of the activities within the same HUC12 watersheds as the Alaska LNG Project are operating facilities or oil and gas leasing/exploration activities that may or may not result in impacts on fisheries resources. Moreover, the several activities that could affect fisheries may not occur concurrently with construction of the Alaska LNG Project. These factors would limit the magnitude of cumulative impacts on fisheries resources to less than significant.

Benthic Invertebrates

The geographic scope of the cumulative impacts analysis for marine benthic invertebrates includes the seafloor within and near the Alaska LNG Project footprint in Prudhoe Bay near the West Dock Causeway and in Upper Cook Inlet from Beluga to Nikiski. Potential impacts on benthic invertebrates in these areas due to construction of the Project and other actions in the analysis area include those associated with dredging, pile driving, water discharges, benthic disturbances, vessel anchoring, and accidental spills. The activities with the greatest potential impacts on benthic invertebrates would be those that directly disturb or destroy benthic habitat, such as dredging, screeding, and construction of various project components in Cook Inlet and Prudhoe Bay.

Dredging or dredged material disposal occurring at similar times in adjacent areas could contribute to cumulative impacts on benthic invertebrates due to increased sedimentation and turbidity, habitat loss, and/or direct take. As previously discussed, dredging associated with the PTU Expansion Project in the Beaufort Sea would occur about 55 miles east of the screeding and filling proposed for the Alaska LNG Project, and no other projects have been identified in the vicinity of Dock Head 4 that would require dredging, screeding, or filling. Therefore, there would be no cumulative impact on benthic invertebrates in the Beaufort Sea. In Cook Inlet, AGDC's proposed dredging for the Marine Terminal MOF could potentially be concurrent with routine maintenance dredging by the COE, but even if these activities overlap, the cumulative impact would not be significant because turbidity and sedimentation rates are naturally high in Upper Cook Inlet.

Projects that increase subsurface noise, such as pile driving and dredging, could have a cumulative effect on benthic invertebrates in Cook Inlet and Prudhoe Bay. As discussed in section 4.7.2, research on this subject is sparse, so it is not possible to determine the magnitude of these impacts on benthic invertebrates.

Increases in vessel traffic could lead to an increased risk of the introduction of invasive species through ballast water vessel discharges, and increased risk of accidental spills. As discussed in section 4.7.1, vessels brought into the State of Alaska or federal waters are subject to Coast Guard regulations at 33 CFR 151, which prohibit the discharge of untreated ballast water into waters of the United States unless the ballast water has been subject to mid-ocean ballast water exchange (at least 200 nautical miles offshore). The regulations also require a ship-specific BMW Plan, a ballast water record book, an approved ballast water treatment system, and an International Ballast Water Management Certificate. Consequently, we do not anticipate cumulative impacts stemming from the releases of ballast water contaminated with invasive species.

Plankton

The geographic scope of the cumulative impact analysis for plankton resources includes marine waters within and near the Project footprint and along marine transit routes in Prudhoe Bay near the West

Dock Causeway and in Upper Cook Inlet from Beluga to Nikiski. The activities with the greatest potential impacts on plankton would be water withdrawals and discharges from and to the marine environment.

Hydrostatic testing of each of the two 240,000-cubic-meter LNG tanks would require about 42 million gallons of Cook Inlet seawater. In addition, about 10 million gallons of Cook Inlet seawater would be used to test the offshore portion of the Mainline Pipeline. Water withdrawals would lead to impingement and entrainment of phytoplankton, zooplankton, and, most notably, ichthyoplankton. While the intake within Cook Inlet would be screened to reduce impacts on marine life, this would not prevent the entrainment and impingement of plankton, and 100-percent mortality of affected plankton would occur. Similar mortality is expected from impingement and entrainment of plankton in cooling water intakes on LNG carriers. Water usage and discharge by other projects occurring near the Alaska LNG Project could also cause mortality of planktonic organisms, such as ichthyoplankton resources. Combined, engine cooling water withdrawal by vessels using Cook Inlet would have a minor impact on ichthyoplankton.

An overall increase in development in Cook Inlet and Prudhoe Bay, such as those represented by the projects listed in appendix W-1, could have a cumulative impact on planktonic resources. Changes in water quality from operational water discharges, such as treated wastewater, boiler blowdown waters, reverse-osmosis reject water, site stormwater, or cooling water from LNG carriers could cumulatively affect primary plankton productivity. Noise from ships or underwater construction could result in similar effects. Water quality could also be adversely affected by turbidity from dredging activities and accidental spills, as described above for benthic invertebrates.

In general, impacts on plankton due to the Project and other past, present, or reasonably foreseeable actions would not be significant due to the high natural mortality and short life span of planktonic organisms, as discussed in section 4.7.3. Therefore, we conclude that cumulative impacts on plankton would be less than significant.

4.19.4.8 Threatened, Endangered, and Other Special Status Species

The Alaska LNG Project could contribute to cumulative impacts on threatened, endangered, and other special status species where other past, present, or reasonable foreseeable actions are within the same HUC12 watersheds (HUC10 watersheds for migratory wildlife). Thirty-one federally listed species, DPSs, ESUs, and candidate species were identified by the USFWS and NMFS as potentially occurring in this area (see table 4.8.1-1).

As discussed in section 4.8.1, we determined that the Alaska LNG Project would have no effect on two federally listed species; therefore, the Alaska LNG Project would not contribute discernably to cumulative impacts on these species. For other species, cumulative impacts on federally listed seals, whales, Pacific walruses, sea otters, eiders, short-tailed albatross, and fish would be similar to those described in the marine mammal, avian, and fisheries sections above.

Cumulative impacts could be expected on the following species with critical habitat in the Alaska LNG Project area:

- Cook Inlet beluga whale;
- North Pacific right whale;
- polar bear;
- spectacled eider;
- Alaska-breeding Steller's eider; and
- Steller sea lion.

The Biological Opinion completed by the USFWS for the Point Thomson Project in 2012, which encompasses all of the PTU Expansion Project footprint and a portion of the PBU MGS Project footprint, concluded that the Point Thomson Project would have potential direct and indirect adverse effects on the spectacled eider due to collisions with new structures; increased predator populations such as common ravens, arctic foxes, and gulls; temporary and permanent loss of nesting habitat; and potential spills (USFWS, 2012a). The USFWS determined that the potential loss of production that could result from the Point Thomson Project would not significantly affect the likelihood of survival and recovery of spectacled eiders. Potential impacts on spectacled eiders from the PTU Expansion and PBU MGS Projects would be of a similar or lesser magnitude than those evaluated in the 2012 Biological Opinion for the Point Thomson Project and would not be expected to jeopardize the continued existence of the spectacled eider or prevent its survival and recovery in the wild.

Projects with vessel traffic that could transit through Alaska-breeding Steller's eider and spectacled eider critical habitat could contribute to disturbances, increased collision risks, and spill potential to these species. Critical habitat for the Alaska-breeding Steller's eider is found on the Kuskokwim Delta (breeding); marine waters around the Kuskokwim Shoals (molting); and Seal Islands, Nelson Lagoon, and Izembeck Lagoon (molting). Critical habitat for spectacled eiders is found on the Kuskokwim Delta (nesting); Norton Sound and Ledyard Bay (molting); and south of St. Lawrence Island (wintering). Additional vessel traffic could have adverse effects on eiders using these habitats during sensitive periods.

Critical habitat for polar bears occurs along offshore barrier islands and sea ice, as well as terrestrial denning habitat along the Beaufort Sea near Prudhoe Bay and the Alaska LNG Project area. The following projects occur within the geographic scope and polar bear critical habitat:

- Guitar Unit Oil and Gas Exploration (HUC10 watershed);
- Alaskan Beaufort Sea and Chukchi Sea area oil and gas leasing;
- Hilcorp, Liberty Unit OCS oil development (HUC10 watershed);
- PTU Expansion Project; and
- PBU MGS Project.

Activities associated with these projects that could cumulatively increase effects on polar bear critical habitat include:

- noise from dredging and exploratory drilling;
- habitat loss or alteration;
- human interactions;
- vessel traffic disturbances; and
- aircraft overflight disturbances.

The above activities could affect polar bear critical habitat by making it unavailable for use during feeding, breeding, and denning as defined under 75 FR 76086. Due to the ephemeral nature of polar bear habitat (i.e., seasonally available sea ice and variable denning habitat) and the non-concurrent timing of most of the activities identified above, we do not expect discernable cumulative impacts on polar bear critical habitat. A Biological Opinion for the Point Thomson Project discussed potential impacts on polar bears. Compliance with any Letters of Authorization issued by USFWS for incidental take by harassment of polar bears would be under the Programmatic 2016–2021 Beaufort Sea Incidental Take Regulations (ITRs). After implementation of the 2016–2021 ITR measures, the Point Thomson Project was determined to not jeopardize the continued existence and recovery of the polar bear.

Cook Inlet beluga whale critical habitat occurs in Cook Inlet (see section 4.8.1). Any of the projects occurring within Cook Inlet could contribute to impacts on Cook Inlet beluga whale critical habitat. Effects

on critical habitat for the whale would be similar to those described above for other marine mammals in Cook Inlet. It is not known whether any of the identified projects in these areas would entail permanent losses of critical beluga whale habitat; therefore, the potential for cumulative impacts on beluga whales are unknown.

Critical habitat for North Pacific right whales occurs in the southeastern Bering Sea and south of Kodiak Island. These areas are used for feeding. Projects with vessel traffic that transit these areas during periods of high concentrations for feeding could increase the risk of a vessel strike, especially for vessels traveling at speeds over 12 knots (13.8 miles per hour) (Vanderlaan and Taggart, 2007). It is not known whether any of the identified projects in these areas would entail ship traffic of this speed; therefore, the potential for cumulative impacts on North Pacific right whales are unknown. As noted above, AGDC would implement (or require its vessel operators to implement) measures to avoid or minimize collisions with marine mammals, which would minimize cumulative impacts on whales due to Project construction and operation.

Steller sea lion critical habitat occurs within 20 miles of known rookeries and haulouts (see section 4.8.1). Projects that increase vessel traffic or aircraft overflights near these sensitive habitats could contribute to impacts on Steller sea lions. The Alaska LNG Project might only affect critical habitat for Steller sea lions as vessels transit through these buffer zones at the mouth of Cook Inlet, Shelikof Strait, and the Aleutian Islands. It is unknown if any of the identified projects in these areas would contribute to vessel traffic in these areas; therefore, cumulative impacts on Steller sea lion critical habitat are unknown. As noted for North Pacific right whales, AGDC would implement (or require its vessel operators to implement) measures that would minimize cumulative impacts on Steller sea lions due to Project construction and operation.

No impacts on threatened, endangered, and other special status species have been identified for the Kenai Highway Relocation Project or the Kenai Water System Upgrades, although biological studies and consultations with resource agencies have not been undertaken for these non-jurisdictional projects. Future development associated with the in-state interconnections has the potential to affect threatened and endangered species, but the locations of any such facilities are not yet known. Therefore, the extent of impacts cannot be determined at this time. Most of the projects identified in appendix W-1 would have federal permit requirements and be required to comply with Section 7 of the ESA (described in detail in section 4.8.1).[191] As a result of the Section 7 consultation process, the USFWS or NMFS would review each project's potential impacts on federally listed species and either provide concurrence that the project would not adversely affect listed species or issue a Biological Opinion as to whether the project would likely jeopardize the continued existence of listed species. Therefore, we conclude that cumulative impacts on federally listed species would not be significant.

The Alaska LNG Project crosses BLM land as described in section 4.8.2. Cumulative effects on BLM sensitive and watch list species would be similar as described for terrestrial wildlife, birds, fish, and vegetation. Cumulative effects on SGCN species would be similar as described for terrestrial wildlife, birds, and marine mammals.

4.19.4.9 Land Use, Recreation, and Special Interest Areas

The Alaska LNG Project would contribute to cumulative impacts on land use, recreation, and special interest areas where other actions are within the same HUC12 watersheds.

[191] Activities listed in appendix X-1 that may require no federal permits include: the Kenai Spur Highway Relocation, Kenai Water System Upgrades, in-state gas interconnections to Anchorage and Kenai, CIGGS marine pipeline conversion, and operating facilities with no known expansion plans.

Land Use

The Alaska LNG Project would incrementally change existing land uses, converting forestland, open land, or small amounts of agricultural or residential land to industrial/commercial land. Among the past, present, and reasonable foreseeable actions identified in appendix W-1, several are operating facilities with no current expansion plans (e.g., Andeavor Kenai Refinery, Usibelli Coal Mine, and Hilcorp Beluga River Unit); several are inactive or in the exploratory phase (e.g., Hex LLC's Kitchen Lights Unit oil and gas development, Great Bear Shale Oil Development, and ORPC Cook Inlet Tidal Energy Project); and two are maintenance/upgrades to existing linear facilities (e.g., highway and TAPS pipeline maintenance). The proposed modification at the Kenai LNG Cool Down Project would take place within the plant's existing site, and so would not alter land uses. Cumulative impacts on land use from these projects are not anticipated.

All of the non-jurisdictional facilities, except possibly the Kenai Water System Upgrades, would involve some land use changes. The PTU Expansion facilities would principally affect open land and open water. Changes would not occur where portions of the project would lie within existing rights-of-way, roads, or drill pads. Similar minor changes would occur for most of the acreage associated with the PBU MGS Project facilities.

Three locations along the Mainline Pipeline for future gas distribution facilities have been identified. Although specific facilities associated with delivering gas to end users have not been identified, to the extent that pipeline laterals or distribution pipelines are required through forested and other land uses, maintenance of pipeline rights-of-way would result in some permanent conversion of these lands to utility use. As discussed above, a lateral from the Alaska LNG Project to Fairbanks would likely measure a minimum of 30 miles in length and affect at least 364 acres of land. Because the Project crosses existing ENSTAR pipelines in the Anchorage/Matanuska-Susitna Valley and Kenai Peninsula areas, lateral pipelines most likely would not be required for these interconnections. All three interconnects would require aboveground facilities at or near the interconnect point for metering, pressure regulation, and other functions associated with delivery to the interconnecting customer. The extent and scope of any required distribution facilities for the Fairbanks, Anchorage, and Kenai interconnections are unknown.

With respect to the Kenai Spur Highway Relocation, the preferred alignment would be 3.9 miles long. The highway roadbed would be 100 feet wide (47 acres), within a right-of-way 200 feet wide (encumbering about 93 acres). Seven residences along the new corridor would require relocation; these properties would be purchased by AGDC. Property and right-of-way acquisitions and relocations would follow the ADOT&PF Right-of-Way manual and federal regulations implementing the Uniform Act according to 49 CFR Part 24. Three residences lie within 100 feet of the planned highway right-of-way. AGDC would mitigate impacts on residents adjacent to the planned highway right-of-way by implementing the Fugitive Dust Control Plan developed for the Alaska LNG Project, erecting safety fence at the edge of the work area, retaining trees and mature landscapes consistent with safe operation of construction equipment, restoring lawns and landscaping per landowner agreements, and working during daylight hours.

About 1.7 miles of the highway would lie within forested areas and 1.8 miles would traverse residential areas, with short segments of open and commercial/industrial uses comprising the balance. These land uses would be converted to use as a transportation corridor. A 1.3-mile-long segment of the existing highway that lies within the site of the Liquefaction Facility would be removed, and its use as a transportation corridor would be converted to industrial use. The 93 acres of land use conversions associated with the new highway segment would, when added to the 1,003 acres permanently converted to industrial use on the Liquefaction Facility site, comprise about 3 percent of the area within the Salamatof Creek–Frontal Cook Inlet Watershed.

Based on a preliminary feasibility study submitted by AGDC, the Kenai Water System Upgrades would mostly be on property owned by the City of Kenai or, in the case of the new 6-mile-long water main, within ADOT&PF right-of-way along the Kenai Spur Highway. Four sites for the proposed new pump station are being considered, two of which are privately owned, and two of which are owned by Kenai Peninsula Borough Economic Development District. The sites are all adjacent to the Kenai Spur Highway on currently undeveloped land.

Other actions would also involve land use changes within the Alaska LNG Project's HUC12 watersheds. The South Denali Visitor Center Project affects about 3 acres of land and adds 31 miles of trails. The exact location and acres of land use conversion for the Alaska Roads to Resources (Ambler Road) Project is unknown, but only a relatively short length of road is likely to be built within a HUC12 watershed crossed by Alaska LNG.

Based on the above discussion, cumulative impacts associated with land use changes would not be significant.

Proposed Developments

The actions identified in appendix W-1 include several which are new developments in progress, or which have concrete development plans (e.g., Kenai Spur Highway Relocation and Accumulate Energy Alaska). Taken as a group, these actions represent a substantial share of the planned developments within the Alaska LNG Project's geographic scope. Construction during the same general time frame of some geographically grouped projects, such as the proposed Liquefaction Facilities and the Agrium Kenai Nitrogen Operations Facility, Andeavor Kenai Refinery, and the Kenai LNG Cool Down projects, could result in delays due to availability of construction personnel; however, no major expansions associated with these three operating facilities have been identified. Also, because the development schedules for many of the projects in the geographic scope are uncertain, the degree of impacts caused by simultaneous construction cannot be accurately predicted. Given the overall amount of land and resources in Alaska, multiple geographically separated projects could likely be constructed simultaneously with no appreciable cumulative effects.

Recreation and Special Interest Areas

The Alaska LNG Project and each of the other applicable actions identified in appendix W-1 could cumulatively affect recreation and special interest areas through:

- encroachment, where the footprint of a project is partially or entirely within the boundary of a recreation or special interest area;
- increased project-related traffic on public roads used to access recreation or special interest areas;
- project construction or operational noise impacts within recreation or special interest areas; or
- visual impacts within, or visible from, recreation and special interest areas, including temporary or permanent changes to the landscape, as well as construction-phase dust.

No cumulative recreational impacts would be expected to occur with the in-state gas interconnections, the Kenai Spur Highway Relocation Project, or the Kenai Water System Upgrades. Construction of the PTU Expansion and PBU MGS Projects would take place in the vicinity of certain

special interest areas affected by the Project, including the Dalton Highway Corridor, North Slope Special Interest Areas, and Revised Statute Trail 1043. Impacts on the Dalton Highway Corridor would not be cumulative because the PBU MGS Project and the Alaska LNG facilities do not lie within the corridor in the same locations.[192] Impacts on Revised Statute Trail 1043 would not be cumulative because the planned facilities for the PTU Expansion nor PBU MGS Projects do not cross the trail. Project impacts on the North Slope Special Interest Areas would be cumulative with those of the PTU Expansion and PBU MGS Projects because all such impacts would be within the same HUC12 watershed. Cumulative impacts on the North Slope SUA from the proposed Project and these two non-jurisdictional facilities are estimated at 5,625 acres, of which 5,533 acres (97 percent) is for the proposed Project.

Based on the location of other projects (see figures 4.19.3-1, 4.19.3-2, and 4.19.3-3), the potential for cumulative impacts would be highest for recreation and special interest areas that rely on the Dalton Highway for access, including the Yukon Flats, Kanuti, and ANWRs, and Gates of the Arctic NPP. The primary cumulative impact on these resources would be through increased industrial traffic on the Dalton Highway, which could conflict with recreational drivers and tour operators. The South Denali Visitor Center, which lies 2 miles northeast of the proposed Mainline Pipeline route, opened in 2017 and no further work is planned, so no cumulative impacts associated with this action would occur.

Generally, cumulative impacts on recreation and special interest areas would occur when multiple projects are under construction simultaneously. Following construction, mining projects would likely generate a steady flow of truck traffic on public roads. These operational-phase traffic impacts would likely be less than significant, based on existing traffic volumes, the absence of significant operational-related traffic generated by the Alaska LNG Project, and the reasonable likelihood that these projects would not be constructed simultaneously.

Simultaneous construction of the Alaska LNG Project and other projects in Nikiski could block public access to the Cook Inlet beach area, which is not a publicly designated recreation area, but is used as such by local residents, as described in section 4.9.4. While such encroachment would affect a relatively small number of users, it could be perceived as significant by those users, particularly if construction of multiple projects extends the closure period.

Based on the above discussion, cumulative impacts on recreation and special interest areas could occur but would be temporary and minor.

4.19.4.10 Visual Resources

The Alaska LNG Project could contribute to cumulative impacts on visual resources where other actions are within the viewshed as defined by the Project's Visual Impact Analysis (i.e., the area within 15 miles of the Alaska LNG Project footprint). As described in section 4.10, visual impacts from any project depend on viewer sensitivity and the degree to which the project would contrast with existing or desired landscape conditions. The visual impacts of the Alaska LNG Project would vary from low to high depending on location and viewer type. Residents would generally perceive lower visual impacts than visitors. For the Alaska LNG Project, visual impacts would generally be highest in the Brooks Range (Galbraith Lake to Coldfoot) and Alaska Range (Clear to Talkeetna), as vegetation and high relief landforms in those areas would tend to provide sharp visual contrasts with the Mainline Pipeline right-of-way.

[192] Where the PTU Expansion facilities intersect the corridor, the GTP site is 0.9 mile from the corridor. The Alaska LNG Mainline Pipeline lies within the Dalton Highway corridor beginning at MP 20.

Projects that would combine with the Alaska LNG Project to contribute to cumulative visual impacts are identified in appendix W-1. The magnitude of cumulative impacts would generally be highest for projects closest to the Alaska LNG Project and sensitive visual resource areas, as defined in section 4.10.1. In particular, projects near the DNPP, such as the Usibelli Coal Mine and Eva Creek Wind Projects, could contribute to cumulative visual impacts.

Many of the projects in the North Slope would occur in an area where oil and gas development is common. The Alliance, Beaufort Sea, and Hilcorp Liberty Unit OCS oil development Projects would occur in areas with minimal public access and would therefore have no cumulative visual impact. AGDC identified a single KOP for the PTU Expansion and PBU MGS Projects, in consultation with ADNR and BLM. Cumulative impacts on the viewshed created by construction would be minimal, as the Alaska LNG Project area is 7.5 miles from the KOP location. The presence of equipment, machinery, and materials would cause direct impacts on a closer viewer, but would not be visible from the KOP.

General visual contrast for the PTU Expansion and PBU MGS Projects would consist of construction activities (e.g., work crews and camps, construction equipment and materials, machinery, lighting, etc.) that would have temporary visual effects for viewers in the vicinity, and permanent visual impacts associated with the aboveground pipelines for the PBU MGS Project, which would be cumulative with the proposed Project's GTP and related infrastructure. Most of the viewers in this area, however, would be the workers associated with industrial facilities on the North Slope, making them less sensitive to changes in the visual landscape.

Future facilities associated with the planned gas interconnections could contribute to cumulative visual effects to the extent that pipeline laterals and associated facilities are routed through or sited in forested lands. The locations of any such facilities are not yet known, however, so the extent of impacts cannot be determined at this time.

AGDC consulted with the ADNR and BLM to conduct a visual analysis for the Kenai Spur Highway Relocation Project, using BLM's Visual Resource Management methods. The analysis evaluated three KOPs and concluded there would be no visual impact on two KOPs and low-to-moderate impacts on the third KOP. The Kenai Water System Upgrades, which consist principally of a buried water pipeline and modifications/expansion to existing infrastructure, would not be expected to be a significant contributor to cumulative visual impacts. Section 4.15 discusses the impact of air emission on visibility in PSD Class I areas.

The cluster of projects near the Liquefaction Facilities in Nikiski would contribute cumulative visual impacts. Because these projects would modify existing industrial uses, and would not introduce new visual elements into the landscape, however, cumulative impacts in Nikiski would not be significant.

4.19.4.11 Socioeconomics

We have identified the area within which the Alaska LNG Project could contribute to cumulative socioeconomic effects as the entire State of Alaska. This is due both to the scope of the Project, which would lie in or near most major population centers in the state, as well as far-reaching indirect effects of such a large and costly infrastructure project on a state already heavily dependent on fossil fuel extraction to drive its economy. Moreover, the 8-year construction period and the continued socioeconomic effects during the operational life of the Alaska LNG Project (particularly in the Kenai Peninsula Borough) suggest that virtually all the projects listed in appendix W-1 when combined with those of the Project could contribute to cumulative impacts on socioeconomic conditions.

For our analysis, we evaluated cumulative impacts on employment, housing, tax revenues, public services, and environmental justice, as well as overall economic conditions. Generally, the Alaska LNG Project and each of the other projects represent sources of employment, tax revenue, and overall economic growth benefits, which accrue to the entire State of Alaska, and even beyond to the extent that labor, materials, or other items come from out-of-state locations. Negative cumulative effects are possible when multiple projects occur simultaneously in sufficient proximity that housing, transportation networks, and public services become strained. Negative cumulative impacts could also occur if episodic "boom and bust" cycles cause economic hardship to individuals or communities, or strain the commercial environment and public institutions.

Although it is difficult to predict whether and when each of the many future projects identified as potentially contributing to cumulative socioeconomic impacts would be built, appendix W-1 provides the best current information regarding each project's status. A great number of projects listed in appendix W-1 are in early development stages; some percentage of these projects would not move forward to construction due to commercial, permitting, or other reasons. Some projects listed, such as the non-jurisdictional projects, are likely to be constructed in the same time frame and are in close proximity to the Alaska LNG Project, and so an incremental increase in each of the socioeconomic impacts associated with the Alaska LNG Project can be projected. Others, such as the Donlin Gold Mine, appear likely to occur within the same timeframe as the Alaska LNG Project but are at such distances that cumulative effects would tend to be indirect economic impacts felt at the state or regional level rather than direct effects on any particular local community. The City of Kenai notes that overall reductions in State of Alaska revenues to local municipalities may impair the ability of affected municipalities to respond to adverse impacts from the Project; this effect would also apply more broadly to the cumulative impacts of multiple projects within the same socioeconomic region of influence.

Section 4.11 examines the socioeconomic impact of the Alaska LNG Project across Alaska and concludes that construction of the Project is likely to result in minor, temporary population increases on the North Slope and communities along the Mainline Pipeline. Increases would be expected to be significant, albeit temporary, in the Kenai Peninsula Borough during construction of the Liquefaction Facilities. Population increases attributable to operation of the Mainline Pipeline and Liquefaction Facilities would be expected to be significant and permanent in the Kenai Peninsula Borough due to the relatively high operational-related employment created by the Alaska LNG Project. Indirect economic benefits via tax revenue, employment, and spending would be expected to be permanent and significant.

The Alaska LNG Project's socioeconomic impacts combined with the other current, past, and reasonably foreseeable actions in the geographic scope would be similar in kind to that described in Section 4.11, but greater in magnitude. If these projects should be constructed simultaneously with the Alaska LNG Project, the impacts of population growth, including tax revenues, employment, and indirect economic effects of increased spending would be greater than that of the Alaska LNG Project alone.

Construction of the Alaska LNG Project would increase the demand for housing and reduce vacancy rates. Because temporary housing camps would be used during the construction phase, housing impacts from the Alaska LNG Project would not be expected to be significant. However, some Project workers, job-seekers, or new workers employed in jobs indirectly related to the Project may choose to relocate in the Kenai Peninsula Borough or other nearby municipalities. This could increase the demand for social services and law enforcement in these areas. The City of Kenai notes that there may be an increase in illegal dry cabins, RV camps, or other illegal makeshift camps from both workers trying to avoid the requirement to live in Project work camps and from workers who migrate to the Project area seeking employment directly or indirectly with the Project.

An increase in housing demand during the operational phase would be felt most keenly in the Matanuska-Susitna Borough, although the overall increase in demand would be relatively small and not significant. Similarly, impacts on local services such as schools, police, fire protection, and utilities would not be expected to be significant. Cumulative effects on housing would not be expected to be significant, in part, because the Project's contribution is relatively minor, and because the other projects contributing to a cumulative need for housing are concentrated in the Anchorage area and the North Slope, areas with the greatest ability to absorb increased housing demand.

Marine construction and operation of the Alaska LNG Project activities are projected to have some impacts on commercial fishing. No other concurrent activities that would restrict commercial fishing have been identified, so cumulative impacts on commercial fishing are unlikely.

Impacts on tourism from the Alaska LNG Project would be expected to be temporary and minor, potentially resulting from the overtaxing of existing tourism infrastructure or inconveniences to tourists caused by traffic congestion or delays. Cumulative effects on tourism would occur only where multiple projects are being constructed in high-tourism areas, such as DNPP, at the same time. Although this scenario is possible, most of the projects listed in appendix W-1 are either too far from the Alaska LNG Project to present that kind of overlap, or, as in the case of the North Slope projects, not in areas that attract large numbers of tourists.

Impacts on environmental justice populations could include traffic delays and new traffic patterns; visual effects from nighttime lighting or changes to existing viewsheds; interference with subsistence activities or habitats; and health impacts. It is possible that some of the actions identified in appendix W-1 could contribute to cumulative environmental justice impacts, but the nature and magnitude of any such impacts is difficult to assess without more precise knowledge of which actions would move forward and when. In general, the North Slope and the Cook Inlet areas appear to be where current or reasonably foreseeable actions could coincide temporally with the Alaska LNG Project, and therefore the areas in which cumulative impacts from an environmental justice perspective are most likely to occur. The uncertainty surrounding the fate of many of the projects identified in appendix W-1 suggests that many of the potential cumulative environmental justice impacts would not occur, so we conclude the likelihood of significant environmental justice impacts, while possible, is low.

4.19.4.12 Transportation

The Alaska LNG Project could contribute to cumulative impacts on transportation networks where other actions would utilize the same roads, railroads, ports, waterways, and airports as the Alaska LNG Project.

Road Network

The proposed Project and each of the reasonably foreseeable actions would result in cumulative increases in traffic volumes and possible congestion or delay on the Dalton, Elliott, Steese, Parks, Glenn, Seward, Sterling, and Kenai Spur Highways. The existing traffic volumes presented in section 4.12 for these highways include vehicles associated with some active projects, such as the Eva Creek Wind Project, highway maintenance projects, TAPS maintenance and upgrades, Usibelli Coal Mine, and ongoing oil and gas activities in the Nenana Basin and Yukon Flats Basin.

For reasonably foreseeable projects, increased vehicular traffic would be due to deliveries of modules, components, construction materials, supplies, and workers. The location and magnitude of traffic increases would depend on which projects are under construction at a given time. The largest cumulative impacts on road transportation would occur when multiple projects are under construction more-or-less

simultaneously. This could include projects in the North Slope, which would collectively increase traffic on the Dalton Highway, as well as the cluster of projects near Nikiski. Assuming each project generates vehicular traffic volumes similar to those evaluated for the proposed Project (see section 4.12), cumulative impacts would be unlikely to increase traffic volumes beyond the carrying capacity of the major roads listed above. Accordingly, cumulative impacts on traffic volumes and congestion would be less than significant. Because the Dalton Highway and Kenai Spur Highway near Nikiski carry low traffic volumes, drivers on these roads could perceive cumulative traffic increases as more substantial.

Impacts of relocating the Kenai Spur Highway would include changes to traffic patterns in the immediate area of the relocated highway. The existing highway segment would remain open until the new segment is complete. While no residents or businesses would lose road access to the remainder of the Kenai Peninsula road network, relocation of the Kenai Spur Highway segment would increase driving time to and from some residences and businesses, particularly those close to the Liquefaction Facilities. For example, a resident living near the northern boundary of the Liquefaction Facilities and wishing to travel to Soldotna would no longer be able to directly travel south on the Kenai Spur Highway. Instead, that person would need to travel east on Miller Loop Road to the relocated highway segment. For some residents, this detour would be up to about 5 miles.

Assuming that no homes, businesses, or private lands lose access to the road network, impacts of the Kenai Spur Highway relocation on traffic patterns would be minor. Overall, the highway relocation would contribute to cumulative transportation impacts, but the highway relocation would happen before, rather than concurrently with, the Liquefaction Facility construction, which would lessen these impacts.

Railroads

Cumulative impacts on railroads would depend on the degree to which the Alaska Railroad would be used for construction or operation of the reasonably foreseeable actions. Cumulative impacts on railroads could occur due to demand for freight rail service to deliver modules, components, construction materials, and supplies. As with road networks, the magnitude of cumulative rail demand would depend on which projects are under construction at a given time. The largest cumulative impacts on railroad transportation would occur when multiple projects are under construction more-or-less simultaneously. As discussed in section 4.12, railway demand for construction of the Alaska LNG Project would already exceed the number of rail cars available to the Alaska Railroad from Years 1 to 6. Any additional demand from other projects would encounter similar limitations. Cumulative impacts on railroads during periods of construction could limit the availability of commercial railroad service to other users. AGDC states that it would implement long-lead contracting, procurement, and cooperation with the Alaska Railroad. AGDC further indicates that it would provide Alaska Railroad a 2-year notice to allow procurement of additional railcars needed to support construction. These measures would reduce cumulative effects on rail transport capacity.

Ports and Waterways

Many of the current or reasonably foreseeable actions are either in open-water or shoreline locations, or would require use of the same ports and waterways affected by construction of the Alaska LNG Project. The proposed Project construction would use much of the available capacity of the Ports of Alaska (Anchorage) and Seward (see section 4.12). To the degree that any of the reasonably foreseeable actions would also use these ports, demand for port facilities could exceed capacity, resulting in cumulative impacts. AGDC has stated that if capacity limitations emerge, it would shift containerized deliveries from the Port of Anchorage to the Port of Seward. In addition, shipping companies serving the Port of Whittier could add capacity. This would reduce the potential for significant cumulative impacts on port capacities.

Major sealift modules and pipe imported for the Project would go through the established customs entry process in the Port of Dutch Harbor, which would be used as a staging area for imported Project construction materials to be transported to the Gas Treatment Facilities by oceangoing tugs pulling barges. Due to the number of vessels in operation in and around the Port of Dutch Harbor, adequate anchorage could be limited. AGDC would prepare a Sealift Entry and Exit Strategy prepared in conjunction with the Coast Guard that specifies the anticipated schedule, as well as anchorage, offloading, and loading needs of Project-related vessels. Implementation of this measure is expected to reduce the potential for cumulative impacts at this port.

None of the other actions considered as potentially contributing to cumulative impacts would be expected to entail incremental additions to operational vessel use. Assuming the reasonably foreseeable projects generate similar or less vessel traffic than the proposed Project, cumulative impacts on ports and waterways would be less than significant.

Air Transportation

The reasonably foreseeable actions could increase demand for air transportation (including airports and aircraft), primarily to transport workers. In combination with the proposed Project's air transportation demands, reasonably foreseeable projects could further increase demand for flights and aircraft, and could further strain the physical capacity of smaller air terminals, such as those at Deadhorse or Kenai. Compared, for example, to rail cars, aircraft and aircrews could be quickly transferred to Alaska to address temporary spikes in demand. Improvements to Ted Stevens Anchorage International Airport and expansion of the terminal at Kenai (as discussed in section 4.12) would be positive cumulative impacts, and could help to offset the adverse impacts of reasonably foreseeable projects. Accordingly, and considering the proposed Project's minor impacts on air transportation, cumulative impacts on air transportation would not be significant.

4.19.4.13 Cultural Resources

Cumulative impacts on cultural resources would only occur if other past, present, or reasonably foreseeable actions affect the same historic properties as the Alaska LNG Project. We defined the APE for direct Project effects on historic properties as the construction footprint for the proposed facilities, including temporary workspace and ATWS, access roads, staging areas, material source locations, etc. Only minor portions of the PTU Expansion and PBU MGS Projects and in-state gas interconnections would overlap within the APE for direct Project impacts. We defined the APE for indirect Project effects as a 1-mile buffer around the proposed facilities. Several of the projects or existing facilities listed in appendix W-1 would lie within this 1-mile buffer, including the Kenai Highway Spur Relocation, Kenai Water System Upgrades, Kenai LNG Cool Down Project, ORPC Cook Inlet Tidal Energy Project, TAPS maintenance and upgrades, Andeavor Kenai Refinery, Alaska Roads to Resources (Ambler Road), highway maintenance and upgrades, Agrium Kenai Nitrogen Operations Facility, and Quintillion Terrestrial/GCI Alaska United Fiber Optic Projects.

With regard to non-jurisdictional facilities, AGDC indicates that previous cultural resources studies have covered the footprint for the PTU Expansion Project and determined that this project would not affect known sites. No cultural resources assessments or studies have been performed to date for the PBU MGS Project or the Kenai Water System Upgrades. No known cultural resources have been identified within the footprint of the Kenai Spur Highway Relocation Project, although cultural resources field surveys have not yet been completed. Laterals or other facilities associated with the in-state gas interconnections have not been identified, so their potential to affect cultural resources is unknown.

Where direct impacts on significant cultural resources are unavoidable, mitigation (e.g., recovery of data and curation of materials) would occur before construction. The federal projects listed in appendix W-1, like the Project, would be required to comply with Section 106 of the NHPA, which requires federal agencies to identify, assess, and mitigate adverse effects, including cumulative effects, on historic properties within the APE. AGDC has conducted surveys to identify sensitive cultural resources and historic properties that could be affected by the Project and has developed a plan to address unanticipated discoveries of cultural resources and human remains during construction. Other federal projects would implement similar plans and measures. For these reasons, cumulative impacts on cultural resources, if any, would not likely be significant.

4.19.4.14 Subsistence

The geographic area of consideration for cumulative effects on subsistence includes habitat and the migratory ranges for subsistence resources, such as caribou herd ranges, salmon and non-salmon migratory ranges, and migratory bird ranges, and the traditional subsistence use areas for communities affected by the Project. These geographic areas, which vary in extent, are depicted in the community subsistence use area maps provided in section 4.14. In combination with the Project, many of the current or reasonably foreseeable actions could affect subsistence resource availability.

On the North Slope, oil and gas activities on state and federal lands near the Project have already deterred subsistence hunters from using traditional caribou hunting areas (BLM, 2013; North Slope Borough, 2014; National Research Council, 2003). The projects listed in appendix W-1 that are between the Colville and Canning Rivers could increase the amount of activity within the Central Arctic Herd caribou range, and could expose a large number of the Teshekpuk Caribou Herd and Western Arctic Herd caribou to development in their summer and winter grounds and during migration. Continued expansion of industrial activity could displace caribou from their normal migratory routes. The PTTL could affect the movement of the Central Arctic Herd to important insect relief areas along the coast, which could affect hunter access from the coast. The GTP and associated gravel roads and pads, a material site, a reservoir, and pipelines represent a permanent loss of sensitive caribou habitat. Overall, the cumulative impacts could increase the area considered to be undesirable by subsistence users, and require subsistence users to travel farther to harvest subsistence foods at a greater cost in terms of time, fuel, wear and tear on equipment, and harvester's lost wages and increased safety risks.

While direct habitat loss from cumulative oil and gas development near the Project would affect only a small proportion of the total area used by caribou, functional habitat loss could result from long-term displacement of caribou from the vicinity of the applicable projects listed in appendix W-1 and could encompass a much larger area resulting in reduced availability of caribou. AGDC would implement mitigation measures, including consultation with the potentially affected subsistence communities, to prevent conflicts with subsistence hunting. Nonetheless, the cumulative effects of the Alaska LNG Project in combination with other projects on the North Slope could disrupt or delay the distribution of caribou on the North Slope and could negatively affect subsistence harvests of caribou by the Nuiqsut, Kaktovik, Utqiagvik, and Anaktuvuk Pass village residents.

Cumulative effects on bowhead whales could result from offshore activities, including disturbance attributed to aerial and underwater noise in the Beaufort Sea. Seismic programs, drilling or other activities that produce underwater noise, and noise from aircraft could cause bowhead whales to be temporarily displaced from their travel or migratory routes or change behavioral patterns such as diving and surfacing behaviors. If Alaska LNG Project activities occur concurrently and within proximity to any of the other applicable projects listed in appendix W-1, impacts on marine mammals would likely be exacerbated as a direct result of each project's activities and could result in changes in movement and migratory patterns, shifts in foraging behavior, or access to productive forage areas. These behavioral changes would likely

require subsistence users in Nuiqsut, Kaktovik, and Utqiagvik to travel farther to harvest bowhead whales at a greater cost in terms of time, fuel, and wear and tear on equipment. AGDC would coordinate with the AEWC to work under a Conflict Avoidance Agreement to decrease impacts on bowheads and subsistence hunters. This measure would minimize cumulative impacts on bowhead whales due to Project construction and operation.

The proposed Project, along with the Eva Creek Wind Project, highway maintenance projects, TAPS maintenance and upgrades, Usibelli Coal Mine, and ongoing oil and gas activities in the Nenana Basin and Yukon Flats Basin, would result in cumulative increases in traffic volumes on the Dalton and Parks Highways due to deliveries of construction materials and workers. Projects on the North Slope would also be included. An influx of non-local workers would likely increase competition for subsistence harvesters and subsistence resources, leading to reduced hunter success, a decrease in available resources, and a need to hunt in more distant locations. Any increase in the numbers of hunters in the area would likely increase competition and reduce abundance and availability of caribou and/or moose in several communities, including Wiseman, Stevens Village, Nenana, Four Mile Road CDP, Anderson, Ferry, Healy, Denali Park CDP, and Cantwell. Increased competition from workers would be temporary and AGDC would implement hunting prohibitions for employees stationed at camps. Therefore, the cumulative impacts would not be significant.

New access roads, from the Project or other projects, have the potential to provide easier access to subsistence resources for local harvesters, but if opened to outsiders, they could result in increased competition and pressures on wildlife populations. Outsider access to Minto Flats would result in harvest competition in a previously undeveloped area. AGDC would restrict or impede access to key subsistence use areas near Minto Flats which would minimize impacts, although none of the actions identified as reasonably foreseeable lie within this area. Therefore, the Alaska LNG Project could contribute to moderate, albeit permanent cumulative impacts.

4.19.4.15 Air Quality

Traditional air pollutants such as criteria pollutants, volatile organic compounds, and hazardous air pollutants were listed for chronic and acute health impacts due to inhalation, as well as secondary environmental effects.

GHGs were identified by the EPA as pollutants in the context of climate change. GHG emissions do not cause local impacts, it is the combined concentration in the atmosphere that causes global climate change (see Climate Change below), and these are fundamentally global impacts that feed back to localized climate change impacts. Thus, the geographic scope for cumulative analysis of GHG emissions is global rather than local or regional. For example, a project 1.0 mile away emitting 1 ton of GHGs would contribute to climate change in a similar manner as a project 2,000 miles distant also emitting 1 ton of GHGs.

Construction Emissions

Construction air emissions from the Alaska LNG Project could contribute to cumulative impacts on air quality where other actions are within 0.25 mile of the Project footprint. As discussed in section 4.15.4, air quality impacts comprise intermittent and short-term impacts from construction-related activities, which encompass construction vehicle operation and traffic, marine and air traffic, open burning, fugitive dust, and additional construction support activities.

Four current or reasonably foreseeable future projects are within 0.25 mile of the Alaska LNG Project, and therefore could contribute to cumulative air quality impacts during construction of the Project. These projects include the PTU Expansion and PBU MGS Projects, future development associated with in-state gas interconnections, the Kenai Municipal Water System upgrades, and Kenai Spur Highway

Relocation Project. Construction of the Kenai Spur Highway Relocation, the Kenai Municipal Water System upgrades, and future laterals and other infrastructure associated with the in-state gas interconnections would likely not occur concurrently with construction of the Project, so no cumulative impacts from these actions would be anticipated. Expected construction emissions from the highway relocation project are provided in table 4.19.4-1 for disclosure; however, it is not expected that construction of the Kenai Spur Highway Relocation Project would overlap temporally with construction of the Liquefaction Facilities. Potential construction emissions from infrastructure associated with the in-state gas interconnections and the Kenai Municipal Water System upgrades are unknown.

TABLE 4.19.4-1

Kenai Spur Highway Relocation Construction Emissions (Year 1 of the Alaska LNG Project)

VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)
1.6	17.7	12.6	15.8	3.9	<,0.1

Based on the current Project schedule, construction of the PTU Expansion Project would occur over 6 years, and construction of the PBU MGS Project would occur over 9 years.[193] Construction emission sources associated with these projects are similar and include operation of mobile construction equipment (i.e., light-duty trucks, cranes, forklifts), fugitive dust emissions, operation of stationary equipment (i.e., generators, heaters), and operation of drilling equipment. Estimated construction emissions by Alaska LNG Project construction year for the PTU Expansion and PBU MGS Projects are provided in tables 4.19.4-2 and 4.19.4-3, respectively.

TABLE 4.19.4-2

PTU Expansion Project Construction Emission Estimates by Year

Alaska LNG Project Construction Year	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)
Year 2	357.6	884.6	1,415.5	116.1	115.9	1.5	0.0
Year 3	715.2	1,769.2	2,830.9	400.2	248.7	3.0	0.0
Year 4	945.4	3,196.0	3,503.9	466.6	292.4	75.6	0.9
Year 5	945.4	3,196.0	3,503.9	466.6	292.4	75.6	0.9
Year 6	945.4	3,916.0	3,503.9	298.6	275.5	75.6	0.9
Year 7	115.1	1,073.4	336.5	33.2	21.9	36.3	0.9
Total	**4,024.1**	**14,035.2**	**15,094.6**	**1,781.3**	**1,246.8**	**267.6**	**3.6**

[193] Construction years in tables 4.19.4-1, 4.19.4-2, and 4.19.4-3 are based on AGDC's schedule for non-jurisdictional projects provided in appendix G of Resource Report 9 (Accession No. 20170417-5345) and AGDC's updated construction schedule provided in the November 7, 2018, response (Accession No. 2081107-5072) to FERC information request No. 5, dated October 2, 2018. Both documents are available on the FERC website at http://www.ferc.gov. Using the "eLibrary" link, select "Advanced Search" from the eLibrary menu and enter 20170417-5357 in the "Numbers: Accession Number" field.

TABLE 4.19.4-3

PBU MGS Project Construction Emission Estimates by Year

Alaska LNG Project Construction Year	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)
Year 1	3.6	17.0	23.4	96.7	10.9	0.3	0.0
Year 2	5.2	26.0	34.7	158.0	18.0	0.3	0.0
Year 3	5.0	24.0	33.3	157.8	17.8	0.3	0.0
Year 4	3.4	17.6	21.5	122.5	13.5	0.2	0.0
Year 5	62.0	553.4	175.1	74.6	19.6	0.6	0.5
Year 6	60.4	545.2	164.8	13.4	12.9	0.5	0.5
Year 7	60.4	545.2	164.8	13.4	12.9	0.5	0.5
Year 8	60.4	545.2	164.8	13.4	12.9	0.5	0.5
Year 9	60.4	545.2	164.8	13.4	12.9	0.5	0.5
Total	**320.8**	**2,818.8**	**947.2**	**663.2**	**131.4**	**3.7**	**2.5**

The emission sources described above, as well as the construction emissions included in tables 4.19.4-2 and 4.19.4-3 for the PTU Expansion and PBU MGS Projects, are preliminary estimates based on currently available information. The construction emission estimates for the PTU Expansion in particular, would be expected to be less than shown in table 4.19.4-2, due to changes in the planned design of the project since those estimates were prepared. More detailed emission estimates would be included in the applications being developed for submittal to the respective lead agencies responsible for review and authorization of each of the projects. These analyses would further assess the significance of the construction emissions on the surrounding environment.

Because construction-related emissions tend to be localized, the potential for cumulative impacts is limited to those areas where multiple activities occur in close proximity (i.e., within 0.25 mile) to one another. For example, only very minor portions of the PTU Expansion and PBU MGS Projects construction footprints lie within 0.25 mile of the proposed Project, so the contribution of these two projects to cumulative construction air impacts would be insignificant. During project construction, AGDC would mitigate emissions by implementing a construction emission control plan, Fugitive Dust Control Plan, and Open Burning Plan. Therefore, the Alaska LNG Project, in combination with these other projects, would likely result in only minor, temporary cumulative impacts due to construction emissions.

Operational Emissions of the PTU Expansion and PBU MGS Projects

The PTU Expansion and PBU MGS Projects would begin incremental operation during construction in Year 6 and Year 7 of the Alaska LNG Project, respectively.

New operational sources associated with the PTU Expansion Project would include:

- two natural gas-fired heaters;
- four combustion turbines;
- two flares;
- one waste incinerator;
- two emergency pump engines;
- miscellaneous generators and heaters; and
- fugitive and mobile sources.

New operational sources associated with the PBU MGS Project would include:

- valve model heating system; and
- fugitive emissions from piping components and connectors.

The PBU MGS Project would result in a net air emission decrease at the PBU because the turbine capacity needed to compress and reinject natural gas into the current wells at the PBU would decrease. Therefore, the operational emissions provided for the PBU MGS Project are presented as a net change from the current baseline emissions. Operational emissions for the PTU Expansion and the PBU MGS Projects are presented in tables 4.19.4-4 and 4.19.4-5, respectively.

The emissions included in tables 4.19.4-4 and 4.19.4-5 are preliminary estimates based on currently available information. More detailed estimates would be included in the applications being developed for submittal to the respective lead agencies responsible for review and authorization of each of the projects. These analyses would further assess the significance of these operational emissions on the surrounding environment. The PTU Expansion and PBU MGS Projects would require PSD permits for new major stationary sources and/or major modifications to existing sources. The PSD permits would be obtained from ADEC prior to commencing construction on these projects.

Cumulative Operational Air Impacts

Operation of the Alaska LNG Project would result in permanent air quality impacts associated with ongoing emissions from stationary equipment (e.g., the GTP, compressor stations, heater station, meter stations, and Liquefaction Facilities). Fugitive air emissions would also be generated during operation of the Mainline Facilities. Additional air emissions would be generated by employee vehicles and air travel during maintenance of Project facilities. The air emissions would include criteria pollutants (NO_2, SO_2, CO, VOC, PM_{10}, and $PM_{2.5}$), GHGs, and HAPs. Operational air emissions from the Alaska LNG Project could contribute to cumulative impacts on air quality where other actions are within 31 miles (50 km) of the GTP, compressor stations, heater station, and Liquefaction Facilities. A description and status of these projects is included in appendix W-1.

TABLE 4.19.4-4

PTU Expansion Project Operational Emission Estimates by Year

Alaska LNG Project Construction/Operation Year	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)
Year 6	0.4	18.1	15.3	1.4	1.4	3.8	0.1
Year 7	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 8	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 9	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 10	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 11	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 12	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 13	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 14	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 15	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 16	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 17	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 18	0.8	36.3	30.6	2.7	2.7	7.5	0.1
Year 19 / Peak Operation Capacity	8.2	161.1	43.3	16.8	16.8	61.3	2.2

TABLE 4.19.4-5

PBU MGS Project Operational Emission Estimates by Year

Alaska LNG Project Construction/Operation Year	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)
Year 7	18.0	3,074.0	446.0	54.0	54.0	46.0	6.0
Year 8	18.0	3,074.0	446.0	54.0	54.0	46.0	6.0
Year 9	18.0	3,074.0	446.0	54.0	54.0	46.0	6.0
Year 10	21.0	3,627.0	511.0	63.0	63.0	54.0	8.0
Year 11	24.0	4,268.0	555.4	72.3	72.3	54.5	9.0
Year 12	30.0	5,372.0	715.0	93.0	93.0	77.0	11.0
Year 13	33.0	5,793.0	793.0	105.0	105.0	85.0	13.0
Year 14	36.0	6,056.0	842.0	113.0	113.0	91.0	15.0
Year 15	45.0	7,797.0	1,045.0	143.0	143.0	115.0	18.0
Year 16	48.0	8,299.0	1,108.0	152.0	152.0	123.0	20.0
Year 17	51.0	8,944.0	1,188.0	165.0	165.0	131.0	21.0
Year 18	55.0	9,772.0	1,231.0	178.0	178.0	140.0	23.0
Year 19	59.0	10,588.0	1,279.0	191.0	191.0	149.0	25.0
Year 20	63.0	11,422.0	1,322.0	204.0	204.0	159.0	27.0
Year 21	67.0	12,489.0	1,426.0	217.0	217.0	169.0	29.0
Year 22	70.0	13,132.0	1,460.0	227.0	227.0	177.0	31.0
Year 23	70.0	13,182.0	1,463.0	228.0	228.0	178.0	31.0
Year 24	70.0	13,182.0	1,463.0	228.0	228.0	178.0	31.0
Year 25 / Peak Operation Capacity	70.0	13,228.0	1,465.0	229.0	229.0	179.0	31.0

The PTU Expansion Project's operational emission sources lie about 60 miles east of the proposed Project's facilities, and are therefore outside the geographic scope of cumulative impacts for operations-related air emissions. Emission sources for the PBU MGS Project do lie within the geographic scope for operation-related air emissions, and so would contribute to cumulative air quality impacts. Cumulative operational emission estimates for the GTP and PBU MGS Project are presented in table 4.19.4-6.

Assessment of the Alaska LNG Project's impact on ambient air quality requires the modeling of emissions in conjunction with background ambient air quality concentrations, which includes nearby emission sources. Based on our quantitative analysis, the proposed Project combined with other activities within the Project's temporal and geographic scope would not result in a significant impact on local and regional air quality for the majority of the Project's operation. During the years that simultaneous construction, startup, and operational activities occur at the Liquefaction Facilities, which would likely be Years 7 and 8 of construction, emission levels could result in exceedances of the NAAQS/AAAQS, but AGDC would implement an Ambient Air Quality Monitoring Plan to ensure that these emissions do not have a significant effect on ambient air quality in this area. Emissions from the aboveground facilities, including the GTP, compressor stations, heater station, and Liquefaction Facilities, could cause exceedances of visibility thresholds and sulfur or nitrogen deposition thresholds at some Class II nationally designated protected areas. Additionally, certain short-term activities, such as flaring at the GTP and Liquefaction Facilities, have the potential to result in short-term significant effects. These results are presented in section 4.15.5.

Emissions from existing facilities are considered part of the environmental baseline. We have included a comparison of the emissions of these facilities against the Alaska state inventory for 2014, which

is the most recently available data.[194] As presented in table 4.19.4-6, the overall cumulative emissions would be low with the exception of NO_x emissions, which would be a large increase in overall state inventory.

TABLE 4.19.4-6

Cumulative Operational Emission Estimates from Alaska LNG GTP and PBU MGS Expansion Projects by Year

Alaska LNG Project Construction/Operation Year [a]	VOC (tons)	NOx (tons)	CO (tons)	PM_{10} (tons)	$PM_{2.5}$ (tons)	SO_2 (tons)	Total HAPs (tons)
Year 7	18.0	3,074.0	466.0	54.0	54.0	46.0	6.0
Year 8	372.4	5,316.1	2,525.5	318.1	318.0	639.3	48.4
Year 9	372.4	5,316.1	2,525.1	318.1	318.0	639.3	48.4
Year 10	375.4	5,869.1	2,590.5	327.1	327.0	647.3	50.4
Year 11	378.5	6,510.0	2,634.9	336.9	336.3	647.8	51.4
Year 12	384.4	7,614.1	2,794.5	357.1	357.0	670.3	53.4
Year 13	387.4	8,035.1	2,872.5	369.1	369.0	678.3	55.4
Year 14	390.4	8,298.1	2,921.5	377.1	377.0	684.3	57.4
Year 15	399.4	10,039.1	3,124.5	407.1	407.0	708.3	60.4
Year 16	402.4	10,541.1	3,187.5	416.1	416.0	716.3	62.4
Year 17	405.4	11,186.1	3,267.5	429.1	429.0	724.3	63.4
Year 18	409.4	12,014.1	3,310.5	442.1	442.0	733.3	65.4
Year 19	405.4	12,830.1	3,358.5	455.1	455.2	742.3	67.4
Year 20	4109.2	13,503.0	3,358.2	451.3	451.2	691.0	67.2
Year 21	416.2	14,570.0	3,462.2	464.3	464.2	701.0	69.2
Year 22	416.2	15,213.0	3,496.2	474.3	474.2	709.0	71.2
Year 23	416.2	15,263.0	3,499.2	475.3	475.2	710.0	71.2
Year 24	416.2	15,263.0	3,499.2	475.3	475.2	710.0	71.2
Year 25	416.24	15,307.0	3,501.2	476.3	476.2	711.0	71.2
2014 Alaska Inventory	557,000	146,000	2,300,000	274,000	187,000	22,000	NA

NA = Not available

[a] Alaska LNG GTP emissions do not include maximum flare conditions.

Based on comments from the NPS and other cooperating agencies, we requested that AGDC complete cumulative modeling to assess impacts from operational emissions associated with all components of the Project (i.e., GTP, compressor stations, heater station, and Liquefaction Facilities) to Class I and II nationally designated protected areas. Tables 4.19.4-7 to 4.19.4-9 present the cumulative NAAQS/AAAQS, regional haze, and acid depositional impacts associated with all the Project components.

As shown in table 4.19.4-7, the cumulative air quality emissions from aboveground facilities associated with the Project, when combined with estimated background emissions, would not exceed any NAAQS/AAAQS at Class I or Class II nationally designated protected areas. Based on information presented in tables 4.19.4-8 and 4.19.4-9, the cumulative air quality emissions from aboveground facilities associated with the Project would exceed screening-level visibility extinction thresholds and sulfur and nitrogen deposition thresholds at some Class I or Class II nationally designated protected areas, which could have a significant impact on these areas. Additional mitigation measures could be implemented during the air permitting phase that would reduce these impacts.

[194] The 2014 Alaska Inventory is from EPA's *2014 National Emissions Inventory Report* (EPA, 2014).

TABLE 4.19.4-7

Cumulative NAAQS/AAAQS Modeling Results for Class I and Class II Nationally Designated Protected Areas near the Alaska LNG Project

Pollutant	Averaging Period	Concentrations: Model Predicted (Alaska LNG Project Sources) ($\mu g/m^3$) [a]	Concentrations: Background ($\mu g/m^3$)	Concentrations: Total ($\mu g/m^3$) [a]	NAAQS ($\mu g/m^3$)	AAAQS ($\mu g/m^3$)	NAAQS/ AAAQS Exceedance? (Yes/No)
ANWR							
CO	1-hour [b]	52.3	1,150.0	1,202.3	40,000	40,000	No
	8-hour [b]	14.4	1,150.0	1,164.4	10,000	10,000	No
NO_2	1-hour [c]	15.6	61.7	77.3	188	188	No
	Annual [d]	0.2	6.0	6.2	100	100	No
PM_{10}	24-hour [e]	0.6	50.0	50.6	150	150	No
	Annual [g, i]	0.1	3.7	3.8	12	12	No
$PM_{2.5}$	24-hour [f, i]	0.3	15.0	15.3	35	35	No
	Annual [g, i]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	0.6	9.4	10.0	196	196	No
	3-hour [b]	0.5	21.0	21.5	1,300	1,300	No
	24-hour [b]	0.2	8.1	8.3	N/A	365	No
	Annual [d]	<0.1	1.8	1.8	N/A	80	No
Gates of the Arctic NPP							
CO	1-hour [b]	45.1	1,150.0	1,145.1	40,000	40,000	No
	8-hour [b]	12.9	1,150.0	1,162.9	10,000	10,000	No
NO_2	1-hour [c]	11.1	61.7	72.8	188	188	No
	Annual [d]	0.1	6.0	6.1	100	100	No
PM_{10}	24-hour [e]	0.4	50.0	50.4	150	150	No
	Annual [g, i]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	0.2	15.0	15.2	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	0.5	9.4	9.9	196	196	No
	3-hour [b]	0.4	21.0	21.4	1,300	1,300	No
	24-hour [b]	<0.1	8.1	8.1	N/A	365	No
	Annual [d]	<0.1	1.8	1.8	N/A	80	No
Yukon Flats NWR [i]							
CO	1-hour [b]	12.1	573.0	585.1	40,000	40,000	No
	8-hour [b]	3.8	458.0	461.8	10,000	10,000	No
NO_2	1-hour [c]	2.6	61.2	63.8	188	188	No
	Annual [d]	<0.1	2.5	2.5	100	100	No
PM_{10}	24-hour [e]	0.2	38.3	38.5	150	150	No
	Annual [g]	<0.1	2.8	2.8	12	12	No
$PM_{2.5}$	24-hour [f]	<0.1	11.8	11.8	35	35	No
	Annual [g]	<0.1	2.8	2.8	12	12	No
SO_2	1-hour [h]	0.1	5.2	5.3	196	196	No
	3-hour [b]	0.1	6.2	6.3	1,300	1,300	No
	24-hour [b]	<0.1	5.4	5.4	N/A	365	No
	Annual [d]	<0.1	0.5	0.5	N/A	80	No

TABLE 4.19.4-7 (cont'd)

Cumulative NAAQS/AAAQS Modeling Results for Class I and Class II Nationally Designated Protected Areas near the Alaska LNG Project

Pollutant	Averaging Period	Concentrations: Model Predicted (Alaska LNG Project Sources) (µg/m^3) [a]	Background (µg/m^3)	Total (µg/m^3) [a]	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/ AAAQS Exceedance? (Yes/No)
Kanuti NWR [i]							
CO	1-hour [b]	5.6	573.0	578.6	40,000	40,000	No
	8-hour [b]	1.0	458.0	459.0	10,000	10,000	No
NO_2	1-hour [c]	0.8	61.2	62.0	188	188	No
	Annual [d]	<0.1	2.5	2.5	100	100	No
PM_{10}	24-hour [e]	0.2	38.3	38.5	150	150	No
	Annual [g]	<0.1	2.8	2.8	12	12	No
$PM_{2.5}$	24-hour [f]	<0.1	11.8	11.8	35	35	No
	Annual [g]	<0.1	2.8	2.8	12	12	No
SO_2	1-hour [h]	<0.1	5.2	5.2	196	196	No
	3-hour [b]	<0.1	6.2	6.2	1,300	1,300	No
	24-hour [b]	<0.1	5.4	5.4	N/A	365	No
	Annual [d]	<0.1	0.5	0.5	N/A	80	No
Denali NPP							
CO	1-hour [b]	46.2	1,145.0	1,191.2	40,000	40,000	No
	8-hour [b]	15.1	1,145.0	1,160.1	10,000	10,000	No
NO_2	1-hour [c]	14.0	32.3	46.3	188	188	No
	Annual [d]	0.2	2.6	2.8	100	100	No
PM_{10}	24-hour [e]	0.4	40.0	40.4	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	0.2	12.0	12.2	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	0.7	5.0	5.7	196	196	No
	3-hour [b]	0.5	5.0	5.5	1,300	1,300	No
	24-hour [b]	0.1	2.3	2.4	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No
Lake Clark Wilderness and National Park							
CO	1-hour [b]	65.4	1,145.0	1,210.4	40,000	40,000	No
	8-hour [b]	4.3	1,145.0	1,149.3	10,000	10,000	No
NO_2	1-hour [c]	0.8	32.3	33.1	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	0.2	40.0	40.2	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	0.1	12.0	12.1	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	0.1	5.0	5.1	196	196	No
	3-hour [b]	0.1	5.0	5.1	1,300	1,300	No
	24-hour [b]	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No

TABLE 4.19.4-7 (cont'd)

Cumulative NAAQS/AAAQS Modeling Results for Class I and Class II Nationally Designated Protected Areas near the Alaska LNG Project

Pollutant	Averaging Period	Concentrations: Model Predicted (Alaska LNG Project Sources) (µg/m^3) [a]	Background (µg/m^3)	Total (µg/m^3) [a]	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/ AAAQS Exceedance? (Yes/No)
Kenai NWR							
CO	1-hour [b]	39.8	1,145.0	1,184.8	40,000	40,000	No
	8-hour [b]	14.7	1,145.0	1,159.7	10,000	10,000	No
NO_2	1-hour [c]	6.4	32.3	38.7	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	1.1	40.0	41.1	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	0.4	12.0	12.4	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	1.2	5.0	6.2	196	196	No
	3-hour [b]	0.8	5.0	5.8	1,300	1,300	No
	24-hour [b]	0.2	2.3	2.5	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No
Kenai Fjords National Park							
CO	1-hour [b]	39.8	1,145.0	1,184.8	40,000	40,000	No
	8-hour [b]	2.7	1,145.0	1,147.7	10,000	10,000	No
NO_2	1-Hour [c]	0.4	32.3	32.7	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	0.2	40.0	40.2	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	<0.1	12.0	12.0	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	<0.1	5.0	5.0	196	196	No
	3-hour [b]	<0.1	5.0	5.0	1,300	1,300	No
	24-hour [b]	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No
Tuxedni NWR							
CO	1-hour [b]	26.8	1,145.0	1,171.8	40,000	40,000	No
	8-hour [b]	2.1	1,145.0	1,147.1	10,000	10,000	No
NO_2	1-hour [c]	0.5	32.3	32.8	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	0.2	40.0	40.2	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	0.1	12.0	12.1	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	<0.1	5.0	5.0	196	196	No
	3-hour [b]	<0.1	5.0	5.0	1,300	1,300	No
	24-hour [b]	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No

TABLE 4.19.4-7 (cont'd)

Cumulative NAAQS/AAAQS Modeling Results for Class I and Class II Nationally Designated Protected Areas near the Alaska LNG Project

Pollutant	Averaging Period	Concentrations: Model Predicted (Alaska LNG Project Sources) (µg/m^3) [a]	Background (µg/m^3)	Total (µg/m^3) [a]	NAAQS (µg/m^3)	AAAQS (µg/m^3)	NAAQS/ AAAQS Exceedance? (Yes/No)
Chugach National Forest							
CO	1-hour [b]	25.2	1,145.0	1,170.2	40,000	40,000	No
	8-hour [b]	2.0	1,145.0	1,147.0	10,000	10,000	No
NO_2	1-hour [c]	0.4	32.3	32.7	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	0.2	40.0	40.2	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	<0.1	12.0	12.0	35	35	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
SO_2	1-hour [h]	<0.1	5.0	5.0	196	196	No
	3-hour [b]	<0.1	5.0	5.0	1,300	1,300	No
	24-hour [b]	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No
Kodiak NWR							
CO	1-hour [b]	8.4	1,145.0	1,153.4	40,000	40,000	No
	8-hour [b]	1.1	1,145.0	1,146.1	10,000	10,000	No
NO_2	1-hour [c]	0.2	32.3	32.5	188	188	No
	Annual [d]	<0.1	2.6	2.6	100	100	No
PM_{10}	24-hour [e]	0.1	40.0	40.1	150	150	No
	Annual [g]	<0.1	3.7	3.7	12	12	No
$PM_{2.5}$	24-hour [f]	<0.1	12.0	12.0	35	35	No
	Annual [g]	<0.1	3.7	3.	12	12	No
SO_2	1-hour [h]	<0.1	5.0	5.0	196	196	No
	3-hour [b]	<0.1	5.0	5.0	1,300	1,300	No
	24-hour [b]	<0.1	2.3	2.3	N/A	365	No
	Annual [d]	<0.1	0	<0.1	N/A	80	No

N/A = Not applicable

[a] Alaska LNG Project sources include the GTP, compressor stations, heater station, and Liquefaction Facilities. Total is the sum of the Alaska LNG Project source and background concentration.

[b] Value reported is the highest-second-high concentration of the values determined for each of the 3 modeled years.

[c] Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[d] Value reported is the maximum annual average concentration for the 3-year period.

[e] Value reported is the highest-sixth-high concentration over the 3-year period.

[f] Value reported is the highest 98th percentile averaged over the 3-year period.

[g] Value reported is the annual mean concentration, averaged over the 3-year period.

[h] Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

[i] Estimated background concentrations for the Ray River Compressor Station were used to provided estimated background for the Yukon Flats and Kanuti NWRs.

TABLE 4.19.4-8

Cumulative Regional Haze Modeling Results for the Alaska LNG Project

Model Year	Alaska LNG Project Results: 8th Highest Change in Extinction (%) [a]	Alaska LNG Project Results: Visibility Extinction Threshold for a Project (Contribute/ Cause) (%)	Cause or Contribute to Exceedance of Visibility Extinction Threshold? (Yes/No)
ANWR			
1	17.5	5.0 / 10.0	Yes (cause)
2	24.2	5.0 / 10.0	Yes (cause)
3	21.3	5.0 / 10.0	Yes (cause)
Gates of the Arctic NPP			
1	18.5	5.0 / 10.0	Yes (cause)
2	16.5	5.0 / 10.0	Yes (cause)
3	16.2	5.0 / 10.0	Yes (cause)
Yukon Flats NWR			
1	7.5	5.0 / 10.0	Yes (contribute)
2	7.0	5.0 / 10.0	Yes (contribute)
3	7.5	5.0 / 10.0	Yes (contribute)
Kanuti NWR			
1	4.7	5.0 / 10.0	No
2	4.9	5.0 / 10.0	No
3	5.3	5.0 / 10.0	Yes (contribute)
Denali NPP			
1	14.5	5.0 / 10.0	Yes (cause)
2	17.1	5.0 / 10.0	Yes (cause)
3	14.9	5.0 / 10.0	Yes (cause)
Lake Clark Wilderness and National Park			
1	9.0	5.0 / 10.0	Yes (contribute)
2	6.3	5.0 / 10.0	Yes (contribute)
3	7.6	5.0 / 10.0	Yes (contribute)
Kenai NWR			
1	18.8	5.0 / 10.0	Yes (cause)
2	23.2	5.0 / 10.0	Yes (cause)
3	18.2	5.0 / 10.0	Yes (cause)
Kenai Fjords National Park			
1	5.0	5.0 / 10.0	Yes (contribute)
2	4.7	5.0 / 10.0	No
3	5.0	5.0 / 10.0	Yes (contribute)
Tuxedni NWR			
1	6.1	5.0 / 10.0	Yes (contribute)
2	4.9	5.0 / 10.0	No
3	5.8	5.0 / 10.0	Yes (contribute)
Chugach National Forest			
1	4.2	5.0 / 10.0	No
2	4.1	5.0 / 10.0	No
3	4.1	5.0 / 10.0	No
Kodiak NWR			
1	2.3	5.0 / 10.0	No
2	3.5	5.0 / 10.0	No
3	2.3	5.0 / 10.0	No

[a] 8th highest result corresponds to the 98th percentile of modeled results.

TABLE 4.19.4-9

Cumulative Deposition Analysis Thresholds for the Alaska LNG Project

Pollutant / Class I/II National Designated Protected Area	Predicted Deposition Impact (Alaska LNG Project Results) (kg/ha/yr)	NPS Deposition Analysis Thresholds (kg/ha/yr)	Exceeds Deposition Analysis Thresholds (Yes/No)
Sulfur Deposition			
ANWR	0.003	0.005	No
Gates of the Arctic NPP	0.001	0.005	No
Yukon Flats NWR	0.0006	0.005	No
Kanuti NWR	0.0004	0.005	No
Denali NPP	0.002	0.005	No
Lake Clark Wilderness and National Park	0.002	0.005	No
Kenai NWR	0.003	0.005	No
Kenai Fjords National Park	0.0004	0.005	No
Tuxedni NWR	0.001	0.005	No
Chugach National Forest	0.0004	0.005	No
Kodiak NWR	0.001	0.005	No
Nitrogen Deposition			
ANWR	0.047	0.005	Yes
Gates of the Arctic NPP	0.021	0.005	Yes
Yukon Flats NWR	0.006	0.005	Yes
Kanuti NWR	0.005	0.005	Yes
Denali NPP	0.035	0.005	Yes
Lake Clark Wilderness and National Park	0.012	0.005	Yes
Kenai NWR	0.016	0.005	Yes
Kenai Fjords National Park	0.002	0.005	No
Tuxedni NWR	0.006	0.005	Yes
Chugach National Forest	0.003	0.005	No
Kodiak NWR	0.001	0.005	No

Although emissions from the Alaska LNG Project would be large, it would contribute only a small proportion of emissions, including NO_x, in relation to the combination of these other area projects, and any new developments and projects would be required to adhere to federal, state, and local regulations for the protection of ambient air quality.

4.19.4.16 Noise

Construction Noise

Construction activities associated with the Alaska LNG Project would result in perceptible noise within 0.25 mile from pipeline or aboveground facility construction activities and at nearby NSAs within 0.5 mile of a DMT location. Therefore, this area is defined as the geographic scope for the analysis of cumulative noise impacts due to construction. Noise from some Project construction activities, such as

DMT operations, would be temporary, but might occur around the clock at certain points in the process. Noise associated with pipeline and aboveground facility construction would also be temporary.

Construction of the aboveground facilities, including the GTP, compressor stations, heater station, meter stations, and Liquefaction Facilities, as well as DMT activities, would occur in one location for an extended period of time and would have a longer-term impact on the area surrounding these facilities or activities. As noted in section 4.16.3, construction of the Healy Compressor Station and the Liquefaction Facilities could have a significant impact on nearby NSAs, especially during 24-hour activities. Therefore, we conclude that if construction of other projects in the analysis area occurs at the same time as construction of the Alaska LNG Project, cumulative noise impacts would occur.

With respect to the Mainline Pipeline, construction would proceed quickly at any given location, and cumulative noise impacts would be spatially limited to a radius of 0.25 mile surrounding the construction work area. With certain exceptions, such as stream crossings, final tie-ins, and DMT crossings, construction would occur during daylight hours for a period of days or weeks in any particular location. While pipeline construction could overlap with some of the applicable projects listed in appendix W-1, the cumulative noise impacts would not be considered significant because the impacts would be temporary and localized.

No NSAs were identified within 1.0 mile of either the PTU Expansion or PBU MGS Projects. Construction of these facilities would result in a temporary increase in noise in the Project vicinity and could potentially affect wildlife or subsistence uses. To the extent that portions of these projects would lie within 0.25 mile of, and would be constructed concurrently with, the proposed Project, minor and temporary cumulative noise impacts would occur.

Construction noise levels for the Kenai Spur Highway Relocation Project are predicted to range between 82 and 86 dBA at NSAs within 100 feet of the activities; these noise levels would be temporary, and experienced during working hours, which AGDC has indicated are between 7:00 a.m. and 10:00 p.m. Because the Kenai Spur Highway Relocation Project would be completed prior to construction at the Liquefaction Facility site, no cumulative impacts would be anticipated. Similarly, construction of future laterals or other infrastructure associated with the in-state gas interconnections would generate noise, but construction of these facilities would not be concurrent with construction of the Liquefaction Facilities. Therefore, no cumulative impacts would be anticipated.

Construction of the water main for the Kenai Water System Upgrades could be concurrent with, and within 0.25 mile of construction at the Liquefaction Facilities, so cumulative noise impacts could occur at nearby residences; however, these cumulative impacts would be short term, i.e., for the duration of water pipeline construction, and would not be significant.

Operational Noise

Operational noise from the Alaska LNG Project could contribute to cumulative noise impacts where other actions are within 1.0 mile of aboveground operating facilities. Operation of the Project would have a long-term effect on noise levels in proximity to the proposed GTP, compressor stations, heater station, meter stations, and Liquefaction Facilities. The noise associated with these facilities is likely to be perceptible at some nearby NSAs; however, AGDC has proposed mitigation measures, such as enclosed compressor buildings, exhaust stack silencers, and other site-specific noise mitigation measures. Noise from the Alaska LNG Project's permanent facilities is not anticipated to have an impact beyond 1.0 mile.

No current or reasonably foreseeable future actions that would generate noise were identified within 1.0 mile of the proposed compressor station locations or the GTP. At the Liquefaction Facilities, operation could result noise impacts at two nearby NSAs. Actions identified within 1.0 mile of the Liquefaction

Facilities (i.e., the Kenai LNG Cool Down Project, and Agrium Kenai Nitrogen Operations Facility) are existing facilities that are not expected to generate significant incremental noise. However, at two NSAs near the Liquefaction Facilities where sound intensities would likely double due to facility operation, noise from these existing sources could cumulatively increase the intensity of this impact.

With respect to the Kenai Spur Highway Relocation, a noise impact analysis commissioned by AGDC predicted noise impacts from traffic on the relocated highway segment at 72 noise sensitive receptor sites within 500 feet of the preferred alignment. Based on ADOT&PF noise abatement criteria, if the project would increase noise above existing levels by 15 dBA or more at any of these sites, noise impacts would occur. Of the 72 receptor sites analyzed, 22 receptor sites representing 24 residences are predicted to experience noise level increases greater than 15 dBA; at 18 of these sites, representing 20 residences, the increases would be substantial. At seven locations, noise levels were predicted to decrease as a result of abandonment of the existing highway corridor; however, the analysis did not factor in cumulative impacts from operation of the Liquefaction Facilities, so the noise decrease could be offset by increases from that facility.

Noise abatement measures along the highway, such as sound barriers, could mitigate impacts to some extent, although a noise mitigation study has not been done. Although the residential areas most affected by traffic noise from the relocated highway are farther than 0.25 mile from the Project noise sources, it is possible that some houses in between the relocated highway and the LNG facilities could experience a cumulative noise increase.

4.19.4.17 Public Health and Safety

Section 4.17 provides an analysis of public health and safety impacts associated with the Alaska LNG Project within boroughs, census areas, and villages where there are Project facilities and major Project transportation routes. Cumulative public health and safety impacts could occur if other actions within these same areas would, when combined with the proposed Project, represent an incremental public health and safety risk.

To aid in the public health and safety assessment, AGDC provided an HIA, which is included as appendix V. The HIA identified eight health effect categories and assigned impact ratings based on the potential severity of the proposed Project's impact and the likelihood that impacts would occur. The health effect categories are as follows:

- Social Determinants of Health (e.g., maternal and child health, mental health, substance use, and economic status);
- Accidents and Injuries;
- Exposure to Potentially Hazardous Materials;
- Food, Nutrition, and Subsistence Activity;
- Infectious Diseases;
- Non-communicable and Chronic Diseases;
- Water and Sanitation; and
- Health Services Infrastructure and Capacity.

Only those health effect categories for which the proposed Project was assigned a medium or high adverse impact rating were considered as candidates for potential cumulative impacts. Those included the "Social Determinants of Health" category, which was assigned a medium adverse impact rating for both Project construction and operation; "Accidents and Injuries," which was assigned a medium adverse impact rating for Project construction and operation; "Food, Nutrition, and Subsistence Activity," which was assigned a medium adverse rating for Project construction; and "Infectious Diseases," which was assigned a high adverse impact rating for Project construction and a medium adverse rating for Project operation. Cumulative impacts on subsistence activities and resources are addressed in section 4.19.4.14.

With respect to the "Social Determinants of Health" category, the basis for the medium adverse impact assessment was the potential for an increase in anxiety and depression due to the influx of construction workers, increased construction activity, and concerns about pipeline safety. At the same time, increased employment opportunities brought by the Project were acknowledged to represent a high positive impact on the alleviation of health stressors by improving family income and the local economy. In varying degrees, these same factors would attach to other activities within the geographic scope of the proposed Project.

As explained in section 4.19.4.11, it is difficult to predict when many of the projects listed in appendix W-1 would be built. Some of these projects would not move forward at all; others are operating facilities with no announced expansion plans. Some projects, such as the non-jurisdictional projects, are likely to be constructed in the same time frame and are in close proximity to the Alaska LNG Project; others, such as the Donlin Gold Mine, could occur within the same timeframe as the proposed Project but their impacts would be attenuated by distance. With a measure of uncertainty, cumulative incremental health impacts in this category can be projected, but any such incremental impacts would be indirect and likely insignificant.

With respect to the "Accidents and Injuries" category, the potential for fatal and non-fatal injuries during construction (e.g., from vehicle accidents) and operation (e.g., from pipeline leaks) resulted in the medium adverse impact ratings. Actions that would occur in the same time frame and in relatively close proximity to the Alaska LNG Project, such as the non-jurisdictional facilities, could represent a cumulative incremental increase in the risk of accidents and injuries, but we expect the impacts to be less than significant.

As discussed in section 4.11.6.3, impacts on police and fire services during construction of the Alaska LNG Project would be minor in communities with high levels of law enforcement, such as Anchorage, but could be taxed in communities such as Kenai with limited resources. To the extent that construction of other projects occurs concurrently with construction of the Project, demand for police and fire services could be exacerbated in or near communities with limited resources. For the Alaska LNG Project, we recommend that AGDC file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. Implementation of this plan and other measures proposed by AGDC, such as providing private security at construction camps, would reduce impacts on local police and fire services. With the implementation of these measures, cumulative impacts on such services would be less than significant.

With respect to the "Infectious Diseases" category, the influx of workers from outside with the potential to bring various contagious diseases to the area was the primary basis for the proposed Project's high adverse impact rating for construction and medium adverse impact rating for operation. The Alaska LNG Project would reduce this potential by keeping construction camps closed to local residents and by providing local outreach programs. As is the case with the "Social Determinants of Health" category, many of the actions within the geographic scope of the proposed Project are uncertain with respect to timing, or are relatively long distances from the Alaska LNG Project. Actions that would occur in the same time frame and in relatively close proximity to the Alaska LNG Project, such as the non-jurisdictional facilities,

could represent a cumulatively incremental increase in the risk to introduce infectious diseases, but any such incremental impacts would be indirect and likely insignificant.

4.19.4.18 Climate Change

Climate change is the variation in climate (including temperature, precipitation, humidity, wind, and other meteorological variables) over time, whether due to natural variability, human activities, or a combination of both, and cannot be characterized by an individual event or anomalous weather pattern. For example, a severe drought or abnormally hot summer in a particular region is not a certain indication of climate change. However, a series of severe droughts or hot summers that statistically alter the trend in average precipitation or temperature over decades may indicate climate change. Recent research has begun to attribute certain extreme weather events to climate change (U.S. Global Change Research Program [USGCRP], 2018).

The leading U.S. scientific body on climate change is the USGCRP, composed of representatives from 13 federal departments and agencies.[195] The Global Change Research Act of 1990 requires the USGCRP to submit a report to the President and Congress no less than every 4 years that "1) integrates, evaluates, and interprets the findings of the Program; 2) analyzes the effects of global change on the natural environment, agriculture, energy production and use, land and water resources, transportation, human health and welfare, human social systems, and biological diversity; and 3) analyzes current trends in global change, both human-induced and natural, and projects major trends for the subsequent 25 to 100 years." These reports describe the state of the science relating to climate change and the effects of climate change on different regions of the United States and on various societal and environmental sectors, such as water resources, agriculture, energy use, and human health.

In 2017 and 2018, the USGCRP issued its *Climate Science Special Report: Fourth National Climate Assessment, Volumes I and II* (Fourth Assessment Report) (USGCRP, 2017 and 2018, respectively). The Fourth Assessment Report states that climate change has resulted in a wide range of impacts across every region of the country. Those impacts extend beyond atmospheric climate change alone and include changes to water resources, transportation, agriculture, ecosystems, and human health. The United States and the world are warming; global sea level is rising and acidifying; and certain weather events are becoming more frequent and more severe. These changes are driven by accumulation of GHGs in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources. These impacts have accelerated throughout the end of the 20th and into the 21st century (USGCRP, 2018).

Climate change is a global phenomenon; however, for this analysis, we will focus on the existing and potential cumulative climate change impacts in the Project area. The USGCRP's Fourth Assessment Report states that "Climate changes in Alaska and across the Arctic continue to outpace changes occurring across the globe," with the observations identified below attributed to climate change in Alaska (USGCRP, 2017, 2018).

- Alaska has experienced an increase in annual average temperature of 1.67°F since the early 20th century. Annual average near-surface air temperatures across Alaska and the Arctic have increased over the last 50 years at a rate more than twice as fast as the global average temperature.

[195] The USGCRP member agencies are: the USDA, U.S. Department of Commerce, U.S. Department of Defense, DOE, U.S. Department of Health and Human Services, DOI, U.S. Department of State, DOT, EPA, National Aeronautics and Space Administration, National Science Foundation, Smithsonian Institution, and U.S. Agency for International Development.

- Rising permafrost temperatures are causing permafrost to thaw and become more discontinuous, releasing additional CO_2 and methane, and consequently amplifying warming effects. The magnitude of the permafrost-carbon feedback is uncertain. Over the past 50 years, Alaska as a whole has shown little change in annual precipitation (+1.5 percent); however, central Alaska shows declines and the panhandle shows increases.

- The incidence of large forest fires in Alaska has increased since the early 1980s. Arctic land and sea ice loss over the last three decades continues and is accelerating in some areas. It is very likely that human activities have contributed to observed Arctic surface temperature warming, sea ice loss, glacier mass loss, and northern hemisphere snow extent decline.

- Alaska has experienced the largest increase in sea temperature increases of about 1°F.

The USGCRP's Fourth Assessment Report notes the following projections of climate change impacts in the Project region with a high or very high level of confidence[196] (USGCRP, 2018).

- Average annual temperatures near the proposed Gas Treatment Facilities are predicted to increase by 6 to 12°F by 2050, and 8 to 16°F by 2100 near the Gas Treatment Facilities depending on the level of future GHG emissions.

- Climate change is expected to affect annual temperatures near the proposed Mainline Facilities and are expected to rise from 6 to 12°F in the northern portion of the state, 4 to 10°F in the interior of the state, and 4 to 8°F in the remainder of the state by 2050, with higher impacts by 2100, depending on future GHG emission levels.

- Climate change is expected to affect weather conditions in the vicinity of the proposed Liquefaction Facilities. Average annual temperatures near the proposed Liquefaction Facilities are expected to rise from 4 to 8°F in the southern portion of the state by 2050, and 6 to 10°F by 2100, depending on future GHG emission levels.

- Annual precipitation is expected to increase 15 to 30 percent across all seasons, but increases in evaporation due to higher temperatures and longer growing seasons are anticipated to reduce water availability.

- Arctic-wide sea ice loss is expected to continue through the twenty-first century, very likely resulting in nearly sea ice-free summers by the 2040s.

- The world's oceans are currently absorbing more than a quarter of the CO_2 emitted to the atmosphere annually from human activities, making them more acidic. Coastal Alaska and its ecosystems are especially vulnerable to ocean acidification.

The GHG emissions associated with Project construction and operation are described in section 4.15. Project construction and operation would increase the atmospheric concentration of GHGs in combination with past and future emissions from all other sources and contribute incrementally to future climate change impacts.

[196] The report authors assessed current scientific understanding of climate change based on available scientific literature. Each "Key Finding" listed in the report is accompanied by a confidence statement indicating the consistency of evidence or the consistency of model projections. A high level of confidence results from "moderate evidence (several sources, some consistency, methods vary and/or documentation limited, etc.), medium consensus." A very high level of confidence results from "strong evidence (established theory, multiple sources, consistent results, well documented and accepted methods, etc.), high consensus" (https://science2017.globalchange.gov/chapter/front-matter-guide/).

Currently, there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to the Project's incremental contribution to GHGs. We have looked at atmospheric modeling used by the EPA, National Aeronautics and Space Administration, the Intergovernmental Panel on Climate Change, and others, and have found that these models are not reasonable for Project-level analysis for a number of reasons. For example, these global models are not suited to determine the incremental impact of individual projects, due to both scale and overwhelming complexity. We also reviewed simpler models and mathematical techniques to determine global physical effects caused by GHG emissions, such as increases in global atmospheric CO_2 concentrations, atmospheric forcing, or ocean CO_2 absorption. We could not identify a reliable, less complex model for this task, and we are not aware of a tool to meaningfully attribute specific increases in global CO_2 concentrations, heat forcing, or similar global impacts to Project-specific GHG emissions. Similarly, it is not currently possible to determine localized or regional impacts from GHG emissions from the Project.

Absent such a method for relating GHG emissions to specific resource impacts, we are not able to assess potential GHG-related impacts attributable to this Project. Additionally, we have not been able to find any GHG emission reduction goals established either at the federal level[197] or by the State of Alaska. Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, we are unable to determine the significance of the Project's contribution to climate change.

In addition to the Project's potential effects on climate change, climate change related impacts (e.g., sea level changes and temperature increases) could affect Project facilities. AGDC considered the GTP facility and trestle height to account for potential future effects of climate change on the Project area, including potential sea level changes, coastal erosion near the facility, and temperature increases.

[197] The national emissions reduction targets expressed in the EPA's Clean Power Plan were repealed, Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emissions Guidelines Implementing Regulations, 84 FR 32,520, 32,522-32 (July 8, 2019); and the targets in the Paris Climate Accord are pending withdrawal.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS OF THE ENVIRONMENTAL ANALYSIS

While the conclusions and recommendations presented in this section are those of the FERC environmental and engineering staff, they were developed with input from PHMSA, the EPA, the COE, the Coast Guard, the BLM, the USFWS, the NPS, the DOE, NMFS, and state and local agencies. The federal cooperating agencies may adopt this EIS per 40 CFR 1506.3 if, after independent review, they conclude that their permitting requirements and/or regulatory responsibilities are satisfied; however, these agencies would present their own conclusions and recommendations in their respective and applicable records of decision. Otherwise, they may elect to conduct their own supplemental environmental analyses.

We have determined that Project construction and operation would result in adverse environmental impacts on some resources. Impacts on permafrost, wetlands, forests, caribou (the Central Arctic Herd), and some sensitive noise receptors would be significant. Cumulative impacts on these resources additionally would be significant. Air quality impacts at the Liquefaction Facilities during the years of simultaneous construction, startup, and operational activities as well as during operation due to flaring events could be significant. Impacts on air quality could also be significant during operation of the aboveground facilities when exceedances of nitrogen and sulfur deposition thresholds and visibility thresholds at nearby Class I and II nationally designated protected areas could occur. The Project would have low to high visual effects in the DNPP. High-pressure piping at the GTP could pose a significant safety impact on off-site persons. In some cases, AGDC's commitments or our recommended mitigations (see below) would reduce these effects to less than significant levels. A summary of the potential Project impacts and our conclusions regarding these impacts are provided by resource below.

As part of our review, we developed mitigation measures we determined would appropriately and reasonably reduce the environmental impacts resulting from Project construction and operation. AGDC has committed to implementing 40 of our recommended mitigation measures from the draft EIS (see appendix X). Recommended mitigation measures AGDC has not agreed to, along with new recommendations identified in this final EIS and recommendations concerning engineering and safety, are provided in section 5.2. We recommend that these measures be attached as conditions to any authorization issued by the Commission. In addition, AGDC is required to obtain all applicable federal permits and authorizations required to construct and operate the Project. Some of these may require additional mitigation measures, including those recommended by the BLM in comments on the draft EIS (see appendix Y). Each applicable agency would have the opportunity to review the Project during their respective permitting processes and could identify additional mitigation measures beyond those provided in this EIS.

5.1.1 Geological Resources

Mineral resources are present along the Mainline Pipeline, including about 60 state and 4 federal mining claims within the Project footprint. No active coal mines occur within 0.5 mile of the Project, but the Project would cross just over 1 mile of CIRI land on discontinuous tracts within the Beluga coal field between MPs 750 and 770.

Future mining would not be allowed within the footprint of the permanent Project facilities, and blasting and drilling to access mineral resources proximal to the Project would be restricted. Mineral Order No. 1162 was enacted to prevent adverse impacts of mining operations on ASAP pipeline construction and operation on state and state selected lands, and to accommodate future related facilities that could be added to the ASAP Right-of-Way Lease; a similar order could be implemented for the Project on state and state selected land.

We received comments from the State of Alaska and BLM regarding access to and activities on existing mining claims. The federal mining law provides for reasonable, but non-discretionary, access to existing claims. The federal government cannot prohibit a claim holder from mining on an existing claim, but they can define how claimants mine by enacting laws and regulations prior to approving mining authorizations. Future mining claims in the Project vicinity could be prevented through federal withdrawals and state mineral closures. In comments on the draft EIS, the State of Alaska said that any limitations on mining must be consistent with state laws and regulations—as determined by the agencies that authorize the activity through the permitting process—including AS 38.34.050(c), AS 38.05.185 to 38.05.275, and AS 38.05.300.

Hazardous wastes and contaminated media from historic mining could be present within or near the Project area. Wastes from historic mines could be transported via runoff, groundwater movement, or wind dispersion. If contaminants from mines should be encountered during construction, AGDC would implement the measures identified in the Project Unanticipated Contamination Discovery Plan, which would reduce or mitigate potential impacts.

Granular fill would be sourced from multiple sites to support Project construction. Impacts from development of these sites on geological and other resources, such as soils and surface waters, could result from activities such as topsoil stripping, overburden removal, blasting, excavation, and dewatering. AGDC indicates that it would mitigate impacts through implementation of site-specific mining and reclamation plans to be developed in coordination with the appropriate land management agencies. Because extraction sites and the required material volumes have not been finalized, AGDC would file an updated Project Gravel Sourcing Plan that identifies the material volumes to be acquired from each site and measures for testing excavated materials for contamination and potential ARD.

Of the material extraction sites identified by AGDC as sources or potential sources of granular fill material, 59 existing sites are located within 250 feet of construction workspace, including 9 sites within the proposed construction right-of-way. AGDC would operate existing material sites selected for use in Project construction in accordance with landowner requirements. Material sites that adjoin the Project's operational right-of-way on state or federal lands could be subject to access or buffer restrictions imposed by the State of Alaska's right-of-way lease or BLM's right-of-way grant, respectively.

Geologic hazards with the potential to affect the Project include seismicity, soil liquefaction, mass wasting, and ARD. Mitigation measures in areas of known seismic hazards include avoidance of fault crossings and modification of pipeline geometry to minimize exposure to ground movement along faults. The Mainline Pipeline would be installed aboveground where it crosses the Denali, Northern Foothills, Castle Mountain, and Park Road faults using designs able to accommodate the maximum predicted horizontal and vertical displacement at the faults. The LNG Plant would be built in accordance with federal standards regarding the susceptibility of critical safety systems to ground shaking and the plant's ability to continue functioning during an earthquake. AGDC would monitor the Alaska Earthquake Center seismic network for earthquakes and initiate facility inspections or repairs based on real-time seismic data.

AGDC indicates that it would also employ additional mitigation measures to minimize or mitigate impacts in areas with moderate to high potential for soil liquefaction. These measures include the use of heavy walled pipe, ground improvements, and pressure relief wells. Because liquefaction hazards could result from permafrost degradation, AGDC would implement the measures identified in the Project Pipeline Operation and Maintenance Plan to assess and remediate impacts on permafrost. AGDC would modify this plan prior to construction of the Mainline Facilities to specify the applicable Project facilities and locations and provide information on monitoring locations and methodologies.

Mass wasting and landslides in the Project area are most likely to occur in the Brooks Range and near the Alaska Range. Portions of the Mainline Pipeline would require mitigation for mass wasting, such as surface water control, heavy wall or high strain capacity pipe, deep pipe burial, slope stabilization, and/or revegetation. In areas of active or potential debris flows, aerial crossings could be installed if flows are perpendicular to the pipeline. AGDC would monitor movement rates and pipeline strain in areas with frozen debris lobes and implement remedial measures, such as removing mass from the lobe, repositioning the pipeline, or installing a buttress or bypass, to reduce the potential for effects on the pipeline.

At the Liquefaction Facilities, the primary mass wasting hazard is erosion of the coastal bluff. To avoid potential impacts, LNG Plant structures and foundations for the Marine Terminal would be set back at least 300 feet inland, erosion and sediment controls would be installed, and a stormwater collection and management system would be implemented. We received scoping comments about bluff erosion in the Project area due to construction of the Liquefaction Facilities. Long-term mitigation would include monitoring the bluff slope and shoreline to determine if additional measures are needed to maintain or enhance stability. Coastal flooding and erosion would also be a concern for the Gas Treatment Facilities, which would be situated close to the Beaufort Sea coastline. To address this concern, we have recommended that AGDC file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan prior to construction, as described in section 4.18.9.

We received a comment from the EPA regarding ARD/ML occurrences in the Project area. AGDC has identified locations requiring site-specific evaluations for ARD/ML prior to construction. In these areas, AGDC would implement a Geotechnical Verification Program to confirm conditions, inform construction planning, and determine mitigation. AGDC would develop an ARD/ML Management Plan based on the results of the site-specific evaluations. To ensure that impacts are adequately addressed, AGDC would file the results of the site-specific evaluations, a map set depicting sampling locations, and a management plan that identifies the measures to be implemented in areas with high ARD/ML potential. In comments on the draft EIS, the EPA additionally recommended monitoring in areas of moderate ARD/ML potential. Therefore, we recommend that AGDC include details for surface and groundwater monitoring in areas of moderate ARD/ML potential in the Project-wide ARD/ML Management Plan.

We received comments during scoping and comments on the draft EIS regarding the potential hydrologic hazards present where the proposed Mainline Pipeline is near Suneva Lake. AGDC provided a scour analysis of the crossing of the Suneva Lake area to analyze potential hydrologic hazards to the Mainline Pipeline. Based on this analysis, AGDC proposes to use deeper burial and protective ditch measures for the pipeline to minimize the risk of pipeline damage should a dam breach occur. Specific engineering details for the crossing of the Suneva Lake area would be developed during detailed design.

Blasting would be required where bedrock is shallow or exposed or in areas where boulders, cobbles, or granular materials are frozen in permafrost. Potential impacts from blasting include turbidity in water wells or springs, damage to nearby structures or utilities, displacement of wildlife, and permafrost degradation. Where required, blasting would be conducted by licensed contractors in accordance with applicable federal, state, and local regulations and the Project Blasting Plan. This plan identifies measures for minimizing impacts from blasting, including pre-blast inspections of nearby structures, the use of blasting mats and padding to contain flyrock, vibration monitoring, and well monitoring.

AGDC proposes to install the Mainline Pipeline beneath five waterbodies (the Middle Fork Koyukuk, Yukon, Tanana, Chulitna, and Deshka Rivers) by DMT. Based on an assessment of geological conditions, we have concluded that DMT is an appropriate installation technique for each of these crossings. Because more information is needed to characterize subsurface conditions at the Middle Fork Koyukuk River, AGDC would file a revised Feasibility Crossing Study with updated geotechnical information for this crossing prior to construction. AGDC would also file a revised Feasibility Crossing Study for the

Chulitna River prior to construction that corrects discrepancies we identified in the proposed entry and exit locations for the DMT crossing.

AGDC has prepared DMT Plans that identify measures for preventing inadvertent releases of drilling mud and for containing and cleaning up any releases that reach the surface or a waterbody. These plans address potential impacts and mitigation specific to each DMT crossing, including measures to minimize water quality impacts in the event of an inadvertent release. Prior to construction of the Mainline Facilities, AGDC would file final installation design and drilling plans along with the results of jacking force and stress analyses for each DMT crossing.

Paleontological resources could be directly affected by ground-disturbing activities causing damage, fragmentation, or stratigraphic displacement, or indirectly affected due to increased potential for erosion and vandalism. AGDC would implement the Project PRUDP and PRMP during construction and for ongoing maintenance activities during Project operation to minimize and mitigate adverse effects on paleontological resources.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that the Project would not result in significant adverse effects on geological resources, and that geologic hazards would not pose a significant risk to the Project.

5.1.2 Soils

Various construction activities, such as clearing, grading, granular fill placement, and excavation, would affect soil resources. AGDC would implement BMPs and Project-specific plans (e.g., the Project Plan, SPCC Plan, Revegetation Plan, and Winter and Permafrost Construction Plan) to avoid, minimize, or mitigate most impacts on soils; however, long-term to permanent impacts would result from permafrost degradation and the loss of soil surfaces from granular fill placement and construction of aboveground facilities.

While the installation of granular work pads would create stable work surfaces, the pads would conduct solar radiation to underlying soils, resulting in changes to thermal regimes in areas with thaw-sensitive permafrost. Because the pads would not be removed, the loss of soil surfaces due to granular fill placement would be permanent. To reduce these impacts, we recommend that AGDC assess if winter construction would be feasible in low slope areas (0 to 2 percent) proposed for Mode 4 construction in summer as an alternative to the use of granular fill. We also recommend that AGDC use timber/synthetic mats in place of granular fill in wetlands and uplands underlain by thaw-stable permafrost in low slope areas where Mode 4 construction is proposed.

The granular work pads remaining in place following construction could settle, saturate, and naturally revegetate. The length of the revegetation process could be decades or more depending on site-specific conditions. AGDC plans to use granular fill consisting of sands and gravels with less than 12-percent fines. Because a greater proportion of fines could improve the probability of successful revegetation, we recommend that AGDC apply aggregate testing to ensure the selection of fills with at least 20-percent fines for the surface layer used on construction workspace and temporary access roads.

Equipment and vehicle traffic could permanently affect permafrost soils by creating fugitive dust. Over long periods, dust deposition could result in thermokarst because a darker surface would absorb more solar radiation, warming permafrost soils. AGDC would minimize these impacts through implementation of the measures identified in the Project Fugitive Dust Control Plan.

Soil impacts due to construction of the GTP would primarily be limited to installation of work pads and piles to support Project facilities. Work pads and access roads would be mostly installed in winter to avoid permafrost impacts and minimize compaction. The GTP would be built on granular pads of sufficient thickness to reduce heat transfer to underlying permafrost. Construction of associated facilities would use granular work pads, piles, VSMs, and thermosiphons to protect permafrost. The primary operational impact would be the conversion of soil to impervious surfaces.

Impacts on soils due to construction and operation of the Mainline Pipeline would include compaction, permafrost degradation, differential thaw settlement, erosion and sedimentation, frost bulb development, frost heave, and the loss of soils to impervious surfaces for granular work pads. The effects of permafrost degradation would include hydrologic impacts, subsidence, thermokarst, solifluction, soil creep, thawed-layer detachment, and erosion. About 15 percent of the pipeline would be built in winter using ice or frost-packed work pads, which would reduce impacts from compaction, rutting, and soil mixing.

Clearing for pipeline construction would remove naturally insulating materials, leading to increased heat flux in soils. AGDC proposes to pre-clear areas by cutting trees and brush in the winter season between 1 and 1.5 years prior to active construction. Clearing vegetation in thaw-sensitive permafrost areas prior to placing granular work pads would increase the likelihood of permafrost thawing and creation of thermokarst. While limiting pre-clearing to the winter would reduce effects on permafrost, permanent impacts would still occur. However, the majority of pre-clearing activities (with the exception of aboveground facility site preparation) would remove overstory vegetation and leave understory vegetation in place, which would reduce the impact.

AGDC would segregate and replace surface organic layers during pipeline construction, but segregated layers would not always be replaced in the same location and segregation would not be feasible in frozen conditions. In areas where the surface organic layer is not segregated, the layer would be mixed with subsoil during stockpiling. To minimize impacts due to soil mixing, AGDC would file a final Revegetation Plan that incorporates all surface layer segregation information, provides the milepost ranges in which surface layer segregation would occur between MPs 0 and 607, and includes an analysis and justification of where the surface layer would and would not be segregated between MPs 607 and 807.

Operation of the Mainline Pipeline could cause long-term changes to permafrost, affecting subsurface hydrologic connectivity, groundwater flow, GHG emissions, right-of-way integrity, and revegetation. Frost heave could cause bending strain in the pipe or disruption to surface drainage patterns. Frost bulbs could prevent or restrict groundwater flow, forcing water to the surface and creating ponding or aufeis. Thaw or ditch settlement could cause strain on the pipe or result in changes in drainage patterns, ponding, thermokarst development, or increased erosion potential.

While the pipeline would be bedded with thaw-stable, non-frost susceptible materials to reduce impacts on permafrost, additional insulation would be provided based on site-specific conditions to help maintain unfrozen soils around the pipeline. Buoyancy control would be used in floodplains or active channels as needed based on site-specific conditions. Impacts due to changes in surface drainage or ponding would be mitigated through installation of ditch plugs, water bars, and erosion control devices; contouring of granular work pads; installation of cross-drainage; restoration of surface contours; and revegetation of disturbed areas. Mitigation for formation of aufeis would include ice removal; installation of fences, drains, culverts, or basins; or thawing of ice with steam or electric cables.

We received comments from the USFWS regarding the potential for impacts on permafrost due to the discharge of hydrostatic test water. The temperature of hydrostatic test water for the pipeline facilities would be similar to that of the surrounding ground temperature. Test water would be discharged through

dispersion devices at the ground surface and, in the majority of locations, would be separated from the frozen subgrade by the depth of the active layer. While some impacts on permafrost would occur, significant impacts would not be expected for these reasons.

We received comments from the USFWS regarding the use of specific types of foam insulation and the potential for foam to become exposed over the life of the Project. Certain types of foam could break down into small pieces and spread across the landscape, becoming a hazard for fish and wildlife. To avoid these impacts, AGDC would use closed-cell extruded polystyrene or other closed cell foams rather than non-extruded expanded polystyrene foam.

To minimize soil impacts from erosion, AGDC would implement the measures identified in the Project Plan and Winter and Permafrost Construction Plan, such as clearing vegetation in winter, leaving root structures intact until grading occurs, installing temporary erosion controls, implementing a SWPPP, and installing a trench crown. In cut slope areas, AGDC would control surface water and infiltration with inceptor ditches and revegetation. At the end of construction, AGDC would return the construction right-of-way to stable contours with the surface soils in a suitable condition for restoration and with temporary erosion and sediment controls in place.

Piping erosion occurs when water conveys fine sands and silts in certain non-cohesive soils between coarse soil particles. This results in fines being removed from the soil matrix, which could lead to the development of voids underneath the pipeline. Mitigation measures to be used in areas identified with the potential for piping erosion include the use of subdrains to control meltwater and groundwater recharge as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipeline. AGDC did not provide the same level of analysis for piping erosion potential between MPs 536.1 and 544.3 that they provided for the rest of Mainline Pipeline. Therefore, we recommend that AGDC file an updated assessment providing the same level of analysis for this area and implement the same mitigation measures if any new areas with piping erosion potential are identified.

After construction of each spread and prior to pipeline operation, the right-of-way would lay dormant at ambient temperatures for 2 to 3 years without any gas flow. During this time, the Mainline Pipeline and surrounding materials would remain frozen in place each year until spring/summer thaw, at which time the crown and backfilled trench materials would thaw slightly. Once restoration and revegetation are satisfactory, temporary erosion and sediment controls would be removed and permanent controls installed as needed.

In areas with poor revegetation potential, and if required by a landowner or land management agency, AGDC would apply a mixture of water, fertilizer, seed, mulch, and tackifier to increase the water-holding capacity of the soil and encourage seed establishment. For granular work pads not needed for operation, and where requested by landowners, AGDC would rip the compacted granular material, grade the area to assist with drainage, and scarify to allow natural revegetation. If revegetation does not meet the performance standard specified in the Project Revegetation Plan, AGDC would implement corrective actions, such as seed and fertilizer applications.

Widespread areas of soils with shallow bedrock or permafrost would be encountered during construction, requiring excavation or blasting. AGDC would implement the measures outlined in the Project Blasting Plan to avoid or reduce most impacts on soils. Site-specific information on ice content and distribution would be required to properly design each blast in permafrost. AGDC has indicated that site-specific blasting plans, which include this information, would be prepared by blasting subcontractors.

Soil impacts from construction of the Liquefaction Facilities would result from clearing, excavation, borrow source development, and foundation installation. Because soils are predominantly well

drained, the primary construction concern is erosion. As construction progresses on the site, stabilizing materials such as granular fill would be placed to minimize soil exposure and erosion. Stable contour grading would be used to minimize runoff from the site. The main operational impact would be the permanent conversion of soils to impervious surfaces and the potential for ongoing bluff erosion at the site. AGDC has identified potential mitigation measures for bluff erosion including the use of steel sheet piles, armor rock, gabion structures, geocells, geomat, and sand/gravel bags, which would add to the existing structures to help reduce bluff erosion rates.

Soil contamination during Project construction and operation could result from spills of fuel, oil, or other hazardous materials. AGDC has developed a Project SPCC Plan that identifies fueling, storage, containment, and cleanup measures to avoid, minimize, or mitigate impacts from spills or leaks. The Project Unanticipated Contamination Discovery Plan identifies measures to be implemented if unidentified contaminants in soil are disturbed during construction.

As discussed in section 2.2, the Project Plan includes certain modifications to the FERC Plan. We have reviewed these modifications and found most to be acceptable with some revisions, which AGDC has incorporated into an updated Project Plan. The acceptable modifications are provided in table D-1 of appendix D. We denied one modification, as listed in table D-3 of appendix D.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that most Project effects on soils would be less that significant; however, the long-term to permanent impacts on permafrost and substantial loss of soils due to granular fill placement, particularly for the Mainline Facilities, would be significant.

5.1.3 Water Resources

5.1.3.1 Groundwater Resources

Surface drainage and groundwater recharge patterns could be affected by various construction activities, such as clearing, grading, trenching, and site preparation. If trenching or other excavations intersect shallow groundwater or a talik, dewatering or other water control methods would be required that could result in temporary fluctuations in groundwater levels or increased turbidity. To minimize impacts, water would be discharged into well-vegetated upland areas to allow infiltration such that impacts would be short term and local.

Groundwater contamination could result from spills of fuel, oil, or other hazardous materials during Project construction and operation. To avoid or minimize impacts, AGDC would implement the fueling, storage, containment, and cleanup measures identified in the Project SPCC Plan, and the hazardous material handling measures provided in the Project Procedures and Waste Management Plan.

AGDC would implement a Groundwater Monitoring Plan in areas where dewatering or water discharge is required within 1,500 feet of a known contaminated site. The plan also includes temporary and long-term engineering controls that could be used to prevent the creation of preferential pathways for the migration of contaminated groundwater. AGDC would file a Project ARD/ML Management Plan, which would include mitigation measures to protect groundwater in areas of high ARD/ML potential. As noted above in section 5.1.2, we recommend that AGDC include details for surface and groundwater monitoring in areas of moderate ARD/ML potential in the Project ARD/ML Management Plan.

AGDC would implement a Project Water Well Monitoring Plan to prevent construction impacts on nearby private water supply wells and springs or active PWS sources using groundwater. AGDC would

conduct pre- and post-construction monitoring of water yield and quality in active PWS sources using groundwater and private wells and springs located within 150 feet of the Project footprint.

Blasting could temporarily affect water quality and yields in wells and springs by increasing turbidity, but sediments would rapidly settle such that impacts would be short term and localized. Where blasting would be required, AGDC would implement the BMPs identified in the Project Blasting Plan and conduct blasting in accordance with applicable permits and regulations using licensed contractors. AGDC would offer well monitoring to landowners with water wells identified within 1,000 feet of blasting activities. If construction adversely affects a well or spring, AGDC would provide a new temporary or permanent source, repair the source, or compensate the owner for a comparable source, which would mitigate impacts on well or spring users.

We received scoping comments regarding the identification of wells within or near Project workspaces. In addition to identifying wells through the ADNR WELTS database, AGDC would conduct pre-construction surveys to identify wells where the Mainline Facilities cross the Interior and South-Central Hydrologic Regions (the Project would cross no freshwater aquifers north of the Brooks Range). AGDC would file an updated list of public wells within 500 feet of the Project (to meet requests of the ADEC Division of Environmental Health DWP and address public scoping comments), and private wells and springs within 150 feet of construction workspaces based on the surveys.

While no springs or seeps have been identified to date in the Project footprint, AGDC would conduct spring/seep surveys where the Mainline Facilities cross the Interior and South-Central Hydrologic Regions. If AGDC should identify any springs or seeps in the construction area, they would evaluate the crossing of each spring or seep to assess impacts and identify mitigation that may be required. Mitigation measures could include the installation of springheads and trench drains to redirect water away from the right-of-way; installation of small-diameter culverts to carry water across the right-of-way; or pumping water to the downslope side of the pipeline. During operation, to prevent erosion of backfill over the pipeline associated with springs and seeps, AGDC would install erosion controls in accordance with the Project Pipeline Right-of-Way Operational Monitoring and Maintenance Plan.

With implementation of the measures described above, AGDC's commitments, and our recommendation, we have concluded that the Project would not result in significant adverse effects on groundwater.

5.1.3.2 Freshwater

AGDC provided a comprehensive table of waterbodies that would be crossed or affected by all Project facilities and components. AGDC would use five methods to install the Mainline Pipeline beneath or across waterbodies: wet-ditch open-cut, dry-ditch open-cut, frozen-cut, aerial span, and DMT. The wet-ditch open-cut method would disturb streambanks and beds resulting in temporary increases in turbidity and sedimentation. The dry-ditch open-cut and frozen-cut methods would minimize these impacts by isolating flow or leveraging low flow or frozen conditions, but temporary increases in turbidity and sedimentation would occur when flow is re-established. The aerial span method would avoid direct impacts by installing the pipeline above waterbodies on bridge-type structures or supports, though clearing and grading of streambanks could result in temporary impacts due to erosion. The DMT method would avoid direct impacts because the pipeline would be installed beneath waterbodies by drilling.

To quantify impacts on turbidity and sedimentation from wet-ditch open-cut crossings, AGDC conducted a sediment transport study on representative waterbodies that would be affected by the Project. The study assumed that AGDC would follow the crossing requirements of the Project Procedures (e.g., storage of excavated spoil at least 10 feet from the water's edge and appropriate time limits for the crossing).

According to the sediment transport model, the average sediment accumulation would range from 0.02 to 0.4 inch about 160 feet downstream of excavation. AGDC's model predicted that trenching would lead to a localized exceedance of the designated use water quality standard to a maximum distance of about 290 feet downstream lasting about 1 hour after excavation ceases.

The Project Procedures include two additional waterbody crossing methods, channel diversions, and aerial span crossings, not included in the FERC Procedures. AGDC said that site-specific plans would be developed for waterbodies crossed by these methods, but has not provided plans to FERC for review. AGDC has also not addressed navigation issues associated with major waterbody crossings. To address these issues, AGDC would file site-specific waterbody crossing plans and proposed mitigation measures that address, as applicable, channel diversion and aerial span crossings as well as navigational issues for major waterbody crossings.

AGDC would implement erosion and sediment controls and stabilize streambanks in accordance with the Project Plan and Procedures, SWPPP, and Revegetation Plan, which would minimize turbidity and sedimentation impacts on waterbodies, both at the crossings and in downstream areas. Similar measures would be implemented for other construction activities potentially affecting waterbodies, such as clearing, grading, and material site development. With these measures, most impacts due to increased turbidity and sedimentation would be localized and minor.

To facilitate construction of the Mainline Pipeline, temporary bridges would be installed across waterbodies along the pipeline route. Equipment operating in the waterbody to conduct bridge installation and removal would disturb substrate materials and streambanks, which would reduce water quality, but impacts would be temporary and localized. All other construction equipment would cross over waterbodies on the bridges, which would avoid in-water impacts from traffic.

Flow within waterbodies could be temporarily affected by bridge structures during high streamflow events. During spring breakup, peak streamflow levels would be high and could potentially wash out bridges, resulting in downstream impacts. To reduce this risk, AGDC would design temporary bridges to withstand a 10-year flood event or provide site-specific justification that a design for a 2-year flood event would be adequate.

Use of the DMT method could result in an inadvertent release of drilling fluid into waterbodies, which would temporarily increase turbidity and sedimentation and possibly introduce additives, reducing water quality. AGDC prepared DMT Plans that identify measures for preventing, monitoring, and cleaning up inadvertent releases. Implementation of these plans would reduce impacts on freshwater resources due to inadvertent releases.

Construction dewatering, blasting, and accidental spills or inadvertent releases of fuel and other hazardous materials could adversely affect water quality in freshwater resources. AGDC would implement BMPS in accordance with Project-specific plans (e.g., Plan and Procedures, Blasting Plan, SPCC Plan, and Waste Management Plan) to avoid, minimize, or mitigate potential impacts on freshwater resources from these activities.

Streamflow could be permanently affected by placement of granular fill for access roads and in-stream structures, but AGDC would install appropriately sized culverts to maintain flow. Culverts and gravel placed below the ordinary high-water mark of streams and rivers would be removed following construction if requested by the landowner or land management agency or required by COE permitting. Abandoned roads and pads that require granular fill subject to COE permitting would be monitored for erosion and sedimentation in accordance with COE permitting requirements.

Infrastructure such as granular pads, access roads, pipe storage yards, and disposal sites would permanently fill a portion of some ponds and lakes. AGDC would generally avoid placing granular fill in streams and rivers; however, two pipe storage yards and two disposal sites could encroach upon four streams. To reduce impacts, we recommend that AGDC avoid placing granular fill, spoil, or other materials in the affected streams at these sites. Material site development would also result in impacts on ponds, lakes, or streams within the construction footprint. However, excavated depressions from material sites could retain water, potentially providing similar beneficial functions such as stormwater retention or habitat. Material extraction in river channels would increase turbidity and sedimentation, potentially modify channel morphology, and negatively affect fish habitat.

As discussed in section 2.2, the Project Procedures include certain proposed modifications to the FERC Procedures, such as the siting of ATWS within 50 feet of a waterbody. We have reviewed these modifications and found them to be acceptable with some revisions, which AGDC has incorporated into an updated Project Procedures. The acceptable modifications are provided in table D-2 in appendix D.

Operation of the Mainline Pipeline could affect waterbodies if flow is obstructed due to frost bulb formation. Due to the Joule-Thompson effect, the potential for frost bulb formation is high in river crossings immediately upstream of compressor stations. AGDC would implement measures to prevent and monitor frost bulb obstructions, such as ensuring adequate depth of cover for the pipeline and conducting routine inspections.

The pipeline would cross two waterbodies—the Deshka River and Alexander Creek—that are listed in the NRI and designated as state Recreational Rivers. Because the Deshka River and adjacent areas would be crossed by DMT, no impacts on the river's ORVs would be anticipated. Alexander Creek would be crossed using a dry-ditch open-cut method in winter, which would avoid impacts on summer ORVs. Winter ORVs, such as recreation, would be affected, but impacts would be limited to one season. Based on consultation with the NPS, as discussed in section 4.9.5.1, impacts on the Deshka River and Alexander Creek would be adequately mitigated such that the NRI status of these waterbodies would not be affected.

The Project would result in short-term, long-term, and permanent impacts on floodplains. Surface flow patterns within floodplains would be affected by clearing and ground disturbing activities. In most places, flood storage capacity and surface flow patterns would be restored, resulting in short-term and minor impacts. On lands where granular fill is required, flood storage capacity would be reduced slightly because soil would be permanently displaced and soil has a greater storage capacity than granular fill. Placement of granular fill would also affect surface flow patterns by modifying natural drainage, but AGDC would contour the work pads to restore drainage and hydrologic connectivity in floodplains. Because the Project area is relatively undeveloped, the overall impact on flood storage capacity would be minor.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that the Project would not result in significant adverse effects on freshwater resources.

5.1.3.3 Marine Waters

Nearshore construction activities in Prudhoe Bay and Cook Inlet could result in sedimentation in marine waters due to erosion from stormwater runoff and dewatering, but AGDC would install erosion controls and implement BMPs in accordance with the Project Procedures and SWPPP to avoid or reduce impacts. AGDC also would obtain coverage under the required APDES permits and comply with the requirements of the permits for stormwater discharge. At the Liquefaction Facilities, stormwater runoff would be directed to temporary catch basins during construction and permanent ponds during operation to allow suspended sediments to settle out of the water prior to discharge.

Inadvertent spills of fuel, oil, and other hazardous materials from equipment and vessels could affect marine water quality. To minimize risks and mitigate impacts, AGDC would implement the material handling measures provided in the Project Procedures and Project Waste Management Plan, along with the fueling, storage, containment, and cleanup measures in a site-specific SPCC Plan to be developed by AGDC prior to construction. All material storage and handling procedures would comply with applicable regulations, and Project personnel would be trained in spill response. Any spill of oil or hazardous material into a waterbody would be subject to reporting and response according to the NCP and 18 ACC 75.

For construction and operational activities in Cook Inlet, AGDC would require vessel operators to comply with the Project Emergency Response Vessel Assurance Execution Plan as well as response plans for accidental releases of oil. Large vessels, like the LNG carriers to be used for Project operation, would be required to implement ODPCPs and/or SOPEPs, which include measures to be taken when an oil spill has occurred or is possible. With the implementation of these measures, and given the historically low probability of groundings and large spills in Cook Inlet, adverse impacts from spills would not be expected during operation. An inadvertent release of LNG from a carrier or the Liquefaction Facilities would not affect water quality in Cook Inlet because the LNG would vaporize and dissipate into the air when exposed. Similarly, a leak of natural gas from the Mainline Pipeline would dissipate.

Construction of offshore facilities, screeding, dredging, pile driving, anchoring, and other seabed disturbing activities would increase turbidity and sedimentation, but these impacts would be temporary, localized, and minor, with conditions quickly returning to ambient levels. Because background turbidity in Cook Inlet is naturally high, increases due to Project construction could fall within the natural range of fluctuation. Turbidity and sedimentation impacts from routine maintenance dredging in Cook Inlet would be similar to those for construction. Maintenance dredging is not anticipated in Prudhoe Bay during Project operation.

As discussed in section 4.2.3, Prudhoe Bay sediments within the Project area are free of contaminants. Sediments in Cook Inlet are generally consistent with background levels and/or agency recommended thresholds for contaminants. Tested sediments from Cook Inlet in the Marine Terminal area contained heavy metal concentrations at or near regional background concentrations, and low total petroleum hydrocarbons concentrations indicating no evidence of anthropogenic petroleum contamination. As a result, water quality impacts due to resuspension of contaminants in Cook Inlet would not be expected (see section 5.1.72 for discussion of impacts on benthic invertebrates, which are sensitive to heavy metals).

For Cook Inlet dredging, several disposal options for dredged material are under consideration. AGDC's preferred dredged material disposal sites are unconfined aquatic disposal sites in state waters near the Project area. The sites would accommodate the anticipated volume of dredged material. Disposal would cause localized temporary increases in turbidity and sedimentation, but currents would be expected to rapidly disperse sediments, while diluting the concentration. In addition, turbidity is naturally high in Cook Inlet and could mask temporary increases from dredged material disposal.

Construction of offshore facilities in Prudhoe Bay and Cook Inlet would result in the permanent loss of open marine habitat. Because the area of impact for these facilities would encompass about 0.1 percent of the total water environments in both bodies, the permanent loss of marine habitat would be insignificant.

The permanent extension of the West Dock Causeway and construction of Dock Head 4 in Prudhoe Bay could impede nearshore circulation, affecting local hydrographic conditions. The West Dock Causeway is known to have caused cross-causeway differentials in salinity and temperature conditions, though at least one study showed that impacts are mitigated by breaches in the existing structure. Since the

proposed Project expansion would primarily involve widening the causeway, any impacts on cross-causeway differentials would likely be minor.

Most of the Mainline Pipeline in Cook Inlet would be laid directly on the seabed. For the Beluga Landing and Suneva Lake shoreline approaches, the pipeline needs to be buried to provide adequate hazard protection. AGDC's preferred installation method for the shoreline crossings is open-cut, but HDD and DMT were also evaluated. Geotechnical assessments indicate that crossings by HDD would likely be unsuccessful, but a combination of DMT and open-cut could be feasible, reducing the extent of shoreline disruption, subsea excavation, and associated impacts. A preliminary feasibility study assessed the success probability of DMT crossings as 90 percent at Beluga Landing and 75 percent at Suneva Lake. We also note that AGDC's Geotechnical Report recommended additional analysis of DMT during engineering design.

AGDC said it is agreeable to incorporating the DMT continuation methodology into the shoreline crossings, but first must perform additional geotechnical investigations to confirm the feasibility of the method at these locations. Should the investigations confirm feasibility, AGDC would file revised construction plans, including site-specific shoreline crossing plans, that incorporate the use of the DMT continuation methodology for the shoreline crossings at Beluga Landing and Suneva Lake.

Between the shoreline approaches, the Mainline Pipeline across Cook Inlet would not be buried. Given the strong currents and tides in the inlet, impacts on the pipeline from abrasion and collision with rocks on the seabed are possible. The Project would be subject to PHMSA regulations requiring burial of the pipeline below the sea bottom unless "supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means." AGDC would coat the offshore pipeline with 3.5 inches of concrete coating for on-bottom stability and protection from impacts. AGDC would also conduct preconstruction surveys during the detailed design phase of the Project to address issues related to potential free spans. If free spans that exceed the maximum allowable length or height for the pipeline are identified, AGDC would make localized adjustments to the pipeline route to avoid these areas. If avoidance of a free span area is not possible, AGDC would implement other measures—such as sweeping the seabed, placing support under the pipeline, adding grout bags or sand bags, or placing vortex suppressors on the pipe—to mitigate impacts on pipeline integrity. During operation, AGDC would conduct geophysical surveys along the pipeline route across Cook Inlet every 1 to 2 years to assess conditions on the seabed and mitigate any new free spans that develop under the pipeline.

PHMSA has reviewed the technical information provided by AGDC. With regard to 49 CFR 192.327(f)(2), PHMSA is satisfied that AGDC would mitigate any future pipeline safety conditions due to subsea bottom free spans. Should mitigation of free spans be required after detailed design is completed, or determined to be necessary during Project construction or operation, additional environmental analysis by FERC and other permitting agencies may be required depending on the proposed scope and anticipated impacts of implementing the mitigation measures.

Impacts on marine waters could result from wastewater discharges from vessels during construction and operation. Wastewater discharges from tugs and barges are subject to a VGP and would have minimal impacts on marine water quality. Oceangoing vessels requiring ballast and cooling water would be subject to the protocol for ballast and cooling water discharge as well as the VGP.

LNG carriers visiting the Marine Terminal during operation would discharge ballast water as LNG is loaded into the vessel. Ballast water discharge would occur near the bottom of the berth where dissolved oxygen levels are inhibited. Temperature, pH, dissolved oxygen, and salinity levels at the discharge locations would rapidly dilute to ambient levels due to tidal exchange in Cook Inlet such that impacts on water quality would be local, temporary, and minor. LNG carriers (and barges) would additionally be

required to comply with Coast Guard, EPA, and state regulations regarding BWM as well as the VGP. AGDC has developed a BWM Plan that complies with these standards and has committed to having BWM requirements in place to protect against water quality degradation in Cook Inlet and Prudhoe Bay during Project construction and operation.

LNG carriers would withdraw and discharge engine cooling water while docked at the Marine Terminal in Cook Inlet. Cooling systems on LNG carriers are non-contact to avoid exposing cooling water to fuels, oils, and other potential contaminants on the vessel. While cooling water would be slightly warmer than ambient conditions at the time of discharge, impacts on water quality are unlikely due to rapid dilution in the inlet, so no adverse impacts would be anticipated.

Operation of the sewage treatment plant and LNG Plant for the Project would result in wastewater discharges via outlet pipes to Prudhoe Bay and Cook Inlet, respectively. Discharges would be treated and consistent with water quality standards specified in APDES permits, so impacts on water quality would be minor.

Increases in vessel traffic would occur in Cook Inlet and Prudhoe Bay during construction and in Cook Inlet during operation. The increased traffic is not expected to contribute to turbidity or shoreline erosion due to the low speeds required for operational safety of the vessels.

With implementation of the measures described above and AGDC's commitments, we have concluded that the Project would not result in significant adverse effects on marine waters.

5.1.3.4 Water Use

AGDC would require the use of water for a variety of construction and operational activities, including hydrostatic testing, mixing drilling mud, ice road construction, dust control, and routine maintenance and repairs. Water would be primarily obtained from surface or marine sources, but groundwater withdrawals would also be required. AGDC prepared a draft Water Use Plan that identifies the anticipated water needs for Project construction, but volumes and sources of water have not been finalized. Additionally, AGDC has not estimated water needs for Project operation. Therefore, AGDC would file an updated Water Use Plan that provides final volumes, sources, discharge locations, and proposed treatments of the water needed for Project construction and operation. The plan would also evaluate the potential for reuse of hydrostatic test water and demonstrate that the reuse of water has been applied where practicable.

Water withdrawals for the Project would be subject to state permitting. Permissible withdrawal volumes from surface waters would be identified in Temporary Water Use Authorizations issued by the ADNR. Water withdrawn from streams would typically have a maximum withdrawal limit of 20 percent of stream flow, but this could be adjusted based on site-specific conditions, timing, and total withdrawal volumes. Lake withdrawals would be limited to a percentage of the total seasonal lake volume and conducted in accordance with ADF&G permits. Intake hoses for withdrawals would be screened to reduce impacts on aquatic life and kept off the bottom to avoid sediment uptake. Where groundwater is needed, wells would be installed to access water for construction and operation. Water withdrawals from wells would be conducted in accordance with groundwater allocation permits issued by the ADNR to minimize impacts due to drawdown.

Hydrostatic testing of most Project facilities would occur in summer using water from surface sources without additives. After testing, AGDC would discharge the test water into the same basin from which it was withdrawn in accordance with applicable federal (EPA) and state (ADEC) permit requirements. During discharge, test water would pass through energy dissipation devices and dewatering

structures to minimize the potential for scour, erosion, and sedimentation in receiving surface waters. The primary pollutant of concern during discharges would be sediment debris, which would be removed as water passes through the dewatering structure.

AGDC has stated that hydrostatic testing of the PTTL would occur in the summer; however, hydrostatic testing of other Project facilities on the North Slope could occur year-round and would require additives to prevent the test water from freezing. If hydrostatic testing in winter becomes necessary, any chemical additives (e.g., biocides or antifreeze chemicals) would need to be identified during the permitting process. The water from hydrostatic testing and other wastewater streams associated with construction of the Gas Treatment Facilities, with the exception of the PTTL, would be discharged into two UIC Class I wells, as discussed below.

Hydrostatic testing of the offshore segment of the Mainline Pipeline (and possibly various components of the Liquefaction Facilities, including the LNG tanks) would be conducted using seawater withdrawn from Cook Inlet. AGDC does not plan to use biocides in seawater used for hydrostatic testing. If AGDC determines that biocides would be required, this would be disclosed during the APDES permitting process. Test water would be discharged via outfalls back to Cook Inlet in accordance with applicable federal and state permit requirements.

The remainder of the Mainline Pipeline would be hydrostatically tested in sections up to 20 miles long over three summer seasons. Test water for most sections would be discharged to uplands or wetlands in accordance with applicable state (ADEC) and federal (EPA) permits. Test water from one test section on the North Slope would be discharged to the two UIC Class I wells to be installed at the GTP. Test water would remain in the pipeline an average of 48 hours. For discharges to the surface, the water temperature would be within a few degrees of the surrounding ground temperature at the time of discharge. Test water would be discharged at the ground surface separated from the frozen subgrade, which would reduce heat transfer. While some impacts on permafrost would occur, significant impacts would not be expected.

ADEC developed an APDES general permit that authorizes the discharge of seven waste streams, including hydrostatic test water, from the construction, operation, and maintenance of oil and gas pipelines. The EPA has authority for discharges that occur within the DNPP. AGDC would obtain the required permits for all discharges associated with Project, including hydrostatic testing. The specific sources, volumes, types, frequencies, rates, treatments, and disposal mechanisms for the discharges, as well as the locations of potential outfalls and discharge points, would be determined by AGDC as construction plans are finalized and through the acquisition of the required permits for the discharges.

Construction of the Gas Treatment and Mainline Facilities would require ice roads and ice pads, which would be built using fresh water, snow, and ice chips from nearby lakes, rivers, and flooded gravel mines, which could affect water levels in these sources. Ice bridges could potentially affect stream flow at spring breakup, but AGDC would cut slots in the ice to direct meltwater and minimize flooding potential. Impacts on water sources from ice road and ice pad construction and use would be temporary and minor because surface water volumes would be replenished during spring melt.

Due to the lack of freshwater aquifers on the North Slope, groundwater would not be used during construction of the Gas Treatment Facilities. Instead, water would be trucked in and stored on site until the new water reservoir is completed or water would be withdrawn from surface sources. Water for operation would be withdrawn from the GTP reservoir, which would avoid impacts on other surface waters. The reservoir would require annual withdrawals from the Putuligayuk River to maintain the volumes needed to operate the Project facilities. Water would be withdrawn from the river at peak flows, resulting in temporary and minor effects on water level and quality. Water would be transported from the river to the reservoir by an aboveground pipeline built on VSMs.

For both construction and operation, AGDC would discharge wastewater at the Gas Treatment Facilities, with the exception of the water used for hydrostatically testing the PTTL, into two UIC Class I injection wells installed within the GTP pad footprint (including hydrostatic test water with additives to prevent test water from freezing). The wells would be designed and constructed to prevent the movement of injected wastewaters outside of the injection zone. Operators would monitor the characteristics of the injected wastewater, annular pressures, and containment of wastewater within the injection zone. Disposal of water into the wells or GTP reservoir would avoid impacts on surface waters. The hydrostatic test water associated with the PTTL would be discharged to upland and wetland areas in accordance with applicable federal and state permit requirements.

Due to elevated contaminant concentrations identified in underlying aquifers, AGDC would not withdraw groundwater for use during construction or operation of the Liquefaction Facilities. Instead, AGDC would use freshwater obtained from a proposed expansion of the City of Kenai public drinking water system or seawater withdrawn from Cook Inlet. AGDC would sequence hydrostatic testing of the LNG tanks so that test water from the first tank could be used for the second tank, which would reduce the water needs of the Project.

Water needed for use at construction camps during pipeline construction would be obtained from new groundwater wells or surface sources. For new wells, AGDC would conduct withdrawals in accordance with ADNR groundwater allocation permits. To minimize impacts on local drinking water sources, wells for the construction camps would be sited outside of DWPAs for active PWS sources. The wells would be monitored for water quality and yield to detect potential drawdown in accordance with the Project Water Well Monitoring Plan and Groundwater Monitoring Plan.

Temporary wastewater treatment plants would be installed at each construction camp to process and discharge wastewater in accordance with ADEC requirements. Treatment technologies and anticipated discharge volumes, rates, and frequencies are not known at this time. This information would be determined during the permitting process for discharges from these facilities. AGDC would work with ADEC to ensure that discharges are conducted in accordance with applicable state requirements. Wastewater generated during operation of the Mainline Facilities would be collected and disposed of at an approved disposal facility (industrial wastewater), treated on site and discharged to the ground (grey water), or treated using disinfectants (black water) and either discharged to the ground or transported to proper disposal facilities in accordance with applicable APDES and EPA requirements.

With implementation of the Project construction and restoration plans and AGDC's commitments, we have concluded that the Project would not result in significant adverse effects on water use.

5.1.4 Wetlands

AGDC delineated wetlands in the Project area using the Field Target Sampling Method, which combined desktop review and field surveys to map wetlands. Based on a validation study, this method provided a reasonable proxy for the overall acreage of wetlands that would be affected, but it did not accurately delineate wetland locations and boundaries. As a result, the minimization measures required by FERC and the COE to protect wetlands could not be accurately applied during construction. AGDC has committed to conducting field-verified delineation surveys to provide accurate wetland boundaries and filing wetland delineation reports on an annual basis. Field delineation surveys for winter construction segments would be completed in the growing season prior to construction. Additionally, AGDC would identify field-delineated boundaries with markers in the field and file revised construction alignment sheets depicting the wetland boundaries.

Project construction and operation would affect PEM, PSS, PFO, and estuarine wetlands. Impacts on wetlands would result from clearing, granular fill placement, pipeline and facility installation, material site and water reservoir development, fugitive dust, spills and leaks of fuel or other hazardous materials, invasive species, hydrostatic test water discharges, changes in drainage patterns, blasting, inadvertent releases from DMT crossings, and use of ice roads and ice pads. AGDC would implement BMPs and Project-specific plans (e.g., the Project Procedures, SWPPP, Revegetation Plan, SPCC Plan, Winter and Permafrost Construction Plan, Invasives Plan, and ISPMP) to avoid, minimize, or mitigate impacts on wetlands. Granular fill placed in wetlands (for aboveground facilities, temporary work pads within and outside the construction right-of-way, and access roads), however, would remain in perpetuity resulting in substantial conversion to uplands and loss of wetland functions.

Seasonal use of ice pads and ice roads during winter construction would avoid the need for some granular fill, thus reducing wetland impacts. Fresh water, snow, and ice chips would be used to create ice roads and ice pads on top of wetlands. Ice road and ice pad construction would be conducted in accordance with permits from the DMLW that impose standards to minimize impacts on underlying wetlands. Construction and use of ice roads and ice pads would result in temporary impacts because the ice would melt during spring breakup. Operation and maintenance activities could also require use of ice roads and ice pads, but impacts would be minor.

Pipelines associated with the Gas Treatment Facilities would be built entirely within wetlands, but construction impacts would be minor. The PTTL, PBTL, and GTP support pipelines would be constructed aboveground on VSMs from ice roads and ice pads in the winter. This installation method would limit impacts to a small footprint at the base of each VSM. In the spring and summer following installation, the flushing of sediments disturbed by construction could result in turbidity at the base of each VSM, but the impact would be temporary and minor.

Development of the gravel mine and water reservoir for the Gas Treatment Facilities would result in the permanent conversion of wetlands to open water, which could create habitat that provides different functions and values. Conversion to open water would be dependent on water availability from external sources and could require multiple seasons. Construction activities for the gravel mine and water reservoir could create indirect effects on adjacent wetlands from blasting and overburden stockpiling. Overburden stockpiles would be removed from the gravel mine perimeter as part of reclamation activities in accordance with final approved reclamation plans.

Onshore Mainline Pipeline construction would result in temporary, short-term, long-term, and permanent wetland impacts. The extent of impacts would vary based on construction mode. Modes 1, 2, and 3 would result in the least disturbance, with impacts resulting from a combination of clearing and trenching activities. PEM and PSS wetlands affected by Modes 1, 2, and 3 would be restored, though the recovery time would vary based on the length of the growing season, resulting in short- to long-term impacts. Clearing of PFO wetlands during construction would result in the permanent conversion to PSS and/or PEM wetlands given the slow growth of trees.

We found inconsistencies between wetland impact data filed by AGDC and information included in the Project Winter and Permafrost Construction Plan with regard to Mainline Pipeline construction mode by milepost, season, and spread. We updated the wetland impact data for the Mainline Pipeline to be consistent with the mile-by-mile identification of construction modes in the Project Winter and Permafrost Construction Plan. AGDC reviewed these changes and confirmed that they are consistent with the Project Winter and Permafrost Construction Plan.

Modes 4 and 5A would result in permanent impacts on wetlands from the placement of granular fill and cut fill material to create level work surfaces. Fill placed in wetlands during construction would

remain in perpetuity, resulting in substantial conversions (about 4,133 acres) of wetlands to uplands. To reduce impacts, as discussed above in section 5.1.2, we recommend that AGDC reassess if winter construction in frozen conditions would be a feasible alternative to granular work pads in areas currently proposed for Mode 4 construction in summer. Additionally, we recommend that AGDC file revised construction alignment sheets showing the use of timber/composite mats in place of granular fill in areas proposed for Mode 4 construction on slopes of 0 to 2 percent.

Clearing of forested wetlands and the placement of granular fill for Mainline Pipeline construction would permanently affect substantial areas of wetland. The functions of affected wetlands would be altered or lost resulting in fragmentation, reduced nutrient cycling, drainage and recharge pattern modifications, flood storage reduction, and permafrost degradation. Additionally, Project construction activities would have short-term, long-term, and permanent effects on areas of regionally unique or expansive wetland complexes, including string bogs and the Minto Flats SGR.

During operation, AGDC would conduct vegetation maintenance, if necessary. PEM vegetation would not generally be mowed or otherwise maintained. PSS vegetation would be mowed or cut within a 10-foot-wide strip centered over the Mainline Pipeline no more than every 3 years. Most of the permanent impacts on wetland vegetation due to maintenance would be in PFO wetlands where trees would be cut and removed within 15 feet of the pipeline. The affected wetlands would be permanently altered by conversion to PSS or PEM wetlands.

The Project would permanently and temporarily affect estuarine wetlands through construction of the West Dock Causeway modifications, the offshore segment of the Mainline Pipeline, the Mainline MOF, and the Liquefaction Facilities (LNG Plant and Marine Terminal). Temporary effects on estuarine wetlands from trenching the offshore segment of the Mainline Pipeline would be avoided if the Beluga Landing and Suneva Lake shoreline approach crossings can be completed using the DMT continuation method. As noted in section 5.1.3.3, AGDC is agreeable to incorporating the DMT continuation methodology into the shoreline crossings, but must first perform geotechnical investigations to confirm the feasibility of the method at these locations. If the investigations confirm feasibility, AGDC would file revised construction plans that incorporate the use of the DMT continuation methodology for the shoreline crossings. Installation of permanent facilities, such as the expansion of the West Dock Causeway, the LNG Plant, and the PLF at the Marine Terminal, would result in the permanent loss of estuarine wetlands.

As discussed in section 2.2, the Project Procedures include certain modifications to the FERC Procedures, such as the siting of ATWS within 50 feet of wetlands. We have reviewed these modifications and found them to be acceptable with some revisions, which AGDC has incorporated in an updated Project Procedures. The acceptable modifications are provided in table D-2 of appendix D.

Compensatory mitigation would be required to offset the unavoidable loss of wetland and aquatic resource functions in accordance with the Section 404(b)(1) Guidelines, 33 CFR 332, and the 1990 Memorandum of Agreement Between the DA and the EPA. Examples of compensatory mitigation include restoration, establishment, enhancement, or preservation of wetlands. AGDC provided a Project Wetland Mitigation Plan to the COE for review. AGDC is consulting with the COE and other agencies to determine the appropriate form of mitigation for impacts on wetlands. Project impacts under NPS authority would be required to adhere to wetland compensatory mitigation requirements in accordance with the NPS Director's Order 77-1.

With the implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that most impacts would be temporary, short-term, or long-term, largely dependent on the vegetation affected. However, the substantial permanent loss and conversion of

wetlands and wetland functions due to the use of granular fill and long recovery time for PFO wetland vegetation would result in significant adverse impacts.

5.1.5 Vegetation

Project construction would affect about 26,054 acres of vegetation, including 12,440 acres of forest, 8,080 acres of scrub, and 5,534 acres of herbaceous vegetation. These values encompass the smaller operational area that would affect about 7,596 acres, including 3,282 acres of forest, 2,214 acres of scrub, and 2,101 acres of herbaceous vegetation.

Project construction and operation would result in temporary to permanent impacts (loss or conversion) of vegetation due to various types of disturbance, granular fill placement, clearing, facility installation, material and disposal site development, and right-of-way maintenance. Most impacts would be reduced with implementation of AGDC's various Project-specific plans, such as the Project Plan, Project Procedures, SWPPP, Revegetation Plan, SPCC Plan, Invasives Plan and ISPMP, and Winter and Permafrost Construction Plan. Overall impacts on scrub and herbaceous communities would be less than significant given the smaller areas affected and shorter recovery time relative to forest. Impacts on forest would be significant due to the larger area affected, longer recovery time, and long-term or permanent conversions from forest to other cover types.

Granular fill placement would result in the permanent loss of vegetation due to limited or no plant development in fill following construction. While AGDC would apply restoration measures to granular fill, such as contouring to restore drainage, we have concluded that these measures would not be likely to produce plant communities similar to the pre-existing plant communities during the life of the Project. Because revegetation could be enhanced with a higher proportion of fines in the fill, we recommend that AGDC apply granular fill with at least 20-percent fines in the surface layer of construction workspaces (see section 5.1.2).

During construction, vegetation would be temporarily cleared in the Mainline Pipeline right-of-way and other work areas. Impacts from construction clearing would vary depending on the ability of plant communities to reestablish and the length of time needed for recovery, which could range from several years to decades. Revegetation success would be affected by the short growing season, cool temperatures, and limited precipitation, particularly in the northern portion of the Project area.

Soil impacts due to grading and trenching would affect plant composition and growth. Damage to soil structure and mixing of topsoil, subsoil, and rocks would reduce plant health and productivity. AGDC does not plan to segregate the organic layer along most of the Mainline Pipeline, so soil fertility, native seed banks, and BSCs would be lost or diminished. Erosion of exposed soils could cause instability and topsoil loss, but AGDC would implement measures in the Project Procedures and SWPPP to minimize impacts. Because the PTTL, PBTL, and GTP support pipelines would be installed aboveground from ice roads and ice pads, impacts would be limited to vegetation loss in a small footprint at the base of each VSM support structure and reduced plant productivity due to limited shading by the pipeline.

Revegetation would initially rely on natural plant recruitment except where the Mainline Pipeline would be installed using construction Modes 1 and 5B or in sensitive areas such as streambanks, steep slopes, and places with NNIS infestations. AGDC would use a variety of methods for streambank restoration, such as transplanting native plants, while other sensitive areas would be seeded within the first growing season after construction or via dormant seeding by the subsequent fall. AGDC would consider revegetation successful when 70 percent of the pre-disturbance vascular canopy cover is restored compared to undisturbed reference sites. Because successful revegetation would take a long time, AGDC would use an interim performance standard at 3 years post-construction to assess the probability of success, and

implement remedial measures where the interim standard is not met. To ensure that restoration is successful, AGDC would continue canopy cover surveys annually at RMES with NNIS infestations and every 3 years at all other RMES until the final performance standard in the Project Revegetation Plan is met.

Along with the canopy cover standard, AGDC recommended that restored plant communities in the three northernmost subregions contain at least five native or seeded species that each contribute greater than 0.2 percent to the TLVC, or together greater than 1.0 percent of the TLVC, as an indication of the potential for successful restoration of the native plant community. Other guidance recommends higher cover targets for native plants in Alaska. To help ensure that post-construction plant communities better reflect pre-construction conditions in all subregions, AGDC has agreed to file an updated Revegetation Plan requiring at least 5 percent live canopy cover of non-seeded native species in all subregions.

Where seeding would be applied, AGDC would use seed mixes containing seven native grass species. While seeding would help re-establish vegetation, the use of a grass mix could reduce both species and functional group diversity (e.g., forb and shrub diversity) by suppressing natural recruitment of other species and/or by a single grass cultivar out-competing the other species. This is particularly true for sod-forming grasses, such as red fescue, which are effective in soil stabilization but known to form homogenous stands in restored areas. Therefore, AGDC would limit the use of red fescue in its seed mix to steep slopes or areas with a high erosion potential where there are no other effective species available.

Forest fragmentation and edge effects would occur along portions of the Mainline Pipeline corridor and new access roads. In most areas, the forest that remains on either side of the right-of-way would not be measurably reduced in size. Fragmentation could have greater effects in areas where forest stands are naturally small, such as in the forest-wetland complexes between MPs 677 and 693. Sharp declines in species richness have been found to occur in forest stands less than about 5 to 7 acres (2 to 3 hectares), including late successional spruce forests in forest–wetland complexes (Berglund, 2004) and subtropical woodlands (Drinnan, 2005). Development of the Mainline Pipeline corridor could create fragments of this size in these smaller forest stands. The understory plant communities in forest stands less than about 5 acres before construction would likely already be suited to the conditions of a smaller forest (i.e., greater exposure to forest edges and reduced diversity), such that a further size reduction may not significantly alter baseline conditions.

Plant pests (including spruce beetles) introduced as a result of Project construction could have a detrimental effect on plant communities, particularly forests. Forest vegetation could become more susceptible to pests from increased stress due to limbing, surface or root wounds, or changes in microclimate. Because construction would be temporary and right-of-way maintenance infrequent, tree stress and other vectors for pests would be minimal. Additionally, the Project Invasives Plan includes measures to address pests, and AGDC would comply with the Alaska Forest Practices Act to minimize the risk of spruce beetle infestations.

BSCs are a dominant feature of herbaceous communities and an important component of the organic layer in the Arctic. Fugitive dust and air pollution, particularly pollutants associated with the GTP, could have an adverse effect on BSCs based on previous studies of mosses and lichens, while ground disturbance would remove BSCs from the soil surface layer. Impacts on BSCs would be permanent, adversely affecting revegetation and potentially resulting in increased erosion. Given the broad distribution of BSCs on the North Slope and localized effect of dust and air pollution, and with the implementation of the Project Plan, SWPPP, and Fugitive Dust Control Plan, these impacts would likely be minor.

Project construction and operation could result in the spread of NNIS, affecting adjacent plant communities or causing revegetation efforts to fail. Because NNIS have a limited distribution in Alaska,

an increase in NNIS could have a significant impact. AGDC would address this concern by implementing measures in the ISPMP on BLM lands and the Project Invasives Plan in the rest of the Project area. Measures include marking existing infestations, treating infestations prior to construction and during restoration, cleaning vehicles and equipment, and using seed mixes and fill in accordance with state regulations. AGDC additionally has committed to seeding areas with NNIS infestations within the first growing season following construction to reduce the establishment and/or spread of NNIS prior to natural recruitment. To ensure NNIS infested areas are reseeded in a timely manner, AGDC would incorporate this measure into the Project ISPMP and Invasives Plan.

In addition, to ensure we have sufficient data to monitor NNIS treatments and assess revegetation success relative to existing conditions, AGDC would file the results of pre-construction NNIS surveys along with up-to-date invasiveness rankings for each NNIS found in the Project area. AGDC would also update the Project Revegetation Plan, ISPMP, and Invasives Plan to incorporate a final performance standard that includes a 0-percent increase in high-risk NNIS canopy cover in the Project area following construction and during operation to further reduce the risk of spreading NNIS.

We received comments from the USFWS regarding the potential spread of *Elodea*, which is found upstream of the Mainline Pipeline crossings of the Nenana River and Alexander Creek. The Nenana River No. 3 crossing would be completed using an aerial span, which would avoid exposure to *Elodea* propagules. The Alexander Creek crossing would be dry-ditch, which would minimize the risk of *Elodea* propagules becoming attached to construction equipment. To further avoid the spread of *Elodea* into unaffected waterbodies, AGDC would clean equipment prior to entering and leaving Alexander Creek.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that permanent loss of plant communities, construction clearing, and disturbance from Project construction and operation would not result in significant adverse effects on herbaceous and scrub communities. We have also concluded that potential impacts from the introduction and spread of NNIS would be acceptably minimized. Significant adverse impacts on forest would result from permanent loss or conversions and the long recovery time in restored areas.

5.1.6 Wildlife Resources

5.1.6.1 Terrestrial Wildlife

Project construction and operation would affect terrestrial wildlife due to loss or alteration of habitat and fragmentation. Temporary loss would occur in areas restored to natural conditions, though recovery times could range from years to decades depending on vegetation type and region. Permanent loss would occur at aboveground facilities and granular fill sites, along access roads, and in areas where cover types, such as forest, are modified for right-of-way maintenance. AGDC would implement several measures to minimize impacts, such as avoiding unnecessary clearing; limiting activities to approved work areas; and restoring areas temporarily disturbed by construction.

Direct injury or mortality of terrestrial wildlife could occur due to construction or maintenance activities or vehicle and equipment collisions. Clearing and grading in winter could affect hibernating mammals, particularly smaller, less mobile species. Collisions with vehicles and equipment could occur in construction work areas and access roads or along public roads and highways. Some species would be more vulnerable to collisions, particularly highly mobile species. Collisions on public roads and highways could increase due to Project traffic, but wildlife would be somewhat acclimated to existing traffic on these roads. AGDC would implement measures to minimize collision risks, such as limiting vehicle speeds on access roads and the right-of-way and training personnel to recognize hazards when driving.

During construction, trenching for the Mainline Pipeline could temporarily block animal movements across the right-of-way, which could disrupt seasonal activities or migration patterns, particularly for large mammals. To reduce impacts, AGDC would coordinate with the ADF&G and USFWS to develop procedures to facilitate wildlife movement and minimize migration disruptions due to construction. Where practicable, AGDC would schedule excavation activities to avoid major migrations. Other mitigation measures include minimizing the length of open trench; installing trench crossings in migration corridors; and installing escape ramps for animals who become trapped in the trench.

Construction and operational activities would generate noise that could affect terrestrial wildlife. Some species (or sensitive life stages) could suffer temporary or permanent hearing loss, but most animals would be capable of avoiding noise that could be physically damaging. Impacts on wildlife would be mostly behavioral, such as displacement to adjacent habitats, but Project noise could also disrupt breeding, hibernation, predation, and other temporal patterns. Construction impacts would be short term and localized; operational impacts would be long term to permanent and localized. Noise impacts due to operation of aboveground facilities would be reduced with implementation of sound controls and other design features, as discussed in section 4.16.

Artificial lighting would temporarily and permanently affect terrestrial wildlife behavior and habitat use, particularly during operation. Facility lighting during operation would include lighting panels and fixtures to provide light for working areas and security. AGDC would implement the measures identified in the Project Lighting Plan to reduce impacts on wildlife due to lighting, such as avoidance, displacement, or increased predation. AGDC would design facility lighting to direct light only in places where necessary, and lights would be shielded to reduce trespass, unwanted projection, and upward directed light.

Terrestrial wildlife could be affected by the presence of humans and use of Project facilities, especially in remote areas with limited human populations. Impacts on terrestrial wildlife could include behavioral changes, a decrease in reproduction success due to stress, and mortality from increased hunting and poaching. To minimize impacts, construction camps and waste management systems would be designed to reduce wildlife attraction to camps by food and refuse. Workers would be trained on good housekeeping practices, including implementation of the Project Waste Management Plan, to reduce the potential for interactions with wildlife. Workers would be prohibited from feeding wildlife to avoid adverse human/wildlife interactions. Workers would be prohibited from hunting; camps would be closed with prohibitions against visiting areas outside camps or construction areas during non-work hours; and AGDC would implement measures, in coordination with land management agencies and landowners, to block or limit access to the right-of-way during operation.

With the implementation of the Project construction and restoration plans, we have concluded that Project effects would be less than significant on most terrestrial species. We conducted additional analyses to assess Project effects on large mammals (moose, bear, caribou, Dall sheep, muskoxen, gray wolf, and wolverine) and the only amphibian (wood frog) known to occur in the Project area. Impacts on and mitigation for these species generally would be the same as those described for general terrestrial wildlife. However, impacts would be greater for species with specialized habitat requirements where construction or operation would occur in sensitive habitats and/or during sensitive periods. This includes moose, bear, caribou, Dall sheep, muskoxen, and wood frogs, all of which would experience some construction activities in sensitive habitats during sensitive periods. Likewise, these species would experience some permanent changes in habitat availability. Generally, given the distribution of these species statewide and/or the

availability of other suitable habitat, population-level impacts on these species from Project construction and operation would not be anticipated.

For the Central Arctic Caribou Herd, impacts would be significant due to the timing of impacts during sensitive periods, permanent impacts on sensitive habitats, and the Project location at the center of the herd's range. However, we do not know if the impacts would be temporary or long term, or to what extent, if any, the PTTL could affect caribou herd movements.

5.1.6.2 Avian Resources

Project construction and operation would affect avian resources as a result of habitat degradation and loss; increased stress, injury, and mortality; disturbance and displacement; and loss of reproductive opportunity. Impacts would result from clearing and grading, granular fill placement, facility installation, water withdrawal and discharge, right-of-way maintenance, noise and light, collisions, spills, vessel traffic, aircraft, and human disturbance. AGDC has developed mitigation measures to avoid, minimize, or mitigate impacts on avian resources, including the Migratory Bird Conservation Plan. Impacts would also be addressed through implementation of Project-specific plans, such as the Project Plan, Procedures, Winter and Permafrost Construction Plan, Lighting Plan, and SPCC Plan.

To the extent practicable, AGDC would conduct land disturbing activities on the Beaufort Coastal Plain during winter. Project-wide, AGDC would generally conduct vegetation clearing, grubbing, and other disruptive activities during construction outside of timing windows recommended by the USFWS for nesting birds, but some activities could overlap with nesting seasons based on site-specific conditions (e.g., excessive snow or extreme cold) or the Project schedule. In IBAs, AGDC would always conduct vegetation clearing or initial granular fill placement outside the nesting seasons during construction and operation to provide additional protection for birds in these sensitive areas. For Project operation, Section VII.A.5 of the Project Plan prohibits mowing or clearing for right-of-way maintenance in the nesting season of migratory birds unless approved in writing by the responsible land management agency or the USFWS. AGDC would file the documentation needed to satisfy this requirement should the need arise to conduct vegetative mowing or clearing for right-of-way maintenance during the nesting season for migratory birds.

The discharge of hydrostatic test water during the nesting season could destroy eggs and nestlings of ground nesting birds. AGDC has stated that it would avoid or minimize impacts by avoiding high concentration nest locations to the extent practicable during discharge. Additional measures to reduce impacts would include the reuse of hydrostatic test water in multiple test sections to limit the number of discharge points, where practicable, as well as the use of flow dispersion devices to slow water during discharge.

Impacts on nesting habitat would be permanent in areas affected by granular fill placement or areas where full recovery of vegetation is not possible. Permanent habitat loss for birds would also result from habitat conversion or loss due to maintenance of the pipeline right-of-way and installation of aboveground facilities. As discussed in section 4.7.1, some open water habitat would be created by the Project at material extraction sites, which could benefit waterbirds.

The use of mechanical equipment to construct and operate the Project could result in accidental spills or releases of fuel and other hazardous materials, but impacts would be minimized through implementation of the Project SPCC Plan.

Noise from construction and operational activities could affect birds. Construction noise would temporarily displace birds from adjacent habitats. Operational noise from facility operation could make the habitat around these facilities uninhabitable by birds. To reduce noise disturbance impacts, AGDC

committed to performing non-lethal hazing to clear areas of wildlife prior to blasting. Due to the short duration of construction noise and low levels of operational noise, impacts on birds from Project-related noise would not be significant.

Artificial light from Project construction and operation would affect birds. Artificial light can be disorienting for birds, increase the risks of collision and predation, and affect foraging behavior and navigation. To avoid or reduce these impacts, AGDC would implement FAA and USFWS guidance for lighting; follow agency-recommended standards for the number, color, intensity, and flashes of lights; and design and shield lighting to reduce light trespass, unwanted projection, and the upward direction of light.

Increased vehicle, aircraft, and vessel traffic due to Project construction and operation could disturb or displace birds or cause injury or death due to collisions. Birds are also susceptible to collisions with facility structures, such as flare stacks, buildings, and communication towers. AGDC would implement various design measures to minimize collision risks such as installing freestanding flare stacks and towers, limiting the use of lattice and guy wires, implementing applicable aspects of the USFWS's *Reducing Bird Collisions with Buildings and Building Glass Best Practices*, and installing bird diverters and anti-perching devices.

Construction camps and permanent facilities would create the potential for bird-human interactions and changes in bird behavior or habitat use. Waste generation could attract bird predators, but AGDC would implement the Project Waste Management Plan to reduce the attractions of predators to facilities.

To avoid impacts on nesting eagles, AGDC would comply with the 2007 USFWS *National Bald Eagle Management Guidelines* and USFWS recommended buffers for golden eagles by maintaining buffers between Project activities and nests, where practicable. In areas where buffers between Project activities and nests cannot be maintained, AGDC would consult with the USFWS and pursue the applicable incidental take or eagle disturbance permits.

With implementation of the measures described above and AGDC's commitments, we have concluded that the Project would not result in significant adverse effects on avian resources.

5.1.6.3 Marine Mammals

Project construction and operation would affect marine mammals in the Beaufort Sea, Cook Inlet, GOA, and Bering and Chukchi Seas. The Project would affect foraging, mating, and migration behaviors of marine mammals in oceanic, coastal, and terrestrial habitats due to noise, habitat degradation and loss, decrease or loss of prey, vessel strikes, human interactions, and introduction of invasive species. Spills may occur from vessel traffic in marine environments. AGDC would implement various measures to avoid, reduce, or mitigate these impacts, as discussed below. Impacts would also be addressed through implementation of Project-specific plans, such as the BWM, SPCC, and Restoration Plans, and through compliance with federal regulations regarding vessel transit and ballast water discharges.

Underwater noise impacts on marine mammals due to the Project would result from activities such as pile driving, excavation, dredging, screeding, anchor handling, and vessel operations. Marine mammals use hearing and sound transmission to communicate, navigate, avoid predators, mate, and locate food. Underwater noise can disrupt these behaviors resulting in increased stress, injury, and mortality. Underwater noise can also cause habitat degradation, displacement, strandings, and changes in migration patterns. The majority of noise impacts on marine mammals would be behavioral, but some, such as noise from pile driving, could cause injury. Underwater noise could affect seals, whales, porpoises, or dolphins depending on the type and season of the activity.

Airborne noise from Project activities, such as pile driving, equipment and vessel operations, excavation, and aircraft overflights, could result in behavioral impacts on marine mammals. Airborne sounds over water could affect marine mammals at the surface or when hauled out. Construction noise could cause startle reactions or displacement from areas where equipment is operating.

To minimize impacts, AGDC would use PSOs to monitor construction activities within shutdown and harassment zones based on the distances at which sounds exceed harassment thresholds. PSOs would monitor pile driving in Prudhoe Bay and anchor handling and pile driving in Cook Inlet. For pile driving, PSOs would stop construction or order reductions in sound levels when marine mammals are visible in shutdown or harassment zones. Construction activities would not resume or be returned to full power until the animals leave the applicable zone. If conditions (e.g., fog) prevent the visual detection of marine mammals within the exclusion zone, impact and vibratory pile driving would not be initiated, and impact pile driving would be halted if already started. AGDC would implement other measures to reduce noise impacts from pile driving, such as installing piles during low tide; using a vibratory hammer, where practicable; and using "soft-start" procedures prior to hammering.

AGDC committed to having at least two PSOs on watch during pile driving and at least one PSO on watch during pipe laying in Cook Inlet, but no information was provided regarding the number of PSOs for activities in Prudhoe Bay. In AGDC's draft Marine Mammal Monitoring and Mitigation Plans for Cook Inlet and Prudhoe Bay, AGDC also only committed to using land-based PSOs. Given the area required for monitoring and lack of information on PSOs for Prudhoe Bay, we recommend that AGDC provide a revised PSO deployment plan that includes at least three PSOs for pile driving in Cook Inlet and Prudhoe Bay stationed at specific observation points, and at least one PSO for anchor handling in Cook Inlet. We also recommend that AGDC provide PSOs for dredging and screeding activities and for Mainline Pipeline shoreline installation.

AGDC proposed shutdown, harassment, and mitigation zones for pile driving, but they would not apply to all activities and would not match the modeled distances in appendix L-1. Further, the zone distances could change based on MMPA authorizations. Therefore, we recommend AGDC revise the shutdown distances for all underwater noise generating activities based on modeled distances or conduct a Sound Source Verification during construction to establish the appropriate shutdown or harassment zones.

The Project would result in disturbance and loss of marine mammal habitat, but the overall impacts would be minor. Impacts on habitat in Prudhoe Bay would result from construction of the West Dock Causeway modifications and Dock Head 4 over six seasons, but the area affected would be small relative to the available habitat in Prudhoe Bay, with much of the affected area expected to return to pre-construction conditions within a short time. Impacts on habitat in Cook Inlet would result from construction and operation of the Mainline Pipeline and Marine Facilities, but the area affected would be small relative to the available habitat in the inlet.

Habitat loss and alteration for prey species would occur due to dredging/screeding and facility construction in Cook Inlet and Prudhoe Bay. Prey, such as fish, could experience increased stress, injury, and mortality near pile driving activities, but fish would generally avoid habitats around active construction areas. Benthic communities would be lost due to placement of the Mainline Pipeline across Cook Inlet and as a result of dredging and screeding, but the impacts would be temporary and minor given the availability of benthic resources in other areas. Construction impacts on prey sources for marine mammals, such as zooplankton, benthic invertebrates, and fish, would also be primarily temporary and localized.

Vessel traffic in the Bering, Beaufort, Chukchi, and Bering Seas and Cook Inlet and the GOA would result in temporary and minor behavioral effects on marine mammals and could strike individual animals, resulting in injury or death. Vessel speed is the main factor in the probability of a vessel strike

occurrence. To minimize impacts, AGDC would implement a Transit Management Plan, which identifies measures, such as reduced vessel speeds, to reduce traffic and collisions. In its vessel contracts, AGDC would require vessels to comply with NMFS' *Vessel Strike Avoidance Measures & Reporting for Mariners*, which recommends, among other provisions, reducing speeds and maintaining separation between vessels and marine mammals, when present. Vessels in transit through the Aleutian Islands area would maintain compliance with the International Maritime Organization's Aleutian "Areas to be Avoided," as possible, which would maintain HLV and LNG carrier traffic well offshore of the Aleutian Islands.

Because Project construction and operation would require fuel transport and staging, spills of fuel from vessels in transit or when re-fueling are possible, which could affect marine mammals. To minimize the risk of a spill, AGDC would ensure that all contractors comply with the Project Emergency Response Vessel Assurance Execution Plan, SPCC Plan, and/or SWPPP, as applicable. AGDC would additionally ensure that vessel operators required to have ODPCPs and/or SOPEPs have current and approved plans, which would include measures to be taken when an oil pollution incident has occurred or is possible.

Vessel operations could introduce aquatic invasive species from ballast water discharge, fouled hulls, and equipment placed overboard. Aquatic invasive species could affect marine mammals by altering prey populations. To avoid or minimize impacts, vessels would be required to adhere to federal regulations regarding BWM, and AGDC's Project BWM Plan that includes measures to minimize the risk of introducing aquatic invasive species.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that the Project would not result in significant adverse effects on non ESA-listed marine mammals.

5.1.7 Aquatic Resources

5.1.7.1 Fisheries Resources

Project construction and operation would result in temporary and permanent impacts on freshwater and marine fisheries and their habitats. Activities resulting in turbidity and sedimentation, alteration or removal of cover, blasting, introduction of pollutants, introduction of aquatic nuisance and nonindigenous fish species, permafrost degradation, water depletions, or entrainment or impingement could increase rates of stress, injury, or mortality of fish. While impacts could result from any activity that harms fish or affects their behavior, most impacts would be minimized through implementation of AGDC's Project-specific Plans, such as the Plan and Procedures, Revegetation Plan, Site-Specific Waterbody Crossing Plans, Water Use Plan, Invasives Plan, SPCC Plan, BWM Plan, and DMT Plans.

The ADF&G regularly updates its list of AWC waters, which are important fishery resources in Alaska. We recommend that AGDC review the newest available ADF&G AWC list and NMFS EFH species list to ensure that applicable mitigation and conservation measures regarding culvert design, water withdrawals, and time of year restrictions for in-stream activities would be applied to AWC waters.

AGDC compiled available data and conducted limited surveys at or near waterbody crossings for the Project, but fish use and habitat data is not available at, or near, all stream crossings that would be affected by the Mainline Pipeline or PTTL. To ensure that minimization techniques for fisheries are appropriately applied at stream crossings, AGDC would complete fish surveys at waterbodies where there is no available fish survey data within 290 feet of the current pipeline crossing locations to identify AWC streams, EFH, and waterbodies with anadromous fish, including Pacific salmon.

Construction activities within or adjacent to streams and adjacent wetlands could increase turbidity and sedimentation, alter stream channels or substrate composition, alter or remove cover, increase erosion, or degrade habitat. Impacts on fish could include displacement; changes in feeding or breeding behaviors; interference with passage; and stress, injury, or death. AGDC would minimize impacts by installing erosion and sediment controls; using dry-crossing, buried trenchless, or aerial installation methods at certain waterbodies; crossing waterbodies in dry or frozen conditions; and stabilizing and restoring stream beds and banks. With the implementation of these measures, impacts would generally be localized, temporary, and minor.

AGDC would place granular fill in the wetland associated with an Unnamed Tributary of the Chulitna River near MP 655.2. Because coho salmon use this waterbody to migrate between spawning and feeding grounds, the granular fill left in place would cause a permanent impact on migrating salmon. Therefore, AGDC would remove the granular fill from the wetland after completing in-stream construction activities at the Unnamed Tributary of the Chulitna River. Removing granular fill would restore fish passage after construction is completed.

Open-cut pipeline crossings in winter at waterbodies with overwintering habitat could increase sedimentation downstream of the crossing through unfrozen deep water. Overwintering habitat is a limiting factor for fish in Alaska, with limited areas within a stream that have suitable depths where the stream does not freeze to the bottom. These areas can be isolated and contain no discernable flow during the winter. Overwintering fish would not be able to escape construction equipment or increased turbidity, which could have effects on local populations. Fish would congregate in these areas during the winter, so an impact on an occupied overwintering fish stream reach could lead to the loss of a year class of fish in that stream segment. Overwintering habitat is known to occur at 14 waterbody crossings proposed for winter construction along the Mainline Pipeline, but overwintering habitat could be present in other waterbodies as well.

To minimize fisheries impacts, the ADF&G provided construction timing windows for various sensitive waterbodies. AGDC would develop a Fisheries Conservation Plan that incorporates these windows for waterbodies listed as AWC, including EFH, or with known salmon populations. AGDC additionally would include measures in the Fisheries Conservation Plan for avoiding extraction in material sites within or near waterbodies listed as AWC, including EFH, during sensitive spawning time periods, and prohibit in-stream winter construction in waterbodies with known overwintering habitat.

The USFWS recommended that AGDC create a vegetated littoral zone in material sites that fill with water upon abandonment. This and other measures, such as creating ponded areas in material extraction sites connected to streams with EFH, could enhance or create fish habitat. AGDC would develop measures in consultation with the ADF&G to minimize long-term impacts on fisheries from development of material extraction sites that are hydrologically connected to streams listed as AWC, including EFH, or with known salmon populations.

Blasting in waterbodies for material extraction or trench excavation could cause turbidity and downstream sedimentation and potentially harm fish directly in the blast zone. To minimize impacts on fish, AGDC would develop site-specific mitigation measures in consultation with the ADF&G and implement the Alaska Blasting Standard for trench or material site blasting near and within anadromous waterbodies. AGDC would file an updated Project Blasting Plan that includes monitoring of stream flow between blasting and in-stream construction activities as well as contingency measures to remediate loss of stream flow due to blasting should this occur.

Some access roads built across waterbodies would require the installation of culverts to maintain flow and provide fish passage. Long-term impacts on fish, particularly salmon, could occur if poorly designed or maintained culverts restrict the movement of migrating adults or fry. To reduce impacts, the

NMFS suggested that AGDC follow the *Anadromous Salmonid Passage Facility Design* for culverts. AGDC would provide, as part of the Fisheries Conservation Plan, a design and maintenance plan for culverts installed within fish bearing streams based on these guidelines. AGDC also would apply measures from the FWS's *Alaska Fish Passage Program Fish Passage Design Guidelines* to the extent practicable.

Construction activities in marine waters, such as excavation, pipe laying, pile driving, screeding, and dredging, could increase turbidity and sedimentation or degrade habitat. While turbidity could result in physical impairment of fish or changes in foraging behavior, fish would typically avoid areas of increased suspended sediment, and conditions would return to background after completion of the activity. Temporary and permanent habitat loss in Cook Inlet for salmonid and other anadromous and marine species would occur from construction and operation of the Marine Terminal and Mainline MOF, but impacts would be minor due to the temporary disturbance from construction and limited amount of habitat lost.

Construction of Dock Head 4 and use of the barge bridge would affect fish habitat in Prudhoe Bay. During construction, granular fill would be placed behind sheet piling to construct Dock Head 4, resulting in the permanent loss of fish habitat. Mobile species would avoid the area due to turbidity and construction noise. A temporary barge bridge, consisting of two barges ballasted to the sea floor, would be installed and removed at the start and end of each open water construction season to bridge the gap between dock bulkheads. Fish passage through the bridge would be provided in the area between the barges and the areas between each barge and the bulkheads.

Water withdrawals from surface freshwater sources could affect fish due to entrainment or impingement, reductions in water levels or flows, habitat degradation, or changes in water temperature or quality. Impacts could include reduced productivity; interference with passage; or increased stress, injury, or death. To minimize impacts, AGDC would include mitigation measures for water withdrawals, such as screening and positioning of the pump and limitations on withdrawal volumes and rates, in the Fisheries Conservation Plan. Water withdrawals from Cook Inlet could also entrain or impinge fish, but impacts would be minimized through use of a screen on the intake hose and positioning of the intake above the seafloor.

Water from the Putuligayuk River would be used to fill the reservoir at the GTP for use during Project operation. Water withdrawals from the river would not exceed 20 percent of flows, which would minimize impacts on fish. AGDC would additionally install an intake screen to reduce the potential for entrapment, entrainment, and impingement associated with the withdrawal.

Artificial light has the potential to affect marine and freshwater fish, but the overall impact would be temporary, localized, and minor. The response of fish to artificial light is variable depending on light intensity and the species and age-class of fish. Impacts would be minimized through implementation of the Project Lighting Plan, such as shielding light and directing it to work surfaces.

Temporary shading of the seabed would result from construction of the Marine Terminal MOF; permanent shading of the seabed would result from construction of Dock Head 4, the Mainline MOF, and the Marine Terminal PLF. Shading from over-water structures could displace or cause changes in fish behavior, but impacts would be localized and, for temporary structures, limited to a few years. Longer-term impacts from permanent over-water structures could cause salmon to avoid those areas, but the overall impact would be minor given the abundance of habitat in adjacent areas.

Noise impacts on fish could result from pile driving, excavation, dredging, screeding, VSM installation, DMT, and vessel operations. Impacts could include displacement, behavioral changes, masking, hearing loss, injury, or death in areas where noise exceeds critical thresholds. While pile driving has been shown to cause significant injury to fish, displacement or behavioral effects are more common.

Sounds generated by vessels could cause avoidance behaviors or displacement of fish. Construction impacts would be temporary, and in Cook Inlet, consistent with existing conditions. Longer-term displacement in Cook Inlet could occur from Marine Terminal operation due to noise from LNG carriers.

Additional vessel traffic due to construction and operation of the Project, including LNG carriers, would result in an increased risk of spills in marine habitats. To reduce risks and minimize impacts, AGDC would require contractors and vessel operators to comply with the Project Emergency Response Vessel Assurance Execution Plan. In addition, various types of vessels, including LNG carriers, are required to develop and implement SOPEPs and/or ODPCPs, which include measures to be taken when an oil pollution incident has occurred or is possible. AGDC would ensure applicable vessel operators have current and approved SOPEPs and ODPCPs, as applicable.

AGDC would implement its Invasives Plan during Project construction and operation to reduce the risk of introducing ANS or NAS fish species, which could affect native fish species. Compliance with Coast Guard regulations and the Project BWM Plan would reduce the potential for impacts due to the introduction of invasive species from ballast discharge or hull fouling.

While the Project would affect EFH for multiple species, we have concluded that impacts would be minor with the implementation of AGDC's mitigation measures and our recommendations. We requested that NMFS consider the draft EIS as initiation of consultation and provide conservation measures for impacts on EFH. We subsequently completed EFH consultation with NMFS on September 23, 2019.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that the Project would not result in significant adverse effects on fisheries.

5.1.7.2 Marine Benthic Invertebrates

Project construction and operation would result in mortality of benthic organisms from activities that disturb the seabed. Dredging and screeding would result in 100-percent mortality of non-mobile organisms and a high percentage of mortality, injury, or displacement of other benthic organisms. Mortality, injury, and displacement also would occur in areas affected by trenching, anchoring, pipelay, and dredged material disposal. Affected communities could take a decade or more to recover as benthic organisms in the arctic have slow growth rates due to cold temperatures and low organic matter input. Affected habitats could be repopulated by different species, thereby failing to recover original community compositions. Impacts could be minor to major depending on recovery, but would be localized to the area of disturbance. The overall Project effect would be minor given that a small portion of the benthic population in Cook Inlet or Prudhoe Bay would be affected.

The offshore portion of the Mainline Pipeline would involve trenching in nearshore areas and laying pipe on top of the seafloor. As noted in section 5.1.3.3, if geotechnical investigations confirm its feasibility, AGDC would incorporate the use of the DMT continuation methodology for the shoreline crossings at Beluga Landing and Suneva Lake. Use of the DMT continuation methodology would reduce impacts on benthic invertebrates.

Impacts on benthic invertebrates could result from the release of contaminants in sediments, particularly heavy metals, disturbed by dredging, screeding, or other activities affecting the seabed. No evidence of contamination was found in tested sediments from the screeding area in Prudhoe Bay. Contaminants in tested sediments from the dredging area in Cook Inlet included heavy metals. Given their sensitivity to heavy metals, disturbance of Cook Inlet sediments could increase exposure and toxicity to benthic filter-feeders. Construction and maintenance dredging activities would cause localized effects on

marine benthic invertebrates near the Marine Terminal from exposure to contaminants, which would be a long-term impact because dredging would occur over multiple years, recovery could be slow, and community composition could be affected.

Increased turbidity and sedimentation due to dredging, screeding, and other seabed disturbing activities could affect benthic invertebrates by clogging feeding and respiration apparatuses, diluting food resources, reducing predator responses, and burying organisms. Dredging could result in impacts on benthic organisms, particularly if sedimentation coincides with spawning, causing increased mortality of eggs and larva. Indirect effects on habitat quality would be minor given the high ambient turbidity in Prudhoe Bay and Cook Inlet.

Vessel operations, particularly those of LNG carriers, could affect benthic organisms through ballast water discharges; introduction of invasive species; or spills of fuel and other hazardous materials. Based on LNG carrier design, a significant difference in temperature and salinity between ballast and ambient waters would not be anticipated. Potential impacts due to the introduction of invasive species due to ballast discharge or hull fouling would be minimized through compliance with Coast Guard regulations and the Project BWM Plan. Vessel traffic could affect benthic organisms by increasing the risk of inadvertent spills, but impacts would be reduced through implementation of the Emergency Response Vessel Assurance Execution Plan and, as applicable, ODPCPs and/or SOPEPs.

Vessel traffic, docking, and over-water structures could cause shading of the benthic environment, altering community structures and reducing primary production. New infrastructure could also act as an artificial reef, however, creating new habitat. Therefore, impacts would be permanent but minor.

With implementation of the measures described above and AGDC's commitments, we have concluded that the Project would not result in significant adverse effects on marine benthic invertebrates.

5.1.7.3 Plankton

Impacts on plankton could result from exposure to turbidity. Phytoplankton production is tied to underwater light, which is affected by ice and turbidity. Seasonal or artificial increases in turbidity affect the vertical and horizontal density of phytoplankton production via shading. Project activities that affect water clarity would affect phytoplankton productivity. Because zooplankton life histories are tied to phytoplankton productivity, these same activities would affect zooplankton abundance. Ichthyoplankton and higher trophic level species that feed on plankton would also be affected. Potential impacts include behavioral changes, injury, or mortality, but effects would be mostly temporary, minor, and localized. In Cook Inlet, where turbidity is naturally high, impacts would be negligible.

Impacts on plankton due to spills of fuel, oil, or other hazardous materials would be minimized through implementation of the Project Emergency Response Vessel Assurance Execution Plan and, as applicable, ODPCPs and/or SOPEPs. Resuspension of contaminants that could be present in sediments during construction activities could affect species composition in the long term. Noise impacts on phytoplankton and zooplankton could occur, possibly resulting in injury or death, but research on this subject is limited and the potential extent of impacts is unknown. Regardless, most construction impacts would be temporary, localized, and minor.

Impacts on plankton would result from water withdrawal and discharges. Withdrawals would likely result in 100 percent mortality of plankton entrained in or impinged on the intake system. Discharges could affect plankton through exposure to biocides (if used during hydrostatic testing; see section 5.1.3.4) or temporary changes in temperature or turbidity (all discharges). Mortality rates would vary by season and species, with the highest rates occurring in summer. The impact from impingement and entrainment

by LNG carriers on ichthyoplankton would be permanent due to the persistence of LNG carrier traffic over 30 years of operation. The impacts would be minor, however, due to high natural mortality rates and dynamic seasonal shifts in plankton community structure. Discharges would be conducted in accordance with applicable regulations and permits, which would minimize impacts.

Overall, we have concluded that the Project would not result in significant impacts on plankton.

5.1.8 Threatened, Endangered, and Other Special Status Species

We consulted with the USFWS and NMFS, who identified 32 federally listed threatened or endangered species, DPSs, or ESUs known to occur in the Project area, including 7 with designated critical habitat in the Project area. Of these, we have determined that Project construction and operation would have *no effect* on two species, is *not likely to adversely affect* 23 species (DPSs or ESUs), and is *likely to adversely affect* six species (spectacled eider, polar bear, bearded seal, Cook Inlet beluga whale, humpback whale, and ringed seal). We have also determined that the Project is *not likely to adversely affect* designated critical habitat for five species and is *likely to adversely affect* designated critical habitat for two species (polar bear and Cook Inlet beluga whale).

We initiated formal consultation with the Services regarding Project effects on ESA-listed species in June 2019. Because compliance with Section 7 of the ESA is not complete, we recommend that AGDC not begin construction until we complete formal consultation with the Services and AGDC has received written notification from the Director of the OEP that construction or use of mitigation may begin. In addition, we recommend that AGDC not begin construction until they have received applicable ITAs for the MMPA from the USFWS and NMFS.

Impacts on ESA-listed threatened and endangered species and designated critical habitat would be similar to those described above for terrestrial wildlife, avian resources, marine mammals, and fisheries. Implementation of the construction, restoration, and mitigation measures for these types of species along with our recommendation would avoid, minimize, or mitigate impacts on most ESA-listed species and their habitats. Impacts on six species (spectacled eider, polar bear, bearded seal, Cook Inlet beluga whale, humpback whale, and ringed seal) would or could be adverse. Several mitigation measures specific to federally listed species would be implemented, as discussed below.

For impacts on polar bear and Pacific walrus, construction activities in Prudhoe Bay would be covered under the Beaufort Sea ITR. In accordance with these regulations, AGDC would provide a Polar Bear and Pacific Walrus Avoidance and Interaction Plan and implement all applicable provisions regarding avoidance, minimization, and mitigation measures for these species. AGDC has committed to conducting surveys for polar bears and providing a monitoring and mitigation plan to the Services each year construction activities covered by the ITR occur.

Measures described in section 5.1.6.3 for marine mammals, such as use of PSOs in shutdown and harassment zones, would reduce the risk of disturbance to marine mammals from underwater noise. To minimize the potential for vessel strikes, AGDC would require vessels to comply with NMFS guidelines and other measures regarding strike avoidance and reporting. AGDC would develop a Project Transit Management Plan for all vessels and a Ship Strike Avoidance Package for LNG carriers. Other measures would be implemented, such as slowing vessel speeds and implementing timing restrictions for pile driving, to reduce impacts on marine mammals. Dock Head 4 piles and sheet piles would be installed from June through August, for example, to avoid sensitive bowhead whale periods. AGDC additionally has committed to conducting surveys for ringed seal lairs and polar bear dens prior to construction in suitable habitat.

Nearly the entire population of Cook Inlet beluga whales is present on the western side of Cook Inlet near the Project area each year in the months of June and July for feeding and reproduction. Pile driving for construction of the Mainline MOF and anchor handling for the Mainline Pipeline pipelay could occur during these months, potentially resulting in noise impacts that exceed injury or behavioral disturbance thresholds for beluga whales. As discussed in section 5.1.6.3, AGDC would deploy PSOs and implement harassment and shut down zones for pile driving activities and anchor handling. We recommend that AGDC also provide PSOs for Cook Inlet dredging to avoid or minimize impacts on marine mammals, including Cook Inlet beluga whales. To further reduce impacts on Cook Inlet beluga whales, AGDC would not conduct pile driving activities for construction of the Mainline MOF during the months of June and July.

Based on the 2008 and 2010 BLM 6840 Manual, we have identified 89 sensitive or watch list species, including birds, mammals, invertebrates, fish, and plants, with the potential to occur in the Project area on BLM lands (BLM, 2019) (see table P-1 in appendix P). Five of these species (Alaska-breeding Steller's eider, spectacled eider, northern sea otter, polar bear, and wood bison) are federally listed. The Eskimo curlew is federally listed and considered BLM sensitive, but it is presumed extinct. Impacts and avoidance, minimization, and mitigation measures for BLM sensitive and watch list species would be similar to those for vegetation, terrestrial wildlife, birds, fisheries, and federally listed species. Permanent loss of suitable habitats would be limited, with significant amounts of similar habitats available in adjacent areas. Therefore, impacts on BLM sensitive and watch list species would not be expected to be significant.

Based on the 2015 Alaska Wildlife Action Plan, we have identified 26 high priority SGCN, including birds and marine mammals, with the potential to occur in the Project area. Eight of these species (short-tailed albatross, spectacled eider, Alaska-breeding Steller's eider, Cook Inlet beluga whale, blue whale, North Pacific right whale, northern sea otter, and polar bear) are federally listed under the ESA; and six of the species (Cook Inlet beluga whale, blue whale, North Pacific right whale, northern sea otter, northern fur seal, and polar bear) are protected under the MMPA. Impacts and avoidance, minimization, and mitigation measures for these species would be similar to those for birds, marine mammals, and federally listed species. Permanent habitat loss would be small in comparison to other habitat available for use. Impacts on most SGCN would be temporary, with the exception of the federally listed Cook Inlet beluga whales, as noted above.

5.1.9 Land Use, Recreation, and Special Use Areas

Project construction and operation would primarily affect open land and forested land, with less impact on agricultural, industrial/commercial, and residential land. AGDC also identifies sizable impacts on open water, but these impacts are based on anchor cable arrays, which would have limited temporary impacts on water. With the exception of forest, impacts on most land use types would be minor to moderate. Given the conversion of forest to open or industrial land in the maintained pipeline right-of-way and at aboveground facility sites, as well as the long recovery time for forest in areas temporarily affected by construction, impacts on forested land would be long term to permanent and significant. Impacts on open land north of the Brooks Range could also be significant due to the long recovery time for vegetation in this area.

A majority of the land (excluding open water) that would be affected by Project construction is owned or managed by federal and state governments (19 percent and 69 percent, respectively). The remainder is owned by cities/boroughs (4 percent), Alaska Native corporations or other Alaska Native entities (4 percent), and private landowners (5 percent). Similarly, a majority of the land (excluding open water) that would be affected by Project operation is owned or managed by the federal and state government (19 and 63 percent, respectively), with the remainder owned by cities/boroughs (5 percent), Alaska Native corporations or other Alaska Native entities (3 percent), and private landowners (10 percent).

The Mainline Pipeline would cross or pass near industrial or commercial lands at Coldfoot, McKinley Village, and Byers Lake Campground (in Denali State Park), as well as a parcel used by a river tour operator near MP 560. In these areas, there are 43 industrial or commercial buildings or properties within 200 feet of the proposed Mainline Facilities, including one building within the footprint, and six other buildings within 50 feet of the Mainline Facilities footprint. Construction would affect visitors to McKinley Village, campground visitors, and the river tour operator. Visitors to McKinley Village would experience increased noise and traffic, reduced access to businesses during construction, and traffic delays due to temporary lane and road closures of the Parks Highway. To minimize these impacts, AGDC would schedule pipelay outside the peak tourist season and implement its Traffic Mitigation Plan for work during the tourist season.

Development of material extraction sites would block access to and permanently remove a portion of the campground at Byers Lake Campground near MP 630 and require temporary closure of the parcel used by the river tour operator near MP 560. We received comments from the ADNR Division of Parks and Outdoor Recreation that the proposed material site near Beyer's Lake Campground would not be compatible with the agency's mission and the park's management zones, and therefore, the ADNR is unlikely to approve the material site. Should the material site be approved, ACDC would file a detailed schedule of construction activities for the site to mitigate impacts. With regard to the material site near MP 560, AGDC states that it would develop a site-specific schedule for construction activities to minimize disruption to the river tour operation.

We received comments regarding potential impacts on a family fishing operation where construction of the Mainline Pipeline could disrupt their fishing access along the south shore of Cook Inlet on Boulder Point. As noted in section 5.1.3.3, AGDC would incorporate the use of the DMT continuation methodology for the shoreline crossing at Suneva Lake if geotechnical investigations confirm the feasibility of this method. If adopted by AGDC, implementation of the DMT continuation methodology would avoid impacts on the fishing operation; otherwise, measures in the Project Recreation and Commercial Fishing Construction and Mitigation Plan would minimize impacts.

AGDC identified 127 residential buildings within 200 feet of the Mainline Facilities footprint, including two within 50 feet of the Mainline Pipeline footprint and one within 50 feet of a Mainline access road. Construction impacts on these and any other residents near the pipeline would be temporary and minor. AGDC would implement site-specific mitigation measures to reduce impacts on residences in addition to the standard BMPs identified in the Project Plan. AGDC would additionally conduct field surveys to confirm the locations and occupational status (i.e., seasonal or permanent; occupied or vacant) of residences.

Construction of the Liquefaction Facilities would result in the permanent conversion of residential land to industrial/commercial land, including the removal of 10 residences from within the footprint of the LNG Plant. AGDC would purchase these residences prior to construction. No other residences are within 200 feet of the plant, and there are no residences in the immediate vicinity of the Gas Treatment Facilities.

During Project operation, a 1,000-yard security zone would be established around LNG carriers in transit to and docked at the Marine Terminal. Other vessels would be prohibited from the security zone without prior approval from the Coast Guard.

To date, AGDC has identified three planned developments within 0.25 mile of the Mainline Pipeline. For each of these, AGDC would coordinate with the Project proponent and affected landowners to minimize potential impacts or conflicts through the Project Stakeholder Engagement Plan. There are no known planned developments in the vicinities of the Gas Treatment and Liquefaction Facilities.

The Project would cross or pass near recreational areas on public lands, including the ANWR, DNPP, George Parks Highway National Scenic Byway, INHT, and Dalton Highway Utility Corridor on federal lands; and Denali State Park, Nenana River Gorge and North Slope SUAs, Tanana Basin Planning Area, Tanana Valley State Forest, and various GMUs and refuges on state lands. The Project would also cross state-managed resources including the Dalton Highway Scenic Byway, Alaska Railroad Scenic Byway, and Susitna Basin and Alexander Creek River Management Areas.

Most impacts on recreation areas during construction would be temporary and minor. AGDC would minimize or mitigate impacts through implementation of construction and restoration BMPs. AGDC additionally would provide alternate access to affected sites, use flaggers or pilot cars to direct traffic, schedule activities outside peak tourist seasons, and comply with applicable crossing permits. The main impact of Project operation on recreational areas would be long-term to permanent changes in views due to maintenance of the pipeline right-of-way or installation of aboveground facilities. Visual impacts during operation could be low to high depending on the location and sensitivity of affected viewers.

The Mainline Pipeline would cross the DNPP outside the DNPP Wilderness boundary from about MPs 537.1 to 543.1, and pass less than 0.2 mile from the DNPP between MPs 532.1 and 536.2. Construction impacts, such as reduced visual quality, traffic, and noise, would be temporary, lasting up to 4 years. Noise impacts could include those caused by construction of the Healy Compressor Station, which would be moderate to high at the DNPP boundary, as described in section 5.1.16. Construction impacts would not generally prohibit recreational uses of the park, but could disrupt or delay some uses. Access to the proposed Nenana River Trail could be disrupted for up to a day or two during construction, and the pedestrian bridge across the Nenana River would be closed for about 2 months during construction. Additionally, construction along the Parks Highway could delay access to the DNPP through traffic congestion and lane closures. However, disruptions to trail use and the pedestrian bridge, as well as highway access to the DNPP, would be minimized since construction would occur outside the peak tourism season.

Establishment and maintenance of the pipeline right-of-way would cause permanent changes to viewsheds within some portions of the DNPP, which would affect the user experience by altering the scenery, vegetation, and wildlife in the affected area. The pipeline right-of-way could both alter planned recreational development—including recreational trails that have been proposed in the area—and encourage greater use of adjacent areas through increased access. Noise impacts on the DNPP from operation of the Healy Compressor Station would be negligible. The potential for light impacts from the compressor station would be reduced with implementation of a site-specific lighting plan for the station, as addressed in section 5.1.10. The NPS would determine consistency of the Project with its applicable plans.

The Mainline Pipeline would be built across two segments of the INHT during winter, which is peak use season for the trail. Pipeline installation would require brief closures of each trail segment, which would likely last several hours, but could be as long as 2 days depending on local conditions at the time of each crossing. AGDC would consult with trail users, management agencies, and other stakeholders regarding the construction schedule, and propose alternate trail access on the Yentna River to minimize impacts. The trail would be restored following construction, so no impacts would be expected during Project operation. While AGDC filed a site-specific crossing plan for the INHT, the plan does not address coordination with trail managers and other stakeholders; the potential for scheduling conflicts with other trail uses, including races; or alternate access to the trail. To address these issues, AGDC would file a revised site-specific crossing plan for the INHT, to be developed in consultation with the ADNR, that identifies the locations of detours, signs, or alternate access to the trail; and provides for public notice of construction dates and any required trail closures.

The Mainline Pipeline would cross about 45 miles of Denali State Park, mostly within 0.5 mile of the Parks Highway. Within the park, the pipeline would be installed beneath the Chulitna River by DMT, which would avoid direct impacts on the waterbody, but would restrict public access on the riverbanks for about 6 to 12 weeks. The pipeline would be installed beneath Lower Troublesome Creek Trail using an open-cut trench, but AGDC would keep the trail open by installing a temporary bridge or rerouting the trail within the right-of-way. AGDC would file a site-specific crossing plan for the Lower Troublesome Creek Trail, including the location of the temporary bridge or trail reroute. Other trails in the park could require temporary closures ranging from several hours to 2 days. Construction noise would affect recreational uses throughout the park.

To minimize impacts on visitors to and recreational resources within Denali State Park, AGDC would schedule major construction activities to avoid peak tourist season; provide alternate access to recreation sites; block access roads and the right-of-way to prevent their use by off-road vehicles; and restore the right-of-way with native vegetation. With the implementation of these measures and the development of the site-specific crossing plan for Lower Troublesome Creek Trail, Project impacts would be temporary and minor, although maintenance of the pipeline right-of-way during operation would change the park's visual character and could affect the quality of visitor experiences.

The Mainline Pipeline would be parallel to the George Parks and Dalton Highways for hundreds of miles and would cross both highways in multiple locations. The crossings would be by conventional bore, which would avoid direct impacts on each highway. Construction would increase traffic on the highways, which could be perceived as locally significant. Temporary lane closures would be required where construction activities occur in close proximity to the highways, but flaggers or pilot cars would be used to manage traffic and/or the closures would occur at night. The main operational impacts on the highways would be long-term to permanent changes in viewsheds due to right-of-way maintenance and installation of aboveground facilities. The Dalton Highway's primary use is industrial, with existing facilities such as TAPS already present in its viewshed. Impacts on both highways would be minor.

We received comments during scoping about potential impacts on access to North Beach at Cook Inlet due to construction of the Liquefaction Facilities. The Mainline MOF and PLF would be constructed on the shoreline, blocking access to the beach from Salamatof Road. AGDC states that development of a plan to construct an alternate public beach access point, including consultation with the ADNR, Kenai Peninsula Borough, and private landowners, would occur prior to construction. The plan would address pedestrian and vehicular access, traffic and parking, signage, and construction methods to maintain bluff integrity, as well as ownership, management, and maintenance of beach access.

As discussed in section 5.1.3.2, the Mainline Pipeline would cross two NRI-eligible waterbodies: the Deshka River and Alexander Creek. The affected segments of these waterbodies would be on state or borough lands, however, where federal designation is unlikely. Construction impacts on these waterbodies, such as increased sedimentation or turbidity, would be temporary and minor, and Project operation would not affect recreational uses of the rivers.

We received comments from the State of Alaska that the module staging pad for the Gas Treatment Facilities would eliminate a state-run tundra monitoring station, which provides data on whether the tundra can be opened or closed for ice road construction and use. The ADNR would be responsible for issuing the lease for the staging pad, including provisions (if any) related to avoidance, relocation, or replacement of the monitoring station.

The installation of Long Range Discrimination Radar at Clear AFS in 2019 could result in the development of Special Use Airspace necessary for radar operation that would overlap or occur within about 0.25 mile of the Mainline Facilities near MP 493.5, including an MLV and associated helipad. Clear

AFS personnel requested that MLV 14 and its helipad be relocated to avoid potential conflicts with the airspace. AGDC said that it would coordinate with Clear AFS representatives to avoid or mitigate impacts on Clear AFS during Project construction and operation, and has committed to relocating MLV 14 and its helipad. To ensure these facilities would be relocated to an area that would avoid impacts on Clear AFS, we recommend that AGDC develop a relocation plan developed in coordination with Clear AFS representatives.

Components of the Liquefaction Facilities could affect U.S. Air Force radar operations in the Anchorage Alaska vicinity. The DOD provided a preliminary finding that the Project would not adversely affect DOD missions within this area. We will continue to work with DOD staff to confirm that the Mainline and Liquefaction Facilities would not adversely affect DOD operations at the Clear AFS and in the Anchorage, Alaska vicinity.

AGDC identified known sites within or near the Project area where contaminated media could be disturbed. To reduce impacts at or from these sites, AGDC would consult with agencies and landowners to identify the contaminants present; adhere to applicable land use and institutional controls; restore drainage patterns to minimize erosion; install ditch plugs to prevent migration of contaminated water in the pipe trench; and implement a Groundwater Monitoring Plan in areas where dewatering would occur near contaminated sites. AGDC would also coordinate with landfill and mine owners to ensure that the Project does not affect waste containment or monitoring infrastructure at these sites.

The Project Unanticipated Contamination Discovery Plan identifies general measures to be implemented if construction disturbs previously unidentified contaminants in soil or groundwater. AGDC would file an update to this plan that addresses operational and maintenance activities, includes phone numbers for applicable emergency responders, and incorporates a FERC notification requirement if contaminants should be identified.

With implementation of the measures described above, AGDC's commitments, and our recommendation, we have concluded that most impacts on land use, recreation, SUAs, and hazardous waste sites would be minor. Significant adverse impacts on forested land would result from permanent loss or conversions as well as the long recovery time in restored areas.

5.1.10 Visual Resources

AGDC identified 91 KOPs where Project facilities could potentially be visible from visually sensitive resources or landscapes. Of these, AGDC conducted field visits at 87 KOPs to assess current conditions and evaluate potential impacts on views at these sites, if any, from Project construction and operation. AGDC determined that additional analysis of 54 KOPs was not warranted based on the expected extent of visibility of the Project facilities, the anticipated scope of visual impacts, and the availability of other KOPs with more representative views to the Project area. AGDC prepared pre- and post-construction simulations for the remaining 33 KOPs.

The visual analysis relied on BLM's VRM system except in the DNPP, where the NPS's VRI system was applied with input from the NPS. Information on the expected extent of visual impacts at the KOPs is provided in table 4.10.2-1 and in appendix S; a summary of site-specific impacts and visual mitigation measures for select KOPs is provided in table 4.10.2-2. AGDC's analyses and simulations show that most KOPs would have no visual impacts from either construction or operation. For those KOPs that would be affected, impacts would mostly be moderate with implementation of the Project Revegetation Plan, though some would be long term to permanent due to the recovery time for vegetation. Moderate to high impacts would occur at KOPs with views of aboveground facilities or the maintained pipeline right-of-way in forested areas, which would create noticeable contrasts with existing conditions.

Prior to publication of the draft EIS, AGDC stated that six KOPs (i.e., KOPs 23, F, R, and 46 through 48) could not be surveyed due to lack of accessibility or weather conditions at the time of survey. In response to our recommendation in the draft EIS, AGDC filed updated information and photo simulations for KOPs F, 29, and 47, along with a new KOP (KOP 2019-1) near Mainline Pipeline MP 720.9. We determined that photo simulations from KOPs 23, R, 46, and 48 were not necessary to assess visual impacts from the Project based on the information provided and the simulations available for other KOPs.

We received comments from the NPS regarding visual impacts in the DNPP. Generally, Project construction and operation would have low to moderate impacts on KOPs in the DNPP. The general lack of high impacts would be due in part to the Project's position in the landscape; the Mainline Pipeline right-of-way would be parallel to and near the Parks Highway where topography, screening vegetation, and the highway would limit the contrast generated by the Project. The one high impact, which would occur at the trail leading to the Nenana River pedestrian bridge north of the DNPP entrance (KOP 2018-13) would potentially be significant, although the site has a low scenic inventory value and the impact rating would drop to moderate following construction. Project construction during the summer months could produce particulate matter and dust visible to DNPP visitors, but impacts would be minimized through implementation of the Project Fugitive Dust Control Plan.

Impacts on visual resources at Project facilities due to artificial lighting would be reduced through implementation of the Project Lighting Plan. We received a comment from the NPS that outdoor lighting at the Healy Compressor Station, which could be visible from portions of the DNPP, should follow International Dark-Sky Association Guidelines and have a color temperature of 3,000 Kelvins or less. AGDC would file a site-specific lighting plan for the Healy Compressor Station conforming to these guidelines or provide justification for why it cannot.

We have determined that visual impacts due to construction and operation of the GTP and Liquefaction Facilities would be low for residents and workers and moderate for recreational visitors, who have higher sensitivities to visual effects. For the Mainline Pipeline and associated facilities, including compressor stations, we have found that impacts would vary from low to high. Impacts would be greatest in the Brooks and Alaska Ranges, including the DNPP and Denali State Park, particularly for recreational visitors in these areas.

With implementation of the measures described above and AGDC's commitments, we have concluded that Projects effects on visual resources would be less than significant.

5.1.11 Socioeconomics

Project construction would increase population in the AOI due to worker influx (both in-state and out-of-state), but impacts would only last the length of construction (8 years) and would be minor in most areas due to the use of closed construction camps and rotation staffing for most workers. Non-local workers stationed at construction camps would be transported to and from pick-up stations in large communities such as Fairbanks, Anchorage, or Seattle at the start and end of their deployments. Additional population growth in urban areas—Anchorage, Fairbanks, Matanuska-Susitna Borough, and Kenai Peninsula Borough—could result from indirect and induced impacts, such as subcontractor and supplier hiring. During operation, population increases due to direct Project hires would be relatively small, but the increases from indirect and induced hires in urban areas could be substantial. In addition, direct, indirect, and induced population growth in the Kenai Peninsula Borough, particularly in communities around the LNG facilities, could be substantial. The total population in the Kenai Peninsula Borough is expected to increase by an estimated 3.5 percent over 2017 population levels.

In addition to the direct effects associated with increased employment, Project construction would result in economic benefits due to worker spending and purchases of materials, supplies, and services. These impacts would be somewhat reduced due to out-of-state sourcing of workers and supplies as well as the use of closed construction camps, but increased economic activity would result from this indirect and induced economic growth. Project construction would result in temporary, positive impacts on employment rates and wages. Project operation would result in similar impacts on a smaller scale in most of the Project area though increased income, and spending from permanent hires would be positive and significant in more rural areas, such as the Yukon-Koyukuk Census Area.

We received scoping comments about cost-of-living increases, particularly in remote areas, during Project construction. While inflation is possible, impacts would be mitigated by use of closed construction camps and supply procurement from major centers rather than local sources. We also received comments about hiring practices for Alaska residents. Although a large percentage of the Project workforce would be from out-of-state, ADOLWD is developing programs to train Alaskans for work on the Project, and AGDC has agreed to use local labor sources where feasible.

Project construction could temporarily affect commercial fisheries (mostly in Cook Inlet) by impeding access to fishing areas, increasing vessel traffic, or damaging gear. Impacts could be negligible to minor depending on the specific fishery, but construction would not likely affect overall harvest rates. To reduce impacts, AGDC would develop a Project Recreational and Commercial Fishing Construction and Mitigation Plan, coordinate its activities with industry sources, and notify commercial fishers and other mariners prior to starting construction. Additionally, AGDC would work with set-netters and the ADF&G to estimate measureable loss of harvest and provide compensation based on a methodology applied and provided by the ADF&G. Operational impacts on commercial fisheries due to the transit of LNG carriers would be negligible to minor.

Because most construction workers would live in closed construction camps, impacts on housing from worker influx are expected to be low. Vacancy rates in the Project area are generally sufficient to accommodate the relatively small number of workers who would live outside the camps as well as the expected increased demand for housing due to indirect and induced population growth. However, some impacts on housing availability and affordability could occur where demand exceeds supply. Adverse impacts on housing are not expected from the increase in residents and households during Project operation. The Project is not expected to affect residential or commercial property values.

Construction of the Project would result in temporary, but positive, impacts on local government revenues due to increased receipts from sales, property, excise, corporate income, and special use taxes. In most cases, the additional revenues would exceed any increased expenditures for government services due to in-migration (including indirect and induced), though there could be a lag between initial spending and increased revenues that would have a temporary to short-term adverse impact on local communities. Further, at least 25 percent of all mineral lease rentals, royalties, royalty sale proceeds, and federal mineral revenue sharing payments and bonuses received by the State of Alaska would be placed in the Alaska Permanent Fund.

Impacts on public services (schools, police, and fire protection) would generally be minor during Project construction and operation. Because most construction workers would live in self-contained construction camps, they would not be expected to bring their families to the Project area. Impacts on police and fire protection could be greater in some areas, particularly in areas where more substantial population increases would occur due to worker influx and indirect and induced growth, and areas where resources are limited or under staffed. This includes the communities of Nikiski, Kenai, and Soldotna where law enforcement services are currently under-staffed relative to the number of calls received. To

reduce impacts, we recommend that AGDC develop a Cost-Sharing Plan to identify the mechanisms for funding all Project-specific security/emergency management costs.

We evaluated potential Project effects on environmental justice populations and have concluded that certain impacts from constructing and operating the Project would disproportionately affect some environmental justice populations; however, these impacts would not be high and adverse. According to the HIA prepared by AGDC and based on our environmental justice analysis, we have determined that Project construction would have a medium adverse effect on the social determinates of health. This could disproportionately affect environmental justice populations due to anxiety and depression associated with potential impacts on subsistence.

The Project could have a negative effect on tourism and recreation during construction, particularly in areas such as the DNPP and nearby businesses where the Project could have low to high visual impacts in a number of areas and cause traffic delays and congestion near the park's entrance. AGDC would work closely with the Alaska Tourism Industry Association, Explore Fairbanks, Alaska Cruise Association, local chambers of commerce, and others to discuss the Project construction timeline to minimize impacts and tourist displacement. Following construction, we expect tourism would return to normal levels in most areas.

With implementation of the measures described above, AGDC's commitments, and our recommendations, we have concluded that most adverse impacts on socioeconomic conditions due to Project construction and operation would be minor to moderate and not significant. Positive impacts on state and local economies in most areas would be temporary but high during construction and minor but long term during operation.

5.1.12 Transportation

Project construction and operation would require the use of public roads and highways. Because existing traffic on most of these roads is light, significant impacts from the Project would not be expected. Traffic would be managed through implementation of the Project Traffic Mitigation Plan, which includes measures such as traffic control BMPs, site-specific management plans, and bus transportation for workers. AGDC would develop a traffic control plan for each crossing of a public road (to be approved by the ADOT&PF and borough or municipal authorities, as appropriate).

Construction near the Dalton and Parks Highways would require temporary lane closures, but these typically would occur at night. In addition, AGDC proposes intermittent closures of the Parks Highway near the DNPP for specific construction activities such as blasting. These closures, each lasting several hours, would occur outside the primary tourist season. Where the Mainline Pipeline crosses highways, it would be installed using conventional bore methods to avoid closures. Roads crossed by open-cut would require temporary closures, but AGDC would establish detours or keep one lane open for traffic.

Permanent and temporary access roads would cross or originate at private roads. For private roads near or crossed by the Project's access roads, AGDC would work with landowners and tenants to ensure continued access during construction.

AGDC would use the Alaska Railroad and rail spurs to transport fuel, pipe, equipment, and other materials to the Project area. Rail car demand for the Project would exceed available capacity, but AGDC would implement long-lead contracting to allow the Alaska Railroad to procure additional cars. Congestion delays would nonetheless result from increased demand, particularly in the summer tourist season. Where the Mainline Pipeline crosses the railroad, it would be installed using conventional bore methods, which would avoid closures.

Most of the equipment and materials used for Project construction would be shipped to Alaska on oceangoing vessels. AGDC would use multiple ports and construct a Marine Terminal MOF at Nikiski and a Mainline MOF near Beluga Landing for deliveries. The ports generally have available dock space and unused crane capacity. The Port of Alaska's ongoing modernization project could reduce available capacity at this port, which could require AGDC or potentially other shippers to increase the use of other ports. AGDC would minimize impacts by coordinating with port facilities to plan arrivals. Additionally, AGDC would develop and implement a Journey Management Plan to address traffic at the West Dock Causeway, and an Importation Guide and Sealift Entry and Exit Strategy to address customs and anchorage and loading needs at the Port of Dutch Harbor. The Journey Management Plan would be approved by BP Exploration (or if sold, its successor), which operates and controls the West Dock Causeway facility.

Equipment deliveries during construction would increase vessel traffic in navigation channels, resulting in temporary but minor to moderate impacts on other vessels. Construction in Cook Inlet would also affect navigation, but AGDC would coordinate its activities with the Coast Guard, commercial fishing vessels, and other users to reduce impacts.

Project operation would increase deep draft vessel traffic in Cook Inlet from the transit of LNG carriers to the Marine Terminal. A security zone would be established around LNG carriers, including those docked at the Marine Terminal, from which other vessels would be prohibited. Given existing traffic in Cook Inlet (which includes LNG carriers), impacts on other vessels would be incremental and minor. We also note that the Coast Guard concluded that Cook Inlet is suitable for LNG carrier activity.

The Project would use Anchorage International, Fairbanks International, Kenai Municipal, and Deadhorse Airports, along with smaller airstrips, to transport Project personnel. AGDC states that most interstate trips for workers to and from Alaska would be via chartered aircraft. Project demand for intrastate airline seats on commercial flights could displace other passengers, including tourists, resulting in moderate impacts on intrastate commercial air travel during construction.

Project-related passenger traffic at Anchorage International and Fairbanks International Airports would be small in comparison to typical passenger volumes at these airports. Construction of the Liquefaction Facilities would require as many as 10 daily charter flights at the Kenai Municipal Airport. This increase in passenger and flight volumes could likely be accommodated by the existing airport facilities, although in comments on the draft EIS, the City of Kenai said that increased security screening and/or airfield improvements could be necessary to accommodate the additional flight traffic. AGDC would consult with Kenai Municipal Airport representatives to identify solutions to reduce these and other potential impacts. Increased traffic and crowded terminal conditions at the Deadhorse Airport could have temporary but less than significant effects on travelers. The limited use of airstrips would be within the constraints of current design for these facilities.

With implementation of the measures described above, we have concluded that adverse impacts on transportation resources due to Project construction and operation would be less than significant.

5.1.13 Cultural Resources

AGDC conducted research, consulted with state and federal agencies, and performed field surveys to identify archaeological and architectural resources in the APE for direct effects, which is defined as the construction footprint for the Project. About 87 percent of the onshore portion of this area has been surveyed. AGDC would file additional reports for agency review as outstanding surveys are completed. AGDC has not started surveys for cultural resources in the APE for indirect effects, which is defined as 1-mile buffer around all Project facilities.

Field surveys to date identified 52 sites that are listed or eligible for listing in the NRHP with SHPO concurrence, including various segments of roads and trails, the Rosebud Knob Archaeological District, and the Gallagher Flint Station National Historic Landmark. Eligibility determinations for another 20 sites require additional information to evaluate the sites. AGDC has not identified how impacts on NRHP-eligible sites and a historic burial would be avoided or mitigated. Additionally, information is pending regarding Project effects on the Gallagher Flint Station National Historic Landmark.

Review of the shipwreck database and remote sensing data identified two sonar targets that could represent submerged cultural resource sites. Further investigation of these targets and anomalies would be undertaken by AGDC if seafloor disturbance should be required in these areas. Two anomalies would be within the construction footprint for the Marine Terminal and could be affected by construction. AGDC has not indicated whether these anomalies would be avoided.

We consulted with 38 federally recognized tribes to provide them an opportunity to comment on the Project. Several tribes requested information, expressed interest in the Section 106 review process, or commented on cultural or environmental impacts. FERC staff met with nine tribes who requested meetings as well as the CIRI, a regional corporation in which Cook Inlet tribes are shareholders. Additionally, AGDC sent letters to 19 tribes, provided copies of its Environmental Report to 6 tribes, and met with 2 tribes to discuss routing concerns and sites of tribal significance.

AGDC prepared a Project Plan for Unanticipated Discovery of Cultural Resources and Human Remains, which identifies procedures to be implemented if unanticipated cultural sites or human remains are found during construction. The plan also includes procedures for notifying consulting and other relevant parties, including Alaska Native tribes, in the event of a discovery. AGDC has not filed comments from the Alaska SHPO or BLM on the plan.

AGDC has not completed cultural resources surveys and/or NRHP evaluations. To ensure that FERC's responsibilities under the NHPA and its implementing regulations are met, the Commission executed a PA with the ACHP, Alaska SHPO, BLM, NPS, and consulting parties. The PA outlines the process for identifying historic properties and measures that will be taken to resolve adverse effects on historic properties that cannot be avoided. Therefore, we recommend that, as stipulated in the PA, AGDC should not begin construction until all outstanding archaeological and architectural surveys are complete; survey and evaluation reports and treatment or avoidance plans, if required, have been prepared and reviewed by the appropriate agencies; the ACHP is provided an opportunity to comment if historic properties would be adversely affected; and we provide written notice to proceed.

5.1.14 Subsistence

We evaluated potential impacts on subsistence resources and activities for 33 communities who live or harvest within 30 miles of the Project. We characterized subsistence practices for each community based on household surveys, subsistence mapping, interviews, workshops, and/or published data. We considered how changes in resource availability, cost and effort of harvest, access to and competition for resources, and harvest rates due to Project construction and operation would or could affect the subsistence practices of each community. Our evaluation was informed by the analyses of impacts on wildlife, fish, and vegetation as discussed in sections 4.5 through 4.8 and socioeconomic conditions as discussed in section 4.11.

We have determined that Project construction and operation have the potential to affect subsistence practices due to reductions in resource abundance and availability, reduced access to traditional harvest areas during construction activities, and temporary increased competition from non-local harvesters. Impacts would result from the loss or alteration of habitat; loss or displacement of wildlife, birds, or fish;

and increased access to remote areas along the pipeline rights-of-way and access roads. The extent of impacts would vary by community, resource type, and geographic region.

To reduce impacts on subsistence communities and users, AGDC has committed to implementing various measures, including:

- coordinating with local communities, including tribal councils, to identify locations and times where subsistence activities occur, and modify schedules to minimize work, particularly work that could reduce resource availability or user access (e.g., blasting, trenching), to the extent practicable, in those locations and times;
- employing community representatives to alert the Project about planned subsistence activities or key places to avoid, inform local residents about upcoming construction activities, and pass on concerns from locals regarding subsistence impacts on appropriate Project construction management personnel, who can then make efforts to minimize the cause of the concerns;
- reducing the potential for increased competition related to temporary outside workers, station all Project employees at construction camps, and prohibit hunting, fishing, and gathering activities by workers while stationed at camps;
- avoiding and minimizing impacts on subsistence whaling and marine mammal hunting by coordinating with individual whaling associations;
- requiring mandatory subsistence-related training for the Project workforce, including training in the protection of subsistence resources, lands, wildlife, and culturally valued places; and
- establishing a Local Subsistence Implementation Committee consisting of Project personnel, local subsistence representatives, and appropriate agency personnel.

Additionally, AGDC would file the Project Local Subsistence Implementation Plan and a signed Conflict Avoidance Agreement prepared in coordination with NMFS and the AEWC.

While Project construction and operation would result in short-term, long-term, and permanent impacts on subsistence resources and activities, we have concluded that the impacts would be less than significant with the implementation of the measures described above and AGDC's commitments.

The BLM prepared an analysis under Section 810 of ANILCA because a portion of the Project construction and operation would occur on BLM lands. The Section 810 analysis is included in appendix U.

5.1.15 Air Quality

Emissions from vehicles and equipment, marine and air traffic, waste incinerators, open burning, and fugitive dust would affect air quality during Project construction. AGDC would implement various measures to reduce construction emissions, including use of gasoline limited to 10-ppm sulfur and onshore diesel limited to 15-ppm sulfur, use of electric generators in compliance with NSPS Subpart IIII, use of rock crushers equipped with wet dust suppression controls, and implementation of a Project Open Burning Plan and Fugitive Dust Control Plan. Additionally, AGDC would obtain all applicable permits from ADEC to operate construction equipment.

A General Conformity applicability analysis is required for any part of a project occurring in nonattainment or maintenance areas for criteria pollutants. None of the direct Project emissions would occur within a nonattainment or maintenance area. The Project would generate a small amount of indirect emissions within the Fairbanks $PM_{2.5}$ Nonattainment Area, the Fairbanks Area CO Maintenance Area, the Anchorage CO Maintenance Area, and the Eagle River PM_{10} Maintenance Area from construction support and equipment transportation. The maximum annual emissions generated by the Project in these areas would not exceed General Conformity applicability thresholds. Therefore, a General Conformity Analysis is not required.

Based on AGDC's analysis of predicted air emissions, we have concluded that construction of the GTP, PTTL, PBTL, and Mainline Facilities would have temporary, minor impacts on air quality. Construction of the Liquefaction Facilities would have temporary, moderate impacts on air quality, but could contribute to significant impacts during construction Years 7 and 8 when combined with operational emissions, as discussed below.

Operation of the GTP, Mainline compressor stations and heater station, and Liquefaction Facilities would result in emissions of criteria pollutants, GHGs, and HAPs. Fugitive air emissions would also be generated by operation of the PTTL, PBTL, and Mainline Facilities, but the resulting impacts on air quality would be minor and limited to the area near the pipeline systems.

The GTP would be a PSD major source for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and GHGs; a Title V major source for CO, NO_X, VOC, PM_{10}, and $PM_{2.5}$; and a major source for HAPs. Under normal operating conditions, the GTP would not cause or contribute to an exceedance of the NAAQS/AAAQS for any criteria pollutant or exceed PSD incremental thresholds. Similarly, GTP operation would not cause or contribute to an exceedance of the NAAQS/AAAQS or PSD increment thresholds at nearby Class II nationally designated protected areas (ANWR and Gates of the Arctic NPP), but could contribute to visibility impacts at these sites due to haze or nitrogen deposition. Intermittent activities such as flaring could cause short-term impacts on regional haze and deposition. The full PSD impact analysis would be completed as part of the PSD permitting process.

The annual emissions for each of the compressor stations and heater station along the Mainline Pipeline would be below PSD major source thresholds, though each station would be a Title V major source and a minor source under ADEC's Minor NSR program. Operation of the compressor stations and heater station would not cause or contribute to an exceedance of the NAAQS/AAAQS for any criteria pollutant. An analysis of potential impacts on nearby Class I and II nationally designated protected areas found that the FLM-established visibility threshold and sulfur deposition threshold at the ANWR could be exceeded by emissions from the Galbraith Lake Compressor Station. FLM-established nitrogen deposition thresholds at multiple Class I and II areas—including ANWR, Gates of the Arctic NPP, Gates of the Arctic Preserve, Yukon Flats NWR, Kanuti NWR, DNPP, and Kenai NWR—could also be exceeded by operation of the stations.

The Liquefaction Facilities would be a PSD major source for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and GHGs; a Title V major source for CO, NO_X, VOC, PM_{10}, and $PM_{2.5}$; and a major source for HAPs. Under normal operating conditions, the Liquefaction Facilities would not cause or contribute to an exceedance of the NAAQS/AAAQS for any criteria pollutant or exceed PSD incremental thresholds. Additionally, the Liquefaction Facilities would not cause an exceedance of the NAAQS/AAAQS or PSD increments for nearby Class I or II nationally designated protected areas. Emissions would exceed the threshold for causing visibility impairment in the DNPP and for contributing to visibility impairment in Tuxedni NWR, Kenai Fjords National Park, and Lake Clark NPP. Emissions could also exceed sulfur and/or nitrogen deposition thresholds at the Tuxedni NWR, Kenai NWR, Lake Clark National Park, and

the DNPP. Activities such as flaring could cause short-term impacts on regional haze. The full PSD impact analysis would be completed as part of the PSD permitting process.

Based on comments from the NPS and in response to our recommendation in the draft EIS, AGDC filed revised air dispersion modeling for the Project facilities and all air emissions sources to identify and disclose impacts on units of the NPS or other federally protected areas. Without mitigation, emissions from the GTP and Liquefaction Facilities could have a significant impact on regional haze and acid deposition in some Class I and Class II nationally designated areas, including the DNPP. Additional mitigation measures could be implemented during the air permitting phase that would reduce these impacts.

Although AGDC has not provided a detailed construction and operation schedule, there is potential for portions of the Liquefaction Facilities to be placed in-service sequentially while construction is ongoing. Simultaneous construction, startup, and operational activities could occur in Years 7 and 8, which would result in overlapping emissions in excess of the modeled emissions for operation. Emissions in these years could exceed the NAAQS/AAAQS for PM_{10} and $PM_{2.5}$. AGDC would implement a Project Ambient Air Quality Monitoring Plan for monitoring PM_{10} and $PM_{2.5}$ emissions during simultaneous construction, startup, and operational activities. The plan identifies protocols for managing any exceedances of the NAAQS/AAAQS observed during monitoring.

Based on the above discussion, we have concluded that adverse impacts on air quality due to normal Project operation would generally be minor to moderate. Emissions could exceed nitrogen and sulfur deposition thresholds and visibility thresholds at nearby Class I and II nationally designated protected areas, but additional mitigation measures could be implemented during the air permitting phase that would reduce these impacts. During the years of simultaneous construction, startup, and operational activities at the Liquefaction Facilities, emissions could exceed the NAAQS/AAAQS for PM_{10} and $PM_{2.5}$. As noted above, AGDC would implement a Project Ambient Air Quality Monitoring Plan to ensure air quality standards would not be exceeded. Activities such as flaring could result in short-term significant effects on air quality.

5.1.16 Noise

Noise from construction of the Mainline Pipeline would last from about 6 to 12 weeks at any point along the route, while noise from construction of aboveground facilities would last for months to years at each site. Noise levels would vary depending on the specific activities occurring in areas with active construction. Most noise-producing activities would take place in daylight hours, with the exception of pile driving, dredging, and DMT operations, which could occur 24 hours per day.

For the Mainline Pipeline, DMT crossings are planned for the Yukon, Tanana, Chulitna, Middle Fork Koyukuk, and Deshka Rivers. Noise due to DMT activities at NSAs within 1 mile of the entry or exit sites at the Yukon, Tanana, and Chulitna River crossings would be perceptible, but less than our recommended sound level of 55 dBA L_{dn}. No NSAs are present within 1 mile of the entry or exit sites for the DMT crossings of the Middle Fork Koyukuk and Deshka Rivers.

As noted in section 5.1.3.3, AGDC has committed to incorporating the use of the DMT continuation methodology for the shoreline crossings at Beluga Landing and Suneva Lake, if feasible. If this should occur, we recommend that AGDC complete a noise impact analysis for any NSAs within 1 mile of these sites, and provide noise mitigation if the noise estimates for the DMT continuation activities are greater than 55 dBA L_{dn} at any of the nearby NSAs.

Noise due to DMT activities has the potential to affect sound levels at nearby KOPs, which could affect user experiences at these sites. Noise from the DMT crossings of the Yukon and Tanana Rivers would be perceptible at nearby KOPs, but would not noticeably increase existing sound levels at these sites.

Noise from the DMT crossing of the Chulitna River would be perceptible at KOPs O and P (i.e., the Upper and Lower Troublesome Creek Trailheads), and would likely increase existing sound levels at these sites. No KOPs are present near the proposed DMT crossings of the Middle Fork Koyukuk and Deshka Rivers.

NSAs are present within 1 mile of the Coldfoot and Healy Compressor Stations and the Liquefaction Facilities. Noise due to construction of the Coldfoot Compressor Station would be perceptible at the nearest NSA, but within our recommended sound level of 55 dBA L_{dn}. Noise due to construction of the Healy Compressor Station would be perceptible at the nearest NSA and exceed our recommended sound level during the day, with L_{dn} noise levels increasing by 10.0 dB. Based on comments received from the NPS, we determined the L_{50} noise level—used by the NPS for development management policies—in our analysis of construction noise impacts for the Healy Compressor Station; the L_{50} daytime noise levels would increase by 16.6 dB. Based on these values, we have determined that impacts would be moderate to high during construction at the Healy Compressor Station.

Noise due to construction of the Liquefaction Facilities would be perceptible and exceed our recommended sound level at three NSAs, with noise levels increasing by 15.7 to 26.5 dB at these sites. Construction activities at the Liquefaction Facilities would also increase noise levels at KOP 54 (Mt. Redoubt Church) by 24.1 to 26.5 dBA, which would be noticeable. To minimize impacts, AGDC would file a Noise Mitigation Plan for the Liquefaction Facilities, including measures to reduce construction noise by at least 10 dB at affected NSAs, monitoring of noise during construction, and procedures for resolving complaints regarding noise.

Construction of the Mainline Pipeline and aboveground facilities (including the development of material extraction sites) would require blasting in areas of shallow bedrock or permafrost. Noise impacts on NSAs from these activities would be limited due to the temporary nature and short duration of blasting. Noise from blasting could affect subsistence resources in two areas, but impacts would be minimized by restricting blasting during sensitive wildlife periods, using blasting mats or pads to reduce noise, and monitoring nearby nests and denning sites during blasting.

Construction activities in Prudhoe Bay for the GTP and Cook Inlet for the Mainline Pipeline and Liquefaction Facilities would produce underwater noise. Impacts on marine mammals and fish due to underwater noise are discussed in sections 5.1.6 and 5.1.7, respectively.

Noise due to operation of the Coldfoot and Healy Compressor Stations would be perceptible at the nearest NSAs, but within our recommended sound level of 55 dBA L_{dn}. Noise due to operation of the Coldfoot Compressor Station would also be perceptible at the nearby Arctic Interagency Visitor Center, but within our recommended sound level of 55 dBA L_{dn}. To ensure that noise levels due to operation of the Coldfoot and Healy Compressor Stations would comply with FERC's sound level requirement, AGDC would file a noise survey no later than 60 days after placing each compressor station in service. Additionally, the NPS commented that noise levels at the Healy Compressor Station would need to comply with a standard of 40 dBA L_{eq} at the DNPP border per the conditions of the DNPP Backcountry Management Plan.

Noise due to operation of the Liquefaction Facilities would be within our recommended sound level of 55 dBA L_{dn} at nearby NSAs, but the noise would be perceptible, with sound intensity doubling at two NSAs. Noise from operation of the Liquefaction Facilities at KOP 54 (Mt. Redoubt Church) would be between 47 and 53 dBA L_{dn}, which is similar to existing background conditions at this site. To ensure that noise levels due to operation of the Liquefaction Facilities would be below our recommended threshold, AGDC would file noise surveys no later than 60 days after placing each liquefaction train in service and no later than 60 days after placing the entire Liquefaction Facilities into service. AGDC would implement any additional controls needed to reduce noise levels at the nearest NSAs to less than 55 dBA L_{dn} within 60 days.

AGDC evaluated the potential for operations at the Coldfoot and Healy Compressor Stations and Liquefaction Facilities to result in perceptible vibration at nearby NSAs. Based on AGDC's analysis, we have concluded that any potential vibration associated with operation of these facilities would not be perceptible at nearby NSAs with installed controls.

Blowdowns would occur at compressor stations and MLVs as part of normal pipeline safety operations. AGDC would install silencers on blowdown equipment at each compressor station to ensure that noise associated with blowdowns would be less than 55 dBA L_{dn} at nearby NSAs. MLVs with NSAs greater than 1 mile from the site would be outfitted with standard vent mufflers, which would reduce noise from blowdown events at the nearest NSAs to 64 dBA L_{eq} or less. Nighttime blowdowns at these sites could result in perceptible noise at NSAs, but this would be infrequent and impacts would be temporary. AGDC would install increased performance vent silencers at three MLVs (27, 28, and 29) where NSAs would be within 0.5 mile to reduce the noise from blowdowns at these sites.

Operation of the ground-level and elevated low-pressure flares at the Liquefaction Facilities would generate noise between 45 and 78 dBA L_{dn} at durations ranging from less than 1 hour to 36 hours. To minimize impacts, AGDC would schedule most flare events in coordination with the local community and outside potentially sensitive timeframes. Because of the intensity and potential duration of these flare events and the associated noise levels, AGDC would file a Flare Noise Mitigation Plan that addresses mitigation of noise impacts due to flaring, including procedures for contacting the local community and scheduling flaring events.

During Project construction and operation, air traffic at regional airports and airstrips would increase to transport workers, equipment, and supplies. Additionally, 48 helipads would be built along the Mainline Pipeline to support construction, 28 of which would be retained for operation. The increased air traffic and use of the helipads would result in periodic and temporary increases in noise.

Most noise impacts during construction would be temporary and minor. Construction noise would have a minor to moderate effect on NSAs or KOPs at three locations where the Mainline Pipeline is installed by DMT and at the Coldfoot Compressor Station, and a moderate to high effect on an NSA at the Healy Compressor Station. Construction of the Liquefaction Facilities would have a moderate to significant effect on noise at NSAs and a KOP, but AGDC would file a mitigation plan to reduce these impacts. Project operation would have permanent impacts on ambient noise conditions at aboveground facilities. The direct effects on noise levels in the Project area would be minor to moderate during normal facility operation, with the exception of operational noise associated with the Liquefaction Facilities at the two nearest NSAs. The sound intensities at NSAs 1 and 2 would likely double due to facility operation; however, AGDC would conduct noise surveys and implement additional controls as needed to meet FERC's noise criteria.

5.1.17 Health

An HIA for the Project is provided in appendix V. The methodology used to rate health impacts followed ADHSS guidelines (2015b) for HIAs. These guidelines present the methodology for evaluating eight HECs by assigning potential impacts a rating of low, medium, high, or very high based on the potential severity of the impact and the likelihood that an impact would occur. Health severity is evaluated using a numeric scale of 1 to 4 based on the duration, extent, frequency, and magnitude of the health outcome. The likelihood of the impact is then determined according to ADHSS' likelihood scale (ADHSS, 2015b). Positive impacts as well as adverse impacts are assessed using this methodology.

For Project construction, the results of the HIA rated one HEC as high adverse (infectious diseases); three HECs as medium adverse (social determinants of health; accidents and injuries; and food, nutrition, and subsistence activity); and all other HECs as low adverse. For Project operation, the HIA rated

three HECs as medium adverse (social determinants of health; accidents and injuries; and infectious disease); and all other HECs as low adverse. Potential positive effects were also identified, including increased employment opportunities and household incomes and future improvements to air quality in the Fairbanks area through conversion from other fuels to natural gas. Potential mitigation measures identified by AGDC for adverse impacts include worker segregation, community engagement, implementation of health education programs, and training and safety planning.

5.1.18 Reliability and Safety

We evaluated the safety of the Gas Treatment, Mainline, and Liquefaction Facilities. As part of our evaluation, we performed a technical review of the preliminary engineering design to ensure that sufficient layers of protection would be included at each facility to mitigate the potential for an incident that could affect public safety. PHMSA and the Coast Guard—who are participating as cooperating agencies and have oversight responsibilities for federal regulations regarding various aspects of facility siting, design, construction, and/or operation—assisted with our review.

PHMSA has authority to enforce safety regulations and design standards for LNG terminals as well as safety regulations and standards related to the design, construction, and operation of natural gas pipelines. On February 4, 2020, PHMSA provided an LOD on the Project's compliance with 49 CFR 193 Subpart B for consideration by the Commission in its decision to authorize or deny the Project. If the Project is authorized and constructed, it would be subject to PHMSA's inspection and enforcement program. The final determination of whether the Project complies with the requirements of 49 CFR 193 would be made by PHMSA staff.

The Coast Guard exercises regulatory authority over LNG facilities regarding the safety and security of port areas and navigable waterways. The Coast Guard is responsible for matters related to navigation safety, vessel engineering and safety standards, and the safety of facilities or equipment in or adjacent to navigable waters. If the Project is approved, constructed, and operated, the LNG carrier loading facilities and appurtenances between LNG carriers and the last valve immediately before the LNG storage tanks would need to comply with applicable sections of Coast Guard regulations. As discussed in section 1.2.5, the Coast Guard additionally is responsible for issuing an LOR as to the suitability of the waterway for LNG marine traffic following a WSA. The Coast Guard issued its LOR on August 17, 2016 concluding that Cook Inlet is a suitable waterway for LNG marine traffic.

With one exception, our review concluded that the Project design would provide acceptable layers of protection that would reduce the risk of a potentially hazardous scenario from developing into an event that could affect the off-site public with the incorporation of the identified mitigation measures and our recommendations. We are unable to conclude that high pressure piping at the GTP would not pose a significant safety impact on persons off site of the GTP process facilities. We recommend that ERPs for potential large ruptures at the GTP be coordinated with the adjacent PBU CGF plant and include consideration of impacts on the GTP operator camp site. To demonstrate potential safety impacts on persons off site of the GTP process facilities and inform the ERPs, we also recommend that AGDC provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure pipe systems at the GTP.

We received comments from the BLM concerning the geological risks applicable to the Mainline Pipeline. These comments included requests for information on ground movement and activity at each fault crossing, design measures at each fault crossing to mitigate seismic risk, and design measures along the pipeline to withstand subsidence and permafrost thaw. The Mainline Pipeline would be designed to withstand exposure to seismic activity and surface fault offsets at pipeline crossing locations of active earthquake fault zones. Prior to construction, AGDC would conduct detailed studies of the crossings to

determine if some faults could be crossed by burying the pipeline in a well-drained berm configuration above natural grade constructed with uniform-graded granular material or crushed rock, or with loose, well-drained granular fill. The Mainline Pipeline design would also account for the potential for frost-heaving and thaw settlement. AGDC would file final fault crossing designs and plans for the Northern Foothills, Stampede-Little Panguingue Creek, Healy Creek, Healy, Park Road, Denali, and Castle Mountain faults and the Beluga River and North Cook Inlet-SRS anticlines.

We received scoping comments about the crossings of TAPS and concerns regarding the close proximity of Project facilities to TAPS. The Mainline Pipeline would meet design and safety requirements at all TAPS crossing locations. A pipeline failure consequence analysis found that a failure of the Mainline Pipeline where it approaches within 200 feet of, but does not cross, TAPS would not result in exposure of TAPS to the hazard. For crossing locations, mitigation measures such as heavy wall pipe and/or crack arrestor location optimization would be used to reduce overall risk.

As discussed in section 4.3.3, AGDC does not propose to backfill the shore to land crossings associated with the Mainline Pipeline or bury the pipe in Cook Inlet. AGDC would coat the offshore pipeline with 3.5 inches of concrete coating for stability and impact and abrasion protection. PHMSA has indicated it is satisfied that AGDC would mitigate any future pipeline safety conditions consistent with 49 CFR 192.327(f)(2) (see section 5.1.3.3).

A Special Permit, as specified in 49 CFR 190.341, is an order from PHMSA that waives compliance with one or more of the pipeline safety requirements listed in 49 CFR 192 for a technically sound alternative. AGDC applied for Special Permits from PHMSA for strain-based design, multi-layer coating, MLV spacing, and crack arrestor spacing for the Mainline Facilities, as discussed in section 4.18.10. After a public notice and comment period, PHMSA determined that the Special Permit applications complied with the requirements of 49 CFR 190.341 and that waivers of the relevant regulations or standards are not inconsistent with pipeline safety. Consequently, PHMSA granted AGDC the four Special Permits in September 2019. AGDC has also submitted a fifth Special Permit application for the use of a pipe-in-pipe design at the Liquefaction Facilities that will go through the same review process.

Based on our review, we recommend that the Commission incorporate into any authorization for the Project, a number of mitigation measures that would ensure continuous oversight prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the proposed facilities, to enhance the reliability and safety of the facilities and mitigate the risk of impact on the public. With the incorporation of these mitigation measures and oversight, FERC staff have concluded that AGDC's Project design would include acceptable layers of protection or safeguards that would reduce the risk of a potentially hazardous scenario from developing into an event that could affect the off-site public.

There is also ongoing coordination between FERC staff and the DOD in accordance with the Energy Policy Act of 2005, which requires FERC to coordinate and consult with the DOD on the siting, construction, expansion, and operation of LNG terminals that would affect the military. As discussed in section 5.1.9, an MLV and associated helipad could interfere with the Clear AFS, while structures at the Liquefaction Facilities could interfere with a radar facility in the Anchorage, Alaska vicinity. As noted in section 5.1.9, AGDC has committed to relocating the MLV and helipad, and we recommend that AGDC develop a relocation plan in coordination with Clear AFS representatives to ensure impacts would be avoided. With regard to the Liquefaction Facilities, the DOD found that the Project would not adversely affect DOD missions in the Anchorage, Alaska vicinity based on a preliminary review. We will continue to work with DOD staff to confirm that the Mainline and Liquefaction Facilities would not adversely affect DOD operations at the Clear AFS and in the Anchorage, Alaska vicinity.

5.1.19 Cumulative Impacts

We evaluated the Project's potential cumulative impacts combined with other recent, current, or reasonably foreseeable actions. Our analysis included impacts from non-jurisdictional facilities as well as energy, transportation, mining, marine, and other projects. We have concluded that cumulative impacts would be unlikely or minor for most resources, including geology; soils; groundwater; surface and marine waters; most vegetation types; terrestrial wildlife; aquatic species; threatened, endangered, and special status species; land use, recreation, and SUAs; most socioeconomic indicators; transportation; cultural resources; air quality; most noise; and public health and safety.

Because the Project would result in substantial long-term to permanent impacts on permafrost, wetlands, forest, caribou (Central Artic Herds), some noise, and socioeconomics (population), and because other projects in the study area would similarly affect these resources, we found that cumulative impacts would be significant. Permanent indirect economic benefits from the Project could be a positive significant cumulative impact when combined with other development projects. Cumulative visual impacts could result from future actions near the Mainline Pipeline, or from a cluster of projects surrounding the Liquefaction Facility at Nikiski. In particular, the Usibelli Coal Mine and Eva Creek Wind Projects could contribute to Project impacts on visual resources in the DNPP, but the cumulative visual impacts would not be significant with proposed Project mitigation. As discussed in section 4.19.4, because we cannot assess the Project's incremental physical impacts due to climate change, we cannot determine whether the Project's contribution to cumulative impacts on climate change would be significant.

5.1.20 Alternatives

We evaluated several alternatives to the Project and its various components. Under the no action alternative, the impacts described in this EIS would not occur, but the purpose and need of the Project, including commercialization of natural gas supplies on the North Slope, would not be met. In response, AGDC or other applicants would likely develop a new project to transport gas from the North Slope for export and in-state delivery. Given the infrastructure needed to transport the same gas volumes, environmental impacts would likely be comparable to those of the Project. Therefore, we have concluded that the no action alternation provides no significant environmental advantage over the Project.

We assessed the potential use of existing, proposed, or modified natural gas infrastructure to meet the same objectives as the Project while providing a significant environmental advantage. We evaluated expansion of the existing Kenai LNG terminal, proposed ASAP Project, and existing and proposed LNG export terminals in the U.S. and Canada. These alternatives would require design changes or new infrastructure that would result in similar or greater impacts than the Project to meet the Project objectives. We also considered and rejected an export subsea pipeline from Alaska to Asia, which would be technically and economically infeasible. For these reasons, we have concluded that none of the system alternatives would be preferable to the Project.

We examined four alternative sites for the GTP, but found that none would reduce wetland impacts or provide other significant environmental advantages over the Project. We also considered if the work pad footprints at the GTP could be modified to reduce wetland impacts, but no technically feasible alternative configurations were identified. Similarly, we assessed use of existing roads, seasonal use of ice roads, or alternative access routes to reduce wetland impacts. We found that seasonal ice roads would be infeasible given the need for year-round access, and no alternative routes that would significantly reduce impacts were identified.

We evaluated alternative delivery systems to transport modules to the GTP, including highway transportation and on-site fabrication. Overland transportation would exceed load limits and require major

modifications of the Dalton Highway, including bridges, resulting in substantial impacts. Air emissions would also be greater with the use of overland transportation. On-site fabrication could eliminate or reduce the scope of the required dock and highway improvements, but a larger work site would be needed for assembly, and road transport of component parts to the North Slope would result in greater air impacts. Therefore, we have concluded that neither of these alternatives would provide a significant environmental advantage over the Project.

We evaluated five alternative docking stations for module delivery to the GTP. Each of these would increase the length of access roads, require more dredging, or be further from the GTP than the proposed site. We also tried to identify alternative sites at the West Dock Causeway that require less disturbance of marine habitat, but each potential site would require dredging or infrastructure upgrades. Therefore, we have concluded that none of these alternative docking stations or sites would provide a significant environmental advantage over the Project.

We evaluated the use of two existing gravel mines, the Put-23 and Pit-203 sites, as an alternative to the proposed gravel mine on the North Slope. We have determined that use of the existing mines would result in wetland impacts similar to the proposed mine site because the existing sites would need to be expanded to accommodate Project needs, and a new reservoir would still be required for water supply. Use of the existing mines additionally would result in greater emissions than the proposed mine due to longer haul distances to the Gas Treatment Facilities. Therefore, we have concluded that use of the existing mines would not provide a significant environmental advantage over the Project.

We evaluated alternatives to construction of a new water reservoir on the North Slope, including use of the North Slope Borough's water treatment facility, an existing SWTP, and existing lakes and mine sites. We have determined that these alternatives would result in similar environmental impacts as the Project, would not be technically practical, and/or would not provide a sufficient, reliable water supply.

We evaluated alternative routes for the Mainline Pipeline, including the Cook Inlet East and Cook Inlet West Alternatives. We received numerous comments from the public regarding the Cook Inlet West Alternative. Our analysis of the alternative routes considered area of impact, constructability, land uses affected, and wildlife and aquatic impacts. We found that neither the Cook Inlet East Alternative nor the Cook Inlet West Alternative would provide a significant environmental advantage over the Project as proposed.

In the draft EIS, we evaluated an alternative route through the DNPP (the Denali Alternative) and compared it to the then-proposed route for the Mainline Pipeline. After the publication of the draft EIS, on August 16, 2019, AGDC adopted the Denali Alternative as the proposed Project route. Accordingly, at the request of cooperating agencies, we revised our analysis to compare the currently proposed route—inclusive of the Denali Alternative—with suggested alternatives that include the route previously proposed by AGDC, which we refer to as the Denali Avoidance Alternative. We found that the selection of either the proposed route or the Denali Avoidance Alternative would be acceptable, without significant environmental advantages from either. Therefore, we have concluded that the Denali Avoidance Alternative would not provide a significant environmental advantage over the proposed route.

We evaluated an alternative route for the Mainline Pipeline that passes closer to Fairbanks. We received comments from the USFWS that the Fairbanks Alternative could affect less quality habitat than the proposed route and would also avoid the Minto Flats SGR. On balance, however, we have concluded that impacts on land, water, and other resources would be greater for the Fairbanks Alternative than the proposed route. Therefore, we have concluded that the Fairbanks Alternative would not provide a significant environmental advantage over the Project.

For Mainline compressor stations, we evaluated electric driven compressors as an alternative to gas driven compressors. We found that this would provide no environmental advantage over the Project because electricity would be sourced from coal- or oil-fired plants and construction of new electrical lines would be required.

We evaluated the alternative of building the Mainline Pipeline aboveground on the Arctic Coastal Plain to reduce impacts on permafrost. We found that this alternative is not technically practical due to reliability risks from condensation of the gas stream in the pipeline. We also found that the small reduction in permafrost impacts would not be a significant environmental advantage over the Project.

We evaluated alternative sites, with their associated pipeline routes, for the Liquefaction Facilities in the Port of Valdez, Resurrection Bay, and Cook Inlet. We received numerous comments on our analysis of alternatives from the City of Valdez, MSB, and other stakeholders. Our review of the alternatives considered parcel size and availability, waterfront access, proximity to existing infrastructure, ice conditions, geological hazards, land uses, and environmental impacts, including wildlife and threatened and endangered species. We also considered alternative sites for dredged material disposal and the Mainline MOF in Cook Inlet. Based on our analysis, we found that none of the alternatives would provide a significant environmental advantage over the Project.

5.2 FERC STAFF'S RECOMMENDED MITIGATION

If the Commission authorizes the Project, we recommend that the following measures be included as specific conditions in the Commission's Order. We have determined that these measures would further mitigate the environmental impacts associated with Project construction and operation as proposed. The section number in parentheses at the end of a condition corresponds to the section number in which the measure and related resource impact analysis appears in the EIS.

1. AGDC shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff information requests) and as identified in the EIS, unless modified by the Order. AGDC must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;

    b. justify each modification relative to site-specific conditions;

    c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

    d. receive approval in writing from the Director of the OEP **before using that modification**.

2. For the GTP and Liquefaction Facilities, the Director of the OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order and take whatever steps are necessary to ensure the protection of life, health, property, and the environment during Project construction and operation. This authority shall allow:

    a. the modification of conditions of the Order;

    b. stop-work authority and authority to cease operation; and

c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

3. For the pipeline facilities (e.g., Mainline Facilities, PBTL, and PTTL), the Director of the OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order, and take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the Project. This authority shall allow:

   a. the modification of conditions of the Order;

   b. stop-work authority; and

   c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from Project construction and operation.

4. **Prior to any construction**, AGDC shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, EIs, and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

5. The authorized facility locations, including the DMT continuation methodology at the Cook Inlet shoreline crossing, if implemented, and the revisions required in conditions 19 and 28, shall be as shown in the EIS, as supplemented by filed alignment sheets. **As soon as they are available, and before the start of construction**, AGDC shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000, with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

6. AGDC shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of the OEP **before construction in or near that area**.

   This requirement does not apply to extra workspace allowed by FERC's Plan and/or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or other special status species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **At least 60 days before construction begins**, AGDC shall file an Implementation Plan with the Secretary for the review and written approval of the Director of the OEP. AGDC must file revisions to the plan as schedules change. The plan shall identify:

a. how AGDC will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff information requests and FERC staff recommendations in the draft EIS agreed to by AGDC [see appendix X]) and as identified in the EIS and required by the Order;

b. how AGDC will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

c. the number of EIs assigned per spread and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;

e. the location and dates of the environmental compliance training and instructions AGDC will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel change), with the opportunity for OEP staff to participate in the training sessions;

f. the company personnel (if known) and specific portion of AGDC's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) AGDC will follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar Project scheduling diagram), and dates for:

i. the completion of all required surveys and reports;
ii. the environmental compliance training of on-site personnel;
iii. the start of construction; and
iv. the start and completion of restoration.

8. AGDC shall employ a team of EIs per construction spread (the number per spread to be determined by the Director of the OEP). The EIs shall be:

   a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or other authorizing documents;

   b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 7 above) and any other authorizing document;

   c. empowered to order correction of acts that violate the environmental conditions of the Order and any other authorizing document;

   d. a full-time position, separate from all other activity inspectors;

   e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

   f. responsible for maintaining status reports.

9. Beginning with the filing of its Implementation Plan, AGDC shall file updated status reports with the Secretary on a **monthly** basis for the aboveground facilities (GTP, Liquefaction Facilities, Mainline Pipeline compressor stations) and on a **weekly** basis during active construction of the pipeline facilities (PTTL, PBTL, and Mainline Pipeline) until all construction and restoration activities are complete. Problems of a significant magnitude shall be reported to FERC **within 24 hours.** On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. an update on AGDC's efforts to obtain the necessary federal authorizations;

   b. project schedule, including the construction status of each spread and facility, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;

   c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EIs during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;

   e. the effectiveness of all corrective and remedial actions implemented;

   f. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and

   g. copies of any correspondence received by AGDC from other federal, state, or local permitting agencies concerning instances of noncompliance, and AGDC's response.

10. AGDC shall employ a special inspector during construction of the Liquefaction Facilities, and a copy of the special inspector's reports shall be included in the **monthly** status reports filed with the Secretary (see condition 9 above). The special inspector shall be responsible for:

    a. observing the construction of the Project facilities to be certain it conforms to the design drawings and specifications;

    b. furnishing inspection reports to the engineer- or architect-of-record and other designated persons. All discrepancies shall be brought to the immediate attention of the contractor for correction, and then if uncorrected, to the engineer- or architect-of-record; and

    c. submitting a final signed report stating whether the work requiring special inspection was, to the best of his/her knowledge, in conformance with the approved plans and specifications and the applicable workmanship provisions.

11. AGDC shall develop and implement an environmental complaint resolution procedure, and file such procedure with the Secretary, for the review and written approval of the Director of the OEP. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during Project construction and right-of-way restoration. **Prior to construction**, AGDC shall mail the complaint procedures to each landowner whose property will be crossed by the Project.

    a. In its letter to affected landowners, AGDC shall:

        i. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

        ii. instruct the landowners that if they are not satisfied with the response, they should call AGDC's Hotline; the letter should indicate how soon to expect a response; and

        iii. instruct the landowners that if they are still not satisfied with the response from AGDC's Hotline, they should contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

    b. In addition, AGDC shall include in its **monthly** and **weekly** status reports (see condition 9 above) a copy of a table that contains the following information for each problem/concern:

        i. the identity of the caller and date of the call;

        ii. the location by milepost and identification number from the authorized alignment sheet(s) of the affected property;

        iii. a description of the problem/concern; and

        iv. an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

12. AGDC must receive written authorization from the Director of the OEP **before commencing construction of any Project facilities.** To obtain such authorization, AGDC must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof).

13. AGDC must receive written authorization from the Director of the OEP **prior to introducing hazardous fluids into the Project facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

14. AGDC must receive written authorization from the Director of the OEP **before placing the Gas Treatment Facilities and Liquefaction Facilities into service**. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with FERC approval and can be expected to operate safely as designed, and that the rehabilitation and restoration of areas affected by the Project are proceeding satisfactorily.

15. AGDC must receive written authorization from the Director of the OEP **before placing the Mainline Facilities into service**. Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the Project are proceeding satisfactorily.

16. **Within 30 days of placing the authorized facilities in service**, AGDC shall file an affirmative statement with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed and installed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

    b. identifying which of the conditions in the Order AGDC has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

17. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, a Project-wide ARD/ML Management Plan that includes details for surface and groundwater monitoring in areas of moderate ARD/ML potential. (*section 4.1.3.10*)

18. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary a revised Feasibility Crossing Study that provides updated site-specific geotechnical information for the Deshka River with additional borings conducted at the proposed crossing location. If the results of the study indicate that a modification to the crossing location or method is necessary, AGDC shall file, for the review and written approval of the Director of the OEP, a revised crossing plan for the Deshka River. (*section 4.1.5.5*)

19. **Prior to construction of the Mainline Facilities**, AGDC shall review areas proposed for Mode 4 construction in the summer and confirm that winter construction will not be feasible in low slope areas (0 to 2 percent). Additionally, AGDC shall use timber/synthetic mats in place of granular fill in wetlands proposed for Mode 4 construction on slopes of 0 to 2 percent and in uplands proposed for Mode 4 summer construction on slopes of 0 to 2 percent that are underlain by thaw-stable permafrost. AGDC shall prepare revised alignment sheets and resource impact tables adopting changes to Mode 4 areas reflecting the increase in winter construction segments and the replacement of granular fill with timber/synthetic mats. **Prior to construction of the Mainline Facilities**, AGDC shall file the revised sheets and resource impact tables with the Secretary for the review and written approval of the Director of the OEP. *(section 4.2.4)*

20. **Prior to placement of any granular fill**, AGDC shall conduct aggregate testing using sieve analysis to select granular fill with at least 20-percent fines for the surface layer used on all construction workspace, including Mode 4 work pads, temporary aboveground facilities, temporary access roads, etc. AGDC shall include the results of the aggregate tests in its construction status reports filed with the Commission. *(section 4.2.4)*

21. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, an updated assessment of piping erosion potential between MPs 536.1 and 544.3 using the same methodology used for the rest of the Mainline Pipeline (Onshore Geohazard Assessment Methodology and Results summary). If any new areas of piping erosion potential are identified, AGDC shall implement the same mitigation measures that will be implemented for other areas with the potential for piping erosion, including the use of subdrains to control meltwater and groundwater recharge as well as prevent the development of a hydraulic gradient within the erodible soils underneath the pipe. *(section 4.2.5)*

22. **Prior to construction**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, an updated Unanticipated Contamination Discovery Plan that indicates the measures that will be taken in the event that contaminated sediments are discovered in marine water environments, including the appropriate agency notification requirements. Additionally, this plan shall be updated to include notification to the NPS in the event of an unanticipated discovery of contamination on NPS property. *(section 4.2.6)*

23. **During construction of the Mainline Facilities**, AGDC shall restrict the placement of granular fill, spoil, or other materials in waterbodies within the following workspaces:

    a. pipe storage yards "Chandalar PSY" in the Unnamed Tributary to North Fork Chandalar River near MP 174.6 and "65-9-078-2 FP" in the Unnamed Tributary to North Fork Ray River near MP 337.0; and

    b. disposal sites "WD-043" in Ninety-Six Creek near MP 251.8 and "WD-050" in the Unnamed Tributary to Prospect Creek near MP 281.5.

    In the event that the use of fill is unavoidable, then AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, site-specific justifications and measures it will use to preserve water flow and quality within the affected streams. (*section 4.3.2.4*)

24. **Prior to construction**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, revised shutdown distances for all underwater noise generating activities (i.e., pile driving [impact, vibratory, and all pile types], dredging, screeding, anchor handling, Mainline Pipeline shoreline installation, and Marine Terminal MOF removal). For the revised shutdown distances, AGDC shall establish:

    a. shutdown zones for Level A harassment for all marine mammals based on the modeled distances in appendix L-1, tables L-1.1-4, L-1.1-5, L-1.1-9, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (pile driving activities shall stop until the animal moves out of the shutdown injury zone);

    b. shutdown zones for Level B harassment for Cook Inlet beluga whales based on the modeled distances in appendix L-1, tables L-1.1-10, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (pile driving and dredging activities shall stop until the animal moves out of the shutdown harassment zone); and

c. harassment zones for Level B harassment for all marine mammals (except Cook Inlet beluga whales) based on the modeled distances in appendix L-1, tables L-1.1-6, L-1.1-10, L-1.1-11, L-1.1-12, and L-1.1-13 of the EIS (activity noise levels shall be lowered when animals enter these zones, until they leave the area, if possible).

Alternatively, AGDC may commit to conducting a Sound Source Verification **during construction** that will establish appropriate shutdown and harassment zones based on observed underwater noise levels. *(section 4.6.3.2)*

25. **Prior to construction**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, a revised PSO deployment plan that includes the following:

a. for pile driving activities in Cook Inlet and Prudhoe Bay, AGDC shall station at least one PSO at-sea near the edge of the shutdown zone (for Level A) and one PSO stationed at-sea or on land near the edge of the harassment zone (for Level B); and station at least one PSO on the pile-driving barge, or in an adjacent land-based vantage point;

b. for anchor handling activities in Cook Inlet, AGDC shall station at least one PSO on the pipelay vessel; and

c. for dredging and screeding activities and Mainline Pipeline shoreline installation, AGDC shall station at least one PSO on each dredging and screeding vessel or accompanying vessel. *(section 4.6.3.2)*

26. **Prior to construction**, AGDC shall update its list of AWC waters affected by Project facilities using the most current ADF&G AWC list and NMFS EFH species list and apply the conservation measures at the appropriate waterbodies. AGDC shall file with the Secretary the revised list and the measures it will employ at each AWC water. (*section 4.7.1*)

27. AGDC shall **not begin** construction **until**:

a. FERC staff completes formal ESA consultation with the USFWS and NMFS;

b. AGDC has received applicable ITAs per the MMPA from the USFWS and NMFS; and

c. AGDC has received written notification from the Director of the OEP that construction or use of mitigation may begin. *(section 4.8.1)*

28. **Prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary, for the review and written approval of the Director of the OEP, a plan for the relocation of MLV 14 and its helipad, developed in coordination with Clear AFS representatives. (*section 4.9.3*)

29. AGDC shall **not begin** implementation of any treatment program/measures (including archaeological data recovery); facility construction; or use of staging, storage, or temporary work areas, ancillary facilities, and new or to-be-improved access roads **until**:

a. AGDC completes outstanding archaeological and architectural surveys and any special studies, and files with the Secretary all remaining cultural resources survey, evaluation, and special studies reports, and the Alaska SHPO comments, the applicable land management agency comments, and consulting party comments on the reports;

b. AGDC files any necessary avoidance or treatment plans that outline measures to avoid, reduce, and/or mitigate effects on historic properties, and the Alaska SHPO comments, the applicable land management agency comments, and consulting party comments on the plans;

c. the ACHP is provided an opportunity to comment on the undertaking if historic properties would be adversely affected; and

d. FERC staff reviews, and the Director of the OEP approves in writing, all cultural resources survey reports and plans; and FERC staff notifies AGDC in writing that treatment plans/mitigation measures may be implemented or that construction may proceed.

All material filed with the Commission containing **location, character, and ownership information** about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "**CUI/PRIV – DO NOT RELEASE**." *(section 4.13.5).*

30. If the DMT continuation methodology is used for the proposed shoreline crossings at Beluga Landing and Suneva Lake, then **prior to construction of the Mainline Facilities**, AGDC shall file with the Secretary noise impact calculations for any NSAs within 1 mile of these sites to reflect use of the DMT continuation methodology. If the noise impact estimates would result in noise attributable to DMT continuation activities greater than 55 dBA L_{dn} at any of the NSAs, AGDC shall include proposed mitigation measures, for the review and written approval by the Director of the OEP, to ensure the estimated noise attributable to the DMT continuation activities is below 55 dBA L_{dn}. (*section 4.16.3.2*)

31. **Prior to construction of final design**, AGDC shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska:

    a. site preparation drawings and specifications for the Liquefaction Facilities and GTP;

    b. a list of the foundation systems to be used for each structure;

    c. all Liquefaction Facilities and GTP structures and foundation design drawings as well as associated calculations, including prefabricated and field constructed structures;

    d. seismic specifications for procured equipment for the Liquefaction Facilities and GTP; and

    e. quality control procedures to be used for civil/structural design and construction.

    In addition, AGDC shall file, in its Implementation Plan, the schedule for producing this information. (*section 4.18.9*)

32. **Prior to construction of final design**, AGDC shall file with the Secretary a monitoring and maintenance plan, stamped and sealed by the professional engineer-of-record registered in Alaska, that ensures the grade of the GTP site would be maintained to prevent flooding throughout the life of the facility considering settlement, subsidence, thermocycling, and sea level rise. (*section 4.18.9*)

33. **Prior to construction of final design**, AGDC shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record registered in Alaska, related to the LNG storage tank and foundation detailed design documents, including but not limited to:

    a. LNG storage tank base concrete slabs calculations and drawings;

    b. LNG storage tank seismic isolator concrete pedestal calculations and drawings; and

    c. LNG storage tank foundation concrete slabs calculations and drawings.

    AGDC shall request written authorization from the Director of the OEP **before** proceeding with construction of final design and **until** the Director of the OEP, or designee, provides a notice to proceed. (*section 4.18.9*)

34. **Prior to construction of final design**, AGDC shall file with the Secretary documentation that confirms the various tidal levels at the PLF do not exceed transfer arm safe operating envelopes or otherwise demonstrate provisions would be in place to prevent disconnection from the transfer arms during loading operations. (*section 4.18.9*)

35. **Prior to construction of final design**, AGDC shall file with the Secretary an analysis stamped and sealed by a professional engineer in the State of Alaska that demonstrates the PLF can withstand the impact from sea ice that historically occurs at the Nikiski site location and that the PLF structural load conditions consider sea ice and ice buildup. The basis of design for the loads induced by sea ice shall be filed with the Secretary for the review and written approval by the Director of the OEP, or the Director's designee. (*section 4.18.9*)

Conditions 36 through 160 shall apply to both the GTP and Liquefaction Facilities, unless otherwise specified. Information pertaining to these specific conditions shall be filed with the Secretary, for review and written approval by the Director of the OEP, or the Director's designee, within the timeframe indicated by each condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 833 (Docket No. RM16-15-000), including security information, shall be submitted as Critical Energy Infrastructure Information pursuant to 18 CFR 388.113. See Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833, 81 Fed. Reg. 93,732 (December 21, 2016), FERC Stats. & Regs. 31,389 (2016). Information pertaining to items such as off-site emergency response, procedures for public notification and evacuation, and construction and operating reporting requirements would be subject to public disclosure. All information shall be filed a minimum of 30 days before approval to proceed is requested.

36. **Prior to initial site preparation**, AGDC shall file an overall Project schedule, which includes the proposed stages of the commissioning plan. *(section 4.18.9)*

37. **Prior to initial site preparation**, AGDC shall file procedures for controlling access during construction. *(section 4.18.9)*

38. **Prior to initial site preparation**, AGDC shall file quality assurance and quality control procedures for construction activities. *(section 4.18.9)*

39. **Prior to initial site preparation**, AGDC shall file a site-specific geotechnical investigation to ensure proper foundation design of the GTP. The geotechnical investigation shall include a location plan that demonstrates the soil conditions are suitable or could be made suitable for all major foundations and evaluate local geological conditions under the proposed foundations, including the susceptibility to frost heave, thermokarsting, subsidence, load-bearing settlement, and concrete material degradation that are projected to occur over the life of the facilities. Also, the soil PH, chloride ion concentration, sulfate ion concentration, and electrical resistivity testing shall be taken into account as part of the site- specific geotechnical investigation. In addition, the geotechnical investigation must demonstrate that the local conditions and those contained in the ASAP report supporting its foundation recommendations are sufficiently analogous. *(section 4.18.9)*

40. **Prior to construction of final design**, AGDC shall file a site-specific analysis for coastal erosion and propose a prevention and mitigation plan prior to commencement of construction. *(section 4.18.9)*

41. **Prior to initial site preparation**, AGDC shall file a response plan for a significant snow event, or provide calculations that prove the current support structures and equipment will be able to support snow loads. *(section 4.18.9)*

42. **Prior to initial site preparation**, AGDC shall file the updated freeboard height and sloshing wave height design calculation to comply with code requirements, including but not limited to ASCE 7-05, API 620, API 625, API 650, ACI 350 and ACI 376. *(section 4.18.9)*

43. **Prior to initial site preparation**, AGDC shall file the updated reserve capacity test report to determine the vertical load, shear load, and uplift displacement capacities of the triple pendulum seismic isolator type bearing. The test report shall include an analysis for maximum and minimum design liquid levels of the LNG tanks, and the displacement during the empty tank condition. In addition, a separate analysis for variations of design stiffness, minimum values of friction and other properties as required by section 17.2 and 17.5 of ASCE 7-05 shall be performed. *(section 4.18.9)*

44. **Prior to initial site preparation**, AGDC shall file its design wind speed criteria for all GTP facilities to be designed to withstand wind speeds commensurate with the risk and reliability in accordance with ASCE 7-16 or equivalent. *(section 4.18.9)*

45. **Prior to initial site preparation**, AGDC shall file calculations demonstrating the loads on buried pipelines and utilities at temporary crossings will be adequately distributed. The analysis shall be based on API RP 1102 or other approved methodology. *(section 4.18.9)*

46. **Prior to initial site preparation**, AGDC shall develop an ERP (including evacuation) and coordinate procedures, as applicable, with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan shall include at a minimum:

    a. designated contacts with state and local emergency response agencies;

    b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

    c. procedures for notifying residents and recreational users within areas of potential hazard;

d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

e. locations of permanent sirens and other warning devices; and

f. an "emergency coordinator" on each LNG marine vessel to activate sirens and other warning devices.

AGDC shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals**. *(section 4.18.9)*

47. **Prior to initial site preparation**, AGDC shall file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that would be imposed on state and local agencies. This comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. AGDC shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its Cost Sharing Plan **at 3-month intervals**. *(section 4.18.9)*

48. **Prior to initial site preparation**, AGDC shall provide validation or verification for the modeling assumptions and methods used for the vapor dispersion and overpressure modeling for the high pressure CO_2/H_2S and natural gas pipe systems at the GTP, and provide revised modeling to account for any changes made to the assumptions. The results of this modeling shall be used to inform the ERPs. (*section 4.18.9*)

49. **Prior to initial site preparation**, AGDC shall demonstrate that ERPs include processes and procedures that ensure the plant will be placed in a safe shut down prior to an evacuation of staff from the central control building in the event of a pipeline incident, including an incident originating from the relocated Hilcorp pipeline, which could affect the Liquefaction Facilities' central control building. *(section 4.18.9)*

50. **Prior to initial site preparation**, AGDC shall demonstrate that ERPs for potential large pipeline ruptures at the GTP have been coordinated with the adjacent PBU CGF plant and include consideration of impacts on the GTP operator camp site. *(section 4.18.9)*

51. **Prior to construction of final design**, AGDC shall file lighting drawings. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall illustrate adequate coverage, in accordance with federal regulations (e.g., 49 CFR 193, 33 CFR 127, 33 CFR 105, 29 CFR 1910, 29 CFR 1915, and 29 CFR 1926) and API 540 or equivalent, of the perimeter of the facility and along paths/roads of access and egress. *(section 4.18.9)*

52. **Prior to construction of final design**, AGDC shall file security camera and intrusion detection drawings. The security camera drawings shall show the locations, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, and mounting height) to verify coverage of the entire perimeter with redundancies and cameras interior to the facility to enable rapid and reliable monitoring of the facility. The intrusion detection drawings shall show or note the location of the intrusion detection to verify coverage of the entire perimeter of the facility. *(section 4.18.9)*

53. **Prior to construction of final design**, AGDC shall file drawings of the security fence at the Liquefaction Facilities. The fencing drawings shall provide details of fencing (e.g., dimensions and gauge of fence meshes, posts, and barbed or razor wire) that demonstrates it will restrict and deter access around the entire facility and has a 10-foot clearance from exterior features (e.g., power lines and trees) and from interior features (e.g., piping, equipment, and buildings). *(section 4.18.9)*

54. **Prior to construction of final design**, AGDC shall file specifications, drawings, and details of crash rated vehicle barriers at each facility entrance for access control that can mitigate accidental and intentional vehicle impacts. *(section 4.18.9)*

55. **Prior to construction of final design**, AGDC shall file change logs that list and explain any changes made from the front end engineering design provided in AGDC's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings. *(section 4.18.9)*

56. **Prior to construction of final design**, AGDC shall file information/revisions pertaining to its responses to numbers 55, 58, 70, 71, 73, and 75 of the July 7, 2017 information request; responses to numbers 8, 14, 16, 19, and 21 of the December 26, 2018 information request; responses to number 2 and 5 of the December 26, 2018 (non-public enclosure); responses to numbers 3, 11, 17, 18, 21, 22, and 23 of the January 15, 2019 information request; and responses to numbers 4, 5, 14-17, 20–22, 24, 27, 29, 32–34, 42, 46, and 57 of the September 17, 2019 information request, which indicated features to be included or considered in the final design of the GTP. *(section 4.18.9)*

57. **Prior to construction of final design**, AGDC shall file information/revisions pertaining to its responses to numbers 2, 3, 5, 7, 8, 11, 24, 28, 29, 31, 34, 38, 46, 47, and 51 of the July 7, 2017 information request; responses to numbers 32, 34, 35, 37, 41, 42, 46, 54–61, 66, 69–72, 74, and 75 of the December 26, 2018 information request; responses to numbers 8, 9, 10, and 13–15 of the December 26, 2018 information request (non-public enclosure); responses to numbers 56, 60, 66, 70–73, 75–81, and 83 of the January 15, 2019 information request; responses to numbers 63, 71, 74, 93b, and 97 of the September 17, 2019 information request; and responses to numbers 3 and 9 of the November 22, 2019 information request, which indicated features to be included or considered in the final design of the Liquefaction Facilities. *(section 4.18.9)*

58. **Prior to construction of final design**, AGDC shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. *(section 4.18.9)*

59. **Prior to construction of final design**, AGDC shall file documentation that demonstrates the multi-use truck unloading/loading facilities at the GTP and Liquefaction Facilities incorporates safety design features including but not limited to process control and monitoring instrumentation including alarm and automatic shutdown capabilities; configuration of transfer valves, equipment, and hazard mitigation equipment to be activated remotely; unique hose couplings and fill line connections for each type of hazardous fluid; and pipe marking and identification of transfer equipment. *(section 4.18.9)*

60. **Prior to construction of final design**, AGDC shall file the updated LNG tank design that incorporates AGDC's proposed top and bottom filling capabilities in order to mitigate LNG tank stratification and rollover. Also, AGDC shall file procedures to mitigate stratification and potential rollover based on differences in transferring or loading LNG with different compositions and the time it takes to detect stratification and induce sufficient mixing of the LNG storage tank contents based on the flow rate and storage volume compared to the time it takes for the detected stratification to develop into a potential rollover condition. *(section 4.18.9)*

61. **Prior to construction of final design**, AGDC shall file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion. *(section 4.18.9)*

62. **Prior to construction of final design**, AGDC shall file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications shall include:

    a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, and blast resistant buildings);

    b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, and other specialized equipment);

    c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable, and other electrical and instrumentation); and

    d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, and firewater). *(section 4.18.9)*

63. **Prior to construction of final design**, AGDC shall file a summary of all applicable codes and standards and the final specification document number(s) where they are referenced. *(section 4.18.9)*

64. **Prior to construction of final design**, AGDC shall file a complete LNG storage tank specification and design drawings. The specification shall define the battery limits (i.e., engineering design, structural design, supports, piping components, piping connections, electrical power, control, and utilities) of the LNG storage tank. *(section 4.18.9)*

65. **Prior to construction of final design**, AGDC shall file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances. *(section 4.18.9)*

66. **Prior to construction of final design**, AGDC shall file up-to-date process flow diagrams and P&IDs, including vendor P&IDs. The process flow diagrams shall include heat and material balances. The P&IDs shall include the following information:

    a. equipment tag number, name, size, duty, capacity, and design conditions;
    b. equipment insulation type and thickness;
    c. storage tank pipe penetration size and nozzle schedule;
    d. valve high pressure side and internal and external vent locations;
    e. piping with line number, piping class specification, size, and insulation type and thickness;
    f. piping specification breaks and insulation limits;
    g. all control and manual valves numbered;
    h. relief valves with size and set points; and

i. drawing revision number and date. *(section 4.18.9)*

67. **Prior to construction of final design**, AGDC shall file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities. *(section 4.18.9)*

68. **Prior to construction of final design**, AGDC shall file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs. *(section 4.18.9)*

69. **Prior to construction of final design**, AGDC shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (i.e., temperature, pressures, flows, and compositions). *(section 4.18.9)*

70. **Prior to construction of final design**, AGDC shall include a check valve or other means in the sour gas inlet piping to the AGRU absorber to prevent backflow into the inlet piping. *(section 4.18.9)*

71. **Prior to construction of final design**, AGDC shall include LNG storage tank fill flow measurement with high flow alarm. *(section 4.18.9)*

72. **Prior to construction of final design**, AGDC shall include BOG flow measurement from each LNG storage tank. *(section 4.18.9)*

73. **Prior to construction of final design**, AGDC shall evaluate and demonstrate the design pressure of the Process Heat Medium Expansion Drum and associated relief valves is consistent with the heating medium circulation system. *(section 4.18.9)*

74. **Prior to construction of final design**, AGDC shall include layout and design specifications of the pig trap, inlet separation and liquid disposal, inlet/send-out meter station, and pressure control. *(section 4.18.9)*

75. **Prior to construction of final design**, AGDC shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and ESD system for review and written approval. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points. *(section 4.18.9)*

76. **Prior to construction of final design**, AGDC shall specify that all ESD valves are to be equipped with open and closed position switches connected to the Distributed Control System (DCS) / SIS. *(section 4.18.9)*

77. **Prior to construction of final design**, AGDC shall file an evaluation of ESD valve closure times. The evaluation shall account for the time to detect an upset or hazardous condition, notify plant personnel, and close the ESD valve. *(section 4.18.9)*

78. **Prior to construction of final design**, AGDC shall file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump startup and shutdown operations. *(section 4.18.9)*

79. **Prior to construction of final design**, AGDC shall file a HAZOP review of the final design P&IDs, a list of the resulting recommendations, and action taken on the recommendations. The issued for construction P&IDs shall incorporate the HAZOP recommendations and justification shall be provided for any recommendations that are not implemented. *(section 4.18.9)*

80. **Prior to construction of final design**, AGDC shall file specifications that demonstrate the materials of construction have MDMTs that can withstand the minimum expected temperature at the North Slope or that AGDC demonstrates that equipment and piping will be fully depressurized in the event the ambient temperature becomes less than the MDMT with sufficient reliability through SIS or through written procedures. *(section 4.18.9)*

81. **Prior to construction of final design**, AGDC shall demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. *(section 4.18.9)*

82. **Prior to construction of final design**, AGDC shall file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. *(section 4.18.9)*

83. **Prior to construction of final design**, AGDC shall file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, ESD and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). This evaluation shall include justification for blast resistant walls or buildings at the GTP. The justification for the flammable and combustible gas detection and flame and heat detection shall be in accordance with ISA 84.00.07 or equivalent methodologies that will demonstrate 90 percent or more of releases (unignited and ignited) that could result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de-inventory within 10 minutes or less for impoundments that are not sized for 10 minute releases and de-inventory. The analysis shall revise the hazard detection coverage, including, but not limited to, the GTP's outside areas, or adequately demonstrate that failure to detect releases due to lack of hazard detection coverage will not result in direct or indirect offsite impacts, including projectiles from potential BLEVEs resulting from undetected fire events. The analysis shall take into account the set points, voting logic, wind speeds, and wind directions. The justification for firewater shall provide evaluation of the total area that may experience firewater demand due to each governing scenario; calculations for all firewater demands (including firewater coverage on the LNG storage tanks) based on design densities, surface area, and throw distance; and specifications for the corresponding hydrant and monitors needed to reach and cool equipment. *(section 4.18.9)*

84. **Prior to construction of final design**, AGDC shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comer that will transfer spills from the tank top to the ground-level impoundment system. The spill containment drawings shall show containment for all components that could contain hazardous liquids, including all liquids handled above their flashpoint and those with toxic or asphyxiant vapor hazards, from the largest flow from a single line for 10 minutes, including de-inventory and specifying a reliability equivalent to SIL 2 or higher for any pump interlock systems, or the maximum liquid from the largest vessel (or total of impounded vessels), or otherwise demonstrate that providing spill containment will not significantly reduce the vapor dispersion or radiant heat consequences of a spill, including for any tank top LNG releases up to a full guillotine that would not be captured to the tank area impoundment. Spill containment systems shall be constructed of materials that can withstand the liquid hazards. In addition, the rainout calculations for a liquid nitrogen vessel failure shall be provided with validation, or liquid nitrogen containment shall be

provided. Also, AGDC shall provide details of collection for spills occurring at the onshore pipe-in-pipe ESD valve, over road crossings, details of hazardous liquid trenches crossing storm water trenches, containment for the condensate, slop oil, and diesel piping in the area near their storage tank impoundments at the Liquefaction Facilities; and details on whether the miscellaneous hydrocarbon fluid at the GTP site will be handled above its flash point, as well as confirming that the most significant hazardous compositions in knockout drums have been considered. *(section 4.18.9)*

85. **Prior to construction of final design**, AGDC shall file an analysis and/or tests that demonstrate either the pipe-in-pipe system at the Liquefaction Facilities will maintain integrity and not initiate and propagate cracks when subjected to sudden cryogenic temperatures and forces from the full range of jetting release sizes, or alternatively, revise the spill containment design for this piping to include a conventional trough and impoundment system. *(section 4.18.9)*

86. **Prior to construction of final design**, AGDC shall file with the Secretary the following for the final design of the pipe-in-pipe systems at the Liquefaction Facilities, including:

    a. the detailed design and a plot plan layout of the pipe-in-pipe system, including identification of all conventional process lines extending from or attached to the pipe-in-pipe, as well as the locations of any reliefs, instrumentation or other connections along the inner or outer pipes;

    b. an assessment of the vapor production and vapor handling capacities within the annular space during a full inner pipe rupture or smaller release into the outer pipe;

    c. stress analysis for the pipe-in-pipe systems, including at bulkheads and including the differential stresses between the inner pipe and outer pipe for a full inner pipe rupture, or any smaller release, at any location along the system;

    d. leak testing details and pressures for the outer pipe;

    e. details of the maintenance procedures that will be followed over the life of the facility to determine that the outer pipe will be continuing to adequately serve as spill containment;

    f. plans for purging or draining LNG from the outer pipe; and

    g. details of any features that will protect against external common cause failures of the inner and outer pipes, including heavy equipment accidents. *(section 4.18.9)*

87. **Prior to construction of final design**, AGDC shall demonstrate that the design of the marine impoundment system will capture liquid rainout resulting from jetting releases up to a full guillotine rupture of a dock transfer line, which could cause impacts on dock or trestle supports, nearby public, berthed LNG marine vessels and tugs, or other cascading impacts. *(section 4.18.9)*

88. **Prior to construction of final design**, AGDC shall provide details of how LNG spills at the dock will be fully contained in impoundment areas without resulting in cascading failures to structural supports, including how LNG will be collected on the trestle containment system without spreading over the dock surface and ensuring the structural supports will accommodate the liquid weight. *(section 4.18.9)*

89. **Prior to construction of final design**, AGDC shall provide the following on the water, snow, and ice handling systems for impoundments:

    a. water removal pumps for locally-curbed hazardous liquid impoundments at the Liquefaction Facilities, such as those around knockout drums; and

    b. details on how hardened snow will be assured to not inhibit the spill flow path (e.g., maintenance plans and/or details of snowmelt methods), including in spill collection areas and trenches leading to impoundments, and be assured to not reduce the volume of any part the impoundment system beyond the extra height allowed in the impoundment system specifically for snow accumulation. *(section 4.18.9)*

90. **Prior to construction of final design**, AGDC shall file detailed calculations to confirm that the final fire water volumes will be accounted for when evaluating the capacity of the impoundment system during a spill and fire scenario. *(section 4.18.9)*

91. **Prior to construction of final design**, AGDC shall analyze the potential for the overpressures from vapor cloud ignition underneath the module platforms to cause movement of or damage to the platforms that could affect the high pressure equipment above them, such as the treated gas chillers and associated piping as well as CO_2/H_2S piping, and provide any measures needed to prevent significant cascading damage and safety impacts. *(section 4.18.9)*

92. **Prior to construction of final design**, AGDC shall file details of the mitigation measures that will prevent flammable vapors from entering the semi-confined spaces underneath the LNG storage tanks, including details of the measures that will prevent temperatures in this space that could impair the functionality of the seismic isolators or cause frost heave. *(section 4.18.9)*

93. **Prior to construction of final design**, AGDC shall file electrical area classification drawings including cross-sectional drawings. The drawings shall demonstrate compliance with NFPA 59A, NFPA 70, NFPA 497, and API RP 500, or equivalents. In addition, the drawings shall include revisions to the electrical area classification design or provide technical justification that supports the electrical area classification of the following areas using most applicable API RP 500 figures (e.g., figures 20 and 21) or hazard modeling of various release rates from equivalent hole sizes and wind speeds (see NFPA 497 release rate of 1 pound/minute) for the spill trench that will serve the portion of the LNG liquefaction rundown pipe rack located west of the air fin coolers, which would contain process piping, the spill containment systems for both marine berth areas, and the LNG marine transfer lines and marine trestle area. *(section 4.18.9)*

94. **Prior to construction of final design**, AGDC shall file design details and specifications of the LERs located within the GTP's process modules including, but not limited to, the pressurization system, HVAC air intake system, and any openings such as personnel entry door(s), electrical cable entries, and air conditioning unit(s). The design details and specifications shall demonstrate compliance with NFPA 59A, NFPA 70, NFPA 496, NFPA 497, and API RP 500, or equivalents. *(section 4.18.9)*

95. **Prior to construction of final design**, AGDC shall file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001). *(section 4.18.9)*

96. **Prior to construction of final design**, AGDC shall file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that shall continuously monitor for the presence of a flammable fluid, alarm the hazardous condition, and shut down the appropriate systems. *(section 4.18.9)*

97. **Prior to construction of final design**, AGDC shall file a drawing showing the location of the ESD buttons. ESD buttons shall be easily accessible, conspicuously labeled, and located in an area that will be accessible during an emergency. *(section 4.18.9)*

98. **Prior to construction of final design**, AGDC shall file complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment. *(section 4.18.9)*

99. **Prior to construction of final design**, AGDC shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of the hazard detectors when determining the lower flammable limit set points for methane, propane, ethane, and condensate. *(section 4.18.9)*

100. **Prior to construction of final design**, AGDC shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of hazard detectors when determining the set points for toxic components such as natural gas liquids and H_2S. *(section 4.18.9)*

101. **Prior to construction of final design**, AGDC shall file a technical review of facility design that:

    a. identifies all combustion/ventilation air intake equipment and the elevations and distances to any possible flammable gas or toxic release; and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices will isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. *(section 4.18.9)*

102. **Prior to construction of final design**, AGDC shall file analysis of the buildings containing hazardous fluids and the ventilation calculations that limit concentrations below the LFLs (e.g., 25-percent LFL), including an analysis of off gassing of hydrogen in battery rooms, and shall also provide hydrogen detectors that alarm (e.g., 20- to 25-percent LFL) and initiate mitigative actions (e.g., 40- to 50-percent LFL) in accordance with NFPA 59A and NFPA 70, or equivalents. *(section 4.18.9)*

103. **Prior to construction of final design**, AGDC shall provide low oxygen detectors to notify operators of liquid nitrogen releases at the Liquefaction Facilities. *(section 4.18.9)*

104. **Prior to construction of final design**, AGDC shall provide an evaluation of the normal module air changes within buildings at the GTP and reliability of the ventilation system to determine whether oxygen detectors are needed as an additional layer of protection to notify operators of a potential nitrogen release and ensure safe entry into a module/building. The evaluation shall also address whether there will be alarms and notifications in the event ventilation equipment is not operating or functioning as designed. *(section 4.18.9)*

105. **Prior to construction of final design**, AGDC shall file an evaluation of the voting logic and voting degradation for hazard detectors. *(section 4.18.9)*

106. **Prior to construction of final design**, AGDC shall file facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire extinguishers, and other hazard control equipment. Plan drawings shall clearly show the location and elevation by tag number of all fixed dry chemical systems in accordance with NFPA 17, wheeled and handheld extinguishers location travel distances are along normal paths of access and egress in accordance with NFPA 10. The list shall include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units. *(section 4.18.9)*

107. **Prior to construction of final design**, AGDC shall file a design that includes clean agent systems in the instrumentation and electrical equipment buildings that serve safety and security systems. *(section 4.18.9)*

108. **Prior to construction of final design**, AGDC shall file facility plan drawings showing the proposed location of the firewater and any foam systems. Plan drawings shall clearly show the location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam system, water-mist system, and sprinkler. The drawings shall also include piping and instrumentation diagrams of the firewater and foam systems. The firewater coverage drawings shall illustrate firewater coverage by two or more hydrants or monitors accounting for obstructions (or deluge systems) for all areas that contain flammable or combustible fluids. *(section 4.18.9)*

109. **Prior to construction of final design**, AGDC shall specify remotely operated or automatic firewater monitors at the Liquefaction Facilities in areas inaccessible or difficult to access in the event of an emergency. *(section 4.18.9)*

110. **Prior to construction of final design**, AGDC shall demonstrate that the firewater tank will be in compliance with NFPA 22 or an equivalent or better level of safety. *(section 4.18.9)*

111. **Prior to construction of final design**, AGDC shall include or demonstrate the firewater storage volume for its facilities has minimum reserved capacity for its most demanding firewater scenario plus 1,000 gpm for no less than 2 hours. *(section 4.18.9)*

112. **Prior to construction of final design**, AGDC shall specify that firewater pump shelters are designed to remove the largest firewater pump or other component for maintenance with an overhead or external crane. *(section 4.18.9)*

113. **Prior to construction of final design**, due to the absence of firewater monitor coverage, AGDC shall demonstrate that the potential for pool and jet fires to cause cascading hazards in any area of the GTP will be effectively mitigated by systems with a reliability equivalent to SIL 2 or higher. *(section 4.18.9)*

114. **Prior to construction of final design**, AGDC shall file drawings and specifications for the passive protection systems at the GTP and Liquefaction Facilities to protect equipment and supports from cold temperature releases, including for liquids conveyed indoors during winter start-ups at design ambient temperatures at the GTP. *(section 4.18.9)*

115. **Prior to construction of final design**, AGDC shall file calculations or test results for the structural passive protection systems at the GTP and Liquefaction Facilities to demonstrate that equipment and supports are protected from low temperature releases that are below the MDMT of equipment and supports. *(section 4.18.9)*

116. **Prior to construction of final design**, AGDC shall file drawings and specifications for the structural passive protection systems at the GTP and Liquefaction Facilities to demonstrate the equipment and supports are protected from pool and jet fires, including that the fireproofing material will remain effective after potential exposure to the cold temperature of pooling, jetting, or splashing liquids. *(section 4.18.9)*

117. **Prior to construction of final design**, AGDC shall file a detailed quantitative analysis to demonstrate that adequate mitigation will be provided for each pressure vessel that could fail within the 4,000 BTU/ft^2-hr zone from a pool or jet fire; each critical structural component (including the LNG marine vessel and outer pipe of the pipe-in-pipe containment system) and emergency equipment item that could fail within the 4,900 BTU/ft^2-hr zone from a pool or jet fire; and each occupied building that could expose unprotected personnel within the 1,600 BTU/ft^2-hr zone from a pool or jet fire. Trucks at truck transfer stations shall be included in the analysis of potential pressure vessel failures. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires shall be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation shall be supported by calculations or test results for the thickness limiting temperature rise over the fire duration, and active mitigation shall be supported by reliability information by calculations or test results, such as demonstrating that flow rates and durations of any cooling water will mitigate the heat absorbed by the component. The total firewater demand shall account for all components that could fail due to a pool or jet fire. *(section 4.18.9)*

118. **Prior to construction of final design**, AGDC shall provide an analysis demonstrating occupied buildings at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the occupied buildings at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

119. **Prior to construction of final design**, AGDC shall file an analysis demonstrating safety related equipment (e.g., firewater pump buildings, control buildings, and emergency generators) at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the safety related equipment at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

120. **Prior to construction of final design**, AGDC shall file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities will be able to withstand radiant heats from pool fires, as well as jet fires and overpressures and projectiles from vapor cloud explosions from ignition of flammable vapors generated from a design spill release (considering the selection philosophy used for the Hazard Analysis Reports, without time-of-use criteria). Alternatively, AGDC shall file an analysis demonstrating the refrigerant storage vessels at the Liquefaction Facilities have been relocated or provided with passive and active measures that will prevent impacts. *(section 4.18.9)*

121. **Prior to construction of final design**, AGDC shall file specifications and drawings demonstrating how cascading damage of transformers will be prevented (e.g., firewalls or spacing) in accordance with NFPA 850 or equivalent. *(section 4.18.9)*

122. **Prior to construction of final design**, AGDC shall file an evaluation of the final design of grated module platforms at the Liquefaction Facilities that demonstrates a vapor cloud explosion of significant magnitude will not develop from a design spill such that it results in cascading damage that could have impacts offsite. *(section 4.18.9)*

123. **Prior to construction of final design**, AGDC shall file an analysis demonstrating the LNG storage tank outer walls can withstand the overpressures generated from ignition of vapor clouds from design spills in adjacent plant areas. *(section 4.18.9)*

124. **Prior to construction of final design**, AGDC shall file a projectile analysis that demonstrates each LNG storage tank can withstand projectiles from explosions and high winds. The analysis shall detail and justify the projectile speeds and characteristics and method used to determine penetration or perforation depths. *(section 4.18.9)*

125. **Prior to construction of final design**, AGDC shall file drawings of internal road vehicle protections, such as guard rails, barriers, and bollards to protect all equipment containing hazardous fluids or that are safety related (e.g., hydrants and monitors) to ensure that they are located away from roadway or protected from inadvertent damage from vehicles. *(section 4.18.9)*

126. **Prior to construction of final design**, AGDC shall file documentation demonstrating the Seismic Isolation system for the LNG tanks complies with the design, analysis, and testing requirements of Chapter 17 of ASCE 7-05, or equivalent. The Peer Review of the design shall be performed as required by Chapter 17 of ASCE 7-05, or equivalent. *(section 4.18.9)*

127. **Prior to construction of final design**, AGDC shall file an analysis of the structural integrity of the outer containment, tank foundation concrete slabs, tank base concrete slabs, and seismic isolator concrete pedestals, demonstrating they are designed to withstand all loads and combinations that comply with code requirements, including but not limited to ASCE 7-05, ACI 318, ACI 350, ACI 376, API 620, API 625 and API 650, or equivalents. *(section 4.18.9)*

128. **Prior to construction of final design**, AGDC shall file the FEA modeling with the inputs and outputs reports for tanks design, base concrete slabs and foundation concrete slabs design, including details of splicing of precast concrete LNG tank panels, connections to be used between the outer LNG walls and the vapor barrier dome and demonstrate the results of the FEA modeling are within design limits. *(section 4.18.9)*

129. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings that demonstrate seismic sliding and overturning resistance of the LNG tank's inner tank would not result in failure of the tank. *(section 4.18.9)*

130. **Prior to construction of final design**, AGDC shall file design calculations to confirm the combination of overturning moment and seismic vertical acceleration that induce any uplift and shear of the external wall can be handled with the seismic tendons in combination with shear key. *(section 4.18.9)*

131. **Prior to construction of final design**, AGDC shall file the non-linear dynamic analysis (modal response-spectrum analysis, response-history analysis, linear time-history analysis, and nonlinear time-history analysis) for the LNG tank and isolation system that would simultaneously include the time history, vertical component of motion envelope, and the site-specific vertical design response spectra developed for the Project. The analysis shall also account for horizontal components rotated so that one of the components for each set of motions is the maximum component of response at the isolated period of the tank. The Peer Review of the design shall be performed as required by Chapter 17 of ASCE 7-05 or equivalent to demonstrate the LNG tank and isolation system is designed to withstand ground motion without loss of structural or functional integrity. *(section 4.18.9)*

132. **Prior to construction of final design**, AGDC shall file design details of the seismic monitoring system for the proposed Project site location with specific peak ground motion data and include at least one free-field triaxial accelerometer at the site, as well as additional instruments on each tank and its foundation. *(section 4.18.9)*

133. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings of the omega joints detailed in to be used between the bottom LNG tank plate and the bottom of the outer tank wall to demonstrate the final tank design incorporates wall-to-base connections that is consistent with criteria specified in ACI 376 or equivalent. *(section 4.18.9)*

134. **Prior to construction of final design**, AGDC shall file a detailed analysis and any associated drawings detailing the LNG tank secondary bottom design that demonstrates protection of the LNG tank slab and seismic isolators from any cryogenic temperatures it will be exposed to during a spill. *(section 4.18.9)*

135. **Prior to construction of final design**, AGDC shall file the cryogenic protection plan for the LNG tanks foundation concrete slabs and triple pendulum seismic isolator concrete pedestal supports during spill condition. *(section 4.18.9)*

136. **Prior to construction of final design**, AGDC shall file the design analysis to determine the precast panel outer wall behavior for operating and spill conditions and to ensure panel and joint leak tightness. *(section 4.18.9)*

137. **Prior to construction of final design**, AGDC shall file a snow removal plan for critical equipment or provide calculations that prove that support structures and equipment adequately account for snow loads. *(section 4.18.9)*

138. **Prior to construction of final design**, AGDC shall file an analysis indicating areas susceptible to falling ice and snow, and file drawings of structures and coverings that will protect people, piping, and equipment from falling snow and ice. *(section 4.18.9)*

139. **Prior to construction of final design**, AGDC shall file calculations demonstrating the loads induced by vehicles, including cranes and other heavy equipment, associated with operations and maintenance of the Liquefaction and Gas Treatment Facilities that may exceed the design of buried pipelines and utilities (or encasements) at permanent crossings will be adequately distributed. The analysis shall be based on API RP 1102 or other approved methodology. *(section 4.18.9)*

140. **Prior to commissioning**, AGDC shall file a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. AGDC shall file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued. *(section 4.18.9)*

141. **Prior to commissioning**, AGDC shall file detailed plans and procedures for: testing the integrity of on-site mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. *(section 4.18.9)*

142. **Prior to commissioning**, AGDC shall file the procedures for pressure/leak tests which address the requirements of ASME VIII and ASME B31.3. The procedures shall include a line list of pneumatic and hydrostatic test pressures. *(section 4.18.9)*

143. **Prior to commissioning**, AGDC shall file a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice, and shall provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing. *(section 4.18.9)*

144. **Prior to commissioning**, AGDC shall file the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, simultaneous operational procedures, and management of change procedures and forms. In addition, AGDC shall include an LNG storage tank stratification monitoring, prevention, and correction procedure to be included as part of the facility's operation and maintenance procedures. *(section 4.18.9)*

145. **Prior to commissioning**, AGDC shall file truck transfer procedures that require facility personnel to verify, through written checklists, ignition sources are eliminated (e.g., no smoking, ground wire, and engine shutoff) within at least 50 feet prior to transfer operations; transfer connections are marked or labeled and match truck contents prior to transfer operations; and truck transfer operations are constantly attended or visually monitored to physically or remotely shut down truck transfer operations. In addition, the procedures shall include recognition of abnormalities and use of emergency shutoff mechanisms. Operators shall be trained on these procedures and requirements. *(section 4.18.9)*

146. **Prior to commissioning**, AGDC shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. *(section 4.18.9)*

147. **Prior to commissioning**, AGDC shall file a plan to maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff has completed the required training. In addition, AGDC shall file signed documentation that demonstrates training has been conducted, including ESD and response procedures, prior to the respective operation. *(section 4.18.9)*

148. **Prior to commissioning**, AGDC shall equip the LNG storage tanks and adjacent piping and supports with permanent settlement monitors to allow personnel to observe and record the relative settlement between the LNG storage tank and adjacent piping. The settlement record shall be reported in the **semi-annual** operational reports. *(section 4.18.9)*

149. **Prior to commissioning**, AGDC shall file settlement results from hydrostatic tests of the LNG storage containers and shall file a plan to periodically verify settlements are as expected and do not exceed applicable criteria in API 620, API 625, API 653, and ACI 376, or equivalents. *(section 4.18.9)*

150. **Prior to introduction of hazardous fluids**, AGDC shall complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS/SIS that demonstrates full functionality and operability of the system. *(section 4.18.9)*

151. **Prior to introduction of hazardous fluids**, AGDC shall develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms. *(section 4.18.9)*

152. **Prior to introduction of hazardous fluids**, AGDC shall complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s). *(section 4.18.9)*

153. **Prior to introduction of hazardous fluids**, AGDC shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed. *(section 4.18.9)*

154. **Prior to introduction of hazardous fluids**, AGDC shall file finalized ERP(s), including coordination with federal, state, and local agencies and neighboring facilities, such as the PBU CGF and other facilities handling hazardous materials, and shall include processes and procedures to be used in the event of an incident at the GTP, Liquefaction Facilities, and neighboring facilities. *(section 4.18.9)*

155. AGDC shall file a request for written authorization from the Director of the OEP **prior to unloading or loading the first LNG commissioning cargo**. After production of first LNG, AGDC shall file **weekly reports** on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports shall include a summary of activities, problems encountered, and remedial actions taken. The weekly reports shall also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports shall include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude shall be reported to FERC **within 24 hours**. *(section 4.18.9)*

156. **Prior to commencement of service**, AGDC shall notify FERC staff of any proposed revisions to the security plan and physical security of the plant. *(section 4.18.9)*

157. **Prior to commencement of service**, AGDC shall label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001). *(section 4.18.9)*

158. **Prior to commencement of service**, AGDC shall provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring. *(section 4.18.9)*

159. **Prior to commencement of service**, AGDC shall develop procedures for handling off-site contractors including responsibilities, restrictions, and limitations and for supervision of these contractors by AGDC staff. *(section 4.18.9)*

160. **Prior to commencement of service**, AGDC shall file a request for written authorization from the Director of the OEP. Such authorization would only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the MTSA of 2002, and the Security and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by AGDC or other appropriate parties. *(section 4.18.9)*

In addition, conditions 161 through 164 shall apply throughout the life of the Liquefaction Facilities and GTP, unless otherwise specified.

161. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual basis** or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, AGDC shall respond to a specific information request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted. *(section 4.18.9)*

162. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from off-site vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tanks, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled *Significant Plant Modifications Proposed for the Next 12 Months (dates)* shall be included in the semi-annual operational reports. Such information would provide FERC staff with early notice of anticipated future construction/maintenance at the LNG and GTP facilities. *(section 4.18.9)*

163. In the event the temperature of any region of the LNG storage container, including any secondary containment and imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified. *(section 4.18.9)*

164. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site and suspicious activities) shall be reported to FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to FERC staff **within 24 hours**. This notification practice shall be incorporated into the LNG Plant's emergency plan. Examples of reportable hazardous fluids-related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of hazardous fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of a facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of a facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in a facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20-percent reduction in operating pressure or shutdown of operation of a pipeline or a facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the GTP or Liquefaction Facilities; or

m. an event that is significant in the judgment of the operator and/or management even though it does not meet the above criteria or the guidelines set forth in an LNG terminal's incident management plan.

In the event of an incident, the Director of the OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG Plant to cease operations. **Following the initial company notification**, FERC staff would determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident. *(section 4.18.9)*