APPENDIX D ENVIRONMENTAL INFORMATION FOR MULTI-LAYER COATING SPECIAL PERMIT

3LPE Coating
Environmental Information

The purpose of this Attachment is to augment the National Environmental Policy Act analysis presented in the Alaska LNG Project Federal Energy Regulatory Commission Resource Reports (FERC RR) with information that meets specific U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements for a special permit as described in 49 Code of Federal Regulations (CFR) § 190.341. The Special Permit Conditions for usage of three layer polyethylene coatings, as well as this Attachment, are also addressed in the Alaska LNG FERC Resource Report 11.

I. Purpose and Need

Alaska LNG is proposing to build a Mainline pipeline (the pipeline or the Mainline) to transport natural gas to a proposed Liquefied Natural Gas (LNG) facility from a proposed gas treatment plant located on Alaska's North Slope. The Federal Energy Regulatory Commission (the FERC) is the lead Federal agency. The Federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has authority over the design and operation of natural gas transmission pipelines under 49 CFR Part 192. 49 CFR Part 192 includes specific regulatory requirements for the design, construction, operation, and maintenance of natural gas pipelines to maintain safety. If required, special permits can be granted under 49 CFR §190.341 for proposed deviations from the regulatory requirements. PHMSA imposes conditions on the grant of special permits to assure safety and environmental protection in accordance with 49 CFR § 190.341. PHMSA is required to comply with the National Environmental Policy Act (NEPA) in deciding whether to issue the special permit. Alaska LNG is seeking exemption from the requirements of 49 CFR § 192.112(f)(1) in pipeline segments that are built to comply with the Alternative Maximum Allowable Operation Pressure (Alternative MAOP) requirements of 49 CFR 192. This clause requires that "The pipe must be protected against external corrosion by a non-shielding coating."

The Alaska LNG mainline will traverse the state of Alaska. Construction of the pipeline will require transport of line pipe significant distances to remote regions. Fusion bonded epoxy coatings, which are in common use in the lower 48 states, are susceptible to damage during transportation and installation. As a result, the Alaska LNG project proposes to utilize three layer polyethylene (3LPE) coatings, which consist of an FBE layer, a copolymer adhesive layer, and a polyethylene outer layer. 3LPE coatings have increased resistance to damage during transportation and installation. A Special Permit would allow Alaska LNG to apply 3LPE coatings in order to reduce the number of coating repairs, and install a pipeline with fewer coating holidays and higher integrity. The Special Permit would include conditions to ensure the pipeline has equal or greater safety than a pipeline constructed in accordance with 49 CFR Part 192.

II. Background and Site Description

Figure 3 shows the proposed Mainline route from the proposed gas treatment plant located at Prudhoe Bay to the proposed LNG Plant site located on the Kenai Peninsula. The Mainline would be a 42-inch-diameter natural gas pipeline, approximately 807 miles in length, extending from the GTP on the North Slope to the Liquefaction Facility on the shore of Cook Inlet near Nikiski, including an offshore pipeline section crossing Cook Inlet. Alaska LNG is proposing that the onshore pipeline be a buried pipeline with the exception of short above-ground special design segments, such as aerial water crossings and aboveground fault crossings. As presented in Table 1.3.2-1 of FERC Resource Report 1 (inserted below), the Mainline would originate in the North Slope Borough, traverse the Yukon-Koyukuk Census Area, the Fairbanks North Star Borough, the Denali Borough, the Matanuska-Susitna Borough, and the Kenai Peninsula Borough, and terminate at the Liquefaction Facility. The Mainline's proposed design has a maximum allowable operating pressure (MAOP) of 2,075 psig.

TABLE 1.3.2-1 (From FERC Resource Report 1)

Mainline Route Summary for a 42-inch Pipeline

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

The Mainline would include several types of aboveground pipeline facilities. The proposed design includes eight compressor stations, four meter stations, multiple pig launching/receiving stations, multiple Mainline block valves (MLBV), and five potential gas interconnection points. A list of compressor stations, heater station, and meter stations is provided in Table 1.3.2-6 of FERC Resource Report 1.

Approximately 36 percent of the Mainline route is collocated within 500 feet of an existing ROW. Table 1.3.2-2 of FERC Resource Report 1 summarizes collocation of the Mainline route that are within 500 feet of highways, major roads, the Trans-Alaska Pipeline System (TAPS), other pipeline ROWs, utilities, and railroads. The Mainline crosses TAPS 12 times, the TAPS Fuel Gas Line 5 times, and has four railroad crossings. Design of the road and railroad crossings would be validated for applicability of the minimum wall thickness requirements for service loads on crossings in accordance with API RP 1102, using the appropriate design factor for the design class location, and comply with 49 CFR § 192.111. The minimum depth of cover would be four feet for road crossings as specified by the Alaska Administrative Code 17.AAC 15.211 "Underground Facilities" and 10 feet for railroad crossings, as specified in Alaska Railroad Corporation (ARRC) standards below travel surface (this exceeds the 49 CFR 192.327(a) requirement which requires a minimum of three feet at drainage ditches of public roads and railroads). Site-specific designs for major highway and railroad crossings are provided in Appendix H of the FERC application. Additional details on roads, railroads, pipelines, utilities, and power lines crossings can be found in FERC Resource Report 8.

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

Pipeline design standards in 49 CFR § 192.5 are based on "class location units," which classify locations based on population density in the vicinity of an existing or proposed pipeline system. The higher the class location (1-4), the higher the design factor used to find the minimum required wall thickness for pressure containment, i.e. the required minimum thickness of the pipe increases as the Class location. 99% of the Mainline route is in Class 1, which is defined as having 10 or fewer buildings intended for human occupancy located within 220 yards on either side of any continuous 1-mile length of pipeline. On the Kenai Peninsula, near Nikiski, there is a Class 2 location that is about 2.6 miles long. Also on the Kenai Peninsula there is a potential Class 3 location as the Mainline nears the LNG Plant. In the Nenana Canyon region of Denali National Park (~MP 536) there is approximately a half a mile of Class 3. Details on class locations for the Mainline can be found in FERC Resource Report 11. The table from Resource Report 11 designating Class Locations for Route Revision C2 is reproduced below.

Class Locations for the Mainline		
Milepost (MP)		
Start (MP)	End (MP)	Class Location

0.00	535.99	1
535.99	536.49	3
536.49	798.65	1
798.65	801.27	2
801.27	803.78	1
803.78	806.25	2
806.25	806.57	1

There are 10 potential high consequence areas (HCA) along the Mainline as defined under 49 CFR § 192.903. This includes two HCAs that are based on the aforementioned Class 3 locations. The remaining HCAs are located in Class 1 locations, details of which can be found in FERC Resource Report 11, Section 11.7, Table 11.7.4-1. In addition, the pipeline route segments that are addressed in a separate application for a Special Permit for Strain Based Design (the "Strain Based Design segments") will be incorporated into the integrity management program (IMP) and treated as a covered segment in a high consequence area (HCA) in accordance with 49 CFR Part 192, Subpart O, and the Special Permit Conditions if the Special Permit for Strain Based Design is granted by PHMSA.

The construction right of way (ROW) width will vary depending on the type of terrain, the season of construction, and the ease of access from nearby roads. The permanent ROW width will be 50 feet plus the diameter of the pipeline, i.e. 53-1/2 feet. Greater details on construction ROW can be found in FERC Resource Report 1. The Mainline would be sited on land composed of more than 85 percent federal, State of Alaska, and borough land of various holdings, with the remainder on privately owned land (see FERC Resource Report 8).

The proposed gas pipeline corridor spans five physiographic regions including the Arctic Coastal Plain, Arctic Foothills, Brooks Range, Yukon-Tanana Upland, and Tanana-Kuskokwim Lowland. These regions host a variety of ecosystems including muskeg bogs, spruce upland forest, alpine and Arctic tundra, high brush, and bottomland spruce and poplar forests. The associated ecosystems support a variety of species which include grizzly and black bears, arctic foxes, seals, caribou, moose, small terrestrial mammals, birds, and anadromous fish. A variety of marine mammals inhabit the coastal waters in the Project area, including the bowhead whale, polar bear, beluga whale, ringed seal, bearded seal, Stellar sea lion, harbor seal, ribbon seal and spotted seal. Some of these species are critical subsistence resources for Alaska Native peoples.

A detailed description of the Mainline ROW is included in Section 1.3.2.1 of FERC Resource Report 1. Supporting facilities are described in Section 1.3.2.1.3 and temporary construction infrastructure is described in Section 1.3.2.4 of FERC Resource Report 1. Baseline environmental conditions and the analysis of environmental effects resulting from construction and operation of the Mainline are addressed by individual resources as follows:

- Resource Report 2 (Water Use and Quality).
- Resource Report 3 (Fish, Wildlife and Vegetation).
- Resource Report 4 (Cultural Resources)
- Resource Report 5 (Socioeconomics)
- Resource Report 6 (Geological Resources)
- Resource Report 7 (Soils)
- Resource Report 8 (Land Use, Recreation and Aesthetics)
- Resource Report 9 (Air and Noise Quality)

The pipeline will be installed with coatings and cathodic protection (CP) systems in order to prevent external corrosion. This two-fold approach to protecting the pipeline from external corrosion is required by 49 C.F.R. 192 Subpart I “Requirements for Corrosion Control.” Coatings isolate the underlying pipe steel from groundwater and oxygen that could cause corrosion if they were to contact the pipe. In the case that there is a coating damage that exposes bare steel, CP current suppresses the corrosion reaction at the location of the coating holiday. With an increased number of coating holidays for FBE due to transportation and installation damage and repairs and in-service degradation of the coating system, a greater cathodic protection current is required. To generate a larger current, larger cathodic protection systems with more power and more anode ground beds may be required to provide protection against corrosion.

49 CFR Part 192.112, which describes additional design requirements for steel pipe using alternative maximum allowable operating pressure (AMAOP), states that “the pipe must be protected against external corrosion by a non-shielding coating.” Although the regulations do not

provide a definition of what is required to demonstrate that a coating is "non-shielding," PHMSA has interpreted this requirement to require the use of fusion bonded epoxy (FBE) coatings (i.e., single or dual layer FBE coatings).[1] Alaska LNG plans to utilize AMAOP in most Class 1 locations of the Alaska LNG Mainline. In addition, the conditions for a Special Permit for strain-based design require compliance with CFR Part 192.112 for all strain-based design (SBD) segments, but will exclude a requirement to comply with CFR Part 192.112(f)(1). Alaska LNG proposes to utilize 3LPE coatings for the Mainline, except for in locations where the pipeline is above-ground and where the pipeline is installed by trenchless installation methods, which will utilize FBE with an abrasion resistant overcoat. As a result, Alaska LNG is seeking relief from the requirement in 49 CFR Part 192.112(f)(1) to use a "non-shielding" coating.

It is understood that the requirement to utilize a "non-shielding" coating has been included in the regulations in response to historical pipeline integrity issues that have resulted from the use of tape wrap, coal tar enamel and asphalt coatings that performed poorly in service. Failures of these historically applied coating systems have occurred in a manner that has allowed groundwater and oxygen to reach the steel surface, but blocked the flow of cathodic protection current (i.e. caused CP shielding). Failure of these coating systems has been associated with external corrosion and stress corrosion cracking (SCC). The proposed 3LPE coating system is a modern coating system with over 20 years of world-wide field experience that has not been associated with the occurrence of similar issues. Although there has been limited use of this system in the United States, three layer polyolefin coatings, a category of coatings that includes 3LPE, are the most commonly utilized coating systems in the world and have a track record of good performance.

There are several challenges that a coating system faces in Alaska, to include resistance to damage, (transport, UV degradation, backfill), minimizing the potential for interference between cathodic protection systems given the proximity to TAPS, and minimizing the number of CP ground beds, given the remoteness of Alaska. While FBE coatings are often selected for pipelines in the lower 48 states due to their lower cost and acceptable performance when good transportation infrastructure is available, 3LPE coatings have significant advantages over FBE for application in Alaska. Construction of the Alaska LNG mainline will require transporting pipe significant distances from the coating facilities by ship, railroad and/or truck. The limited transportation infrastructure within Alaska means that significant distances of trucking over unpaved roads and the unpaved pipeline right of way will be required. In addition, the coated

[1] PHMSA Enforcement Guidance – Alternative MAOP, FAQ's: FAQ 34 and 35 (2016). http://primis.phmsa.dot.gov/maop/faqs.htm

pipe will need to be handled many times between when the coating is applied in a coating plant and when the pipe is installed in the trench. The inclusion of a polyethylene outer layer in 3LPE coatings provides substantially increased resistance to damage of the coating during transportation and handling compared to FBE only.

III. Alternatives

For PHMSA's NEPA assessment, a No Action alternative reflects a pipeline design that would not require issuance of a Special Permit. The Proposed Action alternative reflects Alaska LNG's use of 3LPE for which a Special Permit with conditions would be issued.

An applicant requesting a Special Permit from PHMSA has the option of building a pipeline which would not require PHMSA to issue a Special Permit. This would require the design, construction, and operation of a pipeline in-compliance with Part 192, and would not involve the use of 3LPE coatings in conjunction with AMAOP or SBD. The two alternatives are described below.

a. No Action Alternative – Construct the pipeline using FBE coatings where AMAOP or SBD apply.

This alternative would involve the use of FBE coatings that are recognized by PHMSA as "non-shielding." The FBE coatings could be single or dual layer FBE. Dual layer FBE includes an abrasion resistant overlay (ARO) as the outer layer.

Because single layer FBE coatings are more brittle than 3LPE coatings, an increased amount of damage to the coatings would occur during transportation if not properly handled. In addition, single layer FBE coatings are more susceptible to damage during installation and service because they are more susceptible to damage due to contact with rocks during laying, burial, and operation of the pipeline.

Dual layer FBE coatings have been formulated to provide greater impact and abrasion resistance than single layer FBE, but are not as resistant to damage as 3LPE. In addition, dual layer FBE, due to its greater thickness, may have reduced flexibility that may make it more susceptible to cracking during field bending in arctic conditions. At least one manufacturer does not recommend the use of dual layer FBE for field bending[2]. Cracking of dual layer FBE has also been reported during field bending in cold conditions in the lower 48 states[3], and the lower

---

[2] Dual Layer FBE Product Data Sheet, http://www.brederoshaw.com/non_html/pds/BrederoShaw_PDS_DLFBE.pdf
[3] A. Kehr, M. Dabiri, R. Hislop, "Dual-layer Fusion-bonded Epoxy (FBE) Coatings Protect Pipelines", http://alankehr-anti-

temperatures in Alaska may increase the frequency of cracking. Therefore, the availability of suitable dual layer FBE products for application in arctic conditions needs to be confirmed to determine if this is a viable alternative. Alaska LNG plans to use dual layer FBE in trenchless installations, but this application does not require field bending of pipe.

As a result of increased susceptibility to damage, FBE coatings are expected to have lower initial coating integrity; and, based on field experience, are expected to degrade more rapidly in service than 3LPE coatings, requiring a greater cathodic protection current. This is recognized in International Organization for Standardization 15589-1:2015, Petroleum, petrochemical and natural gas industries -- Cathodic protection of pipeline systems -- Part 1: On-land pipelines, (ISO 15589-1), a global standard for design of CP systems for onshore pipelines that requires the use of an initial coating breakdown factor for FBE that is 5 times as large as for 3LPE and a coating degradation factor that is 10 times as large for FBE than for 3LPE. The use of FBE is not preferred for the following reasons:

- It will require a larger cathodic protection system that is capable of delivering a higher current. Such as system would require increased power consumption and may require larger and more closely spaced anode ground beds thereby increasing the Mainline's footprint;
- The higher current demand required from the CP system would increase the risk of interference of the Alaska LNG cathodic protection system with other systems, including the system protecting the existing TAPS pipeline;
- The lower coating integrity of an FBE system is expected to increase the risk of external corrosion in service, requiring an increased number of repairs in service to maintain pipeline safety;
- The greater susceptibility to damage during transportation would require a greater number of coating repairs to be performed during construction.

b. Proposed Action Alternative – Construct and operate the pipeline using 3LPE coating in compliance with the Special Permit conditions, which contain requirements for the qualification and testing of the coating system, as well as assessment of stress corrosion cracking during operation.

---

corrosion.com/Technical%20Papers/Dual-layer%20fusion-bonded%20epoxy%20(FBE)%20coatings%20protect%20pipelines.pdf

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

The Special Permit application proposes allowing the use of 3LPE coatings in pipeline segments subject to the requirements of 49 C.F.R. § 192.112: AMAOP and SBD segments.

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

49 C.F.R. § 192.112 (f), which states that the pipe must be protected against external corrosion by a "non-shielding" coating.

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

Except for the design of the coating system itself, the only change to the pipeline design under the SP would be to the cathodic protection system. Under both the SP and the no-action alternative, the cathodic protection system would be designed to deliver sufficient current to prevent corrosion of the pipe steel at locations where coating damage exposes the bare steel of the pipeline ("holidays"). However, the no-action alternative would require an increased current capability due to the greater number of holidays in the as-built condition and more rapid coating degradation. To obtain this higher current capacity, the size and number of anode groundbeds would need to be increased. In some cases, this may require additional power generation facilities in remote locations.

The approach to operation and maintenance of the pipeline is expected to be similar under the SP than under the no-action alternative. Similar approaches to monitor coating condition and cathodic protection system performance would be utilized, and similar inspections for corrosion damage would be performed. Since a greater number of coating holidays and more rapid coating degradation are expected under the no-action alternative, it should be anticipated that, over the life of the pipeline, a greater number of repairs will need to be performed for the no-action alternative with the commensurate increase in ground disturbance along the pipeline route.

a) *What mill applied and field joint coatings systems are being proposed for use?*

Three layer polyethylene (3LPE) is proposed as the mill applied coating system for the majority of the pipeline. 3LPE consists of a FBE layer, a copolymer adhesive layer and a polyethylene outer layer. The polyethylene outer layer is commonly applied by extrusion, but one available system uses a powder applied outer layer. This is the only coating system that is subject to the Special Permit.

For trenchless installations the use of FBE with ARO is planned due to its superior lubricity which results in less coating damage in this application.

A liquid applied epoxy urethane field joint coating system is planned. Fusion bonded epoxy field joint coatings may also be considered. To ensure good bonding to the 3LPE coating, there will be an FBE ‘tail’, with the outer polyethylene layer removed, at the end of each pipe joint. The field joint coating system will bond to this FBE tail. Small repairs can be heated using a hot melt adhesive if the FBE base coat is intact; if FBE base coat is damaged, then entire joint must be re-coated.

b) How do these proposed coating systems different from those used historically to coat pipelines, to include FBE?

Numerous coating types have been used to coat pipelines historically including coal tar enamel, asphalt enamel, adhesive backed polyethylene tapes and dual layer polyethylene, FBE and three layer polyolefin coatings, a class of coatings that includes 3LPE. However, issues with the long term performance of other systems have led to FBE and 3LPE being the predominant systems that are currently selected for new pipeline systems.

The first layer of the 3LPE is similar to an FBE coating. The FBE layer in a 3LPE system can be somewhat thinner (10 mils minimum dry film thickness for the Alaska LNG Project) than a standalone FBE system (typically 12-15 mils minimum dry film thickness) because the outer layers of the 3LPE system provide protection to the inner FBE layer. The proposed 3LPE system includes a copolymer adhesive layer and an outer polyethylene (PE) layer in addition to the FBE layer. The PE outer layer is designed to provide increased impact and damage resistance, while the copolymer adhesive ensures good bonding between the FBE and PE.

The proposed field joint coating systems, described above, are the same systems that would be considered if FBE was to be used as the coating system. Figure 1 shows a summary of recent coating system installations worldwide.

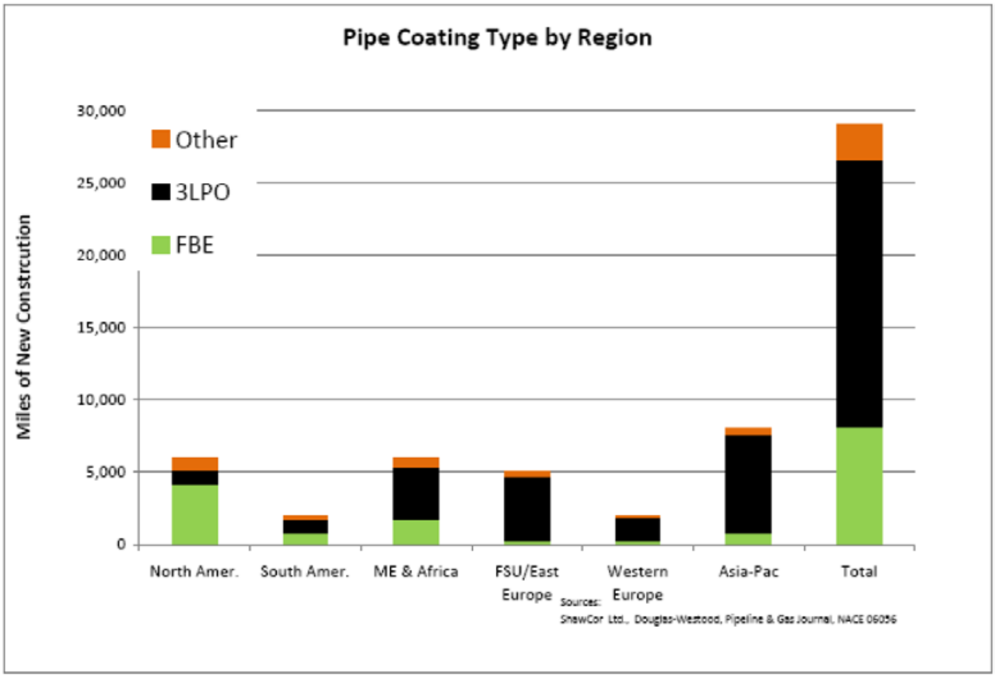


Figure 1: Global Coatings Market Share by Region (Buchanan, 2013)

c) *What are the pros and cons for a 3LPE system in Alaska?*

The pros and cons for a 3LPE system in Alaska as compared to FBE are included in Table 1, where green is a "pro", red is a "con", and tan is "neutral".

d) *Does CP work with 3LPE Coatings?*

See Attachment D, Section 2 for more information on cathodic protection and its effectiveness under various disbondment scenarios.

e) *Are over the line techniques (DCVG, CIS, etc.) effective with 3LPE coatings? Is there anything different with 3LPE coatings that would impair the resultant over the line data? What will these techniques find, and miss with 3LPE (e.g. disbondment vs. break in coating)?*

The same over the line inspection techniques that are utilized for FBE are equally effective with 3LPE. For any coating system, over the line inspection coupled with in-line-inspection is the most effective way to inspect and monitor for coating integrity and corrosion. See Attachment D, Section 6 for further discussion of the utility of over-the-line surveillance techniques with 3LPE coated pipelines.

f) What In-Line Inspection technology will be used to detect SCC?

Electromagnetic Acoustic Transducer (EMAT) in-line inspection tool will be run to inspect for SCC. Additional details on Integrity management for SCC can be found in the SP Conditions in Attachment B.

	FBE	3LPE
Damage Resistance	Susceptible to damage from transport/backfill and UV degradation	High resistance to damage from transport/backfill and UV degradation
Long term integrity	Higher rate of coating degradation; higher reliance on cathodic protection for integrity	Long-term coating integrity (lower rate of coating degradation); low reliance on supplementary cathodic protection for integrity
CP System	High current requirement; special design considerations required to avoid imposing/experiencing stray current corrosion.	Low current requirement; low risk of imposing/experiencing stray current corrosion
	Additional groundbeds would be required at sites without power → Lager footprint, increased emissions	Groundbeds located at compressor stations
Most common failure modes	Cracking, perforations, blisters; not prone to delamination if properly applied	Perforations; not prone to delamination if properly applied.
Potential for shielding CP	Low; FBE is generally conductive when moisture is present in soil	Low; 3LPE is insulating, but works effectively with CP system. Worst case delamination scenario results in limited localized corrosion detectable by regular ILI-MFL inspection.
Experience	Good (extensive use worldwide)	Good (extensive use worldwide)
Potential for SCC	None	None
Coating Repairs	Repairs in and around the trench during construction will be necessary (increased safety exposure)	Excellent mechanical damage resistance; few coating repairs anticipated
Coating Cost	Relatively inexpensive	About double the cost of FBE
Field Joint Coatings	Liquid epoxy polyurethane system	Liquid epoxy polyurethane system
Aboveground Assessment	Can detect coating damage that poses risk of corrosion	Can detect coating damage that poses risk of corrosion

Table 1. Pros and Cons of FBE and 3LPE for application in Alaska

Green = Pro   Yellow = Neutral   Red = Con

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

The Special Permit Segments for the use of 3LPE coatings (below) include the entire onshore portion of the Alaska LNG Mainline in Class 1 locations. This would encompass MP 0 to MP 766, and MP 793 to pipeline terminus at MP 806.57 for Route Rev. C2.

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

v. Mitigation Measures

Additional mitigation measures are addressed in Section VII of this document and the Special Permit Conditions.

The mitigation measures planned will focus on achieving a high quality coating with equal or better adhesion to the pipe as stand-alone FBE.

In addition, mitigation will address the risk of SCC. SCC is a risk associated with tape wrap, coal tar enamel and asphalt coatings, but not FBE coatings. No instances of SCC on pipelines coated with 3LPE are known to date. However, experience with long term use of 3LPE over periods greater than 20 years is limited. As a result, the Alaska LNG pipeline will be monitored for the occurrence of SCC through use of EMAT once the pipeline is in service.

IV. Environmental Impacts of Proposed Action and Alternatives

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

The following consideration of the potential impacts of small and large pipelines leaks/ruptures to the environment/human health apply equally to the proposed action and primary no-action alternatives, given that they both have a below-ground design basis.

i. Any discussion of leak or rupture consequence must be put into the context of its probability. It is highly unlikely that a leak or rupture will occur in the Alaska LNG mainline for the following reasons:

   a) Remoteness of the pipeline route: more than 99% of the Mainline route is in Class 1 location (801.0 miles of 806.6 miles). The frequency of incidents is significantly less for pipelines in Class 1 locations than in Class 2, 3 or 4[4].

   b) Resilience to third party mechanical damage: there is very low risk of mechanical damage given the remoteness of the pipeline and the high thickness of the pipeline. However, fracture mechanics calculations have shown that the pipe is very resistant to fracture, capable of withstanding a through wall thickness puncture of greater than 4” in length without rupturing for Class 1 locations of the pipeline designed with AMAOP, and even longer lengths for the SBD segments and higher Class locations. Through wall thickness punctures of 4” or less would result in a leak. If rupture did occur, the pipe will be designed to prevent a propagating fracture.

   c) Very low probability of internal corrosion damage: the Mainline will be transporting a dry, LNG specification gas, thereby minimizing the probability of internal corrosion. To ensure the integrity of the pipeline, the inline inspection program will comply with the robust requirements of § 192.620. External corrosion will be mitigated by using a high integrity coating, and with a cathodic protection system.

   d) Compliance with AMAOP requirements: the entire Mainline will be operated and maintained per § 192.620. Additionally, more than 615 miles of the total Mainline length will also comply with § 192.112 and § 192.328.

ii. A small leak from a buried pipeline would result in a gradual release of gas, with the total amount of gas being released dependent on the time it takes for the leak to be detected and fixed. Small leaks would primarily be identified through mass balance systems incorporated in gas pipeline control. Gas from a small leak would permeate through the backfill material (soil) before dissipating into the air. Small gas pipeline leaks may result in some impacts to, or loss of, surrounding vegetation. This localized browning of

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

vegetation can facilitate identification of small underground leaks during right of way inspection, which will be performed at intervals not exceeding 45 days, but a least 12 times each calendar year, as per§ 192.620). Other visual techniques are available including inspection of snow pack (seasonal).

iii. A rupture would result in the rapid release of a large volume of natural gas resulting in significant damage to the pipeline, and would create a trench or crater in the immediate vicinity of the rupture. If an ignition source is present, an intense fire or explosion would result. For a fire resulting from a rupture; the damage due to the fire would depend on the extent of the combustible materials in the vicinity, (infrastructure, vegetation), and local environmental conditions, (e.g., rain, snow cover, etc.). The probability for personnel injury and property damage is relatively small for this largely remote pipeline, and decreases as distance from the rupture increases. The potential impact radius (PIR), which is defined as the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property, is 1466 ft. The pipeline will be sectionalized with mainline block valves and the gas released during a rupture scenario would be limited to the gas inventory between valves. The spacing between the block valves is the subject of a Main Line Block Valve Special Permit. This Special Permit includes automatic shut-off valves and remote controlled valves for line break detection and automatic valve closure. Large ruptures would be easily detectable through monitoring of pressure and flow conditions at pipeline facilities.

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

   i. The anticipated differences in effects for individual resources between the No Action alternative and the Proposed Action alternative are discussed below. The differences are negligible. References are made to FERC Resource Reports, where applicable, for further detailed information and analysis of impacted resources. The basis for the FERC Resource Reports is the Proposed Action Alternative; however, the associated environmental impact analysis is also applicable to the No Action alternative, given both alternatives are based on below ground design and installation, and both follow an identical route.

1. Human Health and Safety

Given that both alternatives have a below ground design basis, there is negligible difference in human health and safety impacts between the between the No Action and Proposed Action alternatives. A buried pipeline has the advantage of being less likely to be damaged by:

- Heavy equipment being transported cross country, especially under winter whiteout conditions;
- Intentional or unintentional bullet strikes such as happened to the Trans-Alaska Pipeline in 2001;[5]

Avalanches in the high narrow valleys of the Alaska Range Crossing -The pipeline route through the permafrost areas is extremely remote, with human use consisting primarily of subsistence and recreational hunting and related activities. As such, the potential for people to be impacted by a gas release and potential subsequent explosion and fire is low.

Pipeline design and operational safety is covered in detail in FERC Resource Report 11 (Reliability and Safety).

2. Air Quality

There would be no significant difference in emissions between the No Action and Proposed Action alternatives. The majority of heavy equipment required for construction in either alternative will be the same, including equipment such as brushers and bulldozers for the clearing and leveling of the ROW, trucks for transporting pipe, and sidebooms and welding trucks for pipe placement and welding. Increased power generation would be required for the no action alternative given its larger cathodic protection system, although this is not likely to significantly increase overall emissions. O&M activities to maintain the pipeline for the No Action and proposed Action alternatives would require similar equipment and personnel.

Detailed description of air emissions, including greenhouse gas emissions, from pipeline construction and operations are contained in FERC Resource Report 9 (Air and Noise Quality).

3. Aesthetics

[5] https://dec.alaska.gov/spar/ppr/docs/report/aft_comp.pdf

There would be no difference in visual effects between the No Action and Proposed Action alternatives. Visual effects from both would be limited to the ROW clearance, which would be less obvious with winter snow cover.

Analysis of potential impacts to aesthetics, and associated mitigations, from a below ground pipeline are considered in FERC Resource Report 8 (Land Use, Recreation and Aesthetics).

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

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

FERC Resource Report 3 (Fish, Wildlife and Vegetation) contains descriptions of vegetation and wildlife resources, and potential impacts associated with the Mainline route. FERC Resource Report 2 contains a detailed analysis of wetlands affected by the Mainline route, and mitigation of impacts.

5. Resilience and Adaptation

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

FERC Resource Report 9 (Air and Noise Quality) discusses greenhouse gas emissions from the Project.

6. Cultural Resources

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

7. Environmental Justice

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

8. Geology, Soils and Mineral Resources

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

- The use of winter construction in areas of inundated and frozen ground conditions;
- Use of settlement basins, silt fences, and other Best Management Practices (BMP) for storm water control;
- Use of engineered flow diversions and slope breakers to control water flow on slopes and around water courses; and
- Installation of trench breakers to address storm and groundwater flow through the trench backfill or during construction.

Operations and maintenance activities along the pipeline right-of-way to meet 49 CFR Part 192 would be similar for the two alternatives. All O&M excavations would be conducted as authorized under the applicable ROW authorization. ROWs would be issued by one or both of the Bureau of Land Management and Alaska Department of Natural Resources as the land management agencies responsible for lands along the pipeline route. All excavations and other applicable activities would be permitted through the appropriate Federal and State agencies for both alternatives. Both alternatives would have similar impacts on soil resources.

A more detailed discussion of impacts to soils and erosion resulting from the pipeline construction and the potential mitigation measures to address those impacts is contained in FERC Resource Report 7 (Soils). FERC also has a standard Upland Erosion Control, Revegetation and Maintenance Plan, to which the Alaska LNG Project has proposed alternative measures that will be subject to FERC approval.

9. Indian Trust Assets

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

10. Land Use, Subsistence, and Recreation

There would be no difference in the effect on Land Use, Subsistence, and Recreation between the No Action and Proposed Action Alternatives. During construction, land use in the form of subsistence activities and recreation for both alternatives could be altered in the immediate vicinity of activities. The pipeline’s remote location combined with the relatively small width of the ROW would generally limit the extent of displacement by users to the active construction zones. Construction activities would be timed to avoid potential use conflicts with portions of the trail used during the annual Iditarod sled-dog race.

After construction, the ROW would be graded and revegetated to a stable condition. No long term linear access along the pipeline alignment is proposed. However, under either alternative, PHMSA regulations will require that the pipeline ROW is brushed to prevent the growth of large vegetation over and around the pipeline to maintain a clearly defined ROW.

FERC Resource Report 8 (Land Use, Recreation and Aesthetics) considers potential effects to land use and recreation activities. FERC Resource Report 5 (Socioeconomics) considers potential impacts to subsistence.

11. Noise

There would be no difference in Noise Impacts between the No Action and Proposed Action Alternatives. Impacts would generally be limited to the sounds of construction equipment operations; human use of the area is transient and limited resulting in a relatively short duration of effect, (transiting the area). Wildlife could also be affected by construction-related noise. Noise related to operation of the pipeline itself would primarily result from operation of compressor and heater stations, and periodic ROW maintenance and inspection activities. Compression requirements are the same for both alternatives, so there is no change to the number of compressor and heater stations and the associated noise profile.

A detailed discussion of noise impacts associated with pipeline construction and operation is provided in FERC Resource Report 9 (Air and Noise Quality).

12. Water Resources

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

A detailed discussion regarding the management of water during construction and operation of the pipeline and impacts to ground and surface water flow and quality resulting from the construction and operation of the pipeline is presented in FERC Resource Report 2 (Water Use and Quality).

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

i. What factors were considered to ensure the conditions are adequate to protect against waiving protections of the code.

The successful use of either FBE with ARO coating or 3LPE coating systems requires that coating application, inspection and quality assurance procedures lead to a high quality coating with good adhesion of the coating to the pipe. Similarly, field joint coatings must be compatible with the coating system and the quality of the field joint coating must be ensured.

The function of a coating system is to protect the pipeline from corrosion. The effect of coating type on susceptibility to corrosion and stress corrosion cracking was also considered.

ii. What are the safety and environmental risks from usage of 3LPE that need to be protected against?

The safety and environmental risks associated with the Proposed Action would result from a change to the risk of a leak or rupture and the subsequent release of gas and possible explosion or fire. The risk of leak or rupture can be affected by coating performance because external corrosion and stress corrosion cracking are failure mechanisms that require failure of the coating. Due to its superior coating integrity, the use of 3LPE as outlined in the Special Permit is expected to have a positive impact on pipeline safety. To ensure that this benefit is achieved, it is necessary to ensure that coating application procedures are qualified and that adequate quality control is applied.

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

i. The conditions were designed to ensure that best practices and application, testing and quality control for plant applied and field joint coating are applied.

The conditions were designed to reduce the risk of SCC. Although there is no history that indicates that pipelines coated with 3LPE are susceptible to SCC, EMAT in-line inspection is required by the conditions to ensure that this threat would be detected before it would lead to leak or rupture of the pipeline. The use of the above measures helps to ensure that no significant environmental impact will result from the use of 3LPE. It is anticipated that the higher initial coating integrity and reduced rate of coating degradation with the use of 3LPE will lead to an overall improvement in pipeline safety and reduce potential environmental impact.

ii. Figure 2 shows historical information of 3LPO coating systems installed by ShawCorr, which indicate long term installations of the systems as well as a significant increase in installation of three-layer systems in the past 10 years.

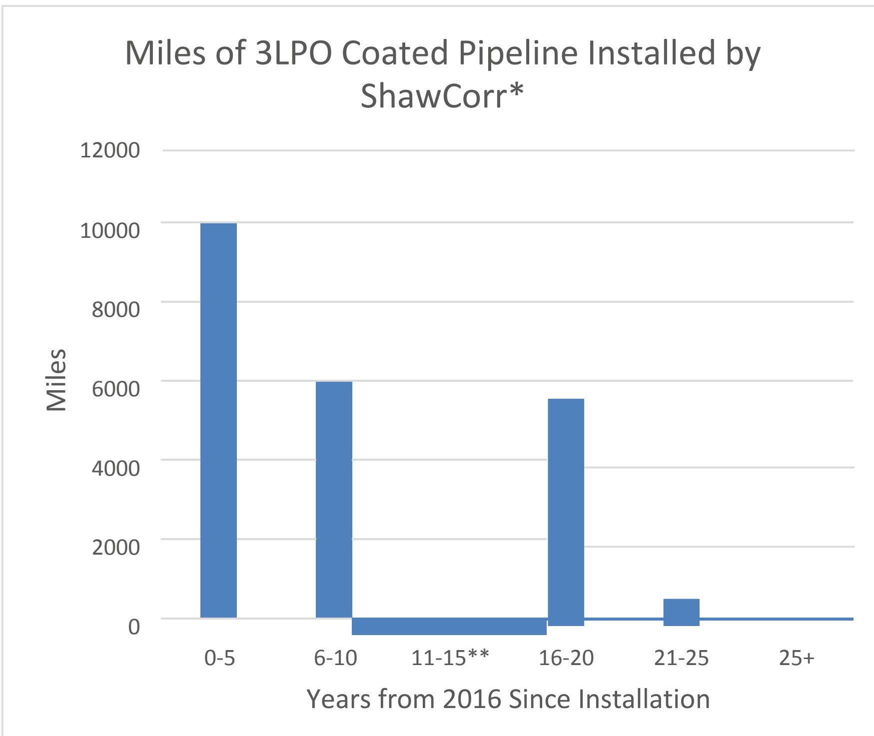
iii. 

Figure 2: Three-layer polyolefin pipeline coating length applied by ShawCorr

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

Use of 3LPE will reduce the risk of a pipeline leak or rupture through a higher integrity coating more resistant to mechanical damage and a reduced reliance on active external corrosion methods such as cathodic protection, but coating type has no effect on the consequences of a leak or rupture. Under either the Proposed Action or the No Action alternative, the consequences of a pipeline failure would be similar.

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

Implementation of the special permit will positively impact pipeline longevity and reliability due to the reduced rate of coating degradation expected for 3LPE coatings.

The approach for integrity management and maintenance of the pipeline is similar for the proposed action and no-action alternatives. In either case, in-line inspection, cathodic protection system monitoring, and coating condition surveys will be performed at the same frequency to identify any required maintenance activities. It is anticipated that fewer repairs in service will be required over the life of the pipeline with a higher integrity 3LPE coating system.

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

Several layers of protection are utilized to prevent pipeline failures due to corrosion:

i. The coating system prevents external corrosion by acting as a barrier between ground water, oxygen, and the steel pipe.

ii. The cathodic protection system prevents corrosion at any breaks in the coating.

iii. In-line inspection detects wall loss and cracking type defects allowing repair before failure.

The use of 3LPE is expected to positively impact the effectiveness of the first two items above. Reduced coating damage and slower coating degradation will lead to fewer coating defects. The higher integrity of the 3LPE coatings will lead to reduced current demand on the cathodic protection system and reduced risk of interference with neighboring structures. Thus, the Special Permit is expected to improve human safety by reducing the overall likelihood of failure and the potential for injury from the resulting release of gas.

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

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

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

The no action alternative may require an increased size and number of anode ground beds to accommodate the higher CP current requirements of an FBE coating pipeline. Implementation of the Special Permit will not affect any other pipeline facilities, public infrastructure, or environmentally sensitive areas.

j. *What scenario would be required for CP shielding leading to corrosion or SCC to occur? How likely are these scenarios?*

See Attachment D, Sections 3 and 4 for a discussion of shielding and SCC scenarios.

k. *Based on industry experience, 1) has SCC occurred with 3LPO coatings and what 2) mitigation and 3) detection techniques will be employed?*

1) Industry and operator experience has not identified any instances of SCC with 3LPO coatings. See Attachment D, Section 9 for a summarized record of Alaska LNG Project's discussions with various pipeline operators. In addition, the Alaska LNG Project contracted DNV GL to perform a search of world-wide literature and pipeline operator data and did not identify any instances of SCC with 3LPE coatings.

2) Mitigation: Stringent quality assurance and quality control (QA/QC) measures will be employed during 3LPE coating application. The surface will be prepared by abrasive grit blasting, which imparts a compressive stress on the surface of the metal that is recognized to provide resistance to SCC. See Attachment D, Section 5 for more information on the QA/QC of 3LPE coatings.

3) Detection: EMAT will be utilized as a means of SCC crack detection.

l. *What survey techniques will be used during Operations?*

The same survey techniques will be used during the construction and maintenance of 3LPE as with any other coating system:

- DCVG and CIPS as part of commissioning the cathodic protection system as well as ongoing surveillance.
- ILI baseline upon commissioning and ongoing inspection in accordance with 49 CFR 192 Subpart O.

m. What is the threat from interference initiated corrosion (e.g. AC interference, DC interference, stray current, tellurics) and how do we plan to monitor and mitigate it?

Interference assessment and mitigation is a standard aspect of cathodic protection design, and will be addressed by the Alaska LNG Project during its detailed engineering stages. Each type of interference (stray current, AC interference, and tellurics) will be individually evaluated and mitigated, as follows.

Stray current interference will be mitigated primarily by one or more of the following methods:

- selection of ground bed location – ensuring that ground beds are a safe distance from foreign structures (including other pipelines). Stray current considerations are a fundamental aspect of detailed CP design, particularly ground bed design and location.
- resistive bonding. Where the potential for stray current cannot be practically mitigated by ground bed design/location, resistive bonding may be installed between the pipeline and the foreign structure. Resistive bonding is a standard, common mitigation method.
- dielectric shielding. Electrically insulating material (e.g., robust coating) may be considered near known pipeline crossings to lower the risk of stray current interference.

AC interference will be a consideration when the Mainline ROW is in close proximity to overhead powerlines. Problematic locations will be identified and evaluated during the detailed engineering stage of the Project. AC mitigation systems will be installed in locations with identified AC interference issues. A common approach is to bury sacrificial anodes to “drain” off AC signals.

Telluric currents can form in long buried electrical conductors, such as pipelines. Telluric currents are induced by placing the conductor in the earth’s magnetic field. Tellurics are not usually a direct integrity concern for a pipeline. More commonly, tellurics are a nuisance, periodically disrupting CP monitoring and control systems. For the onshore Mainline, telluric signals will be mitigated by one or more of the following methods:

- grounding – anode beds can be used to drain telluric currents to ground
- IC rectifiers and associated ground beds – rectifiers of sufficient capacity can be installed to dampen current swings driven by telluric effects

For operational monitoring of CP, test stations will be installed as follows:

- at least once every mile (the need for more frequent test stations will be considered during detailed design in the detailed engineering stage of the Project)
- at any crossing with foreign structures
- at each major river crossing

At a frequency to be determined, coupons will be installed. Coupons are used to determine the amount of voltage gradient (IR drop) in the soil when the CP systems are energized (or connected, in the case of sacrificial anodes). Use of coupons for this purpose is common practice for complex or hybrid CP systems where it is difficult to effectively obtain IR-free potential measurements by cycling the entire CP system on/off at the same time.

Remote monitoring will be installed to provide real time CP operating outputs. The specific products and frequency of installation of these systems will be determined in future Project engineering phases.

V. Consultation and Coordination

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

Preparers: Alaska LNG LLC – Rick Noecker (PHMSA Filing Coordinator), Alyssa Samson (Materials Engineer), Mario Macia (Pipeline Technology Lead), Norm Scott (ERL Advisor).

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

Adjacent landowners/land managers potentially impacted: Alaska LNG to update

Cook Inlet Region, Inc.
Jason Brune
Sr. Director, Land and Resources
PO Box 93330
Anchorage
AK 99509
(907) 263-5104.

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

Alaska Department of Natural Resources
Jason Walsh
State Pipeline Coordinator
3651 Penland Parkway
Anchorage
AK 99508
(907) 269-6419.

Alaska Dept. of Transportation & Public Facilities
David T Bloom
Gasline Liaison
2301 Peger Road
Fairbanks, AK 99709
(907) 451-5497.

Brooke Merrell
Transportation Planner
United States National Park Service, Alaska Regional Office
240 W 5th Ave
Anchorage
AK 99501
(907) 644-3397.

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

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

Alaska LNG has been active in stakeholder engagement throughout Alaska. As well, Federal, state and local agency engagement is ongoing. In 2015 and 2016, Alaska LNG held one-on-one as well as multiagency engagement meetings to cover pipeline design construction and routing. Additionally, there have been over 20 engagement meetings between Alaska LNG and PHMSA. The coatings systems described herein were a topic of discussion at multiple meetings, and Alaska LNG has responded to several requests for additional information on coatings systems that were made by PHMSA. Additionally, an overview of this Special Permit was provided at a joint meeting with PHMSA and FERC on 19 April 2016.

PHMSA has participated in scoping and public outreach lead by FERC related to the Alaska LNG FERC Resource Reports. Details of the public outreach, which included both members of tribal entities and the general public, are provided in Section 1.9 and Appendix D of Resource Report 1of the FERC Resource Reports.

VI. Bibliography

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

See footnotes.

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

a. *Plant-applied coating system qualification and testing: What will be done to ensure the long-term integrity of the coating and the disbondment failures will not occur?*

To ensure that the integrity benefits of 3LPE coatings are achieved, the conditions require that best practices are applied to the qualification of the coating system. The qualification will require that each plant used for the application of coatings be qualified separately. The qualified coating procedure and qualification testing must reflect the industry best practices that are included in ISO 21809-1[6], a global standard for three layer polyolefin coatings. Periodic testing during coating application (production testing) ensures that the properties achieved during qualification continue to be achieved.

Per this standard, the coating application procedure must include details on the following:

a) Incoming inspection of pipes and pipe tracking.

b) Data sheets for coating materials and abrasive blasting materials.

c) Certification, receipt, handling and storage of materials for coating and abrasive blasting.

d) Cleaning procedure for all application equipment.

e) Preparation of the steel surface including monitoring of environmental parameters, methods and tools for inspection, grinding of pipe surface defects and testing of surface preparation.

[6] ISO 21809-1 (2011) Petroleum and natural gas industries - External coatings for buried or submerged pipelines used in pipeline transportation systems Part 1: Polyolefin coatings (3-layer PE and 3- layer PP)

f) Coating application, including tools/equipment for control of process parameters essential for the quality of the coating.
g) Methods and tools/equipment for inspection and testing of the applied coating.
h) Repairs of coating defects and any associated inspection and testing.
i) Preparation of coating cutback areas.
j) Marking and traceability.

Qualification and production testing required by ISO 21809-1 includes:

- Inspection of surface preparation.
- Minimum epoxy thickness.
- Minimum adhesive thickness.
- Degree of cure.
- Continuity (holiday detection).
- Total thickness of coating.
- Impact resistance.
- Peel strength.
- Indentation.
- Elongation at break.
- Cathodic disbondment.
- Hot water immersion test.
- Flexibility.

b. *Field Joint coating system qualification and testing: What will be done to ensure the long-term integrity of the field joint coating?*

Field joint coating systems are used to coat girth welds made in the field and the adjacent pipe ends. Ensuring the success of the coating system requires that the field joint coating system achieve high integrity and that the field joint coating system is compatible with the plan applied system. The conditions require the qualification of the field joint coating procedure that will be used.

The conditions require that the field joint coating application procedure describe the following:

- Method for surface preparation and required surface profile.
- Method for heating the pipe and monitoring temperature.
- Nominal steel temperature for application of field joint coating and permitted range.
- Manufacturer and brand name of product.

- Method and equipment for application of coating.
- Minimum dry film thickness.
- Method for holiday detection and repair.

The required field joint coating qualification tests include:

- Impact resistance testing.
- Hot-water soak/adhesion testing.
- Penetration resistance testing.
- Cathodic disbondment testing.

In addition, the conditions require verification of the coating thickness on each field joint and holiday detection for each field joint.

c. Inspection and qualification of inspectors: What will be done to ensure the qualifications of inspectors?
The conditions require that coating and field joint coating operations are monitored by certified coating inspectors.

d. What measures will be employed to detect SCC, if it were to occur?

There have been pipeline integrity issues due to stress corrosion cracking resulting from the use of tape wrap, coal tar enamel, and asphalt coatings. Failures of these coatings have occurred in a manner that has allowed ground water and oxygen to reach the pipe steel surface, but blocked cathodic protection current (i.e. caused "CP shielding"). The proposed 3LPE coating system is a modern coating system that has not been associated with the occurrence of similar issues. However, there is limited experience with 3LPE service times greater than 20 years. The conditions contain provisions that ensure that the threat of SCC will be assessed throughout the life of the pipeline to ensure that if long term (i.e. 20+ years) use of these coatings leads to increased susceptibility to SCC, the threat will be identified and managed before it leads to leaks or ruptures of the pipeline.

The conditions require periodic inline inspection with a crack detection tool to identify whether SCC is an integrity threat to the Alaska LNG pipeline. Electromagnetic Acoustic Transducer (EMAT) tools are the crack detection tool required by the Conditions.

Because SCC cracks take 10+ years to form, it should also be understood that by the time Alaska LNG's pipelines reach an age at which SCC could begin to develop, significant additional industry experience will be available with longer term use of 3LPE coatings. As a result, there will be a substantial global experience base available to identify whether 3LPE coated pipelines are susceptible to SCC and this additional knowledge will be available to further inform assessments of the risk of SCC.

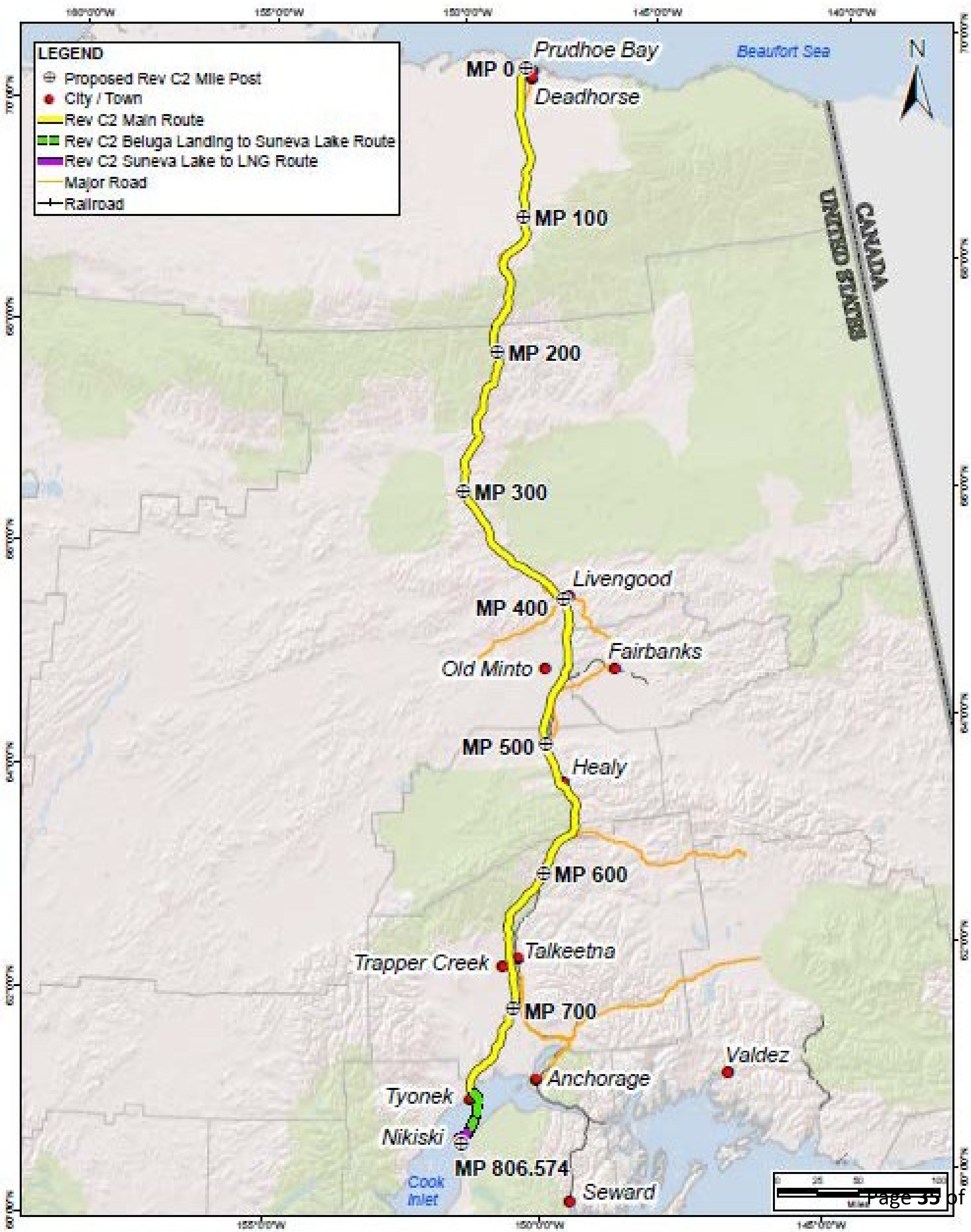

LEGEND
Proposed Rev C2 Mile Post
City / Town
Rev C2 Main Route
Rev C2 Beluga Landing to Suneva Lake Route
Rev C2 Suneva Lake to LNG Route
Major Road
Railroad
Prudhoe Bay
Beaufort Sea
N
MP 0
Deadhorse
MP 100
CANADA
UNITED STATES
MP 200
MP 300
Livengood
MP 400
Fairbanks
Old Minto
MP 500
Healy
MP 600
Talkeetna
Trapper Creek
MP 700
Valdez
Anchorage
Tyonek
Nikiski
MP 806.574
Cook Inlet
Seward

Figure 3: Mainline Route Map