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

FINAL ENVIRONMENTAL ASSESSMENT
and
FINDING OF NO SIGNIFICANT IMPACT

Pipe-in-Pipe System

Alaska LNG Terminal
Nikiski, Alaska

Special Permit Information:

Docket Number:	PHMSA-2017-0157
Requested by:	Alaska Gasline Development Corporation
Operator ID#:	40015
Original Date Requested:	September 8, 2017
Issuance Date:	April 27, 2020
Effective Date:	April 27, 2020 to April 27, 2030
Code Section(s):	49 CFR 193.2167 and 193.2173

Pipe-in-Pipe System to Replace a Covered Impoundment and Water Removal

Final Environmental Assessment

This Final Environmental Assessment (FEA) analyzes a special permit granted to the Alaska Gasline Development Corporation (AGDC or Applicant) to waive the requirements of 49 Code of Federal Regulations (CFR) 193.2167 and 193.2173 at the Alaska LNG Terminal (LNG Terminal, LNG Facility or Liquefaction Plant) to be located near Nikiski, Alaska. The special permit grant described herein is related to, but distinct from, the Federal Energy Regulatory Commission (FERC) decision making process for siting and permitting Alaska LNG Terminal located near Nikiski, Alaska that liquefies natural gas and stores and transfers liquefied natural gas (LNG) to marine carriers for exporting purposes. This FEA is intended to specifically analyze any environmental impact associated with the waiver of certain regulations in Liquefied Natural Gas Facilities: Federal Safety Standards found in 49 CFR Part 193. This FEA is prepared by the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) to analyze the special permit request in accordance with 49 CFR 190.341. PHMSA has also prepared environmental analyses for four (4) other special permit grants to AGDC related to the Alaska LNG Project's mainline pipeline to transport natural gas to the Alaska LNG Terminal located near Nikiski, Alaska. Although the requests are distinct technically, PHMSA has considered safety or environmental impacts holistically.

PHMSA has prescribed the minimum Federal pipeline safety standards for LNG facilities in compliance with 49 U.S.C. 60101 et seq. Those standards are codified in 49 CFR Part 193 and apply to the siting, design, construction, operation, maintenance, and security of LNG facilities. Pursuant to 49 U.S.C. 60118(c), PHMSA may issue a special permit to waive certain regulatory requirements. Special permits are typically contingent on the performance of additional measures beyond minimum Federal pipeline safety regulations, in accordance with 49 CFR 190.341. PHMSA has imposed conditions in the granted special permit that have been determined to be necessary for safety, environmental protection, or otherwise in the public interest. PHMSA has determined that a special permit with conditions is not inconsistent with pipeline safety so the application will be granted. This FEA references the AGDC's FERC Resource Reports to avoid duplication. This FEA accompanies AGDC's special permit request for waiving the covered system requirements in 49 CFR 193.2167 and the water removal requirements in 49 CFR 193.2173 in order to use a pipe-in-pipe (PIP) system (or PIP technology) at various segments of the LNG liquefaction rundown lines and LNG quench lines. This special permit allows AGDC to utilize the outer pipe of the PIP system as containment of the inner pipe and waives the requirements for covered impoundment and water removal systems for the LNG rundown lines and LNG quench lines.

1. PURPOSE AND NEED

AGDC is proposing to construct, own, and operate an integrated natural gas pipeline with gas pre-treatment facilities, interdependent interconnection gas delivery points, and a liquefaction and marine export facility, (collectively known as the Alaska LNG Project) for the purpose of liquefying supplies of natural gas from Alaska. Gas will be supplied from the Point Thomson Unit and Prudhoe Bay Unit production fields on the North Slope, and will provide opportunities for in-state deliveries of natural gas and export of LNG in foreign commerce.

On April 17, 2017, AGDC filed an application with the FERC for approval of the Alaska LNG Project. The FERC issued a final environmental impact statement on March 6, 2020, for the Alaska LNG Project (FERC Docket CP17-178-000[1]). The Alaska LNG Terminal will include LNG rundown lines, which will transfer LNG from the liquefaction units to the LNG storage tanks. These lines will be constructed using PIP technology, which will be designed to contain releases from the inner pipe within an enclosed secondary outer pipe. The three (3) 20-inch diameter PIP rundown lines will start at the outlet line of each liquefaction train and combine to a 30-inch diameter rundown header, which transfers LNG to the storage tanks. The 30-inch diameter PIP rundown header transitions to conventional stainless-steel piping in the LNG storage tank area and before branching to two tank loading lines. Additionally, AGDC will use PIP technology for four (4) LNG quench lines (two (2) supply and two (2) return lines) that will be used to cool down the boil-off gas to the Boil-off Gas Compressors. Four-inch (4-inch) diameter quench lines will be connected to the 28-inch diameter dual LNG marine cargo transfer lines using fabricated PIP tees and continue to the northern edge of the boil off gas compressor unit spill collection area where

[1] https://www.ferc.gov/industries/gas/enviro/eis/2020/03-06-20-FEIS.asp.

the PIP transitions to conventional stainless-steel piping near the inlet of the Boil-off Gas Compressors. Pursuant to 49 CFR 190.341, AGDC submitted a special permit application on September 8, 2017, to waive the covered system requirements in 49 CFR 193.2167 for the LNG rundown lines and LNG quench lines using PIP system for spill containment. Furthermore, AGDC submitted application to waive the requirement of 49 CFR 193.2173 for the removal of water from the impoundment area (or annulus) formed by the outer pipe of a PIP system. In normal operating conditions, the collection of water within the annulus of the PIP system will not occur, thus a water removal system is not necessary. As such, AGDC requested this special permit for 49 CFR 193.2167 and 193.2173 to permit the integral use of the PIP system as covered impoundment without water removal.

The sub-arctic winter weather conditions in Nikiski, Alaska led AGDC to evaluate and select an alternative rundown piping design. The traditional transfer design with open drainage channels for an impounding system will necessitate clearing snow and ice, which may result in personnel entering LNG spill conveyance trenches. The anticipated snow volumes, which can exceed 12 inches, must be removed from the impounding system, including drainage channels and trenches, to ensure potential spills of LNG are conveyed to the designated impounding space. If snow volumes are not removed, based on the density of the snow, it could take up volume or obstruct LNG spills in the open trench from being conveyed to impoundment sumps. With the use of the PIP system as a covered impoundment system without a water removal system, the use of traditional impounding systems will be reduced but not eliminated.

The required impoundment systems used throughout the Alaska LNG Terminal will be designed and constructed to comply with 49 CFR 193.2173. The impoundment basins will have an additional 12 inches of height to provide for the potential accumulation of snow. The winterization design will address the potential for hardened snow in curbed area sumps and methods to maintain spill flow paths and design spill containment capacity. Options will include mechanized snow/ice removal and application of snow melt/deicing agents as part of operations and maintenance plans. Similar operations and maintenance methods for hardened snow removal in the trenches will be considered, however, entry may require addressing work safety when entering certain portion of the impounding space serving hazardous liquid. Variations in the design of trench will consider using heated pavement systems[1] (i.e., electric heat tracing cable within concrete pavement) to melt accumulated snow/ice as site conditions warrant.

Where the outer pipe is adequately designed, tested and constructed to maintain structural integrity for pressurized cryogenic releases, any spill from the primary containment will be contained within the PIP system; therefore, LNG spills will not be able to reach the atmosphere. A conventional system allows LNG spills to reach the atmosphere because such spills are collected into an open-air (or uncovered) impoundment system, creating the potential for fire and other hazards to exist due to the presence of oxygen, a fuel source, and a potential ignition source being available. Without the presence of oxygen and a potential ignition source, the potential for fire and other hazards are significantly decreased.

The use of the PIP system also has many operational benefits associated with lower heat leaking into the system. The Alaska LNG Terminal will have less boil-off gas (BOG) generation, less compressor usage, and therefore a reduction in overall fuel needed to operate the BOG compressors. With the PIP system, the recirculation of LNG is reduced or is intermittent, which results in less usage of pumps and less LNG flowing through lines for cool-down during the holding mode when LNG carriers are not being loaded.

For the above reasons, AGDC will provide the required secondary containment impounding system for LNG transfer piping from the liquefaction units to the LNG storage tanks through the use of a cryogenic PIP system. The outer pipe of the PIP system will serve as the secondary containment and contain releases from the inner pipe.

The Alaska LNG Terminal is subject to PHMSA's jurisdiction under 49 CFR Part 193. Part 193, Subpart C incorporates by reference National Fire Protection Association (NFPA) 59A (2001 edition) for design, construction, and testing of piping systems. Since NFPA 59A (2001 edition) does not include provisions for the PIP system, AGDC will design the system in accordance with NFPA 59A (2001 edition), which addresses the use of this technology as a secondary containment system (see NFPA 59A (2001 edition), Section 10.13, Cryogenic Pipe-in-Pipe Systems). The analysis described herein presents the environmental impacts and public safety risks associated with construction and operation of the Alaska LNG Terminal's PIP system in comparison with full compliance with Part 193. This analysis will also set out special permit conditions, which are intended to mitigate any safety or environmental risks of the Alaska LNG Terminal.

For a conventional piping, a liquid release from the LNG piping will be contained in an open trench and conveyed to an impoundment sump; however, a release from the inner pipe of the pipe-in-pipe system will be impounded within the outer pipe, which is a covered system. As such, AGDC requests relief from 49 CFR 193.2167, Covered System, which states that "a covered impounding system is prohibited except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike."

AGDC also requested relief from 49 CFR 193.2173, Water Removal, which requires that:

(a) Impoundment areas must be constructed such that all areas drain completely to prevent water collection. Drainage pumps and piping must be provided to remove water from collecting in the impoundment area. Alternative means of draining may be acceptable subject to the Administrator's approval.

(b) The water removal system must have adequate capacity to remove water at a rate equal to 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes. For rainfall amounts, operators must use the "Rainfall Frequency Atlas of the United States" published by the National Weather Service of the U.S. Department of Commerce.

(c) Sump pumps for water removal must—

(1) Be operated as necessary to keep the impounding space as dry as practical; and

(2) If sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present.

Since AGDC's outer pipe of the PIP system will serve as impoundment areas (i.e., secondary containment) for releases from the inner pipe, this design will not allow for snow or water accumulation because PIP is a closed system. The PIP segments may share the same pipe racks with conventional piping used for other hazardous liquids, which require conveyance trenches.

Therefore, all open trenches and impoundment sumps at the Alaska LNG Terminal must comply with the water removal requirements in 49 CFR 193.2173.

2. BACKGROUND AND SITE DESCRIPTION

2.1. Background

On April 17, 2017, AGDC filed an application to the FERC pursuant to section 3 of the Natural Gas Act (NGA) for its Alaska LNG Project (Project), which consists of an off-site pre-treatment plant, an 807-mile pipeline facility, and the Alaska LNG Terminal. The Alaska LNG Terminal will be located near Nikiski, Alaska, and will consist of liquefaction, storage, and transfer facilities. The liquefaction unit includes three onshore liquefaction trains designed to produce up to approximately 20 million metric tons per annum. The LNG will be transferred from the liquefaction area to the LNG storage area via three (3) 20-inch diameter LNG rundown lines that will originate from each of the three liquefaction trains and combine into a 30-inch diameter rundown header. The LNG will be stored in two (2) LNG storage tanks, each with storage capacity of 240,000 cubic meters, and subsequently exported to two (2) loading berths for marine carriers via a marine cargo transfer system. The Alaska LNG Terminal is subject to PHMSA's jurisdiction under 49 CFR Part 193. Part 193, Subpart C – Design and Subpart D - Construction incorporates by reference the National Fire Protection Association (NFPA) 59A (2001 edition) for design, construction, and testing of LNG facilities and components, including impoundments and piping systems.

AGDC must use PIP system specifically for the following piping ***special permit segment***:

1. Approximately 2,670 feet of 20-inch diameter with 26-inch or 28-inch diameter outer pipe and 30-inch diameter with 36-inch or 38-inch diameter outer pipe for the LNG rundown lines that will be used to transfer LNG from the liquefaction areas to the LNG storage tanks;

2. Approximately 120 feet of four (4) 4-inch diameter with 10-inch or 12-inch diameter outer pipe for the LNG quench lines (two (2) supply and two (2) return lines) that will be used to cool down the boil-off gas at the inlet of the Boil-off Gas Compressors; and

3. Approximately 11,580 feet of dual 28-inch diameter with 36-inch diameter outer pipe for the marine cargo transfer lines that will be used to transfer LNG from the LNG storage tanks to the marine loading berth.[2]

Figure 2-1 shows the schematic of LNG components within the Alaska LNG Terminal. The blue lines show the PIP segments of the dual 28-inch diameter LNG marine cargo transfer lines from the LNG storage area to the loading berths. In accordance with 49 CFR 193.2001(b)(3), only the siting requirements in Part 193, Subpart B, apply to the marine cargo transfer system and associated facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank. The purple lines show the PIP segments of the 4-inch diameter LNG quench lines delivering LNG from the marine cargo transfer system to the BOG Compressors Suction Drums and returning LNG from the BOG Compressors Suction Drums to the marine cargo transfer system. Since the purpose of these 4-inch diameter LNG quench lines is to lower the temperature of the BOG entering the BOG Compressors and does not contribute to marine cargo transferring operation, PHMSA does not consider the 4-inch quench lines as part of the marine cargo transfer system. The lines exiting the Main Cryogenic Heat Exchanger (MCHE) where liquefaction takes place, shown as brown lines, are conventional stainless-steel (SS 304L) piping for LNG service. The green lines represent the PIP segments of the LNG rundown lines from the liquefaction area where the three Trains are located to the LNG storage area where LNG enters conventional stainless-steel (SS 304L) piping. The PIP system for the three (3) 20-inch diameter LNG rundown lines will originate along the outlet piping of each of the three trains, combine into a 30-inch diameter rundown header, and will terminate at a "T" leading to each LNG storage tank. The line from the "T" to each LNG storage tank, shown as brown lines, are conventional stainless-steel (SS 304L) piping.

[2] In accordance with 49 CFR 193.2001(b)(3), only the siting requirements in Part 193, Subpart B, apply to the marine cargo transfer system and associated facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

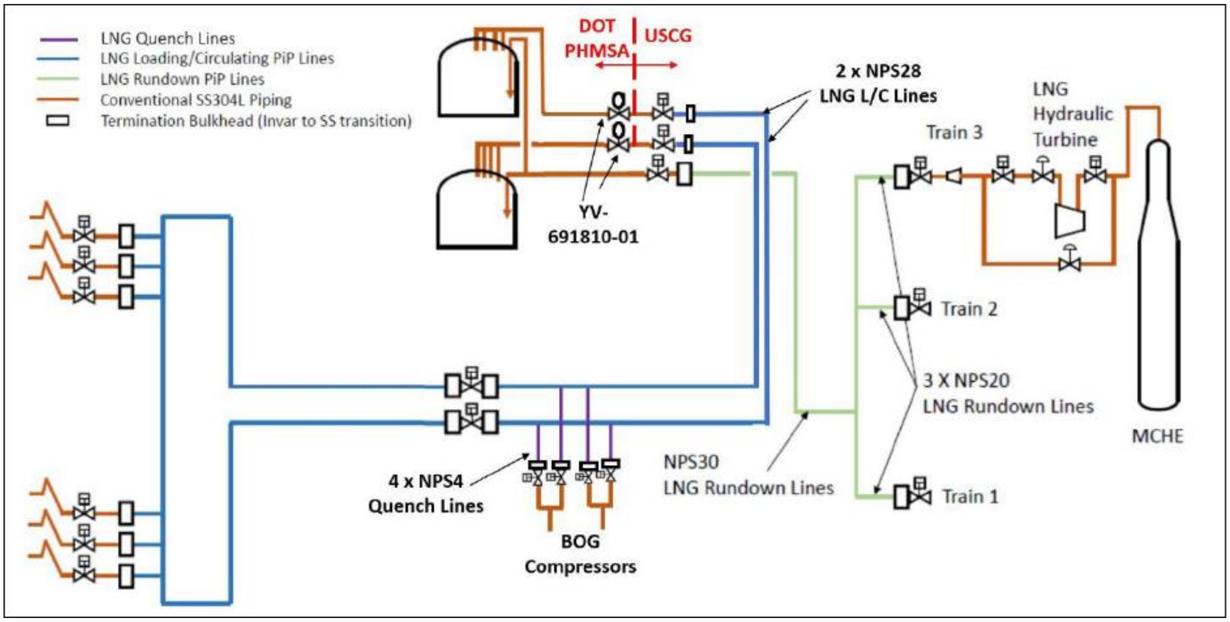

Figure 2-1: Schematic for LNG Loading/Circulation Lines and LNG Rundown Lines

Invar 36 (UNS K93603) will be used as the material of construction for the inner pipe (i.e., primary LNG containment), and austenitic steel of Type 304L stainless steel (SS 304L) will be used for the outer pipe, which serves as a secondary containment. The LNG rundown lines from the outlet of each of the three liquefaction trains will be comprised of 20-inch diameter Invar 36 inner piping with 26/28-inch diameter SS 304L outer piping. These three (3) 20-inch LNG rundown lines will combine to a rundown header that is comprised of a 30-inch diameter Invar 36 inner pipe with 36/38-inch diameter SS 304L outer pipe. Additionally, AGDC will use PIP technology for four 4-inch diameter LNG quench lines (two (2) supply and two (2) return lines) that will be used to cool down the boil-off gas to the inlet of the Boil-off Gas Compressors. The 4-inch diameter quench lines will be Invar 36 inner piping, approximately 120 feet in length, and fitted inside a 10/12-inch diameter SS 304L outer pipe. The quench lines will be connected to the dual 28-inch diameter marine cargo transfer lines using fabricated PIP tees and continue to the northern edge of the boil off gas compressor unit spill collection area where the PIP transitions to conventional stainless-steel piping. The outer diameters are different in size (i.e., 26/28-inch, 36/38-inch, 10/12-inch) because there are two (2) PIP technology vendors solicited, Technip/Genesis (Genesis) and InTerPipe (ITP), who use slightly different methods to insulate the annulus between the inner pipe and the outer pipe. One vendor uses Aerogel insulation and centralizes the inner pipe within the outer pipe, and the other vendor uses Izoflex insulation and allows the insulated inner pipe to rest at the bottom of the outer pipe (the insulation is sufficiently robust). The final outer piping diameters will be selected prior to the construction phase. Since the outer piping is considered the impoundment system, the use of PIP technology for LNG transfer piping (i.e., LNG rundown lines) will result in an enclosed transfer line and drainage channel, which is prohibited under 49 CFR 193.2167 except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike.

AGDC will use PIP technology for 11,580 feet (3,530 meters) of the dual 28-inch diameter inner pipe with 36-inch diameter outer pipe for the LNG marine cargo transfer lines from the LNG storage area to the loading berths. In accordance with 193.2001(b)(3), only the siting requirements in Part 193, Subpart B, apply to the marine cargo transfer system and associated facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank. As shown in Figure 2-1, PIP technology will be used for the segments of the LNG marine cargo transfer lines downstream of the last valves located immediately before the storage tanks. On June 23, 2016, the U.S. Coast Guard (USCG) Sector Anchorage issued a conditional letter approving the use of AGDC's PIP installation for the marine transfer lines with certain stipulations (see Appendix A).

The LNG rundown lines will traverse from the process (i.e., liquefaction) area to the container (i.e., LNG storage tank) area, and the LNG quench lines will traverse from the container (i.e., LNG storage tank) area to the process (i.e., BOG compressor) area. NFPA 59A (2001 edition) Section 2.2.1.1(2) requires an impounding area and drainage system to minimize the possibility of the accidental discharge of LNG at containers from endangering structures, equipment, or adjoining property or from reaching waterways. Section 2.2.1.2 requires that process areas must be graded, drained, or provided with impoundment in a manner that minimizes the possibility of accidental spills and leaks that could endanger structures, equipment, or adjoining property or that could reach waterways. A secondary containment system consisting of graded areas and drainage channels has typically been constructed underneath or adjacent to LNG transfer piping to channel potential spills of LNG into an impoundment area designed for a specified volume of LNG. Neither Part 193 nor the 2001 edition of NFPA 59A (incorporated by reference, see 49 CFR 193.2013) currently addresses the use of PIP design as an impounding system.

Section 193.2167 prohibits a covered impounding system except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike. Since the outer pipe will serve as the secondary impoundment system and will completely cover the inner pipe, the PIP is considered a covered impoundment system.

The brown lines shown in Figure 2-1 are LNG product lines, LNG product headers, and LNG quench lines that will be designed as conventional piping. These segments of conventional piping consist of stainless steel (SS 304L) piping, external insulation, and associated conveyance trenches. These conventional piping segments will be required to comply with the requirements in 49 CFR 193.2167 - Covered Systems and 49 CFR 193.2173 – Water Removal.

The Alaska LNG Terminal will be located on the west coast of the Kenai Peninsula near Nikiski on the eastern shore of Cook Inlet (see Figure 2-2). The Alaska LNG Terminal consists of onshore LNG plant facilities and marine transfer facilities. The Alaska LNG Terminal consists of three liquefaction trains, two LNG storage tanks, and associated components, which are jurisdictional to PHMSA. The marine transfer facilities are jurisdictional to the USCG, with the exception of meeting the siting requirements jurisdictional to PHMSA under 49 CFR 193, Subpart B. Figure 2-3 shows the two loading berths at the marine terminal. The ***special permit segment*** is comprised of the following piping segments:

1. Three (3) 20-inch diameter and one (1) 30-inch diameter LNG rundown lines, approximately 2,670 feet (814 meters) in total length, located in the onshore LNG terminal between the liquefaction area and LNG storage tank area; and

2. Four (4) pipe segments of 4-inch diameter quench lines, each approximately 120-feet in length, located near the BOG Compressor area in the onshore LNG terminal.

As shown in Figure 2-2, the Special Permit Segments are completely inside the Alaska LNG Terminal boundary. The vicinity of the Special Permit Segments is defined as the 901-acre onshore site identified for the Liquefaction Plant and shown in Figure 2-2.

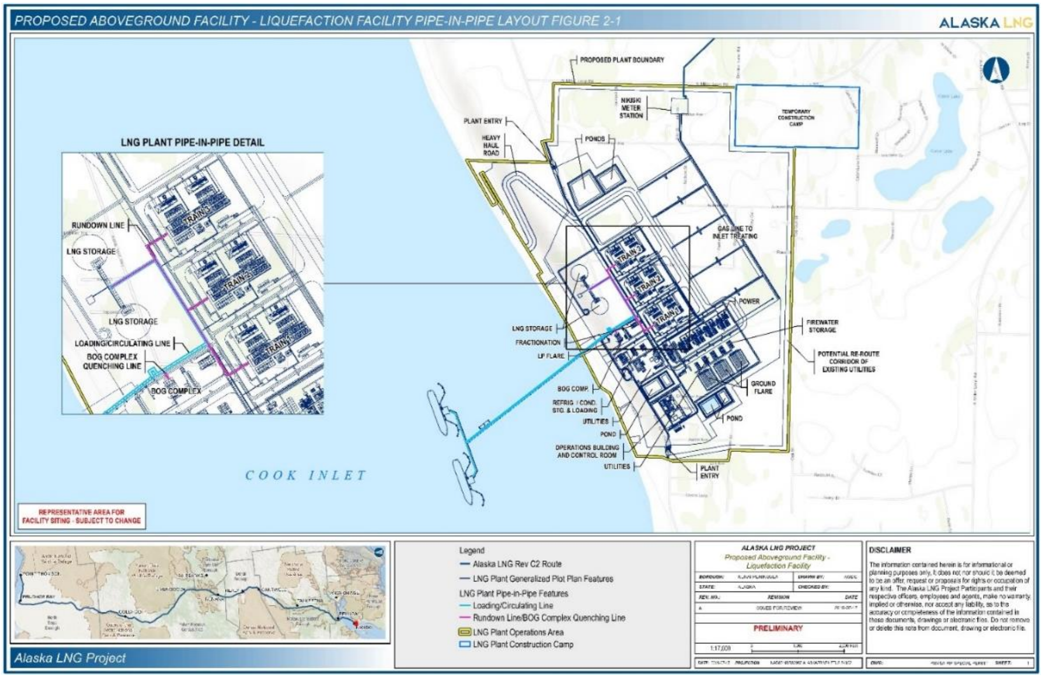

Figure 2-2: Alaska LNG Liquefaction Plant Site Map

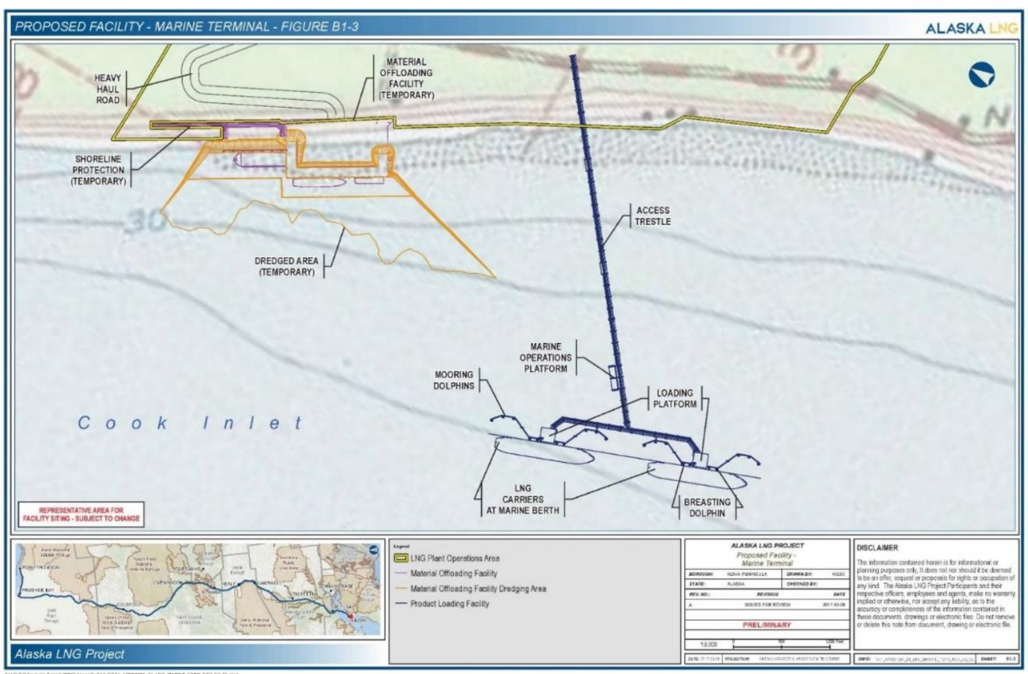

Figure 2-3: Alaska LNG Marine Transfer Facility Map

2.1.1. Design Elements

As defined in 49 CFR 193.2007, Definitions, an "Impounding System includes an impounding space, including dikes and floors for conducting the flow of spilled hazardous liquids to an impounding space." Conventional spill containment systems incorporate an open culvert-type concrete channel or trench that is designed to handle contact with cryogenic liquid and is typically located adjacent to or underneath LNG transfer piping. Furthermore, conventional LNG transfer piping is of single-wall stainless steel (SS 304L) design installed with an outer insulation layer to maintain cryogenic temperatures and minimize heat loss, as well as a weather-resistant coating or jacket.

AGDC will use Invar 36 (UNS K93603) for the inner pipe (i.e., primary LNG containment) while the SS 304L outer pipe serves as secondary containment. The inner pipe will be wrapped with insulation. Depending on the selected PIP vendor, the annular space between the inner pipe and outer pipe will be dried to at least negative 40 degrees Fahrenheit (°F) and will be either in a vacuum stage or purged with inert gas. For both PIP vendors, the annulus outlet gas will be monitored for hydrocarbons using conventional infra-red methane-in-nitrogen gas detectors. Also for both vendors, annulus pressure will be monitored; with an increase in pressure indicating a possible leak. For PIP technology, a release from the inner pipe will be contained within the PIP system's secondary containment outer pipe. The potential for ignition of a flammable vapor cloud and other subsequent hazards from a release of LNG from the inner pipe will be significantly decreased with the use of the PIP application for LNG transfer piping.

2.2. Site Description

The ***special permit segment*** encompasses the land under the ***special permit segment*** piping, which include the LNG rundown lines and the LNG quench lines. The ***special permit segment*** lies within, and represents a very small portion of, the Alaska LNG Liquefaction Terminal site, which is located on the Kenai Peninsula along the eastern shore of Cook Inlet in Nikiski, Alaska (Figure 2-2). The Kenai Peninsula is largely rural and undeveloped with most of it forested and much of it in Federal (e.g. Kenai National Wildlife Refuge, Kenai National Forest, Kenai Fjords National Park) and State ownership; however, some coastal areas have been industrialized and contain existing infrastructure related to marine transport and oil and gas processing. The Kenai Peninsula

Borough has a population of 58,533. The population of Nikiski, one of the larger towns in the borough, was 4,493 in 2010 according to the U.S. census. Other towns in the borough include Kenai (population 6,942) located 8 miles to the south of the site, Soldotna with a population of 3,759 located 15 miles to the southeast, and Homer with a population of 3,759 located 70 miles to the south. The Kenai Peninsula is within the Cook Inlet Basin Ecoregion. Climate in the region is mild and maritime, with a reported mean annual high temperature of 44.8 °F, mean rainfall of 18.16 inches, and mean snowfall of 68 inches, for Kenai, Alaska, about 8 miles south of the Alaska LNG Liquefaction Facility site.

Cook Inlet is a very large estuary, approximately 200 miles long from the mouth at the Gulf of Alaska to the Knik Arm near Anchorage, approximately 60 miles wide over much of its length, and encompassing an area of approximately 12,000 square miles. Hydrodynamically, Cook Inlet is a high-energy environment with one of the largest tidal ranges in the world (26 feet) and very strong tidal currents (over 6.5 knots peak flood and over 5.5 knots peak ebb). Heavy ice is present in Cook Inlet November-March.

The Liquefaction Plant site is located at approximately 60° 40' N latitude, 151° 23' W longitude, on the eastern shore, midway up Cook Inlet and just south of the prominence known as the East Foreland. The forelands (East and West Forelands) mark the boundary between what are known as Lower and Upper Cook Inlet. North of approximately latitude 60° 40' N, all Cook Inlet waters below the high tide line are State waters and the water bottoms are owned by the State. South of that area, Cook Inlet water bottoms more than 3.0 nautical miles seaward of the shoreline are Federal lands.

Commercial, personal use and subsistence, and recreational fishing are also prevalent in Cook Inlet. Commercial fishing in Upper Cook Inlet consists of fishing for the five species of Pacific salmon (*Oncorhynchus* spp.) using gill nets (either set nets or drift nets) in July-August. Recreational and personal use fishing in the Upper Cook Inlet occurs primarily in the anadromous streams flowing into Cook Inlet and is for salmon, rainbow trout (*Oncorhynchus mykiss*), Dolly Varden char (*Salvelinus malma*), and eulachon (*Thaleichthys pacificus*). All of Cook Inlet and anadromous streams flowing into it that support salmon have been designated as essential fish habitat by the National Marine Fisheries Service (NMFS). Upper Cook Inlet is also frequented by marine mammals, with the most common being harbor seal (*Phoca vitulina*) and beluga whale (*Delphinapterus leucas*). Belugas found in Cook Inlet are an isolated population of 338 belugas that are listed as endangered under the Endangered Species Act (ESA).

The study area for the FEA includes the Alaska LNG Liquefaction Terminal site and adjacent waters of Cook Inlet. The site lies within a partially industrialized area; adjoining properties to the north include three marine terminal facilities. The onshore Liquefaction Plant site encompasses 902 acres, and is currently a mixture of industrial, residential, and open land (Table 2) containing 7 residential buildings and 3 commercial buildings. Industrial use of the site consists largely of material sales. The Kenai Spur Highway (Route 1) traverses the Alaska LNG Liquefaction Terminal site from north to south, and will be rerouted to the west of the site during construction. Other paved and unpaved secondary roads are located on the plant site. When developed, the site will be a single parcel constructed and operated solely as a Liquefaction Plant.

TABLE 1. CURRENT LAND USE STATUS ON ALASKA LNG LIQUEFACTION TERMINAL SITE

National Land Cover Database Status of Land in the Alaska LNG Liquefaction Terminal Site					
Industrial	**Forest**	**Open Land**	**Open Water**	**Residential**	**Total**
8.8 ac	473 ac	159 ac	0.9 ac	260 ac	901.7 ac
1 %	52.5 %	17.6 %	0.1 %	28.8 %	100 %

Relief on the Liquefaction Plant site is gradual with elevations ranging from 90 to 140 feet above mean sea level over the 902 acres, but along Cook Inlet, the site drops off precipitously forming a near vertical coastal bluff approximately 100-125 feet tall. Below the bluff lies a broad intertidal area. Surficial sediments in the intertidal area consist of silty sand and gravel with sporadic boulders. Physical and chemical analyses of samples collected from the intertidal area revealed no contamination of the sediments. Ownership of the intertidal area as well as subtidal areas is held by the State; currently there are 8 shore fishery leases in the intertidal areas bordering the Liquefaction Plant site. These leases are issued by the Alaska Department of Natural Resources to commercial fishermen for setting shore-based gill nets for salmon fishing, and provide the holders with priority rights when fishing.

The forested area includes deciduous forest and mixed deciduous/coniferous forest. Coniferous forests are dominated by white spruce (*Picea glauca*), black spruce (*P. mariana*), and Sitka spruce

(*P. sitchensis*). Deciduous forests are dominated by quaking aspen (*Populus tremuloides*), balsam poplar (*P. balsamifera*), black cottonwood (*P. trichocarpa*), and Kenai birch (*Betula kenaica*). A single pond (1-2 acres in size) with no outlets is located in the most southerly portion of the Liquefaction Plant site. There are no streams or other flowing waters within the site's boundaries. A total of 6.21 acres of vegetated wetlands are found on site, with most surrounding the aforementioned on-site pond. These wetlands are palustrine emergent wetlands and palustrine scrub-shrub wetlands.

3. ALTERNATIVES

AGDC has the option of constructing conventional LNG product lines and quench lines with open conveyance trenches, which would not require PHMSA to issue a special permit. This will require that the Project's LNG rundown line, LNG quench lines and impounding system be in full compliance with all applicable Part 193 requirements, including Section 193.2167 Covered Systems and 193.2173 Water Removal. Conventional piping for LNG product lines and LNG quench lines is the No Action alternative that will not require issuance of a Special Permit. The Action (Applicant-Preferred) alternative reflects AGDC's LNG rundown and quench lines to be designed and constructed using PIP technology for which a special permit with conditions will be required. The No Action Alternative (i.e., conventional piping design) is described in Section 3.1, and the Action Alternative (i.e., PIP design) is described in Section 3.2.

3.1. No Action Alternative (Conventional Piping Design)

The "No Action Alternative" or a denial of the special permit request would require AGDC to use a conventional piping system design for the LNG rundown transfer line, which would consist of a design featuring open drainage channels or troughs as the impounding system for conveying potential LNG spills to a below-ground impoundment sump. The details related to conveyance/impoundment systems and public safety are described below. Figure 3-1 shows the general layout for a conventional pipe-in-trough (PIT) system to contain any spills from the liquefaction area to the LNG storage tank area in the event that a PIP system is not utilized. As noted in Figure 3-1, a No Action Alternative will require a trenching system serving the east-west pipe-rack portions for the rundown lines and larger trench sized for the LNG rundown header. The

No Action Alternative also requires an impounding system serving the entire piping length of the LNG quench lines. Figure 3-2 shows the general layout of the PIP design for comparison.

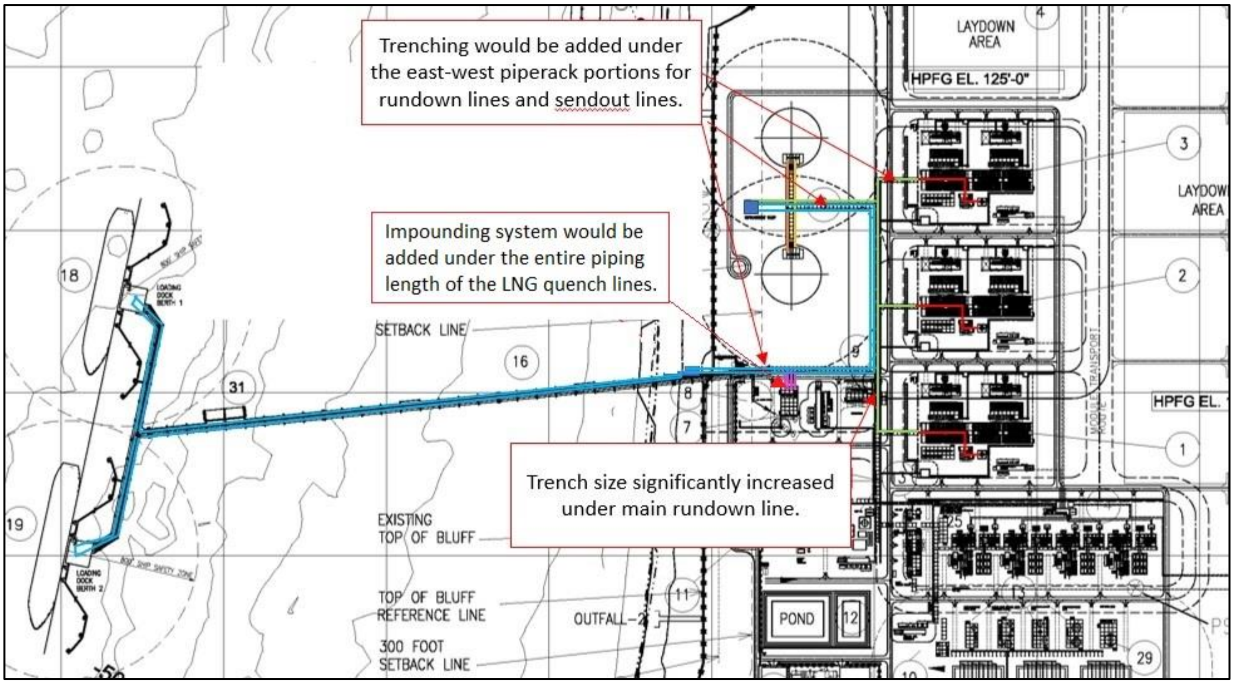

Figure 3-1: Conventional Pipe-in-Trough (PIT) Layout

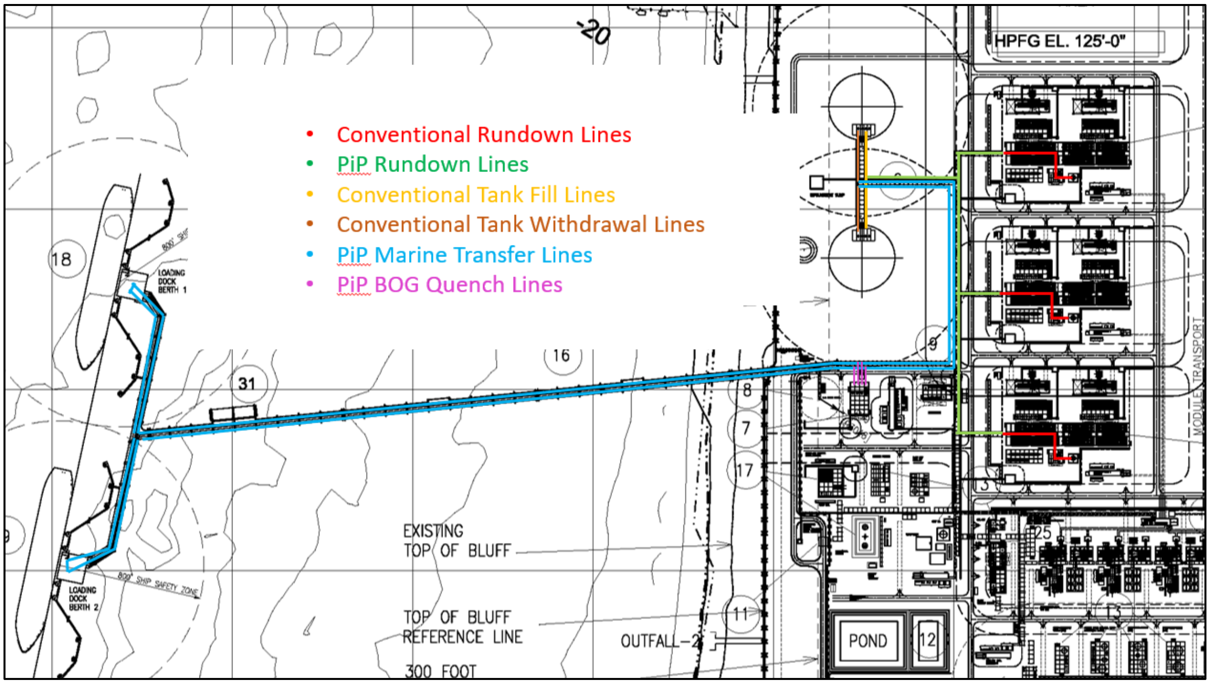

Figure 3-2: Pipe-in-Pipe Layout

3.1.1. Conveyance and Impoundment

For the 20-inch and 30-inch diameter LNG rundown lines and 4-inch LNG quench lines, conventional piping design must meet the following siting and sizing requirements:

- PHMSA FAQ guidelines used in determination of exclusion zones in accordance with Sections 193.2057 and 193.2059 will require a design spill from a 2-inch diameter hole size for piping, i.e., rundown lines, that is larger than or equal to 6 inches in diameter. On the other hand, the design spill for PIP segments, under the Action, will be a 1-inch diameter hole size.

- PHMSA FAQ guidelines used in determination of exclusion zones in accordance with Sections 193.2057 and 193.2059 will require a design spill from a full-bore or guillotine rupture for piping, i.e., quench lines, that are less than 6-inches in diameter. On the other hand, the design spill for PIP segments, under the Action, will be 1-inch diameter hole.

- Section 2.2.2.2 in NFPA 59A (2001 edition), incorporated by reference in Part 193, requires sizing of impounding areas based on the greatest volume of LNG, flammable refrigerant, or flammable liquid that can be discharged into the area during a 10-minute period from any single accidental leakage source. PHMSA LNG FAQ DS2 specifies the guideline for single accidental leakage source as a hole of 2 inches in diameter for piping segments greater than or equal to 6 inches in diameter or a full-bore rupture for piping segments less than 6 inches in diameter. According to the June 2019 Draft Environmental Impact Statement for the Alaska LNG Project, FERC will evaluate the spill containment capacity 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. As a result, the sizing of trench (i.e., conveyance systems) for conventional piping design in the liquefaction area will consider a full-bore rupture of the LNG rundown line at the maximum liquefaction rate from a single liquefaction train for a spill duration of 10 minutes. In addition, the sizing of trench in the storage tank area will consider a full-bore rupture of the LNG rundown line at the maximum combined liquefaction rate from all three liquefaction trains for a spill duration of 10 minutes. The spill volume based on the largest flow capacity from a full-bore rupture of a single pipe required by FERC will be larger than the spill volume from a single accidental leakage source prescribed in NFPA 59A (2001 edition) Section 2.2.2.2.

Under the No Action Alternative, as stated above, the spill containment is made up of a channel or trough to convey the liquid spills and may require vapor barriers to restrict the dispersion of the ½ lower flammability limit (LFL) flammable vapor-gas concentration from extending beyond the property lines. To satisfy 49 CFR Part 193, in order to contain the design spill volume, the spill containment system would be extended and expanded to include the 20-inch diameter and 30-inch diameter rundown lines and 4-inch quench lines. An additional 2,900 feet of trenching and grading would also be necessary to adjust for the long lengths of conventional lines to make sure all spills are directed to the safe collection areas.

3.2. Action Alternative (PIP System)

If the special permit application is issued, AGDC will design, construct, operate, and maintain the PIP system for the LNG rundown line in accordance with the provisions in 49 CFR Part 193 that have not been waived, including, but not limited to the requirements of 49 CFR 193.2155, and as specified in the special permit conditions. The PIP system special permit conditions will require specific engineering design and construction requirements, as well as operation and maintenance (O&M) procedures.

3.2.1. Heat Transfer

Cryogenic PIP technology is comprised of an Invar inner pipe designed for the process conditions of the LNG rundown lines, with Izoflex™ (or Aerogel) insulation wrapping the inner pipe, located in the continuous annular space between the inner and outer pipe. In addition, depending on the vendor; the inner annulus either operates at slightly above atmospheric pressure (maximum 15 pounds per square-inch gauge pressure (psig)) to maintain a N_2 purge rate, or at a partial vacuum (10 – 20 millibar). The overall heat transfer when using this system is typically half of what may occur with conventional insulation. Therefore, the reduction in heat transfer corresponds with a reduction in boil-off gas production and therefore less compressor usage at the Project which results in less emissions.

In addition, the reduction in heat transfer adds operational flexibility related to recirculation. In a conventional system, recirculation of LNG will need to be a constant operation where cold LNG is recirculated to flow the "warm" LNG back to the storage tanks where the "warm" LNG will flash and enter into the BOG system. In a PIP system, due to the reduction in heat transfer, recirculation pumps can operate at a lower flow rate. Alternatively, the recirculation pumps can operate in a start/stop mode; where recirculation is done for a period of time to provide "cold" LNG to the PIP system and once refreshed with cold LNG, the PIP system could sit without recirculation until the LNG warmed up and needed to be recirculated with "cold" LNG. Either option results in less electricity consumption for the LNG pumps. Therefore, the use of PIP technology will decrease environmental impacts.

3.2.2. Bellows Reduction

The inner pipe of invar has a coefficient of thermal expansion that is 10 times lower than that of normal stainless steel. This material therefore minimizes the expansion and contraction of the pipeline and mitigates the need for expansion loops or bellows.

3.2.3. Description of Design Elements and Construction Methods

The PIP system (technology) used for the Alaska LNG Terminal through the special permit grant will be designed with an inner pipe for LNG service constructed of 36% nickel and 64% iron alloy material (UNS K93603), commonly referred to as Invar. AGDC will use Invar due to the minimal coefficient of thermal expansion, 0.8×10^{-6} in/in-°R, approximately one tenth that of stainless steel, thereby reducing the need for bellows or expansion loops. Further, the high nickel content in Invar provides increased ductility while in cryogenic service, helping to prevent brittle failure, while also minimizing fracture propagation.

Insulation material will be wrapped around the inner pipe, located in the continuous annular space between the inner and outer pipe (see Figure 3-3). This annular space and the insulating material will limit overall heat leak to acceptable design levels. AGDC will construct the outer pipe of stainless steel (SS 304L) to provide a method of conveyance and confinement in the event of a leak of LNG from the inner pipe, while maintaining full process and mechanical integrity by withstanding sudden internal pressure rise and any thermal deformation due to rapid exposure to a cryogenic liquid.[3] The inner and outer pipe design pressure will be 387 pounds per square inch gauge (psig) for the BOG quench lines and 120 psig for the rundown lines. The design pressure will be confirmed during final design.

AGDC used finite element analysis software Ansys Mechanical version 18.2 to perform a local stress analysis on a 2-meter piping segment with leak scenarios of 0.11-inch and 1-inch hole sizes applied to the inner pipe to determine the maximum stress on the outer-pipe. The modelled scenarios resulted in stress values under the maximum allowable values per ASME B31.3. Further details for the LNG rundown line will be developed by AGDC as the final design progresses. Despite the leak scenario testing using a 1-inch hole, PHMSA's LNG FAQ DS2 actually suggests a minimum hole size of 2-inch diameter for a design spill from piping segments greater than or equal to 6 inches in diameter (applicable to the LNG rundown line) and a full-bore or guillotine rupture of piping segments less than 6 inches in diameter (applicable to the 4-inch quench lines)

[3] Global stress analysis (Attachment 1, CTR-02 and CTR-03) and Local Finite Element Analysis (FEA) stress analysis (Attachment 1, CTR-08 and CTR-09) were performed on the 0.11-inch equivalent-diameter credible leak scenario and 1-inch diameter worst-case leak scenario to determine the maximum stress on the outer-pipe. The modelled scenarios resulted in stress values under the maximum allowable values per ASME 31.3.

as part of the siting analysis. For this reason, PHMSA requires in condition 8(d) that AGDC must complete a shock load study during the final design phase to demonstrate that the outer pipe can successfully withstand an LNG leak at design pressures from the inner pipe from a hole size of at least 2-inch diameter in the rundown line and 4-inch in the quench lines. A complete list of conditions can be found in Section 7.

The PIP system will include valves at the end of the system to isolate the system in the event of a leak from the inner pipe to the outer pipe. This will allow the PIP system to be taken out of service in the event of a leak, safely de-inventoried, and then replaced. The lines will be de-inventoried to a location based on the failure point. In general, the PIP annulus will be de-inventoried via vent valves or relief valves that lead to the BOG system.

During the construction phase, shop fabricated segments of PIP are welded together. Once welding is complete, the inner pipe will be examined via radiographic non-destructive examination (NDE) and hydrotested. After testing of the inner pipe and installation of insulating blankets, the outer pipe segments of the PIP are welded together. The outer pipe welds will also be non-destructively examined and then re-tested as appropriate with technique such as pneumatic leak-testing, vacuum-testing, or hydrotesting within the segments. Upon final installation of the PIP system, the inner pipe will be pneumatically leak-tested prior to commissioning. PHMSA will require that prior to the introduction of hazardous fluid, AGDC provides to PHMSA the procedures and records to demonstrate that leak testing meets the requirement in NFPA 59A (2019 edition) Chapter 10. Furthermore, the leak monitoring system will include: use of fiber optic cables, maximum and minimum design set points for alarms and emergency shutdown, and system inspections, testing and frequency, and response actions and time.

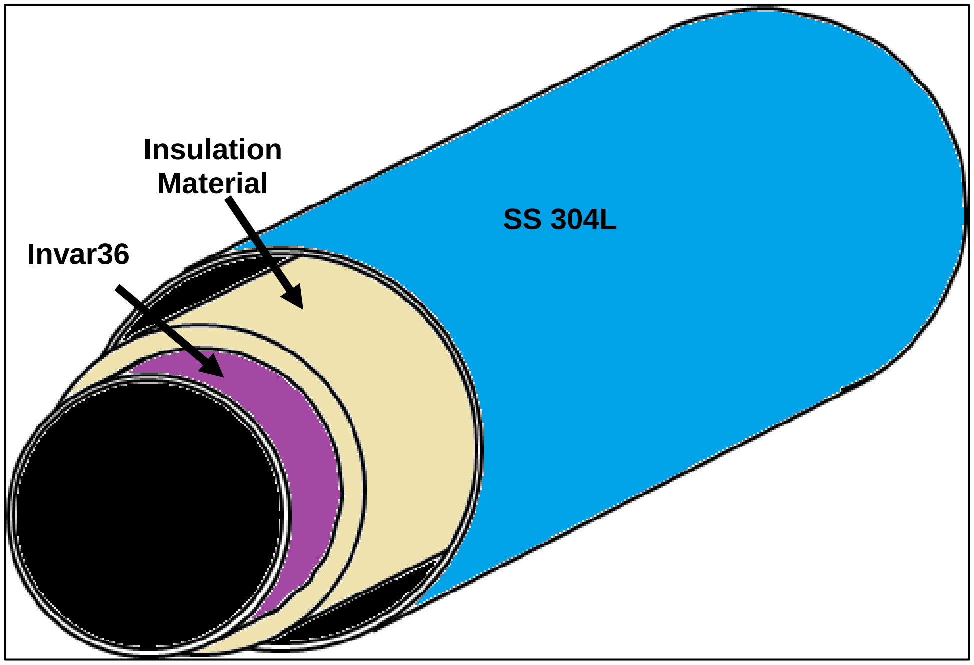

Figure 3-3: Cross-Sectional View of Pipe-In-Pipe

AGDC's application for a special permit requested relief from the following regulations: Sections 193.2167 Covered Systems and 193.2173 Water Removal.

The special permit grant authorizes AGDC to utilize the PIP system for the LNG rundown lines and LNG quench lines. Without the special permit grant, the LNG rundown lines and LNG quench lines must meet applicable requirements for process piping under 49 CFR Part 193 Subparts C and D and the incorporated NFPA 59A (2001) Chapter 6 Piping Systems and Components. The PIP system used for the LNG rundown lines and LNG quench lines will also be subject to additional mitigation measures that impose more rigorous fabrication and testing requirements, construction, and O&M monitoring requirements defined in the PIP special permit conditions by PHMSA including the referenced specifications and procedures developed by AGDC. Brief descriptions of the conditions are discussed below. Section 8 of this FEA has a complete list of safety conditions.

- Since NFPA 59A (2001 edition), incorporated by reference by Part 193 Subparts C - Design and D - Construction, does not provide provisions for PIP system, PHMSA requires that the PIP system must be designed in accordance with Section 10.13 in NFPA 59A (2019 edition). Section 10.13 requires both the inner and outer pipe must be designed, fabricated, examined and tested to ASME B31.3. Section 10.13 also requires the outer pipe to withstand the release conditions from the inner pipe. This condition ensures the integrity of the outer pipe and minimizes the risks to the public in the events of releases from the inner pipe.

- During the final design phase, AGDC must submit the design calculations that demonstrate PIP system integrity for design loadings including but not limited to: shock loads on the outer pipe due to an inner pipe LNG release at design pressures, support conditions, ambient-to-operational thermal stresses, static and dynamic loads, slug flow and loads developed from surge analysis, loads arising from credible thermal bowing, and natural hazard design loadings. The PIP system will be designed for natural hazard design loadings e such as wind and seismic loads. This condition ensures the integrity of the outer pipe from internal impact (i.e., releases from the inner pipe) and external impact (i.e., natural hazards).

- Prior to shop and field fabrication, AGDC must submit the shop and field fabrication procedures that address at a minimum the following items: girth weld testing, insulation continuity and installation, field installation of individual inner and outer pipe segments, and bulkhead connections. This condition ensures that AGDC develop and follow proper procedures during the fabrication process, which reduces the risk of piping failure during operation.

- Since 49 CFR Part 193 does not require quality assurance and quality control plan, PHMSA requires AGDC to submit a QA/QC plan that addresses shop fabrication, transportation, materials testing and traceability, welding procedure specification approval, welder qualification, weld materials inspection, weld joint preparation and fit-up, non-destructive testing, pressure/leak testing procedures of the inner and outer pipes, inspection procedure approval, and documentation acceptance and recordkeeping.

- AGDC must continuously monitor the space between the inner and outer pipe (i.e., annulus space) for leakage and provide adequate response. This condition ensures that a leak from the inner pipe will be contained in a timely manner.

- PHMSA requires all test records must be made available for PHMSA's review to ensure all construction and commissioning test results are satisfactory.

3.2.4. Layout for Onshore Pipelines

The PIP system for the 20-inch diameter and 30-inch diameter LNG rundown lines will be used to convey LNG from each of the three trains to the LNG storage tank area. A bulkhead will be located in the LNG rundown line downstream of each train prior to the LNG flowing into a PIP rundown header, and then bulkheads will also be located in the LNG storage tank area. The bulkheads will allow the LNG rundown PIP line segment to transition back to conventional SS 304 piping prior to entering the LNG storage tanks. The bulkheads will be strategically placed to restrain the potential thermal expansion between the transition between the conventionally insulated SS 304 piping and Invar PIP. Additionally, AGDC will use PIP technology for four LNG quench lines that will be used to cool down the boil-off gas at the inlet of the Boil-off Gas Compressors. The quench lines will be connected to the dual 28-inch marine cargo transfer lines using fabricated PIP tees and continue to the northern edge of the boil off gas compressor unit spill collection area using bulkheads where the PIP transitions to conventional stainless-steel piping. During final design, AGDC will submit supporting documentation on the bulkhead connection details, including shop and field fabrication welding and installation of fittings.

3.2.5. Leak Monitoring

Leak monitoring will be achieved through:

- Temperature measurement by fiber optics on the outer pipe or in the annulus along the entire length of the pipeline;
- Continuous purging in the annulus with nitrogen gas, and monitoring for increased hydrocarbon content within the gas;
- Continuous pressure monitoring system for the annulus, and monitoring for increased pressure compared to background purge pressure; and
- Daily visual inspections the outer pipe by operators, noting condensation or icing will be conducted when ambient temperatures are above 32 degrees Fahrenheit.

During final design, AGDC will submit details and drawings subject to PHMSA's approval on the selected leak monitoring system for the PIP system, including specifics on the alarms, shutdown functions, and set points. AGDC will provide the nitrogen purge pressure during final design. In general, in the event of a leak from the inner pipe to the outer pipe, the operators will verify the leak, safely shut down the liquefaction units, and isolate the PIP section, as needed. Operators will work with the vendors of the PIP system to determine the appropriate repair based on the source of the leak. The line will be safely de-inventoried, warmed up, purged, repaired or replaced, tested, and placed back into service, as necessary. Additionally, AGDC will develop and implement written procedures to monitor and notify PHMSA in the event of a PIP failure.

4. ENVIRONMENTAL IMPACTS OF GRANTED ACTION AND ALTERNATIVES

The overall affected resources and associated consequences from the construction and operation of the Alaska LNG Terminal are addressed in the Environmental Reports (Resource Reports) included in the Applicant's FERC Application under Section 3(a) of the Natural Gas Act filed for the Alaska LNG Project on April 17, 2017 (see FERC Docket No. CP17-178-000).

The Study Area includes the Special Permit Segments including the LNG rundown lines and the LNG quench lines within the Alaska LNG Terminal site in Nikiski. The following sections describe the affected resources and compare potential environmental impacts of the No Action Alternative (i.e., conventional piping design) and Granted Action Alternative (i.e., PIP design).

4.1. Aesthetics/Visual Resources

The Alaska LNG Liquefaction Plant site is located near an industrialized area that contains existing infrastructure related to marine transport and oil and gas processing. Adjoining properties to the north of the Alaska LNG Liquefaction Facility site include three marine terminal facilities (Agrium's Nikiski Wharf, Kenai LNG Corporation's Kenai LNG Dock, and Tesoro Alaska's Port Nikiski Wharf). About half of the site is currently forested but there are also residential lands and industrial lands (gravel mining) on the site. Views of Mount Redoubt and other mountains in the Aleutian Range are present to the west of the site across Cook Inlet. To the east, the Kenai Mountains are visible. Areas with sensitive visual resources identified within 15 miles of the Liquefaction Facility site include:

- Residential areas in Nikiski;
- Views from the water in Cook Inlet;
- The Kenai National Wildlife Refuge;
- The Kenai River Special Management Area; and
- The East Foreland Lighthouse Reserve.

Key Observation Points (KOPs) identified near the Liquefaction Plant site include locations associated with the Nikiski/North Star Community School, Kenai National Wildlife Refuge, Kaleidoscope Charter School in Kenai, and the Pillars Boat Launch in the Kenai Rivers Special Management Area. These sensitive visual resource areas and KOPs are discussed in detail in Resource Report No. 8 in the April 2017 FERC Application and FERC's Environmental Impact Statement.

The alternative design features for the ***special permit segment*** will not substantively affect those visual resources and there are no other sensitive visual resource areas that will be impacted by the alternatives.

There are no additional, anticipated impacts to sensitive visual resources or Key Observation Points (KOPs) to the overall Project area from either the conventional design (No Action Alternative) or the PIP design. The footprint for the Liquefaction Facility will be the same regardless of the alternative, except that in the Preferred Alternative (PIP), the impoundment trench under the subject pipes (***special permit segment***) will be replaced by a gravel pad and a graded ditch of slightly smaller square footage than the PIT trench. Visually there will be no difference. The nearest KOP is 1.5 miles from the Project and the Project is not visible from this location. Potential impacts to visual resources from the No Action and Granted Action are minimal with no significant difference between the two alternatives.

4.1.1. No Action Alternative (Conventional Piping Design)

Although the conventional design would require additional equipment and infrastructure, including open conveyance trenches, there would be minimal visual impact because the area is primarily industrial and the conventional design would be associated with greater overall industrial facilities.

4.1.2. Granted Action Alternative (PIP Design)

The issuance of a special permit by PHMSA will result in nearly identical visual contrast to that of No Action Alternative. A PIP system will introduce larger diameter outer pipes on the LNG rundown lines and will not require a spill containment system. However, other than the PIP segments requested in this special permit, there are conventional piping at the Alaska LNG Terminal that require open conveyance trenches. The potential impact to visual resources will be minimal because the area is mostly developed and the potential impact has no significant difference to the No Action Alternative.

4.2. Air Quality

Existing ambient air quality, emissions, and potential impacts associated with the construction and operations of the Alaska LNG Terminal are discussed in detail in Resource Report No. 9 in the April 2017 FERC Application. The assessment contained in Resource Report No. 9 included construction emissions for the Alaska LNG Terminal components based on the PIP design.

Existing ambient air quality, emissions, and potential impacts associated with the construction and operations of the Alaska LNG Terminal will not be significantly affected by either PIP or conventional design (i.e., PIT).

4.2.1. No Action Alternative (Conventional Piping Design)

The conventional PIT containment system would result in increased construction emissions due to additional construction equipment and operations required to install larger conveyance trenches for the LNG rundown header as well as conveyance trenches for the LNG quench lines at the Alaska LNG Terminal. However, the increased construction emissions would not significantly affect the overall air quality given the larger scale construction activities occurring simultaneously for the Alaska LNG Terminal.

4.2.2. Granted Action Alternative (PIP Design)

The PIP system will result in less construction emissions than a conventional system because it requires installing smaller conveyance trenches underneath the PIP LNG rundown header and no conveyance trenches underneath the PIP LNG quench lines at the Alaska LNG Terminal. Since LNG rundown header Other construction activity, including the construction of the pipe racks and substructure to support either the PIP or PIT conventional design will be essentially equivalent.

The PIP system will allow for reduced boil off gas generated in the rundown lines. This will result in lower boil off gas compressor usage, a reduction in fuel demand for the units, and subsequently fewer overall emissions resulting from power generation. In addition, with more boil off gas remaining in liquid form as LNG, there will be less overall demand for feed gas into the facility.

4.3. Biological Resources

The 900-acre Liquefaction Plant site is in an already partially developed industrial area, but a large portion of it is undeveloped and vegetated with deciduous, coniferous, and mixed coniferous-deciduous forests (66%) or scrub/shrub (8%) or herbaceous (2%) vegetation. The remainder (24%) is barren or developed land. The area under and along the PIP system is currently forested. During construction, the site will be cleared and graded, and much of it, including areas under and along the PIP system, will be resurfaced with gravel. Under No Action Alternative, the PIT and PIP design, a portion of this area will be excavated, and a concrete lined trough will be constructed. These construction activities will replace the vegetation with gravel or gravel and a concrete trough, and destroy most of the habitat value, resulting in limited use by wildlife during operations. These impacts (loss of) on vegetation and forested wildlife habitat from construction and normal operations will be identical under both the No Action and Granted Action.

No wetlands exist under or along the ***special permit segment***, so construction of either No Action Alternative or Granted Action Alternative will result in no impacts to vegetated wetlands.

Existing fish and wildlife resources are described in detail in Resource Report No. 3 in the April 2017 FERC Application. Large mammals like moose (*Alces americanus*), medium-sized mammals, and furbearers, such as porcupine (*Erethizon dorsatum*), red fox (*Vulpes vulpes*), ermine (*Mustela ermine*), least weasel (*Mustela nivalis*), snowshoe hares (*Lepus americanus),* and red squirrel (*Tamiasciuris hudsonicus*), as well small mammals like voles (*Microtus* spp.) and shrews (*Sorex* spp.) may utilize the site, at least occasionally. Numerous bird species utilize the natural environs on the site. Waterbird and shorebird use of the site is likely limited due to the general lack of wetlands and surface waters. Fish are unlikely residents of the site, as the only waterbody on the site is shallow and is thought to freeze to the bottom in winter. Potential impacts associated with the construction and operation of the Alaska LNG Terminal are discussed in detail in Resource Report No. 3 in the April 2017 FERC Application. Because the footprint of the Liquefaction Facility site will not differ based on selection of the Granted Action or the No Action, there will be no difference in impact between the two. In the Preferred Alternative (PIP), the impoundment trench under the subject pipes (***special permit segment***) will be replaced by a gravel pad and a graded ditch of slightly smaller square footage than the PIT trench, but the effect on biological resources will be the same. Most of the site's habitat value will be lost during construction of the site as the vegetation is cleared, land is graded, and replaced with impervious surfaces, gravel, lawn, and stormwater ponds; however, some wildlife will undoubtedly still use portions of the site during operations. The impact assessment contained in Resource Report No. 3 includes potential impacts associated with both construction and operation of the Alaska LNG Terminal based on the PIP design, but regarding construction and operations the relative effects of the No Action alternative (PIT conventional design) will not differ significantly from those described in the Resource Report for the Granted Action (using a PIP system) with the exception that if there was a release, the PIP system will be expected to have fewer wildlife impacts, as described below.

4.3.1. No Action Alternative (Conventional Piping Design)

Although LNG is nontoxic, LNG vapors at high concentrations can displace oxygen, resulting in potential asphyxiation. Other effects on wildlife include freeze injuries or fatalities from rapid temperature changes and injuries and mortalities from fire. Less-mobile animals, such as small mammals and wood frogs, will be unlikely to avoid impacts from released liquids. The conventional PIT design increases the potential for exposure of biological resources to released LNG during a failure. AGDC will be required to avoid and control the presence of foreign materials in the impoundment system in accordance with Subpart G, so direct impacts to released liquids will be minimal. However, released LNG will quickly vaporize, forming a cold, heavierthan-air vapor cloud, and mammals or birds flying over the area at the time of release could experience asphyxiation from the lack of oxygen until the vapor cloud warms and is dispersed by prevailing winds.

In the case of a release with no fire, wildlife will likely respond by moving away from the areas of cold liquid prior to receiving freeze burns but could be overcome by asphyxiation, as methane displaces oxygen. These effects will be expected to occur within a relatively small area within the site boundary – generally less than the area indicated in the dispersion estimates in Table 2-1. If a fire were to occur with the release of LNG, wildlife in the immediate vicinity of the fire will likely be injured or killed, particularly if floating on the surface.

The effects on biological resources will be minor. Few animals will be expected to be affected, as the trough and impoundment will generally provide poor habitat and will be situated within a larger graveled area inside the confines of an active industrial site. The effects will also be of short duration given the evaporation and dispersion rates of LNG.

4.3.2. Granted Action Alternative (PIP System)

The risk of exposure of biological resources to released LNG will be much less with the PIP design, as during the identified failure, released LNG will be captured by the outer pipe. In most cases, there will be no exposure of biological (wildlife) or physical (air quality and water quality) resources to LNG, and no resulting impacts on biological resources. In the highly unlikely event that both the inner and outer pipe failed simultaneously, impacts to wildlife will be higher than under the PIT alternative because there will be no means to contain spilled LNG. LNG will flow overland until full boil-off occurred. This will cause greater impacts from cryogenic temperatures to wildlife and habitat. In the event of ignition, a jet fire or pool fires could occur. This will cause greater impacts from fires to wildlife and habitat in the vicinity.

4.4. Geology, Soils, and Mineral Resources

Existing geology, soils and mineral resources, and potential impacts associated with the construction and operation of the Alaska LNG Terminal are discussed in detail in Resource Report Nos. 6 and 7 in the April 2017 FERC Application. The assessment contained in Resource Report Nos. 6 and 7 included potential impacts for the Alaska LNG Terminal based on the PIP design.

The relative effects of the No Action alternative PIT conventional design would not be significantly different with the following exception.

The Alaska LNG Terminal is located in an area of high seismicity, and therefore, seismic risks are potentially significant if not mitigated. The Project has performed a site-specific seismic hazard study[4] in accordance with NFPA 59A (2006 edition) and ASCE 7-05. The study determined the seismic design ground motions for three levels of design ground motion, the Operating Basis Earthquake (OBE), which has a 10% probability of being exceeded in 50 years, the Safe Shutdown Earthquake (SSE), which has 2% probability of being exceeded in 50 years, and the Design Earthquake (DE), as defined in ASCE 7-05, which is taken as ⅔ of the ground motion that has a 2% chance of being exceeded in 50 years. The study determined that the peak horizontal ground acceleration (PGA) for the OBE was 0.528 g, the PGA for the SSE was 0.897 g, and the PGA for the DE was 0.598 g. These PGA levels of ground motions are considered high compared to most locations in the U.S. The Project also performed a fault investigation and did not find any active surface faults at the Alaska LNG Terminal site.

To mitigate ground motion hazards, the AGDC has indicated the PIP system for the LNG rundown lines will be designed to resist DE ground motions. In addition, the PIP system will be seismically designed to satisfy the requirements of Section 6.1 of NFPA 59A (2001 edition). AGDC evaluated the potential for soil liquefaction at the Alaska LNG Terminal; except at the shoreline, the potential for soil liquefaction was low for all three ground motion levels. At the shoreline, the potential for soil liquefaction occurred in the top 9 feet of soil. Therefore, soil liquefaction mitigation measures were not deemed necessary in the Special Permit Study Area.

AGDC performed dynamic slope stability evaluations of the bluff area in the vicinity of the LNG tanks 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

[4] The site-specific seismic hazard study was provided in the FERC Application Resource Report 13, Appendix I.1.

least 427 feet from the top of bluff. The LNG spill containment basin that is closer to the top of the bluff would need to accommodate larger slope horizontal displacements.

AGDC has also performed a tsunami hazard evaluation[5] of the site and has concluded that the hazard is considered low for the onshore facilities and moderate for the marine facilities. Tsunamis at the Alaska LNG Terminal site could be generated by a great earthquake, like the 1964 event, from a flank collapse of the Augustine volcano or by a submarine landslide in the Cook Inlet. AGDC performed tsunami modeling studies and determined that the maximum wave crest elevation of +39 feet (mean lower low water [MLLW]) occurred at the highest astronomical tide from the landslide source with significantly lower heights from the other two sources. This wave would not reach the onshore LNG facilities because they are located on top of the bluff at an elevation of approximately +130 feet (MLLW) and would not reach the bottom of the pile caps on the marine trestle, which have a minimum elevation of +42 feet (MLLW). The wave may, however, increase erosion of the coastal bluff.

4.4.1. No Action Alternative (Convention Piping Design)

If a conventional PIT design were used, a spill containment system would be able to convey any spill into an impoundment system. The No Action alternative would affect soils in a localized manner. The construction of the trough and spill containment system would require additional excavation and construction, which could result in increased instability of the adjoining bluff area.

4.4.2. Granted Action Alternative (PIP System)

The grant of a special permit by PHMSA will result in less impact because the PIP system will not require excavation and construction of the trough and spill containment system and will, therefore, have less risk of increased instability and erosion. Although the PIP system is more susceptible to risks from seismic activity than the PIT design, the special permit will require the PIP system to be designed to satisfy the requirements of Section 10.13 of NFPA 59A (20019 edition).

[5] The tsunami hazard evaluation was provided in the FERC Application Resource Report 13, Appendix I.2.

4.5. Land Use

Existing land use resources and potential impacts associated with the construction and operations of the Alaska LNG Terminal are discussed in detail in Resource Report No. 8 in the April 2017 FERC Application. The assessment contained in Resource Report No. 8 included potential impacts for the Alaska LNG Terminal components based on the PIP system. The relative effects of the alternative PIT conventional design will not be significantly different.

4.5.1. No Action Alternative (Convention Piping Design)

The conventional design requires the use of areas for containment, and therefore, has a greater footprint. Although the system would be contained within the overall Project footprint of the Alaska LNG Terminal, the specific use of the land designated for the conventional system would be greater than that for the PIP design due to the need for spill containment areas.

4.5.2. Granted Action Alternative (PIP System)

The grant of a special permit by PHMSA will result in fewer impacts to land use. The PIP system requires less infrastructure and area than the conventional design (i.e., the PIP design does not require areas for spill containment below each pipe run).

4.6. Noise

Existing ambient noise conditions and potential impacts associated with the construction and operations of the Alaska LNG Terminal are discussed in detail in Resource Report No. 9 in the April 2017 FERC Application. Data was collected at selected representative noise sensitive areas (NSAs) nearest to the Alaska LNG Terminal. Existing ambient noise conditions at the studied NSA locations ranged from 39 to 59 dBA. Details of the existing ambient noise conditions are provided in the Alaska LNG FERC Application Environment Report, Resource Report No. 9, Appendix N.

The assessment of potential noise impacts contained in Resource Report No. 9 included construction noise estimates for the Alaska LNG Terminal components based on the PIP design. The estimated construction sound levels at NSAs during construction range from 53 to 67 dBA. The conventional PIT containment system would result in increased construction noise due to increased construction equipment and operations needed to install the conveyance trenches for the Alaska LNG Terminal.

Figure 4-1 shows the noise receptor locations adjacent to the AGDC LNG terminal site. Approximately 440 residential receptors and one recreational campground are located within 1 mile of the study area.

Figure 4-1: Noise Receptor Locations

4.6.1. No Action Alternative (Convention Piping Design)

A conventional design requires additional construction activity to install the spill containment and impoundment systems. Otherwise, there are no additional, anticipated noise impacts from a conventional design during operations. Although a conventional design may require additional maintenance activity during operations, maintenance noise would be negligible and consistent with operations of the facility.

4.6.2. Granted Action Alternative (PIP System)

The grant of a special permit by PHMSA will result in fewer noise impacts during construction. The PIP system design requires less construction activity on the bluff. Although the noise impacts from the conventional design are likely of relatively short duration, the impact is less from a PIP system design simply based on the area required to accommodate such a system and the supporting construction activity. Although a PIP system design may require less maintenance activity than a conventional design during operations, maintenance noise will be negligible and consistent with operations of the facility.

4.7. Human Health and Safety

A release of LNG would potentially produce flammable vapors at concentrations between 5 percent (%) and 15% in air. The resulting vapor cloud would ignite if the proper concentration was reached and the cloud comes in contact with an ignition source. Upon ignition, the flame front will begin to propagate at the laminar flame speed of the burning fuel, which is approximately 0.4 meters per second for methane. The presence of obstructions (e.g., pipes, beams, etc.) in the path of the flame will cause the front to accelerate; as the flame speed increases, an overpressure is generated due to the compression of the gases in front of the flame. This phenomenon is known as a deflagration. Due to the low reactivity of methane, however, flame acceleration from the ignition of an LNG vapor cloud is generally slow and would require large flammable clouds and congested volumes in order for a deflagration to produce damaging overpressures. Given the typical placement of impoundment basins away from structures and equipment, the more likely scenario, in the unlikely event of a release, is the ignition of a flammable cloud in an open area, with few if any obstacles (e.g., a pipe rack). In this case, flame acceleration would be much slower and driven primarily by flow instabilities; as a result, the buoyancy of the combustion products would tend to lift the flame front and flammable vapors, resulting in the typical fireball shape.

As discussed above, AGDC believes that a PIP system has a much lower rate of failure than a conventional single-walled pipe system because the inner conveyance pipe would not be exposed to atmosphere and would be protected by the enclosed secondary outer containment pipe. Therefore, failures of the inner pipe from atmospheric corrosion, accidental damage, or external events would be less likely to occur with the implementation of the PIP system with the additional mitigation measures implemented as special permit conditions.

In the unlikely event of a loss of containment of LNG from the inner pipe, the PIP system's enclosed secondary containment pipe will contain the spill. Unlike a conventional containment system with drainage channels or trenches, which is open to atmosphere and could allow a release of LNG to mix with oxygen in the atmosphere forming a flammable vapor cloud, the outer containment system will be designed to prevent an LNG release from reaching the atmosphere and igniting, consequently reducing the likelihood of a fire. In order for a release to the environment to occur from a PIP system, there must be simultaneous failure of the inner and outer pipe. PHMSA included special permit safety conditions in Section 7 of this FEA to reduce the risk of failure of the outer pipe following failure of the inner pipe. The other conceivable scenarios would be caused by outside force damage such as penetrations by wind borne missiles.

The potential for ignition of a flammable vapor cloud and other subsequent hazards from a release of LNG would be significantly decreased with the use of the PIP system for LNG transfer piping. Furthermore, AGDC evaluated the potential release of LNG from a 2-inch hole in the LNG rundown line and determined that the resulting ½-LFL flammable vapor dispersion exclusion zone would not extend offsite beyond the facility's property line that can be built upon.

Therefore, the use of the PIP system with the implementation of the special permit conditions will not significantly impact public and personnel safety beyond those adverse impacts that will be present from a conventional single wall conventional cryogenic piping and a spill containment trench system design.

4.7.1. No Action Alternative (Convention Piping Design)

No Action by PHMSA would result in a conventional design, which poses the following safety issues.

- The impounding space, noted in Section 2.0, would be placed near the Alaska LNG Terminal to collect a single accidental leakage source. The potential impact to personnel and public safety would be as follows:
    - The uncovered liquid conveyance system leads any liquid to the impounding space.
    - While there are approximately 440 residences and one recreational campground are located within 1 mile of the Alaska LNG Terminal, no residences nor the recreational campground are located within the thermal exclusion zone for either alternative.
    - Operation personnel may need to enter the LNG spill collection system to remove snow and ice that may collect in the impoundment system.
- The required vapor dispersion modeling demonstrates that the vapor cloud formation could extend beyond the Alaska LNG Terminal boundary line over the shoreline and navigable water.
- Thermal radiation and flammable vapor dispersion exclusion zones due to releases of design spills from the conventional piping design will be larger than for PIP system as shown in Figures 4-2 through 4-5.

Under the no action alternative, the following project-specific hazards for the LNG quench lines and rundown piping would be evaluated in determination of exclusion zones for compliance with the siting requirements according to 49 CFR 193.2057 and 193.2059, and the related requirements in NFPA 59A:

- Vapor dispersion from an LNG release resulting in a momentum dominated vapor cloud whose constituents may include flashed vapor, evaporated vapor, and aerosolized liquids; and
- Radiant heat associated from an LNG release resulting in a jet fire (following ignition of a momentum dominated vapor release).

In accordance with 49 CFR 193.2051 and 193.2059, and Section 2.2.3.4 in NFPA 59A (2001 edition), AGDC would be required to model a single 4-inch full bore rupture from conventional LNG quench lines and 2- inch diameter hole in the conventional LNG run down lines for a 10-

minute release duration as the design spill to determine the ½-LFL flammable vapor dispersion exclusion zone distances. The hole-size selection methodology is consistent with the recommended guidance in the PHMSA FAQ #DS2, dated July 18, 2018. AGDC selected the vapor dispersion input parameters in accordance with 49 CFR 193.2059(b).

As shown in Figure 4-2, the ½-LFL vapor dispersion due to release from 4-inch full-bore rupture of the conventional LNG quench line (shown as blue hashed circular area) extends beyond Alaska LNG Terminal's western property line over the shoreline, which may not comply with the requirements for flammable vapor exclusion zone. Under the no action alternative, AGDC must install sufficient mitigation measures to maintain the flammable vapor within the Alaska LNG Terminal's properly line or demonstrate legal control of the property under the flammable vapor exclusion zones to comply with Subpart B Siting requirements prescribed in 49 CFR 193.2059. As shown comparatively in Figure 4-2, the ½-LFL vapor cloud due to release from 1-inch-diameter hole in the LNG PIP quench lines (shown as pink hashed circular area) remain within in the Alaska LNG Terminal boundary.

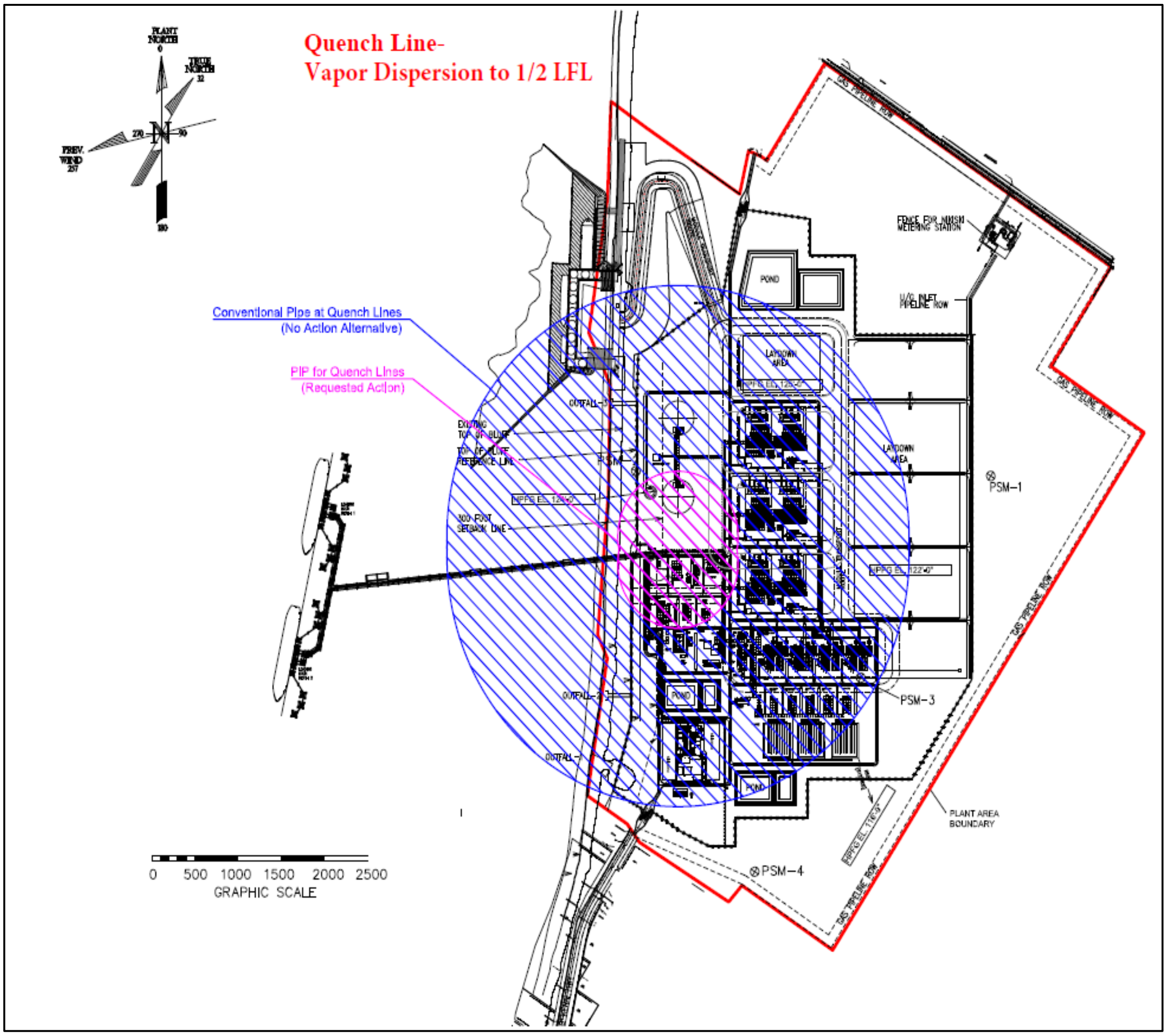

Figure 4-2: Flammable Vapor-Gas Dispersion Exclusion Zones to ½-LFL from the LNG Quench Lines Comparing PIP (Granted Action Alternative) and Conventional Piping (No Action Alternative)

As shown in Figure 4-3, the ½-LFL vapor dispersion due to release from 2-inch-diameter hole in the conventional LNG rundown piping (shown as green hashed area) extends beyond Alaska LNG Terminal's western property line over the shoreline, which may not comply with the requirements for flammable vapor exclusion zone. Under the no action alternative for the conventional LNG rundown piping, AGDC must install sufficient mitigation measures to maintain the flammable vapor within the Alaska LNG Terminal's properly line or demonstrate legal control of the property under the flammable vapor exclusion zones to comply with Subpart B Siting requirements prescribed in 49 CFR 193.2059. As shown comparatively in Figure 4-3, the ½-LFL vapor cloud due to release from 1-inch-diameter hole in the LNG PIP rundown piping (shown as orange hashed area) remain within in the Alaska LNG Terminal boundary.

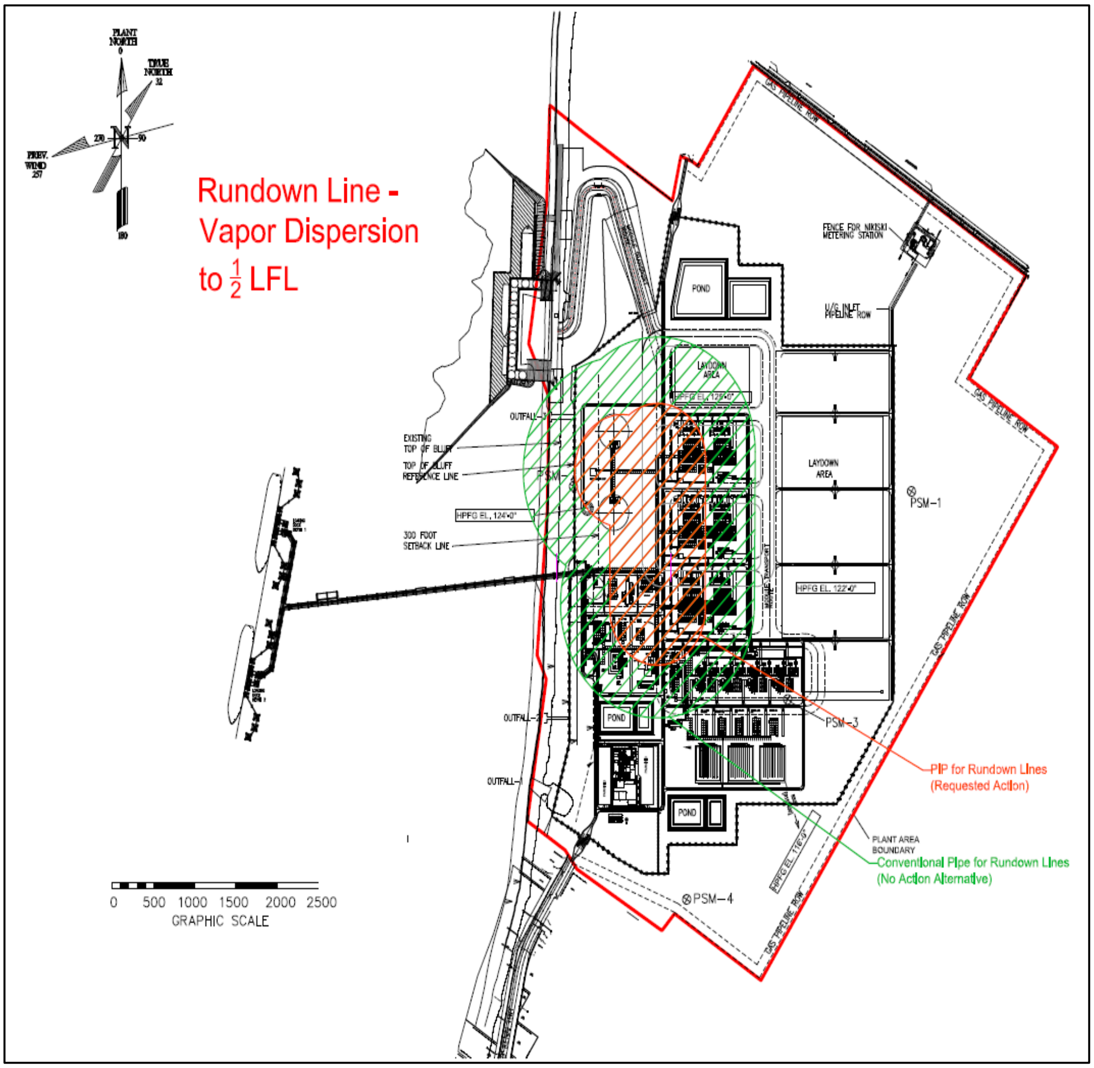

Figure 4-3: Flammable Vapor-Gas Dispersion Exclusion Zones to ½-LFL from the LNG Rundown Lines Comparing PIP (Granted Action Alternative) and Conventional Piping (No Action Alternative)

AGDC must evaluate the radiant heat effects from ignition of a momentum-dominated LNG vapor release or jet fire to demonstrated compliance with the siting requirements prescribed in 49 CFR 193.2051 and 193.2057 with respect to establishing thermal radiation exclusion zones for the Alaska LNG Terminal. AGDC will use the same atmospheric conditions from the flammable vapor dispersion simulations under the worst-case wind speed to compute the thermal radiation protection distances from a LNG jet fire.

As shown comparatively in Figure 4-4, the thermal radiation exclusion zones corresponding to the 1,600 Btu/ft^2-hr flux level from a LNG jet-fire due to release at 4-inch-diameter hole in the conventional quench lines (shown as blue hashed circular area) and 1-inch-diameter hole in PIP quench lines (shown as pink hashed circular area) do not extend beyond the Alaska LNG Terminal boundary.

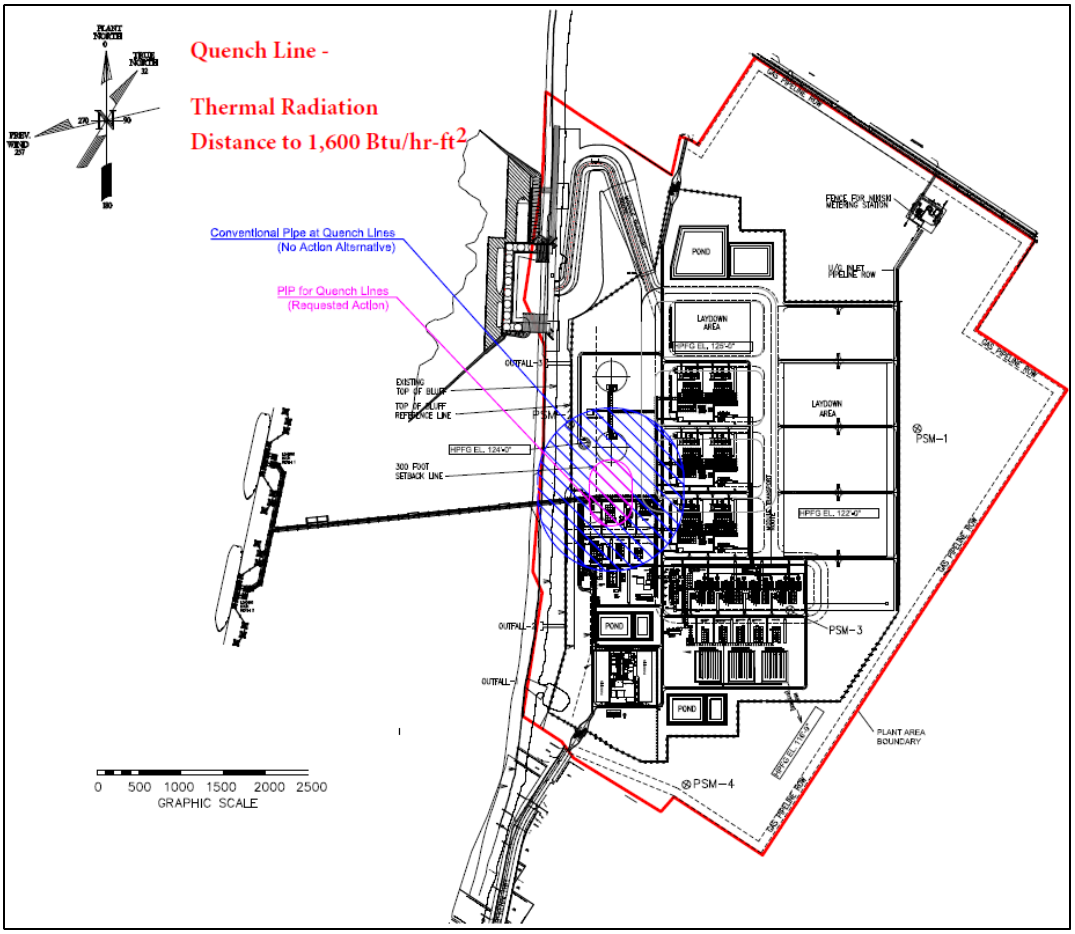

Figure 4-4: Thermal Radiation Exclusion Zones from the LNG Quench Lines Comparing PIP (Granted Action Alternative) and Conventional Piping (No Action Alternative)

As shown comparatively in Figure 4-5, the thermal radiation exclusion zones corresponding to the 1,600 Btu/ft2-hr flux level from a LNG jet-fire due to release with ignition at 2-inch-diameter hole in the conventional LNG rundown piping (shown as green hashed area) and 1-inch-diameter hole in LNG PIP rundown piping (shown as orange hashed area) do not extend beyond the Alaska LNG Terminal boundary.

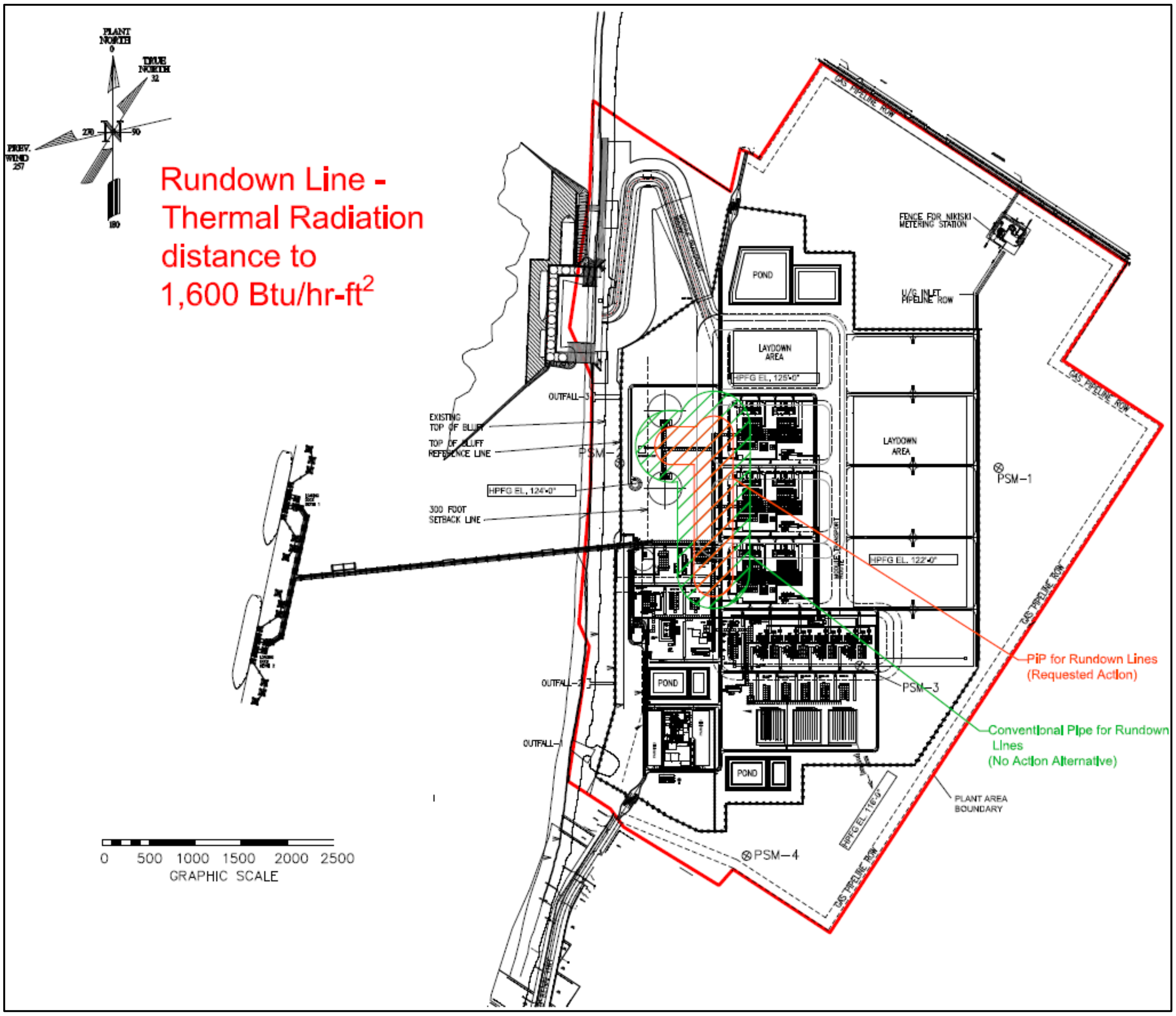

Figure 4-5: Thermal Radiation Exclusion Zones from the LNG Rundown Lines Comparing PIP (Granted Action Alternative) and Conventional Piping (No Action Alternative)

4.7.2. Granted Action Alternative (PIP system)

The use of PIP system with the implementation of applicable safety standards and special permit conditions will not significantly impact public and personnel safety beyond those adverse impacts that will be present from a conventional single wall conventional cryogenic piping and spill containment trench system design.

- The PIP system will contain spills from the inner pipe utilizing a secondary outer pipe as containment based on AGDC's design and additional safety measures defined in the special permit conditions.

- The PIP system reduces hazard impacts to public and plant personnel in the unlikely event of a primary containment failure since the secondary outer pipe will contain a release from the inner pipe. LNG releases from the inner pipe will be contained by the outer pipe. If designed, tested, and constructed according to applicable safety standards and special permit conditions, such releases will be less likely to reach the atmosphere; therefore, the potential for flammable vapors to mix with air and form a potentially ignitable mixture will be minimal. In the unlikely event of a compromised outer pipe concurrent with a spill from the inner pipe, the thermal radiation and flammable vapor dispersion exclusion zones from design spills will not extend beyond the Alaska LNG Terminal boundary as discussed in section 4.7.1.

The PIP system is also equipped with a fiber optic leak detection system which runs along the entire length of the pipes. This fiber optic system allows for advanced detection far superior to typical gas detectors placed near equipment. With conventional gas detectors, small leaks need to develop which must then pass across a gas detectors sensor or line of sight. With a fiber optic system, any leak is immediately detected.

Consistent with the recommended guidance in PHMSA's LNG FAQ DS2, AGDC applied a 1-inch diameter hole for a 10-minute duration as the design spill from the potential failure of the LNG PIP quench lines and LNG PIP rundown piping to determine the flammable vapor dispersion exclusion zone distances. AGDC applied the vapor dispersion input parameters in accordance with § 193.2059(b). As shown in Figures 4-3 and 4-4, the ½-LFL vapor clouds due to releases from 1-inch holes in the LNG PIP quench lines and rundown piping remain within the Alaska LNG Terminal boundary, thus demonstrating compliance with the vapor dispersion exclusion zone siting requirements prescribed in 49 CFR 193.2059 with respect to establishing flammable vapor exclusion zones for the granted action alternative for the Alaska LNG Terminal.

In accordance with 49 CFR 193.2051 and 193.2057, AGDC evaluated the radiant heat effects from ignition of a momentum-dominated LNG vapor release or jet fire from 1-inch-diameter hole in

LNG PIP quench lines and PIP rundown lines. As shown in Figures 4-4 and 4-5, the thermal radiation exclusion zones corresponding to the 1,600 Btu/ft^2-hr flux level from a LNG jet-fire do not extend beyond the Alaska LNG Terminal boundary, thus demonstrating compliance with the thermal exclusion zone siting requirements prescribed in 49 CFR 193.2057 with respect to establishing thermal exclusion zones for the granted action alternative for the Alaska LNG Terminal.

4.8. Topography

The study area is characterized as gently sloping from +140 feet on the north to +100 feet to the south.

4.8.1. No Action Alternative (Convention Piping Design)

The conventional design would require excavation for a spill containment system to convey any spill into an impoundment system; however, this would have negligible impact to overall topography of the site.

4.8.2. Granted Action Alternative (PIP System)

The grant of a special permit by PHMSA will require a smaller conveyance trench for the LNG rundown line and development of new conveyance trench for the LNG quench line; however, there are no significant differences in potential impacts to topography from either design, as the conventional system will have negligible impacts to overall topography of the site.

4.9. Transportation

Existing transportation resources and potential impacts associated with the construction and operations of the Alaska LNG Terminal are discussed in detail in Resource Report No. 8 in the April 2017 FERC Application. The assessment contained in Resource Report No. 8 included potential impacts for the Alaska LNG Terminal components based on the PIP design. The relative effects of the PIT conventional design (No Action Alternative) will not be significantly different as described below.

4.9.1. No Action Alternative (Convention Piping Design)

The conventional design requires additional construction activity to construct the spill containment system; however, the additional travel on nearby roads would be minimal as compared to the overall construction of the Alaska LNG Terminal.

4.9.2. Granted Action Alternative (PIP System)

The grant of a special permit by PHMSA will result in less travel by construction and maintenance crews. The PIP system will act to contain spills from the LNG rundown lines and will not require an additional spill containment system. Of note, there are no significant differences in potential impacts to transportation from either design, as the conventional system will have minimal impacts to transportation during construction and operations.

4.10. Water Resources

The Alaska LNG Terminal will be located on the eastern shore of Cook Inlet near Nikiski in the Upper Kenai Peninsula watershed. Cook Inlet is a tidal estuary extending 150 miles from Anchorage to the southern extent of the Kenai Peninsula where it opens into the Gulf of Alaska. The Cook Inlet has a basin area of approximately 12,000 square miles. The tidal range in Cook Inlet is among the largest in the United States, with a diurnal range of approximately 20 feet at the LNG Facility site. These tides result in a high-energy system with a strong mixing component. River inputs result in a low salinity and very high levels of suspended sediment. Cook Inlet supports a substantial recreational and commercial fishery, which in Upper Cook Inlet is primarily for the five species of Pacific salmon. The entire inlet has been designated essential fish habitat under the Magnuson-Stevens Fishery Conservation and Management Act, and portions of the inlet are also critical habitat for the endangered Cook Inlet beluga whale under the Endangered Species Act.

The planned 900-acre site for the Alaska LNG Terminal will contain a stormwater runoff collection system intended to handle stormwater runoff throughout the facility. The facility's stormwater runoff collection system, consisting of network trenches, impoundment sumps, ditches, and culverts, culminates in three man-made retention ponds with permitted outfalls to Cook Inlet. The retention ponds serve as sediment catchment basins to remove sediments prior to discharge to an outfall leading to Cook Inlet. Under either alternative, stormwater from the Alaska LNG Terminal will drain into the three (3) retention ponds. During normal operations, water from these ponds will be discharged in accordance with Alaska Pollutant Discharge Elimination System (APDES) requirements via outfalls into Cook Inlet. These discharges will be in compliance with APDES permits, which prohibit degradation of receiving water quality.

Stormwater accumulated in the impoundment sumps built to impound LNG and other hazardous liquids will be pumped out such that no overflow is allowed. Stormwater accumulated in the LNG/refrigerant impoundment sumps, is pumped out to a clean stormwater ditch nearby. At a certain water level, these pumps will auto-start. Low temperatures from LNG/refrigerant leakage will disable auto-start instantly. Stormwater accumulated in the fractionation area impoundment sump and condensate truck loading area impoundment sump may have potential oil contamination. There is no auto-start, and contaminated stormwater will be pumped to the equalization tank, once contamination is verified.

Existing water resources and potential impacts associated with the construction and operations of the Alaska LNG Terminal are discussed in more detail in Resource Report No. 2 in the April 2017 FERC Application. The assessment contained in Resource Report No. 2 is based on the PIP design; however, the effects of the alternative PIT conventional design will not be significantly different with the following exceptions.

4.10.1. No Action Alternative (Convention Piping Design)

The conventional PIT design includes construction and operation of an open culvert-type system constructed of cryogenic concrete built for LNG containment. This open containment system would result in a substantial increase in impervious surface and collection of precipitation and runoff. The collected waters would be pumped to the stormwater runoff collection system and would be eventually discharged to the Cook Inlet. The increased catchment area and collected water volumes introduces potential for additional pollutants to enter the system via runoff; however, any such water quality effects upon discharge to Cook Inlet would be negligible, as the discharges must meet the requirements of the APDES permit and because of the large volume and high mixing rate of Cook Inlet. In the event of a failure in the pipelines, as discussed in Section 4.1.7, LNG will collect in the open containment system. The system has sufficient volume and controls, such as low temperature detectors on the sump pumps that LNG will not be inadvertently or purposefully discharged into Cook Inlet. The released LNG held in the containment system will evaporate and will result in no contamination of waters eventually released to Cook Inlet.

4.10.2. Granted Action Alternative (PIP System)

The Alaska LNG Terminal is similar to other LNG plants in that it has a separate spill collection system to collect and impound LNG and other hazardous liquids in the event of a leak or spill. Like other LNG facilities and in accordance with 49 CFR Part 193, the LNG collection sump is equipped with level-controlled pumps to minimize stormwater accumulation; and these pumps are inhibited if low-temperature sensors detect cryogenic conditions in the sump preventing transfer of LNG into the stormwater system. The advantage of the closed containment provided by PIP is that it reduces the size of the spill collection trench; however, the stormwater handling associated with the smaller trench remains unchanged because the impoundment sump capacity will be the same regardless of the open trench sizes.

4.11. Non-Affected Resources

Resources not affected by this special permit, either because these resources are not in the Study Area or vicinity, or because there are no additional, anticipated impacts to these resources from either the No Action or Action alternative, include:

- Agriculture;
- Climate Change;
- Cultural Resources;
- Environmental Justice; and
- Indian Trust Assets.

While there are no Indian Trust Assets in the Study Area, the surrounding area contains Alaskan Native populations, and various Alaska Native Corporations and Federally Recognized Tribes are in close proximity. However, Alaska Native Corporation land, Native Allotments, and subsistence resources upon which many Alaska Native communities and Alaska residents rely upon are not impacted by either alternative. The potential impacts from the construction and operations of the Alaska LNG Terminal to Alaska Native Corporation land is discussed in Resource Report No. 8 and subsistence resources are discussed in Resource Report No. 5 in the April 2017 FERC Application.

5. RESPONSE TO PUBLIC COMMENTS PLACED ON DOCKET PHMSA-2017-0157

PHMSA published a Notice of Availability in the Federal Register on December 10, 2019 for the special permit requests for the PIP LNG rundown and quench lines at the Alaska LNG Terminal (84 FR 67511, Docket No. PHMSA-2017-0157 at www.Regulations.gov). PHMSA requested comment on the special permit applications, the special permit conditions, and the environmental analyses. The public notice comment period ended on February 10, 2020, with all comments received through February 28, 2020, being reviewed and considered. PHMSA received four (4) public comments. One (1) commenter supported the project while three (3) commenters expressed concerns towards safety and environmental impacts of the facility. This special permit allows an alternative design for 49 CFR 193.2167 and 193.2173 with conditions in the special permit for AGDC to implement during the design, construction, and operation of the LNG Terminal to maintain an equivalent level of safety and environmental protection. The public comments received were not concerns directed toward the special permit, the environmental assessment, or the special permit conditions, which were the issues within PHMSA's decision making authority and the intent of the public notice.

6. FINDING OF NO SIGNIFICANT IMPACT

The special permit conditions are designed to ensure a similar level of safety is achieved as if the Alaska LNG Terminal were designed, constructed, operated, and maintained in full compliance with 49 CFR 193.2167 for spill containment and 49 CFR 193.2173 for the removal of water from the impoundment area. Given the safety protections that the special permit conditions provide during the design, construction, operation, and maintenance of the Alaska LNG Terminal, PHMSA finds that the special permit with conditions granted to AGDC for the Alaska LNG Terminal ***special permit segment*** will not impose a significant impact on the human environment and is not inconsistent with safety and the human environment.

7. LIST OF PREPARERS

The following personnel contributed to the preparation of this Environmental Assessment:

- **PHMSA**
  - Sentho White, Engineer
  - Joseph Sieve, Engineer
  - Thach Nguyen, Engineer
  - Steve Nanney, Engineer
  - Nicole Anderson, Engineer
  - Amelia Samaras, Attorney
  - Robert Bachman, Structural Engineering Consultant
- **Alaska Gasline Development Corporation – (Operator of Alaska LNG Project)**
  - Fritz Krusen – Alaska Gasline Development Corporation
  - Phil Suter – Blue Engineering
  - Chris Humphrey, PE – EXP Energy Services, Inc.
  - Derek Moss – EXP Energy Services, Inc.

8. SPECIAL PERMIT SAFETY CONDITIONS

The special permit will require compliance with the following safety conditions:

8.1. Special Permit Segment

The Alaska LNG ***special permit segment*** is defined as follows:

1. Approximately 2,670 feet of PIP LNG rundown lines used to transfer LNG from the liquefaction areas to the LNG storage tanks consisting of:
   a. Three (3) 20-inch diameter inner pipe installed within 26-inch or 28-inch diameter outer pipe;
   b. 30-inch diameter inner pipe installed within 36-inch or 38-inch diameter outer pipe; and

    c. Four (4) outer to inner pipe bulkhead connections that form the transitions between the PIP segments and conventional piping segments.

2. Approximately 480 feet of PIP LNG quench lines used to cool down the boil-off gas at the inlet of the Boil-off Gas Compressors consisting of:
    a. Four (4) 4-inch diameter inner pipe within 10.75-inch or 12.75-inch diameter outer pipe (two (2) supply and two (2) return lines)
    b. Four (4) outer to inner pipe bulkhead connections that form the transitions between the PIP segments and conventional piping segments.

8.2. Special Permit Conditions

PHMSA grants this special permit for the ***special permit segment*** subject to AGDC implementing the following conditions:

1. **<u>Applicable Regulations</u>:** The ***special permit segment*** must be designed, constructed, operated, and maintained in accordance with these special permit conditions and 49 CFR Part 193, with the exceptions of 49 CFR 193.2167 and 193.2173. In the event of a conflict between these special permit conditions and the applicable requirements under 49 CFR Part 193, the special permit conditions prevail.

2. **<u>Design, Specifications and Procedures</u>:** AGDC must develop and implement design, construction, and operating and maintenance (O&M) specifications and procedures in accordance with these special permit conditions and 49 CFR Part 193 for the ***special permit segment***. The outer pipe must comply with all applicable design requirements for impoundment system specified in 49 CFR 193.2155 and spacing requirements for impoundment system specified in NFPA 59A (2019 edition),[6] Chapter 6. AGDC must submit the final design, construction, and O&M specifications and procedures and process hazard analysis of the PIP systems to the PHMSA Western Region Director or the PHMSA Project Designee, when requested.

---

[6] Should 49 CFR 193.2013 documents incorporated by reference (IBR) change to a date later than the NFPA 59A 2019 edition, AGDC can submit a proposed change to the 49 CFR 193.2013 IBR document edition to the PHMSA Associate Administrator for Pipeline Safety. Upon a "no objection" from the PHMSA Associate Administrator for Pipeline Safety to use a later document, AGDC can use the later IBR document.

3. **<u>Final Design</u>:** No later than 90 days prior to the shop and field fabrication of the ***special permit segment***, AGDC must submit the final design information of the PIP systems to the PHMSA Western Region Director or the PHMSA Project Designee.[7] The following documentations must be submitted:

    a. Piping and Instrumentation Diagrams;

    b. PIP System Specification; and

    c. Relief Valve Sizing Calculations.

4. **<u>Inner Pipe</u>:** The ***special permit segment*** inner pipe must be constructed of 36%-Ni / 64%-Fe alloy material, commonly referred to as Invar 36 (Unified Numbering System K93603).

5. **<u>Outer Pipe</u>:** The ***special permit segment*** outer pipe must be constructed of austenitic steel of Type 304L stainless steel.

6. **<u>PIP Termination Bulkheads</u>:** The outer pipe must be rigidly connected to the inner pipeline by means of a forged termination bulkhead. Installation of the termination bulkheads must create a sealed annulus between the outer and inner pipe.

7. **<u>Design, Fabrication, Examination, and Testing</u>:** The ***special permit segment*** inner pipe, outer pipe, and bulkheads must be designed, fabricated, examined, and tested in accordance with Section 10.13 in NPFA 59A (2019 edition).[8]

8. **<u>Design Loading Documentation</u>:** No later than 90 days prior to the field installation of the ***special permit segment***, AGDC must submit to the PHMSA Western Region Director or the PHMSA Project Designee design calculations to demonstrate the PIP system integrity for design loadings. The design calculations must address the following items:

---

[7] The PHMSA Project Designee will be assigned by the PHMSA Western Region Director. Also, PHMSA may elect to assign PHMSA regulatory duties for the Alaska LNG Project to another PHMSA Region and will notify AGDC if this should happen.

[8] Should 49 CFR 193.2013 documents IBR change to a date later than the NFPA 59A 2019 edition, AGDC can submit a proposed change to the 49 CFR 193.2013 IBR document edition to the PHMSA Associate Administrator for Pipeline Safety. Upon a "no objection" from the PHMSA Associate Administrator for Pipeline Safety to use a later document, AGDC can use the later IBR document.

a) Minimum and maximum design and allowable working parameters;

b) Minimum, maximum, and normal operating parameters;

c) Corrosion allowances;

d) Shock loads on the outer pipe due to a worst-case inner pipe release of LNG at design pressures from at least a 2-inch diameter hole in the rundown line and 4-inch diameter hole in the quench line;

e) Supporting structures;

f) Ambient-to-operational thermal stresses, including stresses at bulkheads;

g) Static and dynamic loads;

h) Slug flow, pressure surge, and loads developed from surge analysis, loads arising from credible thermal bowing; and

i) Natural hazard design loadings, including wind forces, impact forces and potential penetrations by wind borne missiles, and seismic loads.

AGDC must receive a letter of "no objection" from PHMSA prior to field installation.

9. **<u>Shop and Field Fabrication Procedures</u>:** No later than 90 days prior to either shop or field fabrication, shop and field procedures for the ***special permit segment*** must be submitted to the PHMSA Western Region Director or the PHMSA Project Designee the following items:

   a) Shop fabrication procedures.

   b) Field fabrication procedures, including, at a minimum, the following items: girth weld testing, insulation continuity and installation, field installation of inner and outer pipe, and bulkhead connections.

10. **<u>Quality Assurance and Quality Control Plan</u>:** No later than 90 days prior to the field installation of the ***special permit segment***, AGDC must submit a quality assurance and quality control (QA/QC) plan to the PHMSA Western Region Director or PHMSA Project Designee that addresses:

   a) Incorporation within a project-wide QA/QC plan;

b) Fabrication shop QA/QC;

c) Transportation QA/QC;

d) Materials testing and traceability;

e) Welding procedure specification approval;

f) Welder qualification;

g) Weld materials inspection;

h) Weld preparation requirements (fit-up, etc.);

i) Non-destructive testing procedures and non-destructive testing of all girth welds;

j) Non-destructive testing procedures and non-destructive testing of all fillet welds designed for pressure containment;

k) Pressure testing procedures for inner pipe, outer pipe, and bulkheads;

l) Inspection procedure approval; and

m) Documentation acceptance.

AGDC must receive a letter of “no objection” from PHMSA prior to implementing the QA/QC plan.

11. **<u>Management of Change</u>:** Justification for any change in design and operating parameters established in final design must be provided by AGDC to the PHMSA Western Region Director or the PHMSA Project Designee. AGDC must receive a letter of “no objection” from PHMSA prior to implementing a change in design or operating parameters after final design.

12. **<u>Atmospheric Corrosion Protection – Outer Pipe</u>:** No later than 90 days prior to the field installation of the ***special permit segment***, AGDC must submit a study of the susceptibility of the outer pipe to atmospheric corrosive attack and the required methods for corrosion protection to the PHMSA Western Region Director or the PHMSA Project Designee for review and must receive a letter of “no objection” from PHMSA prior to installation.

13. **<u>Integrity Management</u>:** No later than 90 days prior to commencement of service of the PIP system, AGDC must submit to the PHMSA Western Region Director or the PHMSA Project Designee, for review a preventative maintenance procedure to ensure long-term integrity of the ***special permit segment***. The procedure must include details of the inspections or tests and their frequency and description of actions necessary to maintain the integrity of the PIP. AGDC must receive a letter of "no objection" from PHMSA prior to commencement of service.

14. **<u>PIP Annular Space</u>:** "PIP annulus," "annulus," or "annular space" refers to the space between the carrier pipe and the casing pipe.

    a) The PIP system must have specifications and procedures implemented for the following (as applicable to the selected vendor's technology):

        i. Casing isolators and spacing;

        ii. Sealing ends with bulkheads;

        iii. Dew point sampling of the annulus prior to commissioning of the PIP system;

        iv. Use of inert gas, such as nitrogen or argon;

        v. Use of fiber optic cable;

        vi. Outer pipe connections and vacuum and inert gas pressure supply systems used to maintain specified pressures; and

        vii. Inner pipe connections and use.

    b) Vacuum and inert gas pressure system must include block valves, a pressure regulator, pressure relief valves, vacuum pump, sample ports, and associated piping. The vacuum system must be operational at all times, except during maintenance activities, which must be conducted during a 12-hour shift and with the knowledge of Alaska LNG Terminal control room operators.

    c) The annulus space must be continuously monitored in the control room for pressure and temperature changes. At least 90 days prior to introduction of hazardous fluids, AGDC must submit the alarm and shutdown set points to the PHMSA Western

Region Director or the PHMSA Project Designee for review and must receive a letter of "no objection" from PHMSA prior to introduction of hazardous fluids.

d) The PIP annulus system must be equipped with redundant pressure and temperature monitoring system.

e) At least 90 days prior to introduction of hazardous fluids, AGDC must submit the cause and effect diagram that demonstrates proper shutdown and isolation of LNG facilities should the annulus pressure exceed the established pressure thresholds, to the PHMSA Western Region Director or PHMSA Project Designee, for review and must receive a letter of "no objection" from PHMSA prior to introduction of hazardous fluids.

15. **Temperature and Pressure Monitoring System:** The Alaska LNG ***special permit segment*** inner pipe must be continuously monitored for operating pressure, temperature, and flow rate, including the following requirements:

a) The inner pipe must be equipped with a redundant pressure and temperature monitoring system.

b) Valves at each end of the PIP ***special permit segment*** must be remote closure. The actuation of the valves must not result in an overpressure event of the inner pipeline, and closure rates must be substantiated by a hydraulic surge analysis. The remote closure valve status and adjacent pipeline pressures must be monitored at all times, except during scheduled equipment maintenance activities when LNG is not in the pipeline. AGDC must develop operations procedures that specify that the manual valves on both ends of the PIP segment remain open at all times of normal operations.

c) AGDC must submit the final design, construction, and O&M specifications and procedures and process hazard analysis for the PIP systems to the PHMSA Western Region Director or the PHMSA Project Designee 30 days prior to construction of the PIP systems.

16. **Leak Monitoring System Design:** No later than 90 days prior to introduction of hazardous fluid in the ***special permit segment***, AGDC must submit to the PHMSA

Western Region Director or the PHMSA Project Designee the cause and effect diagram for the leak detection system, as well as the final design details that address the following:

a) Continuous leak monitoring system;

b) Specifics on the pressure, temperature, and hydrocarbon detection alarms, shutdown functions, and set points;

c) Maximum and minimum design set points for alarms and emergency shutdown;

d) Leak monitoring system inspections, testing, and frequency;

e) Fiber optic cables; and

f) Response actions with the time for those actions.

AGDC must receive a letter of "no objection" from PHMSA prior to introduction of hazardous fluid.

17. **Purge Procedure:** No later than 90 days prior to introduction of hazardous fluid, AGDC must submit to the PHMSA Western Region Director or the PHMSA Project Designee the purge procedure for the annulus space, including purge pressure, and minimum and maximum dew point for the ***special permit segment***.

18. **Construction Notices and Reporting of Repairs:** In addition to the notifications required in the conditions above, AGDC must also provide the following notifications:

a) AGDC must notify the PHMSA Western Region Director or the PHMSA Project Designee 14 days prior to construction relating to shop fabrication and field construction of the ***special permit segment,*** so PHMSA can observe the activity.

b) AGDC must notify the PHMSA Western Region Director or the PHMSA Project Designee of immediate repair conditions no later than two (2) business days after a condition is discovered during operation.

c) AGDC must notify PHMSA Western Region Director or the PHMSA Project Designee of non-conformance items relating to PIP during construction.

19. **<u>Test Records Availability</u>:** All test records, destructive or non-destructive, must be made available upon request for review by PHMSA's Western Region Director or the PHMSA Project Designee no later than 30 days after tests are completed.

20. **<u>Annual Report</u>:** Within twelve (12) months following installation of the ***special permit segment***, and annually thereafter, AGDC must develop and submit annual reports. The annual reports must be sent by AGDC to the PHMSA Western Region Director or the PHMSA Project Designee, the PHMSA Engineering and Research Director, and a copy placed in the Federal Register Docket (PHMSA-2017-0157) at www.regulations.gov. The annual reports must include the following information:

    a) Any reportable incident or leak reported on the DOT Annual Report in the ***special permit segment***;

    b) Repairs that occurred during the previous year in the ***special permit segment***;

    c) Corrosion and corrosion preventative initiatives affecting the ***special permit segment***, as well as an evaluation of the performance of the initiatives; summary of all irregular annulus pressure changes, temperature changes, or dew point changes that required regional notification; and

    d) Any mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the Alaska LNG Terminal.

21. **<u>Documentation</u>:** AGDC must maintain all ***special permit segment*** documentation required by paragraphs (a) and (b) below for the life of the special permit and provide such documentation to the PHMSA Western Region Director or the PHMSA Project Designee upon request:

    a) Documentation showing that AGDC complied with 49 CFR 193.2301, 193.2303, and 193.2304 in Subpart D, as well as additional requirements for PIP in Section 10.13 of NFPA 59A (2019 edition).[9]

[9] Should 49 CFR 193.2013 documents IBR change to a date later than the NFPA 59A 2019 edition, AGDC can submit a proposed change to the 49 CFR 193.2013 IBR document edition to the PHMSA Associate Administrator for Pipeline Safety. Upon a "no objection" from the PHMSA Associate Administrator for Pipeline Safety to use a later document, AGDC can use the later IBR document.

b) Documentation of compliance with all conditions of this special permit.

22. **<u>Certification</u>:** No later than 30 days after commencing service of the Alaska LNG Terminal, a senior executive officer, vice president or higher, of AGDC must certify the following in writing:

a) Alaska LNG Terminal meets the conditions described in this special permit or has procedures meeting these conditions for O&M activities that are completed after placing the ***special permit segment*** into operational service;
b) The written manual of O&M procedures has been updated to include the additional requirements of this special permit;
c) A compliance documentation summary showing that AGDC implemented all conditions as required by this special permit for the ***special permit segment*** in accordance with this special permit
d) AGDC must send the signed and dated written certifications with corresponding completion dates to the PHMSA Associate Administrator for Pipeline Safety, with copies to the Director, PHMSA Western Region; the PHMSA Engineering and Research Director; and to the Federal Register Docket (PHMSA-2017-0157) at https://www.regulations.gov within 30 days of placing the PIP system into LNG service.

9. BIBLIOGRAPHY AND REFERENCES

Alaska Natural Heritage Program. 2014. Conservation Status Report: *Lithobates sylvaticus*. 8 pp. Available online at http://aknhp.uaa.alaska.edu. Accessed October 1, 2014.

Alaska Gasline Development Corporation. 2017a. Alaska LNG Project. Section 3 NGA Application under CP17-178.

Alaska Gasline Development Corporation. 2017b. Alaska LNG Project. Pipeline and Hazardous Materials Safety Administration, Application for Special Permit under CP17-178.

Bureau of Ocean Energy Management. 2016. Cook Inlet Planning Area Oil and Gas Lease Sale 244 In the Cook Inlet, Alaska. Final Environmental Impact Statement. OCS EIS/EA BOEM 2016-069. Available online at https://www.boem.gov/Sale-244/

Boveng, P.L., J.M. London, and J.M. VerHoef. 2012. Distribution and abundance of harbor seals in Cook Inlet, Alaska. Task III: Movements, marine habitat use, diving behavior, and population structure, 2004-2006. . Final Report. BOEM Report 2012-065. Bureau of Ocean Energy Management, Alaska Outer Continental Shelf Region, Anchorage, Alaska, USA. 58 pp.

Broderson, K., and E. Tessler. 2008. Frogs and Toads Fact Sheet. Available online at https://www.adfg.alaska.gov/static/education/wns/frogs_and_toads.pdf, Accessed November 2, 2015.

CH2M. 2016b. Test Pit Dredge Material Characterization Report (USAL-CH-JRZZZ-90-000033-000).

Fugro Consultants, Inc. 2015. Hydrogeologic Report, Alaska LNG Project, Nikiski, Alaska, Report No. 04.10140094-10, AKLNG Document No. USAL-FG-GRZZZ-00-000004-000.

Nemeth, M.J., C.C. Kaplan, A.P. Ramos, G.D. Wade, D.M. Savarese, and C.D. Lyons. 2007. Baseline studies of marine fish and mammals in Upper Cook Inlet, April through October 2006. Final report prepared by LGL Alaska Research Associates, Inc., Anchorage, Alaska for Driven Corporation, Anchorage, Alaska.

NOAA Fisheries. 2014. Alaska ShoreZone Coastal Mapping and Imagery. National Marine Fisheries Service, Alaska Regional Office. Available online at http://alaskafisheries.noaa.gov/shorezone/. Accessed November 12, 2014.

Reger, R.D., A.G. Sturmann, E.E. Berg, and P.A.C. Burns. 2007. A guide to the late Quaternary history of northern and western Kenai Peninsula, Alaska: Alaska Division of Geological & Geophysical Surveys Guidebook 8, 112 p. 6 sheet, scale 1:63,360.

Thurston, D.K.; and Choromanski, D.R. 1995. Quaternary geology of lower Cook Inlet, Alaska, in, Simakov, K.V., and Thurston, D.K., eds., Proceedings of the International Conference on Arctic Margins, Russian Academy of Sciences, Far East Branch, North East Science Center: Magadan, Russian Federation, p. 194-202.

U.S. Army Corps of Engineers. 2011. Kenai River Bluff Limited Economic, Cultural and Historic Property Evaluation – February 2011, Report Produced by Tetra Tech, Surface Water Group, Seattle, WA.

Viereck, L.A., C.T. Dyrness, A.R. Batten, and K.J. Wenzlick. 1992. The Alaska Vegetation Classification. Gen. Tech. Rep. PNW-GTR-286. Portland, OR: U.S. Department of Agriculture, Forest Service, Pacific Northwest Research Station. 278 p.

Completed by PHMSA in Washington, DC on: April 27, 2020

APPENDIX A

United States Coast Guard Sector Anchorage's Conditional Letter dated June 23, 2016

U.S. Department of Homeland Security
United States Coast Guard

Commander
United States Coast Guard
Sector Anchorage

PO Box 5800
JBER, AK 99505-0800
Staff Symbol: s
Phone: (907) 428-4144
FAX: (907) 428-4138

16611
June 23, 2016

Alaska LNG Project
Attn: Charlie Kominas
Safety, Security, Health and Environmental Manager
3201 C Street
Anchorage, AK 99503

Dear Mr. Kominas,

1. Your December 3, 2015 request to use the cryogenic pipe-in-pipe installation as an alternative to conventional containment for your Alaska LNG facility in Nikiski, Alaska has been approved, contingent on the following stipulations:

   (a) Construction of the pipeline and arrangements shall be designed, fabricated, examined, and tested in accordance with ASME B 31.3 as per NFPA 59A (2013) Section 9.11 Cryogenic Pipe-in-Pipe Systems or other alternatives incorporated by reference in 33 CFR Part 127.

   (b) Once construction of the pipeline and arrangements have been completed and inspection levels have been specified, my Facilities Division must verify the satisfactory installation and tests of the arrangement.

   (c) The Marine Transportation-Related Facility shall demonstrate a satisfactory means to prevent corrosion either through corrosion protection and/or detection.

   (d) The Marine Transportation-Related Facility shall demonstrate a satisfactory means to minimize thermal conductance and heat loss in the annular space and inner pipe support system. In addition, provisions shall be provided for temperature monitoring.

   (e) The Marine Transportation-Related Facility shall conduct annual transfer pipeline tests as required by 33 CFR §156.170 and maintain proper records.

   (f) If the Marine Transportation-Related Facility conducts a pneumatic test, an approval letter from the Coast Guard Captain of the Port for alternative testing must be maintained by the facility.

   (g) Satisfactory tests of the emergency shutdown valves must be witnessed by my staff.

   (h) The Marine Transportation-Related Facility is situated in a way that poses no risk of impacting public and commercial water supply intakes if a spill were to occur from any transfer piping or storage tank.

(a) The topography surrounding the Marine Transportation-Related portion of the facility is such that a spill of an average most probable discharge would have minimal potential impact to navigable waters.

(b) The Marine Transportation-Related Facility does not conduct secondary marine transfers.

2. Please keep a copy of this letter with your facility records. Failure to comply with any of the stipulations listed in this letter will invalidate the alternative containment approval and will require the facility to comply with additional measures. If you have any questions concerning this letter please contact the Sector Anchorage Waterways Management Division at (907) 428-4189.

Sincerely,

P. Albertson

P. ALBERTSON
Captain, U.S. Coast Guard
Captain of the Port, Western Alaska